Section 1: 10-K (MDU RESOURCES 2018 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, 2018

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	30-1133956
(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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	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 29, 2018: $5,621,805,532.

Indicate the number of shares outstanding of the registrant's common stock, as of February 14, 2019: 196,092,274 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2019 Proxy Statement, to be filed no later than 120 days from December 31, 2018, are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Audit Committee	Audit Committee of the board of directors of the Company
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
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
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)
CyROC	Cyber Risk Oversight Committee
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 prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
GVTC	Generation Verification Test Capacity

Definitions

Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
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
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
Non-GAAP	Not in accordance with GAAP
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 2019 Proxy Statement to be filed no later than April 30, 2019
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

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
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. Montana-Dakota was incorporated under the laws of the state of Delaware in 1924. The Company was incorporated under the laws of the state of Delaware in 2018. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

On November 21, 2017, the Company announced that its board of directors had directed senior management to explore reorganization to a holding company structure. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. On November 15, 2018, the board of directors approved the Holding Company Reorganization and authorized senior management to take the necessary and appropriate actions to effectuate the Holding Company Reorganization. On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The merger was conducted pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the stockholders of the constituent corporation. Immediately after consummation of the Holding Company Reorganization, the Company had, on a consolidated basis, the same assets, businesses and operations as Montana-Dakota had immediately prior to the consummation of the Holding Company Reorganization. As a result of the Holding Company Reorganization, the Company became the successor issuer to Montana-Dakota pursuant to Rule 12g-3(a) of the Exchange Act, and as a result, the Company's common stock was deemed registered under Section 12(b) of the Exchange Act.

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-mixed 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 business 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.

The Company, through its wholly owned subsidiary, MDU Energy Capital, owns Montana-Dakota, Cascade and Intermountain. Montana-Dakota, Cascade and Intermountain are 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.

For more information on the Company's business segments, see Item 8 - Note 15.

As of December 31, 2018, the Company had 11,797 employees with 218 employed at MDU Resources Group, Inc., 1,004 at Montana-Dakota, 338 at Cascade, 242 at Intermountain, 317 at WBI Holdings, 3,967 at Knife River and 5,711 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, 2018.

At Montana-Dakota and WBI Energy Transmission, 349 and 70 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2021, and March 31, 2022, respectively.

At Cascade, 197 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2021.

At Intermountain, 130 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 673 of its construction materials and contracting employees. Knife River is in negotiations on five of its labor contracts.

MDU Construction Services has 126 labor contracts representing the majority of its employees. MDU Construction Services is not currently in negotiations on any 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 15 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and 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.

The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology systems and network infrastructure. These systems may be vulnerable to failures or unauthorized access. The Company has policies, procedures and processes in place designed to strengthen and protect these systems, which includes the Company's enterprise information technology and operation technology groups continually evaluating new tools and techniques that can be implemented to reduce the risk of a cyber breach.

The Company created CyROC to oversee the Company's approach to cybersecurity. CyROC is responsible for supplying management at all levels and the Audit Committee with analyses, appraisals, recommendations and pertinent information concerning cyber defense of the Company's electronic information and information technology systems. CyROC provides a quarterly cybersecurity report to the Audit Committee. For a discussion of the Company's risks related to cybersecurity, 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 143,022 residential, commercial, industrial and municipal customers in 184 communities and adjacent rural areas in Montana, North Dakota, South Dakota and Wyoming as of December 31, 2018. 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 two 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 75 transmission and 297 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, 2018, Montana-Dakota's net electric plant investment was $1.5 billion and rate base was $1.2 billion.

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

	2018		2017		2016	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**118,426**	**$ 126,173**	118,379	$ 121,171	118,483	$ 117,014
Commercial	**22,756**	**141,961**	22,764	140,856	22,693	135,390
Industrial	**236**	**36,081**	242	34,417	244	31,913
Other	**1,604**	**7,882**	1,516	8,275	1,528	7,580
	143,022	**$ 312,097**	142,901	$ 304,719	142,948	$ 291,897

Other electric revenues for Montana-Dakota were $23.0 million, $38.1 million and $30.4 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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

	2018	2017	2016
North Dakota	**66%**	66%	68%
Montana	**20%**	20%	19%
Wyoming	**9%**	9%	8%
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 certain 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, eastern Montana and northern South Dakota. The interconnected system consists of 15 electric generating units at 10 facilities and two small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 750,318 kW and total net ZRCs of 532.3 in 2018. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2018, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 574.5. Montana-Dakota's planning reserve margin requirement within MISO was 537.2 for 2018. 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 2023 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 two small portable diesel generators.

In June 2016, Montana-Dakota and a partner began construction on the BSSE project within the footprint of MISO. Montana-Dakota began bringing the project on-line on February 5, 2019. On October 31, 2018, the Company finalized the purchase and placed into service the Thunder Spirit Wind farm expansion in southwest North Dakota, which includes 16 turbines. With the addition of the expansion, the total Thunder Spirit Wind farm generation capacity is approximately 155 MW. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. For more information on these projects, see Item 7 - MD&A - Electric and Natural Gas Distribution.

Additional energy is purchased as needed, or in lieu of generation if more economical, from the MISO market, and in 2018, Montana-Dakota purchased approximately 22 percent of its net kWh needs for its interconnected system through the MISO market.

Approximately 21 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2018 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 approximately 24 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 63,686 kW in July 2018. 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)	2018 ZRCs (a)	2018 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	80.8	765,233
Heskett	Steam	86,000	87.4	504,357
Heskett	Combustion Turbine	89,038	61.6	3,981
Glen Ullin	Heat Recovery	7,500	4.8	44,940
Cedar Hills	Wind	19,500	4.4	49,933
Diesel Units	Oil	3,650	3.6	6
Thunder Spirit	Wind	155,500	21.1	407,947
South Dakota:				
Big Stone (b)	Steam	94,111	103.8	521,187
Montana:				
Lewis & Clark	Steam	44,000	50.3	235,882
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	16.7	8,497
Glendive	Combustion Turbine	75,522	70.6	2,734
Miles City	Combustion Turbine	23,150	21.6	273
Diamond Willow	Wind	30,000	5.6	86,103
		750,318	532.3	2,631,073
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	209,280
		778,318	532.3	2,840,353

(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 19.

The owners of Big Stone Station, including Montana-Dakota, have a coal supply agreement with Peabody COALSALES, LLC to meet all of the Big Stone Station's fuel requirements for 2019 and 2020, with the exception of 250,000 tons in 2019, which was previously committed to be purchased from Contura Coal Sales, LLC, all at contracted pricing.

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,	**2018**	2017	2016
Average cost of coal per MMBtu	$ 2.00	$ 2.07	$ 1.89
Average cost of coal per ton	$ 29.08	$ 30.04	$ 27.45

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 2028. Future capacity that is needed to replace contracts, generation retirements 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's 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 on regulatory assets and liabilities, see Item 8 - Note 6.

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 organizations serving parts of Montana-Dakota's system, 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 organizations serving parts of Montana-Dakota's system, along with certain of the transmission investments not recovered through retail rates. This tracking mechanism also 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 18.

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

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. 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 2019. 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 2019.

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 very small-quantity generators of hazardous waste 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 $9.2 million of environmental capital expenditures in 2018, mainly for coal ash management projects at Lewis & Clark Station, Big Stone Station and Coyote Station. Environmental capital expenditures are estimated to be $6.8 million, $2.7 million and $1.8 million in 2019, 2020 and 2021, respectively, for various environmental projects, including 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 GHG 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. For more information, see Item 1A - Risk Factors.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Cascade and Intermountain, which sell natural gas at retail, serving 957,727 residential, commercial and industrial customers in 339 communities and adjacent rural areas across eight states as of December 31, 2018, 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 19,400 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2018, the natural gas distribution operations' net natural gas distribution plant investment was $1.7 billion and rate base was $1.1 billion.

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

	2018		2017		2016	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**850,595**	**$ 464,697**	833,255	$ 477,699	818,163	$ 429,828
Commercial	**106,297**	**279,566**	104,795	283,899	103,438	253,333
Industrial	**835**	**24,555**	817	24,030	807	23,337
	957,727	**$ 768,818**	938,867	$ 785,628	922,408	$ 706,498

Transportation and other revenues for the natural gas distribution operations were $54.4 million, $62.8 million and $59.6 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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

	2018	2017	2016
Idaho	**30%**	33%	34%
Washington	**26%**	26%	26%
North Dakota	**15%**	13%	13%
Montana	**9%**	9%	8%
Oregon	**8%**	8%	8%
South Dakota	**7%**	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; western Minnesota; eastern Montana; North Dakota; central and eastern Oregon; western and north-central South Dakota; western, southeastern and south-central Washington; and northern Wyoming. 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, Dominion Energy Questar Pipeline, LLC, 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.

In Minnesota and Washington, Great Plains and Cascade recover in rates through a cost recovery tracking mechanism, qualifying capital investments related to the safety and integrity of its pipeline system.

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 by Cascade 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 for three years. The decoupling mechanism will reflect the period January 1 through December 31. Great Plains intends to seek continuation of the decoupling mechanism effective upon expiration of the pilot project.

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

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

The Company's natural gas distribution operations are very small-quantity generators of hazardous waste, and subject only to minimum regulation under the RCRA. Washington state rule defines Cascade as a small-quantity generator, but regulation under the rule is similar to 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 2018. 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 2021.

Montana-Dakota has 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 19 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 Minnesota, Montana, North Dakota, South Dakota and Wyoming. WBI Energy Transmission's 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 14 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, 2018, its net plant investment was $458.1 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.

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 continues 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 2018 represented 32 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 2018 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

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, South Dakota, 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 its contracting services with its construction materials 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.

During 2018, Knife River acquired construction materials and contracting businesses with operations in Oregon, Minnesota and South Dakota. For more information on acquisitions, see Item 8 - Note 3.

Knife River's backlog was approximately $706 million, $486 million and $538 million at December 31, 2018, 2017 and 2016, respectively. The increase in backlog at December 31, 2018, compared to backlog at December 31, 2017, was primarily attributable to higher backlog of federal and state agency work, as well as higher backlog of private construction projects. 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, 2018, 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, or backlog estimates in general, 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 938 million tons of the 1.0 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales, including estimated sales from acquired reserves prior to acquisition, from 2016 through 2018. 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, 2018, and sales for the years ended December 31, 2018, 2017 and 2016:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)					
Production Area	owned	leased	owned	leased	**2018**	2017	2016	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	—	—	1	—	**725**	1,425	1,343	13,823	N/A	12
Hawaii	—	5	—	—	**1,734**	1,614	1,901	49,159	2023-2064	28
Northern CA	—	—	9	1	**1,798**	1,785	1,604	42,720	2028	25
Southern CA	—	2	—	—	**356**	55	224	91,211	2035	Over 100
Portland, OR	2	4	5	3	**5,402**	4,694	4,044	212,822	2028-2057	45
Eugene, OR	3	4	5	—	**743**	633	662	153,301	2021-2049	Over 100
Central OR/WA/ID	—	1	6	2	**2,362**	2,160	1,685	85,396	2020-2087	41
Southwest OR	5	5	10	6	**2,395**	2,367	2,689	108,998	2021-2053	44
Central MT	—	—	3	1	**1,081**	1,065	1,135	15,238	2023	14
Northwest MT	—	—	9	1	**1,965**	1,745	1,514	63,182	2020	36
Wyoming	—	—	1	2	**626**	613	742	9,466	2019-2020	14
Central MN	1	1	43	7	**2,890**	2,773	2,831	65,225	2019-2028	18 *
Northern MN	2	—	14	2	**369**	270	537	21,062	2020-2021	54
ND/SD	1	—	3	24	**1,506**	1,100	1,643	74,214	2019-2031	17 *
Texas	1	2	1	—	**1,094**	1,192	1,243	8,614	2022-2029	7
Sales from other sources					**4,749**	4,722	3,783			
					29,795	28,213	27,580	1,014,431		

* Includes estimate of three-year average sales for acquired reserves.

The 1.0 billion tons of estimated aggregate reserves at December 31, 2018, are comprised of 518 million tons that are owned and 496 million tons that are leased. Approximately 48 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 2016 through 2018 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 44 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:

	2018	2017	2016
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**965,036**	989,084	1,022,513
Acquisitions (a)	**81,004**	2,726	24,993
Sales volumes (b)	**(25,046)**	(23,491)	(23,797)
Other (c)	**(6,563)**	(3,283)	(34,625)
End of year	**1,014,431**	965,036	989,084

(a) Includes reserves from acquisitions of businesses.
(b) Excludes sales from other sources.
(c) 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 has 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 are also 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 2018 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 2021.

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 19.

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 segment also 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, 2018, MDU Construction Services owned or leased facilities in 18 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:

	2018	2017	2016
	(In millions)		
Inside specialty contracting	$ 814	$ 625	$ 435
Outside specialty contracting	125	83	40
	$ 939	$ 708	$ 475

The increase in backlog at December 31, 2018, compared to backlog at December 31, 2017, 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, 2018, 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, or backlog estimates in general, 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 2018 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

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, customer service, health care coverage and cost, income taxes, property and other taxes, franchises; recovery of purchased power and purchased natural gas costs; construction 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 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 that the Company's electric and natural gas transmission and distribution businesses' costs have been prudent, which could result in disallowance of costs. Also, the regulatory process for approving rates for these businesses may not allow us full recovery of the costs of providing services or a return on the Company's invested capital. 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 that regulators will allow full recovery of all remaining costs, which could leave 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 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 deter potential acquirers from approaching the Company or impact the Company's ability to pursue 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 general economy. State and federal budget issues affect the funding available for infrastructure spending.

Economic conditions and population growth affect the electric and natural gas distribution businesses' growth in service territory, customer base and usage demand. Economic volatility in the markets served, along with economic conditions such as increased unemployment which could impact the ability of our customers to make payments, could adversely affect the Company's results of operations, cash flows and asset values. Further, any material decreases in customers' energy demand, 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, particularly those related to natural gas and electric transmission and distribution, include a variety of inherent hazards and operating risks, such as product leaks, explosions, mechanical failures, vandalism, fires, 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. A significant incident could also increase regulatory scrutiny and result in penalties and higher amounts of capital expenditures and operational costs. Losses not fully covered by insurance could have a material effect on the Company’s financial position, results of operations and cash flows.

A disruption of the regional electric transmission grid or interstate natural gas infrastructure could negatively impact our business and reputation. Because the Company's electric and natural gas utility and pipeline systems are part of larger interconnecting systems, a disruption could result in a significant decrease in revenues and system repair costs which could have a material impact on the Company's financial position, results of operations and cash flows.

The Company is subject to capital market and interest rate risks.
The Company's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. Consequently, the Company relies on financing sources and capital markets as sources of liquidity for capital requirements not satisfied by its cash flows from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans, make capital expenditures or pursue acquisitions that the Company would otherwise rely on for future growth may be adversely affected. Market disruptions may increase the cost of borrowing or adversely affect the Company's 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, or the perception that such an issuance could occur, could have a dilutive effect on shareholders and/or may adversely affect the market price of the Company's common stock. Higher interest rates on borrowings could also have an adverse effect on the Company's operating results.

Financial market changes could impact the Company’s pension and postretirement benefit plans and obligations.
The Company has pension and postretirement defined benefit plans for some of its employees and former employees. Assumptions regarding future costs, returns on investments, interest rates, and other actuarial assumptions have a significant impact on the funding requirements relating to these plans. Changes in economic indicators, such as consumer spending, inflation data, interest rate changes, political developments and threats of terrorism, among other things, can create volatility in the financial markets. Deteriorating financial market conditions could change these estimates and assumptions and 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.

Significant changes in energy prices could negatively affect the Company's businesses.
Fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; supplies of domestic and foreign 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.

If oil and natural gas prices increase significantly, customer demand for utility, pipeline and midstream, and construction materials could decline, which could have a material impact on the Company's results of operations and cash flows. While the Company has fuel clause recovery mechanisms for its utility operations in most of the states in which it operates, higher utility fuel costs could significantly impact results of operations if such costs are not recovered. Delays in the collection of utility fuel cost recoveries, as compared to expenditures for fuel purchases, could have a negative impact on the Company's cash flows. High oil prices also affect the cost and demand for asphalt products and related contracting services. Low commodity prices could have a positive impact on sales but could negatively impact oil and natural gas production activities and subsequently the Company's pipeline and construction revenues in energy producing states in which the Company operates.

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. Events affecting the Company's financial results may impact its cash flows and credit metrics, potentially resulting in a change in the Company's credit ratings. 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.

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 quantities of large individual health care claims and an overall increase in total 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. 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 could also have indirect credit risk from participating 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.
The TCJA significantly reformed 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. Any future guidance, regulation and interpretations to the Internal Revenue Code could have an adverse impact on the Company.

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.

The Company's operations could be negatively impacted by import tariffs and/or other government mandates.
The Company operates in or provides services to capital intensive industries in which federal trade policies could significantly impact the availability and cost of materials. Imposed and proposed tariffs could significantly increase the prices and delivery lead times on raw materials and finished products that are critical to the Company and its customers, such as aluminum and steel. Prolonged lead times on the delivery of raw materials and further tariff increases on raw materials and finished products could have a material adverse effect on the Company's business, financial condition and results of operations.

Operational Risks

Significant portions of the Company’s natural gas pipelines and power generation and transmission facilities are aging. The aging infrastructure may require significant additional maintenance or replacement that could adversely affect the Company’s results of operations.
The Company’s energy delivery infrastructure is aging, which increases certain risks, including breakdown or failure of equipment, pipeline leaks and fires developing from power lines. Aging infrastructure is more prone to failure which increases maintenance costs, unplanned outages and the need to replace facilities. Even if properly maintained, reliability may ultimately deteriorate and negatively affect the Company’s ability to serve its customers which could result in increased costs associated with regulatory oversight. The costs associated with maintaining the aging infrastructure and capital expenditures for new or replacement infrastructure could cause rate volatility and/or regulatory lag in some jurisdictions. If, at the end of its life, the investment costs of a facility have not been fully recovered the Company may be adversely affected if commissions do not allow such costs to be recovered in rates. Such impacts of an aging infrastructure could have a material adverse effect on the Company’s results of operations and cash flows.

Additionally, hazards from aging infrastructure could result in serious injury, loss of human life, significant damage to property, environmental impacts, and impairment of operations, which in turn could lead to substantial losses. The location of distribution mains and storage facilities near populated areas, including residential areas, business centers, industrial sites, and other public gathering places, could increase the level of damages resulting from these risks. A major domestic incident involving natural gas systems could lead to additional capital expenditures, increased regulation, and fines and penalties on natural gas utilities. The occurrence of any of these events could adversely affect the Company’s results of operations, financial position, and cash flows.

The Company's utility and pipeline operations are subject to planning risks.
Most electric and natural gas utility investments, including natural gas pipeline investments, are made with the intent of being used for decades. In particular, electric transmission and generation resources are planned well in advance of when they are placed into service based upon resource plans using assumptions over the planning horizon; including sales growth, commodity prices, equipment and construction costs, regulatory treatment, available technology and public policy. Public policy changes and technology advancements related to areas such as energy efficient appliances and buildings, renewable and distributive electric generation and storage, carbon dioxide emissions, electric vehicle penetration, and natural gas availability and cost may significantly impact the planning assumptions. Changes in critical planning assumptions may result in excess generation, transmission and distribution resources creating increased per customer costs and downward pressure on load growth. These changes could also result in a stranded investment if the Company is unable to fully recover the costs of its investments.

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 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.

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.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.
Severe weather events, such as tornadoes, rain, ice and snow storms and high and low temperature extremes, do occur in regions in which the Company operates and maintains infrastructure. However, climate change could possibly change the frequency and severity of these weather events. 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 may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather may result in decreased revenues. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, 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 temperatures may create high energy demand and raise electricity prices, which could increase the cost of energy provided to customers.

Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could increase costs to repair facilities and restore service to customers. The cost of providing service could increase to the extent the frequency of severe 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, potentially increasing the cost of gas and the ability to procure gas to meet customer demand. These changes could result in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction.

Increases in severe weather conditions or extreme temperature may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects resulting in decreased revenue or increased project costs at the construction materials and contracting and construction services businesses. In addition, drought conditions could restrict the availability of water supplies, inhibiting the ability of the construction businesses to conduct operations.

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 some 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 Company may also be subject to litigation related to climate change. Costs of such litigation could be significant, and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages which could affect the Company's results of operations and cash flows if the costs are not recoverable in rates.

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, including 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. Environmental laws and regulations can also require the Company to install pollution control equipment at its facilities, clean up spills and other contamination and correct environmental hazards, including payment of all or part of the cost to remediate sites where the Company's past activities, or the activities of other parties, caused environmental contamination. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals and may cause the Company to shut down existing facilities due to difficulties in assuring compliance or where the cost of compliance makes operation of the facilities no longer economical. 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. Some of the Company's coal fired electric generating facilities are subject to this rule. Company facilities where there are ash impoundments and landfills are conducting ground water evaluations and may need to implement projects to meet rule requirements.

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 46 percent of Montana-Dakota's owned generating capacity and approximately 79 percent of the electricity it generated in 2018 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, which was granted. The D.C. Circuit Court has continued to issue orders holding the case in abeyance and requiring the EPA to file ongoing status reports. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and published the proposed Affordable Clean Energy rulemaking to revise the Clean Power Plan. The proposed revised rule would require states to conduct a review of heat rate improvement projects that could be implemented at each individual coal-fired electric generating facility and determine, using a multi-factor analysis, which projects a facility would need to implement. The state would establish a standard of performance for carbon dioxide emissions for each facility based on the heat rate improvement projects required to be implemented. Compliance costs will become clearer as the EPA completes new rulemaking.

On January 14, 2015, the federal government announced a goal to reduce methane emissions from the oil and natural gas industry by 40 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. 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 and Washington DOE suspended the rule's compliance obligations on December 21, 2017. On May 16, 2018, Washington DOE appealed the lower court ruling to the Supreme Court for the State of Washington and oral argument is scheduled for March 19, 2019. Litigation in the United States District Court for the Eastern District of Washington continues to be held in abeyance.

Treaties, legislation or regulations to reduce GHG emissions in response to climate change may be adopted that affect the Company's utility operations by requiring additional energy conservation efforts or renewable energy sources, limiting emissions, imposing carbon taxes or other compliance costs; 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. Significant reductions in demand for the Company's utility services as a result of increased costs or emissions limitations could also 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 remediation costs. The Company could also be impacted by drought conditions, which may restrict the availability of water supplies and inhibit the ability of the construction businesses to conduct operations. As a result, unusually mild winters or summers or 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 competitive forces such 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. New acquisition opportunities are subject to competitive bidding environments which impacts prices the Company must pay to successfully acquire new properties to grow its business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company's operations may be negatively affected if it is unable to obtain, develop and retain key personnel and skilled labor forces.

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 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 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 is a holding company and relies on cash from its subsidiaries to pay dividends.

The Company is a holding company as a result of the Holding Company Reorganization. Its investments in its subsidiaries comprise the Company's primary assets. The Company depends on earnings, cash flows and dividends from its subsidiaries to pay dividends on its common stock. The Company's subsidiaries are separate legal entities that have no obligation to pay any amounts due on its obligations or to make funds available to pay dividends on common stock. Regulatory, contractual and legal limitations, as well as their capital requirements, affect the ability of the subsidiaries to pay dividends to the Company and thereby could restrict or influence the Company's ability or decision to pay dividends on its common stock which could 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 70 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 30 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; newly-enacted government law or regulations and the actual return on assets held in the plans; among others. The Company could experience increased operating expenses as a result of required contributions to MEPPs, which could 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. 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 uses technology in substantially all aspects of its business operations and requires 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, including disaster recovery and backup systems, due to hacking, human error, theft, sabotage, malicious software, acts of terrorism, acts of war, acts of nature or other causes. If these systems fail or become compromised, 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, any of which could have a material adverse effect on the Company's reputation, business, cash flows and results of operations or subject the Company to legal or regulatory liabilities and increased costs.

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 is subject to cyber security and privacy laws and regulations of many government agencies, including FERC and NERC. NERC issues comprehensive regulations and standards surrounding the security of bulk power systems and is continually in the process of updating these requirements as well as establishing new requirements with which the utility industry must comply. As these regulations evolve, the Company will experience increased compliance costs and be at higher risk for violating these standards. Experiencing a cybersecurity incident could cause the Company to be non-compliant with applicable laws and regulations, causing the Company to incur costs related to legal claims or proceedings and regulatory fines or penalties.

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 and could go unnoticed for some time. In addition, there has been an increase in the number and sophistication of cyber-attacks across all industries worldwide and the threats are continually evolving. 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's information systems experience on-going and often sophisticated cyber-attacks by a variety of sources with the apparent aim to breach our cyber-defenses. As cyber-attacks continue to increase in frequency and sophistication, the Company may be unable to prevent all such attacks in the future. The Company is continuously reevaluating the need to upgrade and/or replace systems and network infrastructure. These upgrades and/or replacements could adversely impact operations by imposing substantial capital expenditures, creating delays or outages, or experiencing difficulties transitioning to new systems. Systems implementation disruption and any other information technology disruption, if not anticipated and appropriately mitigated, could have an adverse effect on the Company.

Other factors that could impact the Company's businesses.
The following are other factors that should be considered for a better understanding of the 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 inability 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 19, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

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

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."

As of December 31, 2018, the Company's common stock was held by approximately 11,300 stockholders of record.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. 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 11.

On June 4, 2018, the Company completed an acquisition in which a portion of the consideration consisted of the unregistered issuance of shares of the Company's common stock. On November 7, 2018, an additional amount of consideration was paid relating to this acquisition, which included 7,662 shares of the Company's common stock with a fair value of approximately $193,000. For additional information about this acquisition, see Item 8 - Note 3. The shares of common stock issued relating to this acquisition were issued in reliance upon the exemption from registration provided by Section 4(a)(2) of the Securities Act, as the shares were issued to the owners of businesses acquired in privately negotiated transactions not involving any public offering or solicitation.

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, 2018	—	—	—	—
November 1 through November 30, 2018	38,605	$26.55	—	—
December 1 through December 31, 2018	—	—	—	—
Total	38,605		—	—

(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.
(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

	2018	2017	2016	2015	2014	2013
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 335,123**	$ 342,805	$ 322,356	$ 280,615	$ 277,874	$ 257,260
Natural gas distribution	**823,247**	848,388	766,115	817,419	921,986	851,945
Pipeline and midstream	**128,923**	122,213	141,602	154,904	157,292	144,568
Construction materials and contracting	**1,925,854**	1,812,529	1,874,270	1,904,282	1,765,330	1,712,137
Construction services	**1,371,453**	1,367,602	1,073,272	926,427	1,119,529	1,039,839
Other	**11,259**	7,874	8,643	9,191	9,364	9,620
Intersegment eliminations	**(64,307)**	(58,060)	(57,430)	(78,786)	(136,302)	(95,201)
	$ 4,531,552	$ 4,443,351	$ 4,128,828	$ 4,014,052	$ 4,115,073	$ 3,920,168
Operating income (loss) (000's):						
Electric	**$ 65,148**	$ 79,902	$ 67,929	$ 59,915	$ 61,515	$ 54,386
Natural gas distribution	**72,336**	84,239	66,166	54,974	68,185	79,910
Pipeline and midstream	**36,128**	36,004	42,864	30,218	46,500	20,070
Construction materials and contracting	**141,426**	143,230	178,753	148,312	87,243	92,037
Construction services	**86,764**	81,292	53,546	43,678	82,408	85,242
Other	**(79)**	(619)	(349)	(8,414)	(5,370)	(4,384)
Intersegment eliminations	**—**	—	—	(2,942)	(9,900)	(7,176)
	$ 401,723	$ 424,048	$ 408,909	$ 325,741	$ 330,581	$ 320,085
Earnings (loss) on common stock (000's):						
Electric	**$ 47,000**	$ 49,366	$ 42,222	$ 35,914	$ 36,731	$ 34,837
Natural gas distribution	**37,732**	32,225	27,102	23,607	30,484	37,656
Pipeline and midstream	**28,459**	20,493	23,435	13,250	24,666	7,701
Construction materials and contracting	**92,647**	123,398	102,687	89,096	51,510	50,946
Construction services	**64,309**	53,306	33,945	23,762	54,432	52,213
Other	**(761)**	(1,422)	(3,231)	(14,941)	(7,386)	(10,776)
Intersegment eliminations	**—**	6,849	6,251	5,016	(6,095)	(4,307)
Earnings on common stock before income (loss) from discontinued operations	**269,386**	284,215	232,411	175,704	184,342	168,270
Income (loss) from discontinued operations, net of tax*	**2,932**	(3,783)	(300,354)	(834,080)	109,311	109,615
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)	(35,256)	(3,895)	(363)
	$ 272,318	$ 280,432	$ 63,748	$ (623,120)	$ 297,548	$ 278,248
Earnings per common share before discontinued operations - diluted	**$ 1.38**	$ 1.45	$ 1.19	$ .90	$ .96	$ .89
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)	(4.10)	.59	.58
	$ 1.39	$ 1.43	$ .33	$ (3.20)	$ 1.55	$ 1.47
Common Stock Statistics						
Weighted average common shares outstanding -diluted (000's)	**196,150**	195,687	195,618	194,986	192,587	189,693
Dividends declared per common share	**$ .7950**	$ .7750	$ .7550	$ .7350	$ .7150	$ .6950
Book value per common share	**$ 13.09**	$ 12.44	$ 11.78	$ 12.83	$ 16.66	$ 15.01
Market price per common share (year end)	**$ 23.84**	$ 26.88	$ 28.77	$ 18.32	$ 23.50	$ 30.55
Market price ratios:						
Dividend payout**	**58%**	53%	63%	82%	74%	78%
Yield	**3.4%**	2.9%	2.7%	4.1%	3.1%	2.3%
Market value as a percent of book value	**182.1%**	216.1%	244.2%	142.8%	141.1%	203.5%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) in 2015 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)

	2018	2017	2016	2015	2014	2013
General						
Total assets (000's)	**$ 6,988,110**	$ 6,334,666	$ 6,284,467	$ 6,565,154	$ 7,805,405	$ 7,043,365
Total long-term debt (000's)	**$ 2,108,695**	$ 1,714,853	$ 1,790,159	$ 1,796,163	$ 2,016,198	$ 1,773,050
Capitalization ratios:						
Total equity	**55%**	59%	56%	58%	62%	62%
Total debt	**45**	41	44	42	38	38
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,354,401**	3,306,470	3,258,537	3,316,017	3,308,358	3,173,086
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**574.5**	553.1	559.7	547.3	584.0	583.5
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**537.2**	530.2	559.7	547.3	522.4	508.3
All-time demand peak - kW (Interconnected system)	**611,542**	611,542	611,542	611,542	582,083	573,587
Electricity produced (thousand kWh)	**2,840,353**	2,630,640	2,626,763	1,898,160	2,519,938	2,430,001
Electricity purchased (thousand kWh)	**831,039**	955,687	904,702	1,658,002	1,010,422	971,261
Average cost of electric fuel and purchased power per kWh	**$ .022**	$ .022	$ .021	$ .024	$ .025	$ .025
Natural Gas Distribution						
Sales (Mdk)	**112,566**	112,551	99,296	95,559	104,297	108,260
Transportation (Mdk)	**149,497**	144,477	147,592	154,225	145,941	149,490
Pipeline and Midstream						
Transportation (Mdk)	**351,498**	312,520	285,254	290,494	233,483	178,598
Gathering (Mdk)	**14,882**	16,064	20,049	33,441	38,372	40,737
Customer natural gas storage balance (Mdk)	**13,928**	22,397	26,403	16,600	14,885	26,693
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**29,795**	28,213	27,580	26,959	25,827	24,713
Asphalt (tons)	**6,838**	6,237	7,203	6,705	6,070	6,228
Ready-mixed concrete (cubic yards)	**3,518**	3,548	3,655	3,592	3,460	3,223
Aggregate reserves (000's tons)	**1,014,431**	965,036	989,084	1,022,513	1,061,156	1,083,376

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

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-mixed 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 business 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.

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 that impacted the Company were reduced corporate tax rates, repeal of the domestic production deduction and disallowance of immediate expensing for regulated utility property. The Company has reviewed the impacts of the TCJA and is complying with all known tax rules and guidance. For additional information on the impacts of the TCJA, see Item 8 - Note 13.

Consolidated Earnings Overview

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

Years ended December 31,	**2018**	2017	2016
	(In millions, except per share amounts)		
Electric	**$ 47.0**	$ 49.4	$ 42.2
Natural gas distribution	**37.7**	32.2	27.1
Pipeline and midstream	**28.5**	20.5	23.4
Construction materials and contracting	**92.6**	123.4	102.7
Construction services	**64.3**	53.3	33.9
Other	**(.7)**	(1.5)	(3.2)
Intersegment eliminations	**—**	6.9	6.3
Earnings before discontinued operations	**269.4**	284.2	232.4
Income (loss) from discontinued operations, net of tax	**2.9**	(3.8)	(300.4)
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131.7)
Earnings on common stock	**$ 272.3**	$ 280.4	$ 63.7
Earnings per common share - basic:			
Earnings before discontinued operations	**$ 1.38**	$ 1.46	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - basic	**$ 1.39**	$ 1.44	$ .33
Earnings per common share - diluted:			
Earnings before discontinued operations	**$ 1.38**	$ 1.45	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - diluted	**$ 1.39**	$ 1.43	$ .33

2018 compared to 2017 The Company's consolidated earnings decreased $8.1 million.

The Company's earnings were positively impacted in 2018 as a result of the lower federal statutory tax rate, which was partially offset by the absence of a $39.5 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the business's net deferred tax liabilities. Both tax impacts were the result of the enactment of the TCJA, as further discussed in Item 8 - Note 13. Decreased earnings due to lower returns on investments also offset the lower income tax rate. Also positively impacting the Company's earnings were higher outside specialty contracting gross margins due to increased outside equipment sales and rentals at the construction services business, as well as a $4.2 million income tax benefit relating to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during the third quarter of 2018 at the pipeline and midstream business.

2017 compared to 2016 The Company's consolidated earnings increased $216.7 million.

The Company's earnings were positively impacted due to the absence in 2017 of a loss associated with the sale of the refining business in June 2016 relating to discontinued operations, as well as an overall income tax benefit to the Company of $39.5 million primarily for the revaluation of the Company's net deferred tax liabilities. Also contributing to the Company's increased earnings were higher inside and outside specialty contracting margins driven by decreased costs and higher contracting workloads at the construction services business, higher natural gas retail sales margins as a result of increased retail sales volumes at the natural gas distribution business and higher electric retail sales margins at the electric business. These increases were partially offset by lower asphalt product and construction margins driven by competitive pricing and unfavorable weather at the construction materials and contracting business and lower gathering and processing revenues resulting from lower volumes due to the sale of the Pronghorn assets in January 2017 at the pipeline and midstream business.

A discussion of key financial data from the Company's business segments follows.

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." For more information, see Part I - Forward-Looking Statements. There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

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 15.

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, employee satisfaction, customer service and shareholder return, 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, transmission and distribution 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, weather, competitive factors in the energy industry, population growth 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 in certain jurisdictions. 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.

Tariff increases on steel and aluminum materials could negatively affect the segments' construction projects and maintenance work. The Company continues to monitor the impact tariff increases will have on raw material costs. The natural gas distribution segment is also facing increased lead times on delivery of certain raw materials used in pipeline projects. In addition to the effect of tariffs, long lead times are attributable to increased demand for steel products from pipeline companies as they respond to the United States Department of Transportation Pipeline System Safety and Integrity Plan. The Company continues to monitor the material lead times and is working with manufacturers to proactively order such materials to help mitigate the extended lead times.

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 likely 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. Natural gas 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 on the Company's distribution margins.

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

Years ended December 31,	**2018**	2017	2016
	(Dollars in millions, where applicable)		
Operating revenues	**$ 335.1**	$ 342.8	$ 322.3
Electric fuel and purchased power	**80.7**	78.7	75.5
Taxes, other than income	**.7**	.8	.6
Adjusted gross margin	**253.7**	263.3	246.2
Operating expenses:			
Operation and maintenance	**123.0**	122.2	115.8
Depreciation, depletion and amortization	**51.0**	47.7	50.2
Taxes, other than income	**14.5**	13.5	12.3
Total operating expenses	**188.5**	183.4	178.3
Operating income	**65.2**	79.9	67.9
Other income	**1.2**	3.2	1.3
Interest expense	**25.9**	25.4	25.0
Income before income taxes	**40.5**	57.7	44.2
Income taxes	**(6.5)**	7.7	1.4
Net income	**47.0**	50.0	42.8
Loss/dividends on preferred stock	**—**	.6	.6
Earnings	**$ 47.0**	$ 49.4	$ 42.2
Retail sales (million kWh):			
Residential	**1,196.6**	1,153.5	1,132.5
Commercial	**1,513.9**	1,513.1	1,491.8
Industrial	**551.0**	539.9	544.2
Other	**92.9**	100.0	90.0
	3,354.4	3,306.5	3,258.5
Average cost of electric fuel and purchased power per kWh	**$ .022**	$ .022	$ .021

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the electric segment, see the Non-GAAP Financial Measures section later in this Item.

2018 compared to 2017 Electric earnings decreased $2.4 million (5 percent) as a result of:

Adjusted gross margin: Decrease of $9.6 million, primarily due to lower operating revenues driven by the reserves against revenues in certain jurisdictions for anticipated refunds to customers for lower income taxes due to the enactment of TCJA and a transmission formula rate adjustment due to lower than anticipated project costs on the BSSE project recorded in the third quarter of 2018. Partially offsetting the decreases to adjusted gross margin were the absence in 2018 of reserves related to tracker balances in prior years and increased retail sales volumes of 1 percent to all major customer classes.

Operation and maintenance: Increase of $800,000, largely from higher contract services at certain generating stations. Partially offsetting the increase were lower payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.3 million as a result of increased plant balances.

Taxes, other than income: Increase of $1.0 million, primarily from higher property taxes in certain jurisdictions.

Other income: Decrease of $2.0 million, largely the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $14.2 million, largely due to the enactment of the TCJA reduced corporate tax rate, reduced income before income taxes and the absence of $2.1 million of income tax expense in 2018 for the revaluation of nonutility net deferred tax assets in 2017, as discussed in Item 8 - Note 13. Partially offsetting these decreases were lower production tax credits. A portion of the reduction in income taxes are being reserved against revenues, as previously discussed, resulting in a minimal impact on overall earnings.

2017 compared to 2016 Electric earnings increased $7.2 million (17 percent) as a result of:

Adjusted gross margin: Increase of $17.1 million, primarily from increased electric retail sales margins from the recovery of an additional investment on the BSSE project, approved rate recovery in all jurisdictions and 2 percent higher retail sales volumes to commercial and residential customers.

Operation and maintenance: Increase of $6.4 million, largely from higher payroll-related costs, material costs and contract services at certain generating stations.

Depreciation, depletion and amortization: Decrease of $2.5 million, largely from lower depreciation rates implemented in conjunction with regulatory recovery activity.

Taxes, other than income: Increase of $1.2 million, primarily from higher property taxes in certain jurisdictions.

Other income: Increase of $1.9 million, largely the result of higher returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Increase of $6.3 million, largely from increased income before income taxes and $2.1 million of income tax expense for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13.

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

Years ended December 31,	2018	2017	2016
	(Dollars in millions, where applicable)		
Operating revenues	**$ 823.2**	$ 848.4	$ 766.1
Purchased natural gas sold	**454.8**	479.9	431.5
Taxes, other than income	**28.5**	30.0	26.5
Adjusted gross margin	**339.9**	338.5	308.1
Operating expenses:			
Operation and maintenance	**173.4**	164.3	156.9
Depreciation, depletion and amortization	**72.5**	69.4	65.4
Taxes, other than income	**21.7**	20.5	19.6
Total operating expenses	**267.6**	254.2	241.9
Operating income	**72.3**	84.3	66.2
Other income	**.2**	2.0	.6
Interest expense	**30.7**	31.2	30.4
Income before income taxes	**41.8**	55.1	36.4
Income taxes	**4.1**	22.8	9.2
Net income	**37.7**	32.3	27.2
Loss/dividends on preferred stock	**—**	.1	.1
Earnings	**$ 37.7**	$ 32.2	$ 27.1
Volumes (MMdk)			
Retail sales:			
Residential	**63.7**	63.6	56.2
Commercial	**44.4**	44.3	38.9
Industrial	**4.5**	4.6	4.2
	112.6	112.5	99.3
Transportation sales:			
Commercial	**2.2**	2.0	1.8
Industrial	**147.3**	142.5	145.8
	149.5	144.5	147.6
Total throughput	**262.1**	257.0	246.9
Average cost of natural gas, including transportation, per dk	**$ 4.04**	$ 4.26	$ 4.35

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the natural gas distribution segment, see the Non-GAAP Financial Measures section later in this Item.

2018 compared to 2017 Natural gas distribution earnings increased $5.5 million (17 percent) as a result of:

Adjusted gross margin: Increase of $1.4 million, primarily due to increased retail sales margins, mainly the result of weather normalization mechanisms in certain jurisdictions and conservation revenue, which offsets the conservation expense in operation and maintenance expense. Also contributing to the retail sales margin increase were higher basic service charges as a result of increased retail sales customers and rate design. These increases were partially offset by tax reform revenue impacts for refunds to customers as a result of lower income taxes due to the enactment of TCJA and lower volumes in certain jurisdictions.

Operation and maintenance: Increase of $9.1 million, largely related to conservation expenses being recovered in revenue; contract services, which includes the recognition of a non-recurring expense related to the approved WUTC general rate case settlement in the second quarter 2018; and higher payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.1 million, primarily as a result of increased plant balances offset in part by lower depreciation rates implemented in certain jurisdictions.

Taxes, other than income: Increase of $1.2 million due to higher property taxes in certain jurisdictions.

Other income: Decrease of $1.8 million, primarily the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $18.7 million, largely due to the enactment of the TCJA reduced corporate tax rate, as well as the absence of $4.3 million income tax expense related to the 2017 revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13,

and reduced income before income taxes. A portion of the reduction in income taxes are being reserved against revenues or passed back to customers, as previously discussed, resulting in a minimal impact on overall earnings.

2017 compared to 2016 Natural gas distribution earnings increased $5.1 million (19 percent) as a result of:

Adjusted gross margin: Increase of $30.4 million, primarily due to increased retail sales margins as a result of 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. Also contributing to the increases were approved final and interim rate increases.

Operation and maintenance: Increase of $7.4 million, primarily from increased payroll-related costs and material costs.

Depreciation, depletion and amortization: Increase of $4.0 million as a result of increased plant balances.

Taxes, other than income: Increase of $900,000 due to higher property taxes in certain jurisdictions.

Other income: Increase of $1.4 million as a result of higher returns on investments.

Interest expense: Increase of $800,000 due to increased debt balances.

Income taxes: Increase of $13.6 million, largely the result of increased income before income taxes, as well as an additional $4.3 million income tax expense for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13.

Outlook The Company expects these segments will grow rate base by approximately 5 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. The Company expects its customer base 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.

In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion in southwest North Dakota. Construction of the Thunder Spirit Wind farm expansion began in May 2018 and on October 31, 2018, the Company finalized the purchase and placed it into service. With the addition of the expansion, the total Thunder Spirit Wind farm generation capacity is approximately 155 MW and increased the Company's electric generation portfolio to approximately 27 percent renewables based on nameplate ratings. The Company's integrated resource plans filed in North Dakota and Montana in 2017 include additional generation projects in the 2025 timeframe.

In June 2016, the Company, along with a partner, began construction on the BSSE project. The estimated capital investment for this project has been updated to approximately $130 million. All necessary easements have been secured and construction is complete. The Company began bringing the project on-line on February 5, 2019. In addition, the Company is also expecting to receive a continuation of the return on the project throughout the year.

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 for Lewis & Clark station in Sidney, Montana, and in late 2021 for units 1 and 2 at Heskett station in Mandan, North Dakota. These dates may be impacted by the Company's coal supplier's pending bankruptcy proceeding. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

The Company continues to be focused on the regulatory recovery of its investments. Since January 1, 2018, these segments have implemented rate increases, as well as system integrity mechanisms, in Minnesota, Montana, North Dakota, Washington 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 18.

With the enactment of the TCJA, the state regulators in jurisdictions where the segments operate requested companies submit plans for the estimated impact of the TCJA. The segments determined the use of the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities was appropriate. As such, the Company recorded a regulatory liability for the excess deferred income taxes that related to the effect of the change in tax rates on its regulated deferred tax assets and liabilities in the fourth quarter of 2017. For the twelve months ended December 31, 2018, the Company reserved an additional regulatory liability of approximately $18.5 million, which is an offset to the Company's revenues, as previously discussed. The additional reserves were calculated by completing a revenue requirement calculation in each state where the Company thought it was probable that the refund of tax savings would be returned to the Company's customers, or based on calculations or amounts prescribed by the commissions. The Company has been working on various rate cases with the state regulators relating to the impacts of the TCJA. A majority of these rate cases have been settled with new rates being implemented in 2018 or upcoming in 2019. For further details on the status of implementing the new rates, as well as the status on open rate cases, see

Item 8 - Note 18. Due to not being able to immediately expense utility property for tax purposes, the segments' cash flows are negatively impacted.

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 to expand pipeline capacity; and expansion of energy-related services leveraging on its 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.

Tariff increases on steel and aluminum materials could negatively affect the segment's construction projects and maintenance work. The Company continues to monitor the impact tariff increases will have on raw material costs. The segment experiences extended lead times on raw materials that are critical to the segment's construction and maintenance work. Long lead times on materials could delay maintenance work and project construction potentially causing lost revenues and/or increased costs. The Company continues to proactively monitor and plan for the material lead times, as well as work with manufacturers and suppliers to help mitigate the extended lead times.

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

Years ended December 31,	2018	2017	2016
	(Dollars in millions)		
Operating revenues	**$ 128.9**	$ 122.2	$ 141.6
Operating expenses:			
Operation and maintenance	**62.2**	56.9	61.9
Depreciation, depletion and amortization	**17.9**	16.8	24.9
Taxes, other than income	**12.7**	12.5	11.9
Total operating expenses	**92.8**	86.2	98.7
Operating income	**36.1**	36.0	42.9
Other income	**1.0**	1.8	.9
Interest expense	**5.9**	5.0	8.0
Income before income taxes	**31.2**	32.8	35.8
Income taxes	**2.7**	12.3	12.4
Earnings	**$ 28.5**	$ 20.5	$ 23.4
Transportation volumes (MMdk)	**351.5**	312.5	285.3
Natural gas gathering volumes (MMdk)	**14.9**	16.1	20.0
Customer natural gas storage balance (MMdk):			
Beginning of period	**22.4**	26.4	16.6
Net injection (withdrawal)	**(8.5)**	(4.0)	9.8
End of period	**13.9**	22.4	26.4

2018 compared to 2017 Pipeline and midstream earnings increased $8.0 million (39 percent) as a result of:

Revenues: Increase of $6.7 million, largely attributable to increased volumes of natural gas transported through its system as a result of completed organic growth projects and higher nonregulated project workloads, which increased revenues $4.1 million. These increases were partially offset by decreased storage-related revenues reflecting the decrease in natural gas pricing spreads, as discussed in the Outlook section.

Operation and maintenance: Increase of $5.3 million, primarily from higher nonregulated project costs of $3.9 million directly related to the increase in nonregulated project workloads, as previously discussed, as well as higher professional services, material costs and contract services.

Depreciation, depletion and amortization: Increase of $1.1 million, largely resulting from organic growth projects.

Taxes, other than income: Comparable to the prior year.

Other income: Decrease of $800,000, primarily the result of lower returns on investments partially offset by higher AFUDC.

Interest expense: Increase of $900,000, largely resulting from higher debt balances.

Income taxes: Decrease of $9.6 million, primarily resulting from the lower corporate tax rate due to the enactment of the TCJA creating a reduction to income tax expense, as well as the realization of a $4.2 million income tax benefit related to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during third quarter of 2018.

2017 compared to 2016 Pipeline and midstream earnings decreased $2.9 million (13 percent) as a result of:

Revenues: Decrease of $19.4 million, largely resulting from lower gathering and processing revenues of $22.6 million. The decrease in revenues resulted from lower volumes from the sale of the Pronghorn assets in January 2017. Partially offsetting the decrease was higher transportation revenues of $1.6 million, largely from increased off-system transportation volumes due to organic growth projects completed in 2017.

Operation and maintenance: Decrease of $5.0 million, which includes $3.6 million primarily from the absence of Pronghorn, as previously discussed, and the absence in 2017 of a fair value impairment in 2016 associated with the Pronghorn sale.

Depreciation, depletion and amortization: Decrease of $8.1 million, largely due to the absence of the Pronghorn assets, as previously discussed.

Taxes, other than income: Increase of $600,000 from higher property taxes.

Other income: Increase of $900,000 attributable to higher AFUDC.

Interest expense: Decrease of $3.0 million due to lower debt balances.

Income taxes: Comparable to the prior year.

Outlook The Company has continued to experience the effects of natural gas production at record levels, which has provided opportunities for organic growth projects and increased demand. The completion of organic growth projects has contributed to the Company transporting increasing volumes of natural gas through its system. Additionally, the record levels of natural gas supply have moderated the need for storage services and put downward pressure on natural gas prices and minimized pricing volatility. Both natural gas production levels and pressure on natural gas prices are expected to continue 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.

In January 2019, the Company announced plans to construct approximately 67 miles of new pipeline, compression and ancillary facilities to transport natural gas from core Bakken production areas near Tioga, North Dakota, and extend to a new interconnection point in McKenzie County, North Dakota. This North Bakken Expansion project, as designed, would provide 200 MMcf per day of natural gas transportation capacity. Construction is expected to begin in early 2021 with an estimated completion date late in 2021, which is dependent on regulatory and environmental permitting and finalization of transportation agreements with customers. The estimated cost of the project is approximately $220 million.

In November 2018, the Company completed construction and placed into service its Valley Expansion project, a 38-mile pipeline that delivers natural gas supply to eastern North Dakota and far western Minnesota. The project, which is designed to transport 40 MMcf of natural gas per day, is under the jurisdiction of the FERC.

In September 2018, the Company completed construction and placed into service its Line Section 27 Expansion project in the Bakken area of northwestern North Dakota. The project includes approximately 13 miles of new pipeline and associated facilities and increases capacity by over 200 MMcf per day. The project brings the total capacity of Line Section 27 to over 600 MMcf per day.

In early 2018, the Company announced two additional natural gas pipeline growth projects, the Demicks Lake project and Line Section 22 Expansion project. The Company has signed long-term commitment contracts supporting both projects. The Demicks Lake project, which includes approximately 14 miles of 20-inch pipe and will increase capacity by 175 MMcf per day, is located in McKenzie County, North Dakota. Construction is expected to begin in 2019, with an in-service date in the fall of 2019. The Line Section 22 Expansion project in the Billings, Montana, area is also scheduled to begin construction in 2019, with an expected in-service date in late 2019. This project will increase capacity by 22.5 MMcf per day to serve incremental demand in Billings, Montana.

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 Company's acquisitions in 2018 support this strategy.

As one of the country's largest sand and gravel producers, the segment continues 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 Company's aggregate reserves are naturally declining and as a result, the Company seeks acquisition opportunities to replace the reserves. In 2018, the Company's aggregate reserves increased by nearly 50 million tons primarily due to acquisition activity.

The construction materials and contracting segment faces challenges that are not under the direct control of the business. The segment operates in geographically diverse and highly competitive markets. Competition can put negative pressure on the segment's operating margins. The segment is also subject to volatility in the cost of raw materials such as diesel fuel, gasoline, liquid asphalt, cement and steel. Although it is difficult to determine the split between inflation and supply/demand increases, diesel fuel costs remained fairly stable for the past twelve months, while asphalt oil costs have trended higher in 2018 as compared to 2017. 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 and federal infrastructure spending.

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 continues to face increasing pressure to control costs, as well as find and train a skilled workforce to meet the needs of increasing demand and seasonal work.

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

Years ended December 31,	2018	2017	2016
	(Dollars in millions)		
Operating revenues	$ **1,925.9**	$ 1,812.5	$ 1,874.3
Cost of sales:			
Operation and maintenance	**1,601.7**	1,500.1	1,533.2
Depreciation, depletion and amortization	**59.0**	52.5	54.1
Taxes, other than income	**39.7**	38.0	37.5
Total cost of sales	**1,700.4**	1,590.6	1,624.8
Gross margin	**225.5**	221.9	249.5
Selling, general and administrative expense:			
Operation and maintenance	**77.6**	71.5	62.2
Depreciation, depletion and amortization	**2.2**	3.4	4.3
Taxes, other than income	**4.3**	3.8	4.3
Total selling, general and administrative expense	**84.1**	78.7	70.8
Operating income	**141.4**	143.2	178.7
Other income (expense)	**(3.1)**	.4	(.1)
Interest expense	**17.3**	14.8	15.3
Income before income taxes	**121.0**	128.8	163.3
Income taxes	**28.4**	5.4	60.6
Earnings	$ **92.6**	$ 123.4	$ 102.7
Sales (000's):			
Aggregates (tons)	**29,795**	28,213	27,580
Asphalt (tons)	**6,838**	6,237	7,203
Ready-mixed concrete (cubic yards)	**3,518**	3,548	3,655

2018 compared to 2017 Construction materials and contracting's earnings decreased $30.8 million (25 percent) as a result of:

Revenues: Increase of $113.4 million driven by higher asphalt product and aggregate volumes due to increased agency demand, increased realized prices and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes due to a decrease in available work and unfavorable weather conditions in certain regions.

Gross margin: Increase of $3.6 million resulting from higher asphalt product volumes and margins, largely from recent acquisitions and higher realized prices. Also contributing to the increase were higher aggregate volumes and margins due to strong market demand and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes and margins due to a decrease in available work and unfavorable weather conditions in certain regions.

Selling, general and administrative expense: Increase of $5.4 million, primarily payroll-related costs, acquisition costs and higher insurance-related costs.

Other income: Decrease of $3.5 million, largely the result of lower returns on investments.

Interest expense: Increase of $2.5 million, largely resulting from higher debt balances as a result of recent acquisitions, capital expenditures and higher working capital needs.

Income taxes: Increase of $23.0 million, primarily resulting from the absence in 2018 of a $41.9 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 13. Partially offsetting this increase were lower income taxes due to the enactment of the TCJA, which reduced the corporate tax rate.

2017 compared to 2016 Construction materials and contracting's earnings increased $20.7 million (20 percent) as a result of:

Revenues: Decrease of $61.8 million resulting from lower asphalt product volumes driven by competitive pricing and unfavorable weather during the first half of the year, less available work and increased competition in certain regions.

Gross margin: Decrease of $27.6 million, largely resulting from lower asphalt product margins, as previously discussed, and lower construction margins of $8.8 million driven by decreased workloads caused by unfavorable weather during the first half of the year and less available work in energy-producing states. Partially offsetting these decreases were higher aggregate margins of $8.0 million, primarily due to strong commercial and residential demand in certain regions.

Selling, general and administrative expense: Increase of $7.9 million, largely resulting from the absence in 2017 of an $11.1 million reduction to a MEPP withdrawal liability. Partially offsetting the increase were lower depreciation, depletion and amortization expense and lower office expense.

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $55.2 million, largely resulting from 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 13, and lower income before income taxes.

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 IBISWorld Incorporated Industry Report issued in May 2018 for sand and gravel mining in the United States projects a 1.8 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. The Company believes 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.

In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, a crushed rock and gravel supplier in northwestern Oregon. In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier headquartered in Little Falls, Minnesota. In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., which produces ready-mixed concrete in Molalla, Oregon. In October 2018, the Company acquired Sweetman Construction Company, a premier provider of aggregates, asphalt and ready-mixed concrete in Sioux Falls, South Dakota. These acquisitions are expected to be accretive to the segment's earnings in 2019. The Company continues to evaluate additional acquisition opportunities. For more information on these acquisitions, see Item 8 - Note 3.

The Company had backlog at December 31, 2018, of $706 million, up from $486 million at December 31, 2017. The Company has benefited from increased bidding opportunities in each of its regions. The increase in backlog was primarily attributable to work for state transportation departments, airports, the military, homebuilders and commercial developers. The Company expects to complete a significant amount of the backlog at December 31, 2018, during the next 12 months.

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, the Company believes customer demand for labor resources will continue to increase, possibly surpassing the supply of industry resources.

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

Years ended December 31,	2018	2017	2016
		(In millions)	
Operating revenues	$ 1,371.5	$ 1,367.6	$ 1,073.3
Cost of sales:			
Operation and maintenance	1,150.4	1,153.9	905.4
Depreciation, depletion and amortization	14.3	14.2	13.5
Taxes, other than income	42.0	43.4	35.2
Total cost of sales	1,206.7	1,211.5	954.1
Gross margin	164.8	156.1	119.2
Selling, general and administrative expense:			
Operation and maintenance	72.2	69.3	60.1
Depreciation, depletion and amortization	1.4	1.5	1.8
Taxes, other than income	4.4	4.0	3.8
Total selling, general and administrative expense	78.0	74.8	65.7
Operating income	86.8	81.3	53.5
Other income	1.1	1.3	2.2
Interest expense	3.6	3.7	4.0
Income before income taxes	84.3	78.9	51.7
Income taxes	20.0	25.6	17.8
Earnings	$ 64.3	$ 53.3	$ 33.9

2018 compared to 2017 Construction services earnings increased $11.0 million (21 percent) as a result of:

Revenues: Comparable to the prior year.

Gross margin: Increase of $8.7 million, largely resulting from higher outside specialty contracting gross margins due to increased outside equipment sales and rentals. Partially offsetting the increase were decreased inside specialty contracting gross margins as a result of decreased workloads and customer demand.

Selling, general and administrative expense: Increase of $3.2 million, primarily higher office expense, outside professional costs and payroll-related costs.

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $5.6 million, largely the lower corporate tax rate due to the enactment of the TCJA.

2017 compared to 2016 Construction services earnings increased $19.4 million (57 percent) as a result of:

Revenues: Increase of $294.3 million, primarily from an increase in the number and size of construction projects in 2017, as well as increased equipment sales and rentals.

Gross margin: Increase of $36.9 million resulting from higher inside specialty contracting margins of $20.9 million driven by increased revenues, as previously discussed, 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. Also contributing to the increased margins were higher outside specialty contracting margins of $16.0 million driven by higher contracting workloads and equipment revenues in areas impacted by storm activity.

Selling, general and administrative expense: Increase of $9.1 million, primarily higher payroll-related costs, office expense and outside professional costs.

Other income: Decrease of $900,000 due to the absence of interest income earned on prior year completed jobs.

Interest expense: Comparable to the prior year.

Income taxes: Increase of $7.8 million resulting from an increase in income before income taxes and the absence in 2017 of a $1.5 million tax benefit related to the disposition of a non-strategic asset. Partially offsetting this increase was 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 13.

Outlook The Company continues to expect long-term growth in the electric transmission and distribution market, although the timing of large bids and subsequent construction is likely to be highly variable from year to year. The Company believes several small and medium-sized transmission and distribution projects will continue to be available for bid in 2019. The Company expects bidding activity to remain strong for both outside and inside specialty construction companies in 2019. 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.

The Company had backlog at December 31, 2018, of $939 million, up from $708 million at December 31, 2017. The increase in backlog was largely attributable to the new project opportunities that the Company continues to see across its diverse operations, particularly in inside specialty electrical and mechanical contracting for the hospitality and gaming, high-tech, mission critical and public entities. The Company's outside power, communications and natural gas specialty operations also have a high volume of work. The Company expects to complete a significant amount of the backlog at December 31, 2018, during the next 12 months. Additionally, the Company continues to evaluate potential acquisition opportunities that would be accretive to the Company and grow the Company's backlog.

Other

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Operating revenues	**$ 11.3**	$ 7.9	$ 8.6
Operating expenses:			
Operation and maintenance	**9.3**	6.3	6.7
Depreciation, depletion and amortization	**2.0**	2.0	2.1
Taxes, other than income	**.1**	.2	.1
Total operating expenses	**11.4**	8.5	8.9
Operating loss	**(.1)**	(.6)	(.3)
Other income	**1.0**	.9	.9
Interest expense	**2.8**	3.6	5.8
Loss before income taxes	**(1.9)**	(3.3)	(5.2)
Income taxes	**(1.2)**	(1.8)	(2.0)
Loss	**$ (.7)**	$ (1.5)	$ (3.2)

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. Largely contributing to the increase in operation and maintenance expense in 2018 were costs associated with the Holding Company Reorganization. For further details on the Company's reorganization, see Items 1 and 2 Business Properties - General.

Discontinued Operations

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Income (loss) from discontinued operations before intercompany eliminations, net of tax	**$ 2.9**	$ 3.1	$ (303.2)
Intercompany eliminations	**—**	(6.9)	2.8
Income (loss) from discontinued operations, net of tax	**2.9**	(3.8)	(300.4)
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131.7)
Income (loss) from discontinued operations attributable to the Company, net of tax	**$ 2.9**	$ (3.8)	$ (168.7)

2018 compared to 2017 The income from discontinued operations attributable to the Company was $2.9 million, primarily related to income tax adjustments, compared to a loss of $3.8 million in the prior year. The loss in 2017 was largely due to 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 4.

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,	2018	2017	2016
	(In millions)		
Intersegment transactions:			
Operating revenues	$ **64.3**	$ 58.0	$ 57.4
Operation and maintenance	**13.7**	9.1	8.7
Purchased natural gas sold	**50.6**	48.9	48.7
Income from continuing operations*	**—**	(6.9)	(6.3)

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

For more information on intersegment eliminations, see Item 8 - Note 15.

Liquidity and Capital Commitments

At December 31, 2018, the Company had cash and cash equivalents of $53.9 million and available borrowing capacity of $384.6 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 2018 increased $51.9 million from 2017.

Increases: The increase in cash flows provided by operating activities was largely driven by stronger collection of accounts receivable at the construction services and construction materials and contracting businesses and bonus depreciation for tax purposes due to the enactment of TCJA at the construction materials and contracting business.

Decreases: Partially offsetting these increases were higher inventory balances at the construction materials and contracting business due to higher asphalt oil inventory, largely resulting from higher average per ton cost, and higher aggregate inventory from higher production. Also contributing to the decrease were decreased deferral of production tax credits, re-measurements of taxes on investments and accelerated tax deductions related to the TCJA.

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 tax benefits 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.

Investing activities Cash flows used in investing activities in 2018 increased $496.7 million from 2017. The increase in cash used in investing activities was primarily related to acquisition activity in 2018 at the construction materials and contracting business; the absence in 2018 of net proceeds from the sale of Pronghorn in January 2017 and higher capital expenditures in 2018 at the pipeline and midstream business; and higher capital expenditures related to various construction projects in 2018 at the electric and natural gas distribution businesses.

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.

Financing activities Cash flows provided by financing activities in 2018 increased $475.7 million from 2017. The increase in cash provided by financing activities was largely due to increased debt issuance from an increase in commercial paper balances used for acquisitions, ongoing capital expenditures and working capital needs at the construction materials and contacting business; the issuance of an additional $200 million in term loans for capital projects at the electric and natural gas distribution businesses; and the issuance of an additional $40 million under the private shelf agreement for capital projects at the pipeline and midstream business. The increase in issuance of long-term debt was partially offset by higher debt repayment on a line of credit at the natural gas distribution business; higher debt repayment on debt that matured during third quarter 2018 at the electric and natural gas distribution businesses; and the strong collection of accounts receivable resulting in lower commercial paper balances at the construction services business.

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.

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 and expected return on plan assets. At December 31, 2018, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $83.8 million. Pretax pension expense reflected in the Company's Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016, was $843,000, $1.7 million and $2.0 million, respectively. The Company's pension expense is currently projected to be less than $1.0 million in 2019. Funding for the pension plans is actuarially determined. The minimum required contributions for the year ended December 31, 2018 were approximately $6.1 million. There were no minimum required contributions for 2017 and 2016. For more information on the Company's pension plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures from continuing operations for 2016 through 2018 and as anticipated for 2019 through 2021 are summarized in the following table.

	Actual*			Estimated		
	2016	2017	**2018**	2019	2020	2021
			(In millions)			
Capital expenditures:						
Electric	$ 111	$ 109	**$ 186**	$ 104	$ 103	$ 88
Natural gas distribution	126	147	**206**	204	180	158
Pipeline and midstream	35	31	**70**	113	93	204
Construction materials and contracting	38	44	**280**	133	135	127
Construction services	60	19	**25**	25	17	18
Other	2	2	**2**	5	3	3
Total capital expenditures	$ 372	$ 352	**$ 769**	$ 584	$ 531	$ 598

* $33.4 million, $10.5 million and $(15.8) million, respectively.

The 2018 capital expenditures include the four acquisitions at the construction materials and contracting segment, as discussed in Item 8 - Note 3. The 2018 capital expenditures were funded by internal sources, issuance of long-term debt and issuance of the Company's equity securities. The Company has included in the estimated capital expenditures for 2019 through 2021 the Demicks Lake project, Line Section 22 Expansion project and North Bakken Expansion project, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2019 through 2021 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
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities that would be incremental to the outlined capital program; 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 2019 through 2021 will be funded by 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 and financial 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, 2018. 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 8.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2018:

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		$ 48.5		$ —		6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0	(c)	$ 53.8		$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 56.3		$ —		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 289.6	(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). The amount outstanding under the revolving credit agreement was $48.5 million.
(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.

Total equity as a percent of total capitalization was 55 percent and 59 percent at December 31, 2018 and 2017, 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.

On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same.

Prior to the maturity of the credit agreement, Montana-Dakota expects that it will negotiate the extension or replacement of this agreement. If Montana-Dakota 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 Montana-Dakota does not currently anticipate, it would seek alternative funding.

Cascade Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's ratio of total debt to total capitalization as of December 31, 2018, was 51 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 Intermountain's 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. Intermountain's ratio of total debt to total capitalization as of December 31, 2018, was 49 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 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 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 $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 million.

Off balance sheet arrangements

As of December 31, 2018, 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 8 and 19. At December 31, 2018, the Company's commitments under these obligations were as follows:

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
	(In millions)				
Long-term debt*	$ 251.9	$ 416.3	$ 273.0	$ 1,173.0	$ 2,114.2
Estimated interest payments**	83.0	153.9	123.6	472.5	833.0
Operating leases	37.7	44.2	18.9	49.1	149.9
Purchase commitments	418.1	384.8	200.1	622.4	1,625.4
	$ 790.7	$ 999.2	$ 615.6	$ 2,317.0	$ 4,722.5

* Unamortized debt issuance costs and discount are excluded from the table.

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

At December 31, 2018, the Company had total liabilities of $375.6 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $5.0 million at December 31, 2018, 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 9.

Not reflected in the previous table are $382,000 in uncertain tax positions at December 31, 2018. For more information, see Item 8 - Note 13.

The Company's minimum funding requirements for its defined benefit pension plans for 2019, which are not reflected in the previous table, are $4.0 million. For information on potential contributions above the funding minimum requirements, see item 8 - Note 16.

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 16.

New Accounting Standards

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

Critical Accounting Policies Involving Significant Estimates

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

Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; 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 15. 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, 2018, 2017 and 2016, there were no impairment losses recorded. At December 31, 2018, 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, risk adjusted 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 risk adjusted cost of capital at each reporting unit. The risk adjusted 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 2018. Under the market approach, the Company estimates fair value using multiples derived from 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.

Business combinations

The Company accounts for acquisitions on the Consolidated Financial Statements starting from the date of the acquisition, which is the date that control is obtained. The acquisition method of accounting requires acquired assets and liabilities assumed be recorded at their respective fair values as of the date of the acquisition. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The estimation of fair values of acquired assets and liabilities assumed by the Company requires significant judgment and requires various assumptions. Although independent appraisals may be used to assist in the determination of the fair value of certain assets and liabilities, the appraised values may be based on significant estimates provided by management. The amounts and useful lives assigned to depreciable and amortizable assets compared to amounts assigned to goodwill, which is not amortized, can affect the results of operations in the period of and periods subsequent to a business combination.

In determining fair values of acquired assets and liabilities assumed, the Company uses various observable inputs for similar assets or liabilities in active markets and various unobservable inputs, which includes the use of valuation models. Fair values are based on various factors including, but not limited to, age and condition of property, maintenance records, auction values for equipment with similar characteristics, recent sales and listings of comparable properties, data collected from drill holes and other subsurface investigations and geologic data. The Company primarily uses the market and cost approaches in determining the fair value of land and property, plant and equipment. A combination of the market and income approaches are used for aggregate reserves and intangibles, primarily a discounted cash flow model.

There is a measurement period after the acquisition date during which the Company may adjust the amounts recognized for a business combination. Any such adjustments are recorded in the period the adjustment is determined with the corresponding offset to goodwill. These adjustments are typically based on obtaining additional information that existed at the acquisition date regarding the assets acquired and the liabilities assumed. The measurement period ends once the Company has obtained all necessary information that existed as of the acquisition date, but does not extend beyond one year from the date of the acquisition. Once the measurement period has ended, any adjustments to assets acquired or liabilities assumed are recorded in income from continuing operations.

Revenue recognition

Revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. The accuracy of revenues reported on the Consolidated Financial Statements depends on, among other things, management's estimates of total costs to complete projects because the Company uses the cost-to-cost measure of progress on construction contracts for revenue recognition.

To determine the proper revenue recognition method for contracts, the Company evaluates whether two or more contracts should be combined and accounted for as one single contract and whether the combined or single contract should be accounted for as more than one performance obligation. This evaluation requires significant judgment and the decision to combine a group of contracts or separate the combined or single contract into multiple performance obligations could change the amount of revenue and profit recorded in a given period. For most contracts, the customer contracts with the Company to provide a significant service of integrating a complex set of tasks and components into a single project. Hence, the Company's contracts are generally accounted for as one performance obligation.

The Company recognizes construction contract revenue over time using the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. 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.

Contracts are often modified to account for changes in contract specifications and requirements. The Company considers contract modifications to exist when the modification either creates new or changes the existing enforceable rights and obligations. Generally, contract modifications are for goods or services that are not distinct from the existing contract due to the significant integration of services provided in the context of the contract and are accounted for as if they were part of that existing contract. The effect of a contract modification on the transaction price and the measure of progress for the performance obligation to which it relates, is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company's construction contracts generally contain variable consideration including liquidated damages, performance bonuses or incentives, claims, unapproved/unpriced change orders and penalties or index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis.

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

Pension and other postretirement benefits

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

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, 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, 2018.

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 16.

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, franchise and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements 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.

Non-GAAP Financial Measures

The Business Segment Financial and Operating Data includes financial information prepared in accordance with GAAP, as well as another financial measure, adjusted gross margin, that is considered a non-GAAP financial measure as it relates to the Company's electric and natural gas distribution segments. The presentation of adjusted gross margin is intended to be a useful supplemental financial measure for investors' understanding of the segments' operating performance. This non-GAAP financial measure should not be considered as an alternative to, or more meaningful than, GAAP financial measures such as operating income (loss) or earnings (loss). The Company's non-GAAP financial measure, adjusted gross margin, is not standardized; therefore, it may not be possible to compare this financial measure with other companies' gross margin measures having the same or similar names.

In addition to operating revenues and operating expenses, management also uses the non-GAAP financial measure of adjusted gross margin when evaluating the results of operations for the electric and natural gas distribution segments. Adjusted gross margin for the electric and natural gas distribution segments is calculated by adding back adjustments to operating income (loss). These add-back adjustments include: operation and maintenance expense; depreciation, depletion and amortization expense; and certain taxes, other than income.

Adjusted gross margin includes operating revenues less the cost of electric fuel and purchased power, purchased natural gas sold and certain taxes, other than income. These taxes, other than income, included as a reduction to adjusted gross margin relate to revenue taxes. These segments pass on to their customers the increases and decreases in the wholesale cost of power purchases, natural gas and other fuel supply costs in accordance with regulatory requirements. As such, the segments' revenues are directly impacted by the fluctuations in such commodities. Revenue taxes, which are passed back to customers, fluctuate with revenues as they are calculated as a percentage of revenues. For these reasons, period over period, the segments' operating income (loss) is generally not impacted. The Company's management believes the adjusted gross margin is a useful supplemental financial measure as these items are included in both operating revenues and operating expenses. The Company's management also believes that adjusted gross margin and the remaining operating expenses that calculate operating income (loss) are useful in assessing the Company's utility performance as management has the ability to influence control over the remaining operating expenses.

The following information reconciles operating income to adjusted gross margin for the electric segment.

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Operating income	$ 65.2	$ 79.9	$ 67.9
Adjustments:			
Operating expenses:			
Operation and maintenance	123.0	122.2	115.8
Depreciation, depletion and amortization	51.0	47.7	50.2
Taxes, other than income	14.5	13.5	12.3
Total adjustments	188.5	183.4	178.3
Adjusted gross margin	$ 253.7	$ 263.3	$ 246.2

The following information reconciles operating income to adjusted gross margin for the natural gas distribution segment.

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Operating income	$ 72.3	$ 84.3	$ 66.2
Adjustments:			
Operating expenses:			
Operation and maintenance	173.4	164.3	156.9
Depreciation, depletion and amortization	72.5	69.4	65.4
Taxes, other than income	21.7	20.5	19.6
Total adjustments	267.6	254.2	241.9
Adjusted gross margin	$ 339.9	$ 338.5	$ 308.1

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2018, 2017 or 2016.

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 7 and 8.

At December 31, 2018 and 2017, 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, 2018.

	2019	2020	2021	2022	2023	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 51.9	$ 15.8	$ .8	$ 147.3	$ 77.2	$ 1,173.0	$ 1,466.0	$ 1,540.9
Weighted average interest rate	4.3%	5.1%	2.2%	4.5%	3.7%	4.7%	4.6%	—
Variable rate	200.0	$ 110.1	$ 289.6	—	$ 48.5	—	$ 648.2	$ 648.2
Weighted average interest rate	2.8%	4.4%	3.1%	—	2.8%	—	3.2%	—

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, 2018. 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, 2018.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, 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, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 22, 2019, 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 included 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 22, 2019

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, 2018, 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, 2018, 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, 2018, of the Company and our report dated February 22, 2019, 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 22, 2019

Consolidated Statements of Income

Years ended December 31,	2018	2017	2016
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	**$ 1,213,227**	$ 1,244,759	$ 1,141,454
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**3,318,325**	3,198,592	2,987,374
Total operating revenues	**4,531,552**	4,443,351	4,128,828
Operating expenses:			
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	**340,331**	326,687	312,211
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**2,915,790**	2,808,779	2,581,299
Total operation and maintenance	**3,256,121**	3,135,466	2,893,510
Purchased natural gas sold	**404,153**	430,954	382,753
Depreciation, depletion and amortization	**220,205**	207,486	216,318
Taxes, other than income	**168,638**	166,673	151,826
Electric fuel and purchased power	**80,712**	78,724	75,512
Total operating expenses	**4,129,829**	4,019,303	3,719,919
Operating income	**401,723**	424,048	408,909
Other income (expense)	**(238)**	8,767	5,167
Interest expense	**84,614**	82,788	87,848
Income before income taxes	**316,871**	350,027	326,228
Income taxes	**47,485**	65,041	93,132
Income from continuing operations	**269,386**	284,986	233,096
Income (loss) from discontinued operations, net of tax (Note 4)	**2,932**	(3,783)	(300,354)
Net income (loss)	**272,318**	281,203	(67,258)
Loss from discontinued operations attributable to noncontrolling interest (Note 4)	**—**	—	(131,691)
Loss on redemption of preferred stocks (Note 10)	**—**	600	—
Dividends declared on preferred stocks	**—**	171	685
Earnings on common stock	**$ 272,318**	$ 280,432	$ 63,748
Earnings per common share - basic:			
Earnings before discontinued operations	**$ 1.38**	$ 1.46	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - basic	**$ 1.39**	$ 1.44	$ .33
Earnings per common share - diluted:			
Earnings before discontinued operations	**$ 1.38**	$ 1.45	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - diluted	**$ 1.39**	$ 1.43	$ .33
Weighted average common shares outstanding - basic	**195,720**	195,304	195,299
Weighted average common shares outstanding - diluted	**196,150**	195,687	195,618

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2018	2017	2016
		(In thousands)	
Net income (loss)	**$ 272,318**	$ 281,203	$ (67,258)
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $429, $224 and $226 in 2018, 2017 and 2016, respectively	**162**	366	367
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $1,471, $(1,162) and $(836) in 2018, 2017 and 2016, respectively	**4,441**	(1,812)	(1,470)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $721, $645 and $1,425 in 2018, 2017 and 2016, respectively	**2,173**	1,013	2,506
Reclassification of postretirement liability adjustment from regulatory asset, net of tax of $0, $(876) and $0 in 2018, 2017 and 2016, respectively	**—**	(1,143)	—
Postretirement liability adjustment	**6,614**	(1,942)	1,036
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(14), $(3) and $31 in 2018, 2017 and 2016, respectively	**(61)**	(6)	51
Reclassification adjustment for foreign currency translation adjustment included in net income (loss), net of tax of $75, $0 and $0 in 2018, 2017 and 2016, respectively	**249**	—	—
Foreign currency translation adjustment	**188**	(6)	51
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(38), $(75) and $(98) in 2018, 2017 and 2016, respectively	**(144)**	(139)	(182)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $35, $65 and $77 in 2018, 2017 and 2016, respectively	**131**	120	143
Net unrealized loss on available-for-sale investments	**(13)**	(19)	(39)
Other comprehensive income (loss)	**6,951**	(1,601)	1,415
Comprehensive income (loss)	**279,269**	279,602	(65,843)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)
Comprehensive income attributable to common stockholders	**$ 279,269**	$ 279,602	$ 65,848

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

Consolidated Balance Sheets

December 31,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 53,948**	$ 34,599
Receivables, net	**722,945**	727,030
Inventories	**287,309**	226,583
Prepayments and other current assets	**119,500**	81,304
Current assets held for sale	**430**	479
Total current assets	**1,184,132**	1,069,995
Investments	**138,620**	137,613
Property, plant and equipment (Note 1)	**7,397,321**	6,770,829
Less accumulated depreciation, depletion and amortization	**2,818,644**	2,691,641
Net property, plant and equipment	**4,578,677**	4,079,188
Deferred charges and other assets:		
Goodwill (Note 5)	**664,922**	631,791
Other intangible assets, net (Note 5)	**10,815**	3,837
Other	**408,857**	407,850
Noncurrent assets held for sale	**2,087**	4,392
Total deferred charges and other assets	**1,086,681**	1,047,870
Total assets	**$ 6,988,110**	$ 6,334,666
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	**$ 251,854**	$ 148,499
Accounts payable	**358,505**	312,327
Taxes payable	**41,929**	42,537
Dividends payable	**39,695**	38,573
Accrued compensation	**69,007**	72,919
Other accrued liabilities	**221,059**	186,010
Current liabilities held for sale	**4,001**	11,993
Total current liabilities	**986,050**	812,858
Long-term debt (Note 8)	**1,856,841**	1,566,354
Deferred credits and other liabilities:		
Deferred income taxes	**430,085**	347,271
Other	**1,148,359**	1,179,140
Total deferred credits and other liabilities	**1,578,444**	1,526,411
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Common stock (Note 11)		
Authorized - 500,000,000 shares, $1.00 par value Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	**196,565**	195,843
Other paid-in capital	**1,248,576**	1,233,412
Retained earnings	**1,163,602**	1,040,748
Accumulated other comprehensive loss	**(38,342)**	(37,334)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total stockholders' equity	**2,566,775**	2,429,043
Total liabilities and stockholders' equity	**$ 6,988,110**	$ 6,334,666

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

Consolidated Statements of Equity

Years ended December 31, 2018, 2017 and 2016

	Preferred Stock		Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock		Noncontrolling Interest	Total
	Shares	Amount	Shares	Amount				Shares	Amount		
	(In thousands, except shares)										
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
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)
At December 31, 2017	—	—	195,843,297	195,843	1,233,412	1,040,748	(37,334)	(538,921)	(3,626)	—	2,429,043
Cumulative effect of adoption of ASU 2014-09	—	—	—	—	—	(970)	—	—	—	—	(970)
Adjusted balance at January 1, 2018	—	—	195,843,297	195,843	1,233,412	1,039,778	(37,334)	(538,921)	(3,626)	—	2,428,073
Net income	—	—	—	—	—	272,318	—	—	—	—	272,318
Other comprehensive income	—	—	—	—	—	—	6,951	—	—	—	6,951
Reclassification of certain prior period tax effects from accumulated other comprehensive loss	—	—	—	—	—	7,959	(7,959)	—	—	—	—
Dividends declared on common stock	—	—	—	—	—	(156,453)	—	—	—	—	(156,453)

Stock-based compensation	—	—	—	—	5,060	—	—	—	—	—	5,060
Repurchase of common stock	—	—	—	—	—	—	—	(182,424)	(5,020)	—	(5,020)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	—	—	(7,350)	—	—	182,424	5,020	—	(2,330)
Issuance of common stock	—	—	721,610	722	17,454	—	—	—	—	—	18,176
At December 31, 2018	**—**	**$ —**	**196,564,907**	**$ 196,565**	**$ 1,248,576**	**$ 1,163,602**	**$ (38,342)**	**(538,921)**	**$ (3,626)**	**$ —**	**$ 2,566,775**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2018	2017	2016
		(In thousands)	
Operating activities:			
Net income (loss)	**$ 272,318**	$ 281,203	$ (67,258)
Income (loss) from discontinued operations, net of tax	**2,932**	(3,783)	(300,354)
Income from continuing operations	**269,386**	284,986	233,096
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**220,205**	207,486	216,318
Deferred income taxes	**59,735**	(25,423)	(2,049)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**28,234**	(108,255)	(25,641)
Inventories	**(46,796)**	9,135	2,433
Other current assets	**(31,814)**	(30,588)	(17,925)
Accounts payable	**21,109**	26,013	7,039
Other current liabilities	**22,285**	4,648	36,146
Other noncurrent changes	**(38,521)**	(18,790)	(26,459)
Net cash provided by continuing operations	**503,823**	349,212	422,958
Net cash provided by (used in) discontinued operations	**(3,942)**	98,799	39,251
Net cash provided by operating activities	**499,881**	448,011	462,209
Investing activities:			
Capital expenditures	**(568,230)**	(341,382)	(388,183)
Acquisitions, net of cash acquired	**(167,692)**	—	—
Net proceeds from sale or disposition of property and other	**26,100**	126,588	44,826
Investments	**(2,321)**	(1,608)	(1,396)
Net cash used in continuing operations	**(712,143)**	(216,402)	(344,753)
Net cash provided by discontinued operations	**1,236**	2,234	39,658
Net cash used in investing activities	**(710,907)**	(214,168)	(305,095)
Financing activities:			
Issuance of long-term debt	**566,829**	140,812	309,064
Repayment of long-term debt	**(174,520)**	(217,394)	(315,647)
Payments of stock issuance costs	**(10)**	—	—
Dividends paid	**(154,573)**	(150,727)	(147,156)
Redemption of preferred stock	**—**	(15,600)	—
Repurchase of common stock	**(5,020)**	(1,684)	—
Tax withholding on stock-based compensation	**(2,330)**	(757)	(323)
Net cash provided by (used in) continuing operations	**230,376**	(245,350)	(154,062)
Net cash used in discontinued operations	**—**	—	(40,852)
Net cash provided by (used in) financing activities	**230,376**	(245,350)	(194,914)
Effect of exchange rate changes on cash and cash equivalents	**(1)**	(1)	4
Increase (decrease) in cash and cash equivalents	**19,349**	(11,508)	(37,796)
Cash and cash equivalents - beginning of year	**34,599**	46,107	83,903
Cash and cash equivalents - end of year	**$ 53,948**	$ 34,599	$ 46,107

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 15. 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 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's corporate structure prior to the Holding Company Reorganization.

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. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed 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. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Due to the enactment of the TCJA, the regulated jurisdictions in which the Company's regulated businesses provide service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company's rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or passed back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 18.

Effective January 1, 2018, the Company adopted the requirements of the accounting standard update on revenue from contracts with customers following the modified retrospective method, as further discussed in this note, as well as in Note 2. As such, results for reporting periods beginning January 1, 2018, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for revenue recognition. Based on the Company's analysis, the Company did not identify a significant change in the timing of revenue recognition under the new guidance as compared to the historic accounting for revenue recognition.

Certain prior year amounts have been reclassified to conform to the current year presentation in the consolidated financial statements related to the retrospective adoption of the accounting standard update to improve the presentation of net periodic pension and net periodic postretirement benefit costs, which was effective on January 1, 2018. The components of net periodic pension and postretirement costs, other than service costs, were reclassified from operating expenses to other income on the Consolidated Statements of Income, as further discussed in this note.

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. 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 4.

Management has also evaluated the impact of events occurring after December 31, 2018, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Note 2. The total balance of receivables past due 90 days or more was $30.0 million and $34.7 million at December 31, 2018 and 2017, 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, 2018 and 2017, was $8.9 million and $8.1 million, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $96.2 million and $112.7 million at December 31, 2018 and 2017, respectively.

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

	2018	2017
	(In thousands)	
Short-term retainage*	**$ 56,228**	$ 57,134
Long-term retainage**	**4,152**	1,410
Total retainage	**$ 60,380**	$ 58,544

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

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:

	2018	2017
	(In thousands)	
Aggregates held for resale	**$ 139,681**	$ 115,268
Asphalt oil	**54,741**	30,360
Materials and supplies	**23,611**	18,650
Merchandise for resale	**22,552**	14,905
Natural gas in storage (current)	**22,117**	20,950
Other	**24,607**	26,450
Total	**$ 287,309**	$ 226,583

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 $48.5 million and $49.3 million at December 31, 2018 and 2017, 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 7 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, 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 for the years ended December 31 were as follows:

	2018	2017	2016
	(In thousands)		
AFUDC - borrowed	**$ 2,290**	$ 966	$ 914
AFUDC - equity	**$ 1,897**	$ 909	$ 565

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:

	2018	2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 1,131,484	$ 1,034,765	49
Distribution	430,750	415,543	46
Transmission	302,315	296,941	64
Construction in progress	161,893	117,906	—
Other	122,127	117,109	13
Natural gas distribution:			
Distribution	1,981,356	1,831,795	47
Construction in progress	21,028	19,823	—
Other	496,708	468,227	16
Pipeline and midstream:			
Transmission	585,594	516,932	54
Gathering	37,829	37,837	20
Storage	49,101	45,629	61
Construction in progress	5,915	17,488	—
Other	45,763	41,054	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	31,094	31,678	19
Construction in progress	86	17	—
Other	9,577	9,649	10
Construction materials and contracting:			
Land	109,541	95,745	—
Buildings and improvements	114,905	102,435	20
Machinery, vehicles and equipment	1,090,790	947,979	12
Construction in progress	22,507	7,750	—
Aggregate reserves	430,263	406,139	*
Construction services:			
Land	5,216	5,216	—
Buildings and improvements	29,795	27,351	25
Machinery, vehicles and equipment	145,859	137,924	6
Other	7,716	6,774	3
Other:			
Land	2,648	2,837	—
Other	25,461	28,286	14
Less accumulated depreciation, depletion and amortization	2,818,644	2,691,641	
Net property, plant and equipment	$ 4,578,677	$ 4,079,188	

* 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. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income.

No significant impairment losses were recorded in 2018, 2017 or 2016, other than those related to the Company's assets held for sale and discontinued operations recorded in 2016. For more information regarding these impairments, see Note 4.

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 15. 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, 2018, 2017 and 2016, there were no impairment losses recorded. At December 31, 2018, 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, risk adjusted 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 risk adjusted cost of capital at each reporting unit. The risk adjusted 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 2018. Under the market approach, the Company estimates fair value using multiples derived from 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 a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The electric and natural gas distribution segments generate revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. These segments establish a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company’s utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state’s tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The pipeline and midstream segment generates revenue from providing natural gas transportation, gathering and underground storage services, as well as other energy-related services to both third parties and internal customers, largely the natural gas distribution segment. The pipeline and midstream segment establishes a contract with a customer based upon the customer’s request for firm or interruptible natural gas transportation, storage or gathering service(s). The contract identifies an obligation for the segment to provide the requested service(s) in exchange for consideration from the customer over a specified term. Depending on the type of service(s) requested and contracted, the service provided may include transporting, gathering or storing an identified quantity of natural gas and/or standing ready to deliver or store an identified quantity of natural gas. Natural gas transportation, gathering and storage revenues are based on fixed rates, which may include reservation fees and/or per-unit commodity rates. The services provided by the segment are generally treated as single performance obligations satisfied over time simultaneous to when the service is provided and revenue is recognized. Rates for the segment's regulated services are based on its FERC approved tariff or customer negotiated rates on special projects, and rates for its non-regulated services are negotiated with its customers and set forth in the contract. For contracts governed by the company's tariff, amounts are billed on or before the ninth business day of the following month and the amount is due within 12 days of receipt of the invoice. For gathering contracts not governed by the tariff, amounts are due within twenty days of invoice receipt. For other contracts not governed by the tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The construction materials and contracting segment generates revenue from contracting services and construction materials sales. This segment focuses on the vertical integration of its contracting services with its construction materials to support the aggregate based product lines. This segment provides contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes integrating a set of services and related construction materials into a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include liquidated damages; performance bonuses or incentives and penalties; claims; unapproved/unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction materials to third parties and internal customers. The contract for material sales is the use of a sales order or an invoice, which includes the pricing and payment terms. All material contracts contain a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The construction services segment generates revenue from specialty contracting services which also includes the sale of construction equipment and other supplies. This segment provides specialty contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes multiple promised goods and services in a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include claims, unapproved/unpriced change orders, bonuses, incentives, penalties and liquidated damages. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction equipment and other supplies to third parties and internal customers. The contract for these sales is the use of a sales order or invoice, which includes the pricing and payment terms. All such contracts include a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered. For more information on revenue from contracts with customers, see Note 2.

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 9.

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 $30.0 million and $28.5 million at December 31, 2018 and 2017, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $42.7 million and $14.5 million at December 31, 2018 and 2017, respectively, which is included in prepayments and other current assets.

Stock-based compensation

The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

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 per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of nonvested performance share awards and restricted stock units. Common stock outstanding includes issued shares less shares held in treasury. Earnings on common stock was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2018	2017	2016
		(In thousands)	
Weighted average common shares outstanding - basic	**195,720**	195,304	195,299
Effect of dilutive performance share awards	**430**	383	319
Weighted average common shares outstanding - diluted	**196,150**	195,687	195,618
Shares excluded from the calculation of diluted earnings per share	**10**	—	—

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; revenue recognized using the cost-to-cost measure of progress for contracts; 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

ASU 2014-09 - 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 elected the practical expedient to not disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, along with an explanation of when such revenue would be expected to be recognized. This practical expedient was used since the performance obligations are part of contracts with an original duration of one year or less. The Company also elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is one year or less. Upon completion of the Company's evaluation of contracts and methods of revenue recognition under the previous accounting guidance, the Company did not identify any material cumulative effect adjustments to be made to retained earnings. In addition, the Company has 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, as discussed in Note 2. The Company reviewed its revenue streams to evaluate the impact of this guidance and did not identify 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 impacted certain business processes and controls. As such, the Company 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. Results for reporting periods beginning after December 31, 2017, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting for revenue recognition.

Under the modified retrospective approach, the guidance was applied only to contracts that were not completed as of January 1, 2018. Therefore, the Company recognized the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings at January 1, 2018. For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance. The cumulative effect of the changes made to the Consolidated Balance Sheet were as follows:

	December 31, 2017	Adjustments	January 1, 2018
		(In thousands)	
Liabilities and Stockholders' Equity			
Current liabilities:			
Other accrued liabilities	$ 186,010	$ 903	$ 186,913
Deferred credits and other liabilities:			
Deferred income taxes	347,271	(332)	346,939
Other	1,179,140	399	1,179,539
Commitments and contingencies			
Stockholders' equity:			
Common stockholders' equity:			
Retained earnings	1,040,748	(970)	1,039,778

The cumulative effect adjustment is related to prepaid natural gas transportation to storage contracts where a separate performance obligation existed and has not yet been satisfied. As such, these contracts were still open and met the criteria for a cumulative effect adjustment.

ASU 2016-15 - 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 guidance did not have a material effect on the Company's statement of cash flows.

ASU 2017-01 - 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 guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

ASU 2017-07 - 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 and net periodic postretirement benefit costs. The guidance required 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 periodic benefit cost shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also only allows the service cost component to be capitalized.

The Company adopted the guidance on January 1, 2018, on a retrospective basis. The guidance required the reclassification of all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income on the Consolidated Statements of Income with no impact to earnings. As a result of the retrospective application of this change in accounting guidance, the Company reclassified $6.2 million and $4.5 million from operation and maintenance expense to other income on the Consolidated Statements of Income for the years ended December 31, 2017 and 2016, respectively. The Company also reclassified unrealized gains on investments used to satisfy obligations under the defined benefit plans of $10.8 million and $4.7 million for the years ended December 31, 2017 and 2016, respectively, which were included in operation and maintenance expense, to other income on the Consolidated Statements of Income. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

ASU 2018-02 - 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 early adopted the guidance on January 1, 2018, and elected to reclassify the stranded income taxes at the beginning of the period. During the first quarter of 2018, the Company reclassified $7.9 million of stranded tax expense from accumulated other comprehensive loss to retained earnings. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

SEC File Number S7-15-16 - Disclosure Update and Simplification In October 2018, the SEC published guidance in the Federal Register on disclosure updates and simplifications. The guidance removed disclosures that are no longer considered cost beneficial, duplicative of GAAP required disclosures, clarified the specific requirements of disclosures and added disclosure requirements identified as relevant. The amendments were intended to facilitate disclosure of information to investors and simplify the compliance without significantly altering the total mix of information provided to investors. The guidance was effective for the Company on November 5, 2018, including interim periods. The Company adopted the guidance in the Annual Report on Form 10-K for the year ended December 31, 2018, which required minimal disclosure updates. The guidance was applied on a prospective basis and did not have a material effect on the Company's disclosures or certain sections of the Annual Report on Form 10-K.

Recently issued accounting standards not yet adopted

ASU 2016-02 - 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. 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. The Company adopted the standard on January 1, 2019.

In July 2018, the FASB issued ASU 2018-11 - Leases: Targeted Improvements, an accounting standard update to ASU 2016-02. This ASU provides an entity the option to adopt the guidance using one of two modified retrospective approaches. An entity can adopt the guidance using the modified retrospective transition approach beginning in the earliest year presented in the financial statements. This method of adoption would require the restatement of prior periods reported and the presentation of lease disclosures under the new guidance for all periods reported. The additional transition method of adoption introduced by ASU 2018-11, allows entities the option to apply the guidance on the date of adoption by recognizing a cumulative effect adjustment to retained earnings during the period of adoption and does not require prior comparative periods to be restated. The Company adopted 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, as well as the additional transition method of adoption applied on the date of adoption. The Company also adopted a short-term leasing policy as the lessee where leases with a term of 12 months or less will not be included on the Consolidated Balance Sheet.

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 has adopted this practical expedient. The Company will evaluate any new or modified agreements that fall within the scope of the standard. The Company continues to monitor other industry-specific issues as it relates to its regulated businesses but does not expect these issues to have a material impact on the Company's results of operations, financial position or disclosures.

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team has implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also has assessed the impact the standard will have on its processes and internal controls and has identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases are subject to the guidance and will be recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheets upon adoption. The Company expects the impact of the lessee guidance to be approximately $105 million to $125 million of an increase to assets and liabilities on January 1, 2019. In addition, the Company has evaluated the impact the new guidance will have on lease contracts where the Company is the lessor and does not anticipate a significant impact.

ASU 2017-04 - 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 must be applied on a prospective basis with early adoption permitted. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August 2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January 1, 2020, including interim periods, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August 2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be effective for the Company on January 1, 2021, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on the its disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The guidance will be effective for the Company on January 1, 2020, including interim periods, and may be applied on a retrospective or a prospective basis with early adoption permitted. The Company adopted the guidance effective January 1, 2019, on a prospective basis. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-18 - Clarifying the Interaction between Topic 808 and Topic 606 In November 2018, the FASB issued guidance on whether certain transactions between collaborative arrangement participants should be accounted for within revenue under Topic 606 in order to provide for better comparability among entities. The guidance clarifies which transactions should be accounted for as revenue under Topic 606 and provides unit-of-account guidance in Topic 808 to align with the guidance in Topic 606 regarding distinct goods or services. The guidance also specifies that transactions with a collaborative arrangement not directly related to sales to third parties may not be presented together with revenue recognized under Topic 606. The guidance will be effective for the Company on January 1, 2020, including interim periods, and must be applied retrospectively to January 1, 2018, the date in which the Company adopted Topic 606. An entity may apply the guidance to either all contracts or to only contracts that are not completed as of the date of the initial application of Topic 606. The Company is evaluating the effects the adoption of the new guidance will have on the its results of operations, financial position, cash flows and disclosures.

SEC Final Rulemaking Release Number 33-10570 - Modernization of Property Disclosures for Mining Registrants In November 2018, the SEC published guidance in the Federal Register on the modernization of property disclosures for mining registrants. The guidance requires additional disclosures related to activities under material mining operations to be included as an exhibit, including a technical report summary by a qualified person about an organization's mineral resources or mineral reserves; an overview of mining properties and operations; a summary of all mineral resources and mineral reserves as of the most recently completed fiscal year; a description of each material property, including the proposed program of exploration and development, stage of the development or production, and current production activities, among other things; and a description of the organization's internal controls surrounding mineral resource and reserve estimates. The guidance will be effective on a prospective basis for the Company on January 1, 2021, including interim periods, with early adoption permitted. The Company is evaluating the effects the adoption of the guidance will have on its disclosures in the Annual Report on Form 10-K.

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 losses on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and loss on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2018, 2017 and 2016, 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, 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)
Other comprehensive income (loss) before reclassifications	—	4,441	(61)	(144)	4,236
Amounts reclassified from accumulated other comprehensive loss	162	2,173	249	131	2,715
Net current-period other comprehensive income (loss)	162	6,614	188	(13)	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(389)	(7,520)	(33)	(17)	(7,959)
Balance at December 31, 2018	**$ (2,161)**	**$ (36,069)**	**$ —**	**$ (112)**	**$ (38,342)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Consolidated Statements of Income. The reclassifications for the years ended December 31 were as follows:

	2018	2017	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income	**$ (591)**	$ (590)	Interest expense
	429	224	Income taxes
	(162)	(366)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**(2,894)**	(1,658)	Other income
	721	645	Income taxes
	(2,173)	(1,013)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	**(324)**	—	Other income
	75	—	Income taxes
	(249)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income	**(166)**	(185)	Other income
	35	65	Income taxes
	(131)	(120)	
Total reclassifications	**$ (2,715)**	$ (1,499)	

Note 2 - Revenue from Contracts with Customers

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on the Company's business segments, see Note 15.

Year ended December 31, 2018	Electric	Natural gas distribution	Pipeline and midstream	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 121,477	$ 457,959	$ —	$ —	$ —	$ —	$ 579,436
Commercial utility sales	136,236	276,716	—	—	—	—	412,952
Industrial utility sales	34,353	24,603	—	—	—	—	58,956
Other utility sales	7,556	—	—	—	—	—	7,556
Natural gas transportation	—	43,238	89,159	—	—	—	132,397
Natural gas gathering	—	—	9,159	—	—	—	9,159
Natural gas storage	—	—	11,543	—	—	—	11,543
Contracting services	—	—	—	968,755	—	—	968,755
Construction materials	—	—	—	1,423,068	—	—	1,423,068
Intrasegment eliminations*	—	—	—	(465,969)	—	—	(465,969)
Inside specialty contracting	—	—	—	—	926,875	—	926,875
Outside specialty contracting	—	—	—	—	392,544	—	392,544
Other	31,568	14,579	18,865	—	525	11,259	76,796
Intersegment eliminations	—	—	(50,905)	(669)	(1,681)	(11,052)	(64,307)
Revenues from contracts with customers	331,190	817,095	77,821	1,925,185	1,318,263	207	4,469,761
Revenues out of scope	3,933	6,152	197	—	51,509	—	61,791
Total external operating revenues	$ 335,123	$ 823,247	$ 78,018	$ 1,925,185	$ 1,369,772	$ 207	$ 4,531,552

* Intrasegment revenues are presented within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, these revenues must be eliminated against construction materials to arrive at the external operating revenue total for the segment.

Contract balances

The timing of revenue recognition may differ from the timing of invoicing to customers. The timing of invoicing to customers does not necessarily correlate with the timing of revenues being recognized under the cost- to- cost method of accounting. Contracts from contracting services are billed as work progresses in accordance with agreed upon contractual terms. Generally, billing to the customer occurs contemporaneous to revenue recognition. A variance in timing of the billings may result in a contract asset or a contract liability. A contract asset occurs when revenues are recognized under the cost-to-cost measure of progress, which exceeds amounts billed on uncompleted contracts. Such amounts will be billed as standard contract terms allow, usually based on various measures of performance or achievement. A contract liability occurs when there are billings in excess of revenues recognized under the cost-to-cost measure of progress on uncompleted contracts. Contract liabilities decrease as revenue is recognized from the satisfaction of the related performance obligation. The changes in contract assets and liabilities were as follows:

	December 31, 2018	December 31, 2017	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 104,239	$ 109,540	$ (5,301)	Receivables, net
Contract liabilities - current	(93,901)	(84,123)	(9,778)	Accounts payable
Contract liabilities - noncurrent	(135)	—	(135)	Deferred credits and other liabilities - other
Net contract assets	$ 10,203	$ 25,417	$ (15,214)	

At December 31, 2018, the Company's net contract assets decreased $15.2 million compared to December 31, 2017. Included in the change of total net contract assets was a decrease in contract assets due to revenue recognized in excess of billings on contracts and an increase in contract liabilities due to billings on contracts in excess of revenues recognized. The Company recognized $78.6 million in revenue for the year ended December 31, 2018, which was previously included in contract liabilities at December 31, 2017.

The Company recognized a net increase in revenues of $36.7 million for the year ended December 31, 2018, from performance obligations satisfied in prior periods.

Note 3 - Acquisitions

During 2018, the Company completed four acquisitions. The results of the acquired businesses have been included in the Company's construction materials and contracting segment and Consolidated Financial Statements beginning on the acquisition dates. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material, both individually and in the aggregate, to the Company's financial position or results of operations. The following is a listing of the acquisitions made during 2018:

- In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, an aggregate producer that provides crushed rock and gravel to construction and retail customers in Oregon.
- In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier in Minnesota.
- In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., a producer of ready-mixed concrete in Oregon.
- In October 2018, the Company acquired Sweetman Construction Company, a provider of aggregates, asphalt and ready-mixed concrete in South Dakota.

As of December 31, 2018, the gross aggregate consideration for these acquisitions, which were all accounted for as business combinations, was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. In addition to the issuance of the Company's equity securities, the Company issued debt to finance these acquisitions. As of December 31, 2018, costs incurred for acquisitions were $1.5 million and included in operation and maintenance expense on the Consolidated Statements of Income. The acquisitions are subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the businesses as of the closing dates.

The Company preliminarily allocated the purchase price of the acquisitions to the assets acquired and liabilities assumed based on their estimated fair values as of the acquisition dates and are considered provisional until final fair values are determined or the measurement period has passed. The Company expects to record adjustments as it accumulates the information needed to estimate the fair value of assets acquired and liabilities assumed, including working capital balances, estimated fair value of identifiable intangible assets, property, plant and equipment, total consideration and goodwill. The excess of the purchase price over the aggregate fair values was recorded as goodwill. The Company calculated the fair value of the assets acquired using the market or cost approach (or a combination of both). Fair values for some of the assets were determined based on Level 3 inputs including estimated future cash flows, discount rates, growth rates, sales projections, retention rates and terminal values, all of which require significant management judgment and are susceptible to change. The final fair value of the net assets acquired may result in adjustments to the assets and liabilities, including goodwill, and will be made as soon as practical, but no later than one year from the respective acquisition dates. However, any subsequent measurement period adjustments are not expected to have a material impact on the Company's results of operations. The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

The aggregate total consideration for the acquisitions and the preliminary amounts allocated to the assets acquired and liabilities assumed based on the estimated fair values as of the respective acquisition dates were as follows:

		2018 Acquisitions
		(In thousands)
Assets		
Current assets:		
Receivables, net	$	18,984
Inventories		10,329
Other current assets		515
Total current assets		29,828
Property, plant and equipment		131,766
Deferred charges and other assets:		
Goodwill		33,131
Other intangible assets, net		8,227
Other		927
Total deferred charges and other assets		42,285
Total assets acquired	$	203,879
Liabilities		
Current liabilities	$	11,122
Deferred credits and other liabilities:		
Asset retirement obligation		914
Deferred income taxes		5,565
Total deferred credits and other liabilities		6,479
Total liabilities assumed	$	17,601
Total consideration (fair value)	$	186,278

Note 4 - Discontinued Operations

The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. 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.

In connection with the sale of Dakota Prairie Refining, Centennial guaranteed certain debt obligations of Dakota Prairie Refining and Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. On October 17, 2018, Centennial was released of any further liabilities or obligations under this guarantee. For more information related to the guarantee, see Note 19.

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:

		2018		2017
		(In thousands)		
Assets				
Current assets:				
Income taxes receivable*	$	—	$	1,778
Total current assets held for sale		—		1,778
Total assets held for sale	$	—	$	1,778
Liabilities				
Deferred credits and other liabilities:				
Deferred income taxes**	$	—	$	37
Total noncurrent liabilities held for sale		—		37
Total liabilities held for sale	$	—	$	37

* On the Company's Consolidated Balance Sheets, these amounts were reclassified to taxes payable and are reflected in current liabilities held for sale.

** On the Company's Consolidated Balance Sheets, these amounts were reclassified to deferred charges and other assets - deferred income taxes 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, 2018, Dakota Prairie Refining incurred no material exit and disposal costs, and does not expect to incur any future 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. In July 2018, the Company completed the sale of a majority of the remaining property, plant and equipment. 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:

	2018	2017
	(In thousands)	
Assets		
Current assets:		
Receivables, net	$ 430	$ 479
Total current assets held for sale	430	479
Noncurrent assets:		
Net property, plant and equipment	—	1,631
Deferred income taxes	1,926	2,637
Other	161	161
Total noncurrent assets held for sale	2,087	4,429
Total assets held for sale	$ 2,517	$ 4,908
Liabilities		
Current liabilities:		
Accounts payable	$ 80	$ 30
Taxes payable	1,451	10,857
Other accrued liabilities	2,470	2,884
Total current liabilities held for sale	4,001	13,771
Total liabilities held for sale	$ 4,001	$ 13,771

At December 31, 2018 and 2017, the Company's deferred tax assets included in assets held for sale were largely comprised of $1.9 million and $2.6 million, respectively, of federal and state net operating loss carryforwards and state alternative minimum tax credits. The Company realized substantially all of the outstanding net operating loss carryforwards from prior periods in 2017.

At December 31, 2017, the Company had federal income tax net operating loss carryforwards and various state income tax net operating loss carryforwards of $4.4 million and $13.8 million, respectively. At December 31, 2018, the Company had no federal or state income tax net operating loss carryforwards.

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.

The Company has incurred $10.5 million of exit and disposal costs to date and has incurred no exit or disposal costs in 2018. The Company does not expect to incur any additional material exit and disposal costs in connection with Fidelity. 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 were made during the second quarter of 2016. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

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 income (loss) from discontinued operations on the Company's Consolidated Statements of Income for the years ended December 31 were as follows:

	2018	2017	2016
	(In thousands)		
Operating revenues	$ **(459)**	$ 465	$ 123,024
Operating expenses	**921**	(4,607)	513,813
Operating income (loss)	**(1,380)**	5,072	(390,789)
Other income (expense)	**12**	(13)	306
Interest expense	**575**	250	1,753
Income (loss) from discontinued operations before income taxes	**(1,943)**	4,809	(392,236)
Income taxes*	**(4,875)**	8,592	(91,882)
Income (loss) from discontinued operations	**2,932**	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)
Income (loss) from discontinued operations attributable to the Company	$ **2,932**	$ (3,783)	$ (168,663)

* 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 $(7,000), $6.9 million and $(253.5) million for the years ended December 31, 2018, 2017 and 2016, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2018, were as follows:

	Balance at January 1, 2018	Goodwill Acquired During the Year	Balance at December 31, 2018
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Construction materials and contracting	176,290	33,131	209,421
Construction services	109,765	—	109,765
Total	$ 631,791	$ 33,131	$ 664,922

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

During 2018, the Company completed four acquisitions and the results of the acquired businesses have been included in the Company's construction materials and contracting segment. At December 31, 2018, the construction materials and contracting segment's goodwill increased by $33.1 million and other intangible assets increased by $8.2 million for these acquisitions. For more information about these acquisitions, see Note 3.

Other amortizable intangible assets at December 31 were as follows:

	2018	2017
	(In thousands)	
Customer relationships	$ 22,720	$ 15,248
Less accumulated amortization	13,535	13,382
	9,185	1,866
Noncompete agreements	2,605	2,430
Less accumulated amortization	1,956	1,805
	649	625
Other	6,458	6,990
Less accumulated amortization	5,477	5,644
	981	1,346
Total	$ 10,815	$ 3,837

Amortization expense for amortizable intangible assets for the years ended December 31, 2018, 2017 and 2016, was $1.2 million, $2.0 million and $2.5 million, respectively. The amounts of estimated amortization expense for identifiable intangible assets as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Amortization expense	$ 1,856	$ 1,486	$ 1,096	$ 1,072	$ 1,006	$ 4,299

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2018	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 165,898	$ 163,896
Asset retirement obligations (a)	Over plant lives	60,097	56,078
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	42,652	14,465
Taxes recoverable from customers (a)	Over plant lives	11,946	12,073
Manufactured gas plant sites remediation (a)	-	16,504	18,213
Long-term debt refinancing costs (a)	Up to 19 years	4,898	5,563
Costs related to identifying generation development (a)	Up to 8 years	2,508	2,960
Other (a) (b)	Up to 20 years	35,614	27,715
Total regulatory assets		340,117	300,963
Regulatory liabilities:			
Taxes refundable to customers (c)		277,833	279,668
Plant removal and decommissioning costs (c)		173,143	176,190
Natural gas costs refundable through rate adjustments (d)		29,995	28,514
Pension and postretirement benefits (c)		15,264	16,021
Other (c) (d)		25,197	18,905
Total regulatory liabilities		521,432	519,298
Net regulatory position		$ (181,315)	$ (218,335)

* 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, 2018 and 2017, approximately $313.5 million and $269.1 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. 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. The revaluation of the Company's regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019. TCJA filings are pending in Wyoming and Oregon. For more information on the various rate cases, see Note 18. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

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 7 - 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 $73.8 million and $77.4 million at December 31, 2018 and 2017, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized loss on these investments for the year ended December 31, 2018, was $3.6 million. The net unrealized gains on these investments for the years ended December 31, 2017 and 2016, were $9.3 million and $3.4 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income on the Consolidated Statements of Income. In connection with the adoption of ASU 2017-07, as discussed in Note 1, the Company has elected to reclassify prior period unrealized gains from operation and maintenance expense to other income 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, 2018	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,473	$ 21	$ 162	$ 10,332
U.S. Treasury securities	179	—	—	179
Total	$ 10,652	$ 21	$ 162	$ 10,511

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

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, 2018 and 2017, 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, 2018, 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, 2018
	(In thousands)			
Assets:				
Money market funds	$ —	$ 10,799	$ —	$ 10,799
Insurance contract*	—	73,838	—	73,838
Available-for-sale securities:				
Mortgage-backed securities	—	10,332	—	10,332
U.S. Treasury securities	—	179	—	179
Total assets measured at fair value	$ —	$ 95,148	$ —	$ 95,148

* The insurance contract invests approximately 53 percent in fixed-income investments, 21 percent in common stock of large-cap companies, 11 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 2 percent in cash equivalents.

	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.

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.

The Company performed a fair value assessment of the assets acquired and liabilities assumed in the business combinations that occurred during 2018. For more information on these Level 2 and Level 3 fair value measurements, see Note 3.

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 4.

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:

	2018		2017	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 2,108,695**	**$ 2,183,819**	$ 1,714,853	$ 1,826,256

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

Note 8 - 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. At December 31, 2018, the Company and its subsidiaries, as applicable, complied with all applicable financial covenants and restrictions. 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, 2018	Amount Outstanding at December 31, 2017	Letters of Credit at December 31, 2018	Expiration Date
				(In millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0	$ 48.5	$ 73.8 (b)	$ —	6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0 (c)	$ 53.8	$ 17.3	$ 2.2 (d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0 (e)	$ 56.3	$ 40.0	$ —	4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0	$ 289.6 (b)	$ 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). The amount outstanding under the revolving credit agreement was $48.5 million.
(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. The Company's ratio of funded debt to total capitalization at December 31, 2018, was 45 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

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

On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

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

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's ratio of total debt to total capitalization at December 31, 2018, was 51 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 Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Intermountain's ratio of total debt to total capitalization at December 31, 2018, was 49 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 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 contains customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Centennial's ratio of total debt to total capitalization at December 31, 2018, was 38 percent. 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 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 $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 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. WBI Energy Transmission's total debt to total capitalization at December 31, 2018, was

40 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

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

	Weighted Average Interest Rate at December 31, 2018		December 31, 2018		December 31, 2017
			(In thousands)		
Senior Notes due on dates ranging from July 1, 2019 to January 15, 2055	**4.57%**	**$**	**1,381,000**	$	1,499,916
Commercial paper supported by revolving credit agreements	**3.10%**		**338,100**		88,350
Term Loan Agreements due on dates ranging from October 17, 2019 to September 3, 2032	**2.75%**		**209,800**		—
Credit agreements due on April 24, 2020	**4.40%**		**110,100**		57,300
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	**5.22%**		**25,229**		24,982
Less unamortized debt issuance costs			**5,207**		5,694
Less discount			**327**		1
Total long-term debt			**2,108,695**		1,714,853
Less current maturities			**251,854**		148,499
Net long-term debt		**$**	**1,856,841**	$	1,566,354

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, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	$ 251,854	$ 125,912	$ 290,413	$ 147,314	$ 125,714	$ 1,173,022

Note 9 - 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:

		2018		2017
		(In thousands)		
Balance at beginning of year	**$**	**341,969**	$	314,970
Liabilities incurred		**13,424**		15,110
Liabilities acquired		**1,002**		—
Liabilities settled		**(3,699)**		(4,981)
Accretion expense*		**18,242**		16,839
Revisions in estimates		**4,615**		31
Balance at end of year	**$**	**375,553**	$	341,969

* Includes $16.8 million and $15.6 million in 2018 and 2017, respectively, related to regulatory assets.

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 6.

Note 10 - Preferred Stocks

The Company currently has 500,000 shares of preferred stock authorized to be issued with a $100 par value; 1,000,000 shares of preferred stock A authorized to be issued with no par value; and 500,000 shares of preference stock authorized to be issued with no par value. At December 31, 2018, there were no shares outstanding. At December 31, 2017, there were no shares outstanding. In 2016, 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 11 - Common Stock

For the years 2018, 2017 and 2016, dividends declared on common stock were $.7950, $.7750 and $.7550 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. For the years ended December 31, 2018, 2017 and 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2018, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From January 2016 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 and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. 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. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately $1.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2018. 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 $424 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, 2018. 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 12 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2018, there were 5.0 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock based awards.

Total stock-based compensation expense (after tax) was $4.6 million, $2.7 million and $3.3 million in 2018, 2017 and 2016, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.2 million (before income taxes) which will be amortized over a weighted average period of 1.7 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 38,605 shares with a fair value of $1.0 million, 40,572 shares with a fair value of $1.1 million and 37,218 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2018, 2017 and 2016, respectively.

Restricted stock awards

In February 2018, the Company began granting restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. At December 31, 2018, the total nonvested shares were 22,838 with a weighted average grant-date fair value of $27.48 per share.

Performance share awards

Since 2003, key employees of the Company have been granted performance share awards each year under the long-term performance-based incentive plan. Entitlement to performance shares is established by either the market condition or the performance metrics and service condition relative to the designated award.

Target grants of performance shares outstanding at December 31, 2018, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	255,773
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558
February 2018	2018-2020	246,309

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned 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 applicable to the market condition for certain performance shares issued in 2018, 2017 and 2016 were:

		2018			2017			2016	
Weighted average grant-date fair value			**$34.55**			$24.31			$14.60
Blended volatility range	**17.87%**	**–**	**22.14%**	22.70%	–	25.56%	29.25%	–	32.51%
Risk-free interest rate range	**1.86%**	**–**	**2.46%**	.69%	–	1.61%	.47%	–	.92%
Weighted average discounted dividends per share			**$2.46**			$1.70			$1.56

Under the performance conditions for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The performance shares applicable to these performance conditions have a weighted average grant-date fair value of $27.48 per share.

There were no performance shares that vested in 2018. 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.

A summary of the status of the performance share awards for the year ended December 31, 2018, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	425,534	$ 18.35
Granted	246,309	31.02
Less:		
Forfeited	3,052	14.60
Nonvested at end of period	668,791	$ 23.03

Note 13 - Income Taxes

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

	2018	2017	2016
		(In thousands)	
United States	**$ 317,655**	$ 350,064	$ 326,252
Foreign	**(784)**	(37)	(24)
Income before income taxes from continuing operations	**$ 316,871**	$ 350,027	$ 326,228

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

	2018	2017	2016
		(In thousands)	
Current:			
Federal	**$ (15,901)**	$ 74,272	$ 81,989
State	**3,651**	16,192	13,190
Foreign	**—**	—	2
	(12,250)	90,464	95,181
Deferred:			
Income taxes:			
Federal	**50,755**	(24,497)	(2,102)
State	**7,206**	(864)	1,184
Investment tax credit - net	**1,774**	(62)	(1,131)
	59,735	(25,423)	(2,049)
Total income tax expense	**$ 47,485**	$ 65,041	$ 93,132

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 to plan for amounts expected to be returned to customers, as discussed in Notes 6 and 18. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $285.5 million in the fourth quarter of 2017. In the third quarter of 2018, the Company reversed a regulatory liability recorded in 2017 based on a FERC final accounting order being issued, which resulted in a $4.2 million tax benefit. These regulatory amounts will largely be refunded over the remaining life of the related assets.

The changes included in the TCJA were broad and complex. The SEC issued rules that allowed 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 has reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

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

		2018		2017
		(In thousands)		
Deferred tax assets:				
Postretirement	$	**51,930**	$	55,736
Compensation-related		**29,885**		16,298
Alternative minimum tax credit carryforward		**13,404**		37,683
Federal renewable energy credit		**8,015**		19,367
Customer advances		**7,734**		8,712
Asset retirement obligations		**7,083**		6,380
Legal and environmental contingencies		**6,729**		7,363
Other		**37,347**		35,738
Total deferred tax assets		**162,127**		187,277
Deferred tax liabilities:				
Depreciation and basis differences on property, plant and equipment		**476,832**		429,577
Postretirement		**44,432**		43,505
Intangible asset amortization		**17,752**		16,979
Other		**39,712**		32,591
Total deferred tax liabilities		**578,728**		522,652
Valuation allowance		**13,484**		11,896
Net deferred income tax liability	$	**430,085**	$	347,271

As of December 31, 2018 and 2017, the Company had various state income tax net operating loss carryforwards of $153.2 million and $130.1 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.5 million and $52.5 million, respectively. Included in the state credits are various regulatory investment tax credits of approximately $32.2 million and $28.0 million at December 31, 2018 and 2017, respectively. The federal income tax credit carryforwards expire in 2037 and 2038 if not utilized and state income tax credit carryforwards are due to expire between 2020 and 2046. 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 4.

The following table reconciles the change in the net deferred income tax liability from December 31, 2017, to December 31, 2018, to deferred income tax expense:

		2018
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	**82,814**
Deferred taxes associated with other comprehensive income		**(2,679)**
Deferred taxes associated with TCJA enactment for regulated activities		**(13,776)**
Deferred taxes associated with acquisitions		**(5,565)**
Other		**(1,059)**
Deferred income tax expense for the period	$	**59,735**

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,	2018		2017		2016	
	Amount	**%**	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 66,543**	**21.0**	$ 122,509	35.0	$ 114,179	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	**12,190**	**3.8**	10,724	3.1	9,027	2.8
Federal renewable energy credit	**(11,759)**	**(3.7)**	(13,958)	(4.0)	(13,544)	(4.2)
Tax compliance and uncertain tax positions	**(2,725)**	**(.9)**	(643)	(.2)	(3,028)	(.9)
Domestic production deduction	**—**	**—**	(6,849)	(2.0)	(6,251)	(1.9)
Excess deferred income tax amortization	**(9,319)**	**(2.9)**	(397)	—	(828)	(.2)
TCJA revaluation	**(5,947)**	**(1.9)**	(47,242)	(13.5)	—	—
TCJA revaluation related to accumulated other comprehensive loss balance	**(42)**	**—**	7,735	2.2	—	—
Other	**(1,456)**	**(.4)**	(6,838)	(2.0)	(6,423)	(2.1)
Total income tax expense	**$ 47,485**	**15.0**	$ 65,041	18.6	$ 93,132	28.5

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 2015. With few exceptions, as of December 31, 2018, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2014.

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

	2018	2017	2016
		(In thousands)	
Balance at beginning of year	**$ —**	$ —	$ —
Additions based on tax positions related to current year	**120**	—	—
Additions for tax positions of prior years	**262**	—	—
Balance at end of year	**$ 382**	$ —	$ —

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2018, 2017 and 2016, the Company recognized approximately $31,000, $99,000 and $92,000, respectively, of interest income in income tax expense. At December 31, 2018, the Company had no accrued receivables for interest. At December 31, 2017, the Company had accrued receivables of approximately $46,000, for interest.

Note 14 - Cash Flow Information

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

	2018	2017	2016
		(In thousands)	
Interest, net*	**$ 83,009**	$ 79,638	$ 87,920
Income taxes paid, net**	**$ 16,041**	$ 112,137	$ 105,908

* AFUDC - borrowed was $2.3 million, $966,000 and $914,000 for the years ended December 31, 2018, 2017 and 2016, respectively.
** Income taxes paid, net of discontinued operations, were $5.5 million, $9.7 million and $1.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Noncash investing transactions at December 31 were as follows:

	2018	2017	2016
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 42,355**	$ 29,263	$ 22,712
Issuance of common stock in connection with acquisition	**$ 18,186**	$ —	$ —

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The 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.

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 its contracting services with its construction materials 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 segment also 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 self-insured layers of the insured Company's 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. For more information on discontinued operations, see Note 4.

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:

	2018	2017	2016
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	$ **335,123**	$ 342,805	$ 322,356
Natural gas distribution	**823,247**	848,388	766,115
Pipeline and midstream	**54,857**	53,566	52,983
	1,213,227	1,244,759	1,141,454
Nonregulated operations:			
Pipeline and midstream	**23,161**	19,602	39,602
Construction materials and contracting	**1,925,185**	1,811,964	1,873,696
Construction services	**1,369,772**	1,366,317	1,072,663
Other	**207**	709	1,413
	3,318,325	3,198,592	2,987,374
Total external operating revenues	$ **4,531,552**	$ 4,443,351	$ 4,128,828
Intersegment operating revenues:			
Regulated operations:			
Electric	$ **—**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and midstream	**50,580**	48,867	48,794
	50,580	48,867	48,794
Nonregulated operations:			
Pipeline and midstream	**325**	178	223
Construction materials and contracting	**669**	565	574
Construction services	**1,681**	1,285	609
Other	**11,052**	7,165	7,230
	13,727	9,193	8,636
Intersegment eliminations	**(64,307)**	(58,060)	(57,430)
Total intersegment operating revenues	$ **—**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ **50,982**	$ 47,715	$ 50,220
Natural gas distribution	**72,486**	69,381	65,426
Pipeline and midstream	**17,896**	16,788	24,885
Construction materials and contracting	**61,158**	55,862	58,413
Construction services	**15,728**	15,739	15,307
Other	**1,955**	2,001	2,067
Total depreciation, depletion and amortization	$ **220,205**	$ 207,486	$ 216,318
Operating income (loss):			
Electric	$ **65,148**	$ 79,902	$ 67,929
Natural gas distribution	**72,336**	84,239	66,166
Pipeline and midstream	**36,128**	36,004	42,864
Construction materials and contracting	**141,426**	143,230	178,753
Construction services	**86,764**	81,292	53,546
Other	**(79)**	(619)	(349)
Total operating income	$ **401,723**	$ 424,048	$ 408,909

	2018	2017	2016
		(In thousands)	
Interest expense:			
Electric	$ **25,860**	$ 25,377	$ 24,982
Natural gas distribution	**30,768**	31,234	30,405
Pipeline and midstream	**5,964**	4,990	7,903
Construction materials and contracting	**17,290**	14,778	15,265
Construction services	**3,551**	3,742	4,059
Other	**2,762**	3,564	5,854
Intersegment eliminations	**(1,581)**	(897)	(620)
Total interest expense	$ **84,614**	$ 82,788	$ 87,848
Income taxes:			
Electric	$ **(6,482)**	$ 7,699	$ 1,449
Natural gas distribution	**4,075**	22,756	9,181
Pipeline and midstream	**2,677**	12,281	12,408
Construction materials and contracting	**28,357**	5,405	60,625
Construction services	**20,000**	25,558	17,748
Other	**(1,142)**	(1,809)	(2,028)
Intersegment eliminations	**—**	(6,849)	(6,251)
Total income taxes	$ **47,485**	$ 65,041	$ 93,132
Earnings on common stock:			
Regulated operations:			
Electric	$ **47,000**	$ 49,366	$ 42,222
Natural gas distribution	**37,732**	32,225	27,102
Pipeline and midstream	**26,905**	20,620	22,060
	111,637	102,211	91,384
Nonregulated operations:			
Pipeline and midstream	**1,554**	(127)	1,375
Construction materials and contracting	**92,647**	123,398	102,687
Construction services	**64,309**	53,306	33,945
Other	**(761)**	(1,422)	(3,231)
	157,749	175,155	134,776
Intersegment eliminations (a)	**—**	6,849	6,251
Earnings on common stock before income (loss) from discontinued operations	**269,386**	284,215	232,411
Income (loss) from discontinued operations, net of tax (a)	**2,932**	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)
Earnings on common stock	$ **272,318**	$ 280,432	$ 63,748
Capital expenditures:			
Electric	$ **186,105**	$ 109,107	$ 111,134
Natural gas distribution	**205,896**	146,981	126,272
Pipeline and midstream	**70,057**	31,054	34,467
Construction materials and contracting	**280,396**	44,302	37,845
Construction services	**25,081**	18,630	60,344
Other	**1,768**	1,850	2,358
Total capital expenditures (b)	$ **769,303**	$ 351,924	$ 372,420

	2018	2017	2016
		(In thousands)	
Assets:			
Electric (c)	$ 1,613,822	$ 1,470,922	$ 1,406,694
Natural gas distribution (c)	2,375,871	2,201,081	2,099,296
Pipeline and midstream	616,959	566,295	550,615
Construction materials and contracting	1,508,032	1,238,696	1,220,459
Construction services	604,798	591,382	513,093
Other (d)	266,111	261,419	283,255
Assets held for sale	2,517	4,871	211,055
Total assets	$ 6,988,110	$ 6,334,666	$ 6,284,467
Property, plant and equipment:			
Electric (c)	$ 2,148,569	$ 1,982,264	$ 1,888,613
Natural gas distribution (c)	2,499,093	2,319,845	2,179,413
Pipeline and midstream	764,959	700,284	672,199
Construction materials and contracting	1,768,006	1,560,048	1,549,375
Construction services	188,586	177,265	171,361
Other	28,108	31,123	49,268
Less accumulated depreciation, depletion and amortization	2,818,644	2,691,641	2,578,902
Net property, plant and equipment	$ 4,578,677	$ 4,079,188	$ 3,931,327

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) $33.4 million, $10.5 million and $(15.8) 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 16 - 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 benefit pension plan benefits and accruals for all nonunion and certain union plans were frozen and on June 30, 2015, the remaining union plan was frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduces the Company's liability and future premiums.

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, 2018 and 2017, and amounts recognized in the Consolidated Balance Sheets at December 31, 2018 and 2017, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 445,923**	$ 436,307	**$ 91,206**	$ 89,304
Service cost	**—**	—	**1,494**	1,508
Interest cost	**14,591**	16,207	**2,899**	3,265
Plan participants' contributions	**—**	—	**1,282**	1,368
Actuarial (gain) loss	**(32,637)**	19,119	**(10,115)**	1,781
Benefits paid	**(36,275)**	(25,710)	**(5,565)**	(6,020)
Benefit obligation at end of year	**391,602**	445,923	**81,201**	91,206
Change in net plan assets:				
Fair value of plan assets at beginning of year	**354,384**	333,509	**88,739**	82,846
Actual gain (loss) on plan assets	**(21,138)**	45,473	**(2,781)**	9,612
Employer contribution	**10,838**	1,112	**842**	933
Plan participants' contributions	**—**	—	**1,281**	1,368
Benefits paid	**(36,275)**	(25,710)	**(5,565)**	(6,020)
Fair value of net plan assets at end of year	**307,809**	354,384	**82,516**	88,739
Funded status - over (under)	**$ (83,793)**	$ (91,539)	**$ 1,315**	$ (2,467)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Deferred charges and other assets - other	**$ —**	$ —	**$ 20,843**	19,114
Other accrued liabilities	**—**	—	**660**	612
Deferred credits and other liabilities - other	**83,793**	91,539	**18,868**	20,969
Benefit obligation assets (liabilities) - net amount recognized	**$ (83,793)**	$ (91,539)	**$ 1,315**	$ (2,467)
Amounts recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 188,735**	$ 186,486	**$ 10,316**	$ 13,423
Prior service credit	**—**	—	**(10,238)**	(11,632)
Total	**$ 188,735**	$ 186,486	**$ 78**	$ 1,791

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 table above 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 6.

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:

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 391,602**	$ 445,923
Accumulated benefit obligation	**$ 391,602**	$ 445,923
Fair value of plan assets	**$ 307,809**	$ 354,384

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		
	2018	2017	2016	**2018**	2017	2016
	(In thousands)					
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ —	$ —	**$ 1,494**	$ 1,508	$ 1,647
Interest cost	**14,591**	16,207	17,218	**2,899**	3,265	3,688
Expected return on assets	**(20,753)**	(20,528)	(20,924)	**(4,866)**	(4,641)	(4,533)
Amortization of prior service credit	**—**	—	—	**(1,394)**	(1,371)	(1,371)
Recognized net actuarial loss	**7,005**	6,355	6,215	**640**	857	1,491
Net periodic benefit cost (credit), including amount capitalized	**843**	2,034	2,509	**(1,227)**	(382)	922
Less amount capitalized	**—**	310	381	**153**	(370)	(52)
Net periodic benefit cost (credit)	**843**	1,724	2,128	**(1,380)**	(12)	974
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive (income) loss or regulatory assets (liabilities):						
Net (gain) loss	**9,254**	(5,827)	(3,789)	**(2,467)**	(3,190)	(3,523)
Amortization of actuarial loss	**(7,005)**	(6,355)	(6,215)	**(640)**	(857)	(1,491)
Amortization of prior service credit	**—**	—	—	**1,394**	1,371	1,371
Total recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities)	**2,249**	(12,182)	(10,004)	**(1,713)**	(2,676)	(3,643)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**$ 3,092**	$ (10,458)	$ (7,876)	**$ (3,093)**	$ (2,688)	$ (2,669)

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 2019 is $5.6 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 (credit) in 2019 are $500,000 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	
	2018	2017	**2018**	2017
Discount rate	**4.03%**	3.38%	**4.05%**	3.41%
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 (credit) for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
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%

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, 2018, 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 25 percent to 30 percent equity securities and 70 percent to 75 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:

	2018	2017
Health care trend rate assumed for next year	**7.5% – 8.1%**	7.5% – 8.5%
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, 2018:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 223	$ (184)
Effect on postretirement benefit obligation	$ 4,296	$ (3,622)

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 fair value 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, 2018 and 2017, 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, 2018, 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, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 4,930	$ —	$ 4,930
Equity securities:				
U.S. companies	11,038	—	—	11,038
International companies	—	967	—	967
Collective and mutual funds*	145,960	51,600	—	197,560
Corporate bonds	—	73,110	—	73,110
Municipal bonds	—	10,624	—	10,624
U.S. Government securities	479	5,896	—	6,375
Total assets measured at fair value	$ 157,477	$ 147,127	$ —	$ 304,604

* Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents and 19 percent in other investments.

	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	—	8,546	—	8,546
U.S. Government securities	1,038	8,293	—	9,331
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.

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, 2018 and 2017, 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, 2018, 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, 2018
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 3,866	$ —	$ 3,866
Equity securities:				
U.S. companies	1,767	—	—	1,767
International companies	—	2	—	2
Insurance contract*	1	76,880	—	76,881
Total assets measured at fair value	$ 1,768	$ 80,748	$ —	$ 82,516

* The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.

	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.

The Company expects to contribute approximately $4.0 million to its defined benefit pension plans and approximately $700,000 to its postretirement benefit plans in 2019.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2018, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2019	$ 24,026	$ 5,332	$ 117
2020	24,287	5,232	112
2021	24,633	5,201	105
2022	24,929	5,259	98
2023	25,173	5,270	90
2024 - 2028	124,688	25,851	320

Nonqualified benefit plans

In addition to the qualified defined benefit pension 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 projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 93,988**	$ 102,484
Accumulated benefit obligation	**$ 93,988**	$ 102,484

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

	2018	2017	2016
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	**$ 185**	$ 289	$ 493
Interest cost	**3,157**	3,494	3,742
Amortization of prior service cost	**—**	—	(80)
Recognized net actuarial loss	**1,047**	883	952
Curtailment gain	**—**	—	(3,292)
Net periodic benefit cost	**$ 4,389**	$ 4,666	$ 1,815

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	**3.86%**	3.20%
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.20%**	3.56%
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified benefit plans at December 31, 2018, are expected to aggregate as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Nonqualified benefits	$ 7,350	$ 7,766	$ 7,787	$ 7,018	$ 7,213	$ 36,885

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018, 2017 and 2016 were $597,000, $736,000 and $395,000, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2018	2017
	(In thousands)	
Investments		
Insurance contract*	$ 73,838	$ 77,388
Life insurance**	37,274	38,568
Other	10,818	6,971
Total investments	$ 121,930	$ 122,927

* For more information on the insurance contract, see Note 7.
** Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $42.4 million in 2018, $41.2 million in 2017 and $40.9 million in 2016.

Multiemployer plans

The Company contributes to a number of MEPPs 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 2018 and 2017 is for the plan's year-end at December 31, 2017, and December 31, 2016, 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 2018	Pension Protection Act Zone Status 2017	FIP/RP Status Pending/Implemented	Contributions 2018	Contributions 2017	Contributions 2016	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2018	Yellow as of 6/30/2017	Implemented	**$ 732**	$ 690	$ 766	No	12/31/2018 *
Construction Industry and Laborers Joint Pension Trust for So Nevada, Plan A	88-0135695-001	Red	Red	Implemented	**346**	377	523	No	6/30/2019
Edison Pension Plan	93-6061681-001	Green	Green	No	**12,111**	12,725	6,242	No	6/30/2019
IBEW Local 212 Pension Trust	31-6127280-001	Green as of 4/30/2018	Green as of 4/30/2017	No	**1,341**	1,312	1,146	No	6/2/2019
IBEW Local 357 Pension Plan A	88-6023284-001	Green	Green	No	**3,460**	3,286	3,016	No	5/31/2021
IBEW Local 648 Pension Plan	31-6134845-001	Yellow as of 2/28/2018	Red as of 2/28/2017	Implemented	**2,175**	2,254	773	No	8/29/2021
IBEW Local 82 Pension Plan	31-6127268-001	Green as of 6/30/2018	Green as of 6/30/2017	No	**1,569**	1,757	2,560	No	12/1/2019
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2018	Green as of 5/31/2017	No	**1,247**	1,156	1,221	No	9/30/2019
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	Green as of 11/30/2017	Green as of 11/30/2016	No	**740**	826	690	No	4/30/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red	Red	Implemented	**738**	718	775	No	3/31/2021-7/31/2024
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**8,468**	8,891	6,366	No	1/31/2018-5/31/2022
Pension Trust Fund for Operating Engineers	94-6090764-001	Yellow	Red	Implemented	**2,403**	2,391	2,069	No	6/15/2019-6/30/2020
Sheet Metal Workers Pension Plan of Southern CA, AZ, and NV	95-6052257-001	Yellow	Yellow	Implemented	**1,774**	1,016	1,087	No	6/30/2019
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**81**	48	50	No	1/31/2019 *
Other funds					**21,537**	19,298	17,243		
Total contributions					**$ 58,722**	$ 56,745	$ 44,527		

* Plan includes contributions required by collective bargaining agreements which have expired, but contain provisions automatically renewing their terms in the absence of a subsequent negotiated agreement.

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2017 and 2016
IBEW Local 82 Pension Plan	2017 and 2016
IBEW Local 124 Pension Trust Fund	2017 and 2016
IBEW Local 212 Pension Trust Fund	2017 and 2016
IBEW Local 357 Pension Plan A	2017 and 2016
IBEW Local 648 Pension Plan	2017 and 2016
Idaho Plumbers and Pipefitters Pension Plan	2017 and 2016
International Union of Operating Engineers Local 701 Pension Trust Fund	2017 and 2016
Minnesota Teamsters Construction Division Pension Fund	2017 and 2016
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2017 and 2016

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 $53.3 million, $52.2 million and $36.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Amounts contributed in 2018, 2017 and 2016 to defined contribution multiemployer plans were $31.1 million, $32.2 million and $23.8 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of 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 has an ownership interest of 22.7 percent in Big Stone Station, 25 percent in Coyote Station and 25 percent in Wygen III.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power; 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:

	2018	2017
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 156,534**	$ 158,084
Less accumulated depreciation	**49,345**	51,740
	$ 107,189	$ 106,344
Coyote Station:		
Utility plant in service	**$ 155,236**	$ 155,287
Less accumulated depreciation	**105,565**	103,897
	$ 49,671	$ 51,390
Wygen III:		
Utility plant in service	**$ 65,382**	$ 65,065
Less accumulated depreciation	**9,174**	7,652
	$ 56,208	$ 57,413

Note 18 - 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 and statuses of each open request.

MNPUC

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. Pursuant to the notice, Great Plains provided preliminary impacts of the TCJA on January 30, 2018. On March 2, 2018, Great Plains submitted its initial filing addressing the impacts of the TCJA advocating existing rates are reasonable and a reduction in rates is not warranted. On August 9, 2018, the MNPUC ruled that Great Plains reduce rates to reflect TCJA impacts and to also provide a one-time refund that captures the TCJA impacts from January 1, 2018 through the implementation date of new rates. On December 5, 2018, the MNPUC issued an order requiring Great Plains reduce its rates by $400,000 on an annual basis and provide a one-time refund of approximately $400,000, as previously mentioned, within 90 days after the rates are implemented through credits to customers' bills. The required compliance filing was submitted to the MNPUC on January 4, 2019.

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. On April 2, 2018, Montana-Dakota submitted its plan requesting the MTPSC recognize the identified need for additional rate relief and to consider the effects of the TCJA in a general electric rate case to be submitted by September 30, 2018. Montana-Dakota submitted the general electric rate case on September 28, 2018, as discussed below. On November 30, 2018, Montana-Dakota and interveners of the case submitted a stipulation and settlement agreement reflecting a one-time refund of approximately $1.5 million to account for all TCJA related impacts from January 1, 2018 through the date new rates are effective in the rate case noted below. A hearing was held on December 4, 2018, and the MTPSC issued an order accepting the stipulation and settlement agreement on December 21, 2018, requiring a one-time bill credit to occur in April 2019.

On September 28, 2018, Montana-Dakota filed an application with the MTPSC for an electric rate increase of approximately $11.9 million annually or approximately 18.9 percent above current rates. The requested increase is primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. The increase was offset by tax savings related to the TCJA. This matter is pending before the MTPSC.

NDPSC

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 also introduced a 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 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. On March 1, 2018, the updated interim rates were implemented. The impact of the TCJA was submitted as part of a rebuttal testimony identifying a reduction of the adjusted revenue requirement to approximately $3.6 million. On July 19, 2018, a settlement was filed reflecting a revised annual revenue increase of approximately $2.5 million or approximately 2.3 percent. The proposed adjustment mechanism to fund the SSIP was not included in the settlement and will be decided on separately by the NDPSC. On September 26, 2018, the NDPSC issued an order approving the settlement as filed but did not approve the SSIP recovery mechanism. On October 5, 2018, Montana-Dakota submitted a compliance filing, which included a plan for the one-time refund to be available March 1, 2019, for the interim amount to be refunded to customers. The NDPSC approved the compliance rates and were effective with service rendered on and after December 1, 2018.

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. On March 9, 2018, Montana-Dakota submitted a request to decrease its electric rates by $7.2 million or 3.9 percent annually. On August 10, 2018, a settlement agreement was filed requesting a decrease in rates of approximately $8.4 million. On September 26, 2018, the NDPSC issued an order approving the settlement along with requiring an additional adjustment to the rates to return 100 percent of the tax-effective 2018 excess deferred income taxes. On October 10, 2018, Montana-Dakota submitted a compliance filing, which included a refund plan for the interim amount to be refunded to customers. On November 20, 2018, the NDPSC approved the compliance rates which were effective with service rendered on and after December 1, 2018. The NDPSC also approved a one-time refund of approximately $7.9 million to be credited to customers' bills by March 15, 2019, based on 4.7 percent of the revenues collected between January 1, 2018 through November 30, 2018.

On October 19, 2018, Great Plains and the NDPSC advocacy staff filed a settlement agreement to resolve all outstanding issues in the NDPSC's investigation into the TCJA and a revenue neutral tariff filing submitted by Great Plains. The settlement agreement provides for miscellaneous tariff changes and a reduction in annual revenues of $168,000. On January 9, 2019, the NDPSC issued an order approving the settlement agreement and a refund requirement for the period from January 1, 2018 through the month preceding the effective date of the rate change. On January 23, 2019, the NDPSC approved the compliance rates to be effective February 1, 2019, along with the refund plan that provides for approximately $200,000 in refunds to be credited to customers' bills by April 15, 2019.

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. The deferral request was renewed on December 28, 2018. This matter is pending before the OPUC.

On May 31, 2018, Cascade filed a general rate case with the OPUC requesting an overall increase of approximately $2.3 million or approximately 3.5 percent on an annual basis, which incorporates the impact of the TCJA. On January 22, 2019, Cascade filed a stipulation with the OPUC for an annual increase in revenues of $1.7 million with a $500,000 reduction for excess deferred income taxes, for a net increase of $1.2 million. This matter is pending before the OPUC.

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. On May 4, 2018 and June 2, 2018, Montana-Dakota submitted detailed plans to address the TCJA impacts on the natural gas and electric utilities, respectively, to the SDPUC staff. On September 28, 2018, a settlement agreement was submitted to the SDPUC reflecting a proposal to refund approximately $600,000 to electric customers and approximately $1.3 million to natural gas customers. These refunds reflect the impact of the TCJA on 2018. On October 23, 2018, an order was issued by the SDPUC approving the settlement agreement with the refunds being credited to customers' bills beginning on February 15, 2019. On December 3, 2018, Montana-Dakota submitted proposed rate changes to reflect 2018 pro forma results and the TCJA impacts. On December 28, 2018, the SDPUC approved an annual decrease in revenues of approximately $300,000 for the natural gas operations and approximately $100,000 for the electric operations. The decrease in revenues was effective January 1, 2019.

WUTC

On June 1, 2018, Cascade filed its annual pipeline cost recovery mechanism requesting an increase in annual revenue of $2.3 million or approximately 1.1 percent. On October 11, 2018, Cascade filed a revised increase in annual revenue of $2.1 million or approximately 1.0 percent. The increase was effective November 1, 2018.

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. On March 23, 2018, the WYPSC issued an order requiring all public utilities to submit an initial assessment of the overall effects on the TCJA on their rates by March 30, 2018. On March 30, 2018, Montana-Dakota submitted its initial assessment indicating a rate reduction for its electric rates in the amount of approximately $1.1 million annually or approximately 4.2 percent. Revised electric rates reflecting this reduction were submitted to the WYPSC on June 13, 2018. Montana-Dakota reported its natural gas earnings do not support a decrease in rates and requested the WYPSC allow the impacts of the TCJA be addressed in a natural gas rate case to be submitted by June 1, 2019. Both matters are pending before the WYPSC.

FERC

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. On March 15, 2018, the FERC approved the waiver request and new rates reflecting the effects of the TCJA were implemented by MISO on March 1, 2018. MISO also retroactively re-billed the January and February 2018 services to reflect the new rates. On September 4, 2018, Montana-Dakota filed an update to its transmission formula rate under the MISO tariff for the multivalue project for $12.5 million, which is effective January 1, 2019.

On July 18, 2018, the FERC issued a final rule on Rate Changes Relating to Federal Income Tax Rate reductions resulting from the TCJA which requires natural gas pipeline companies to make a one-time informational filing to evaluate the impact of the lower corporate income tax rate and also select one of four options presented by the FERC to address the impact. 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. On October 31, 2018, the Company filed a rate case with the FERC. Due to the timing of the rate case filing, the Company was exempt from the one-time informational filing required by the FERC's final rule. On November 30, 2018, the FERC issued an order accepting and suspending tariff records, subject to refund, and establishing hearing procedures. The FERC order accepted the Company's rate case filing and suspended the associated tariff records to be effective May 1, 2019, subject to refund and the outcome of a hearing.

Note 19 - 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 has accrued liabilities of $30.4 million and $35.4 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, 2018 and 2017, respectively. This includes amounts that have been accrued for matters discussed in 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.

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 accruals related to these claims are reflected in regulatory assets. For more information, see Note 6.

The first claim is for contamination at a site in Eugene, Oregon, which was received in 1995. 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. Cascade and other PRPs will share in the cleanup costs with Cascade expecting to pay approximately 50 percent of the remediation and maintenance costs. Cascade has an accrual balance of $1.5 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, December 1, 2017 and December 1, 2018.

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. 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 $3.1 million has been incurred. Cascade has accrued $4.5 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 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. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. 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 recorded an accrual for this site for an amount that is not material.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for certain of the 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.

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, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Operating leases	$ 37,740	$ 26,255	$ 17,868	$ 11,647	$ 7,278	$ 49,098

Rent expense was $74.6 million, $73.7 million and $65.0 million for the years ended December 31, 2018, 2017 and 2016, 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 42 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
	(In thousands)					
Purchase commitments	$ 418,106	$ 215,069	$ 169,716	$ 115,884	$ 84,268	$ 622,383

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2018, 2017 and 2016, were $548.0 million, $516.1 million and $539.3 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 were expected to mature in 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining. On October 17, 2018, Centennial was released from this guarantee of certain debt obligations of Dakota Prairie Refining.

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

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, 2018, the fixed maximum amounts guaranteed under these agreements aggregated $196.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate to $85.3 million in 2019; $104.0 million in 2020; $500,000 in 2021; $500,000 in 2022; $500,000 in 2023; $1.5 million thereafter; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2018. 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, 2018, the fixed maximum amounts guaranteed under these letters of credit aggregated $30.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate to $6.7 million in 2019 and $23.3 million in 2020. There were no amounts outstanding under the above letters of credit at December 31, 2018. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the 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 or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company were reflected on the Consolidated Balance Sheet at December 31, 2018.

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. At December 31, 2018, approximately $697.9 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.

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, 2018, 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 $38.5 million.

Note 20 - Subsequent Event

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 in Sidney, Montana, and in late 2021 in Mandan, North Dakota. A plan is in place to maintain staff until the plant retirements. These dates may be impacted by the Company's coal supplier's pending bankruptcy proceeding. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2018 and 2017:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2018				
Operating revenues	**$ 976,293**	**$ 1,064,597**	**$ 1,280,787**	**$ 1,209,875**
Operating expenses	**906,917**	**990,605**	**1,140,783**	**1,091,524**
Operating income	**69,376**	**73,992**	**140,004**	**118,351**
Income from continuing operations	**41,960**	**44,075**	**107,369**	**75,982**
Income (loss) from discontinued operations, net of tax	**477**	**(273)**	**(118)**	**2,846**
Net income	**42,437**	**43,802**	**107,251**	**78,828**
Earnings per common share - basic:				
Earnings before discontinued operations	**.22**	**.22**	**.55**	**.39**
Discontinued operations, net of tax	**—**	**—**	**—**	**.01**
Earnings per common share - basic	**.22**	**.22**	**.55**	**.40**
Earnings per common share - diluted:				
Earnings before discontinued operations	**.22**	**.22**	**.55**	**.39**
Discontinued operations, net of tax	**—**	**—**	**—**	**.01**
Earnings per common share - diluted	**.22**	**.22**	**.55**	**.40**
Weighted average common shares outstanding:				
Basic	**195,304**	**195,524**	**196,018**	**196,023**
Diluted	**195,982**	**196,169**	**196,265**	**196,385**
2017				
Operating revenues	$ 937,925	$ 1,067,639	$ 1,272,548	$ 1,165,239
Operating expenses	872,139	988,979	1,117,228	1,040,957
Operating income	65,786	78,660	155,320	124,282
Income from continuing operations	35,638	44,405	89,549	115,394
Income (loss) from discontinued operations, net of tax	1,687	(3,190)	(2,198)	(82)
Net income	37,325	41,215	87,351	115,312
Earnings per common share - basic:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations, 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, 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

Notes:
- Fourth quarter 2017 reflects an income tax benefit of $39.5 million related to the TCJA. For more information, see Note 13.

Certain operations of the Company 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.

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
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.
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. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
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 prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PRP	Potentially Responsible Party
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
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 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 three months ended December 31, 2018, 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 will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be 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, 2018, 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)	691,629	(2)	$ —	(3)	4,357,330	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	
Total	691,629		$ —		4,357,330	

(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 and restricted stock awards.
(3) No weighted average exercise price is shown for the performance shares or restricted stock awards because such awards have no exercise price.
(4) This amount includes 4,041,479 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 315,851 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan.

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

Part IV

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

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data.

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Consolidated Statements of Comprehensive Income for each of the three years in the period ended December 31, 2018	59
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Consolidated Statements of Equity for each of the three years in the period ended December 31, 2018	61
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2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.

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MDU RESOURCES GROUP, INC.

Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	2018	2017	2016
		(In thousands)	
Operating revenues	**$ 628,331**	$ 623,693	$ 561,266
Operating expenses	**540,125**	520,069	469,853
Operating income	**88,206**	103,624	91,413
Other income	**1,504**	4,876	2,282
Interest expense	**32,761**	31,997	31,519
Income before income taxes	**56,949**	76,503	62,176
Income taxes	**(4,259)**	13,800	6,355
Equity in earnings of subsidiaries from continuing operations	**208,177**	222,283	177,275
Net income from continuing operations	**269,385**	284,986	233,096
Equity in earnings (loss) of subsidiaries from discontinued operations attributable to the Company	**2,933**	(3,783)	(168,663)
Loss on redemption of preferred stocks	**—**	600	—
Dividends declared on preferred stocks	**—**	171	685
Earnings on common stock	**$ 272,318**	$ 280,432	$ 63,748
Comprehensive income	**$ 279,269**	$ 279,602	$ 65,848

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,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,271	$ 843
Receivables, net	92,724	83,453
Accounts receivable from subsidiaries	36,015	34,029
Inventories	13,293	13,864
Prepayments and other current assets	14,488	34,400
Total current assets	158,791	166,589
Investments	76,202	76,779
Investment in subsidiaries	1,790,886	1,704,908
Property, plant and equipment	2,846,715	2,631,161
Less accumulated depreciation, depletion and amortization	836,735	797,130
Net property, plant and equipment	2,009,980	1,834,031
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	180,473	175,599
Total deferred charges and other assets	185,285	180,411
Total assets	$ 4,221,144	$ 3,962,718
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 200,711	$ 100,011
Accounts payable	50,051	47,000
Accounts payable to subsidiaries	12,438	7,234
Taxes payable	24,704	13,717
Dividends payable	39,695	38,573
Accrued compensation	14,346	20,017
Other accrued liabilities	54,099	36,881
Total current liabilities	396,044	263,433
Long-term debt	586,012	612,493
Deferred credits and other liabilities:		
Deferred income taxes	165,122	147,847
Other	507,191	509,902
Total deferred credits and other liabilities	672,313	657,749
Commitments and contingencies		
Stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	196,565	195,843
Other paid-in capital	1,248,576	1,233,412
Retained earnings	1,163,602	1,040,748
Accumulated other comprehensive loss	(38,342)	(37,334)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total stockholders' equity	2,566,775	2,429,043
Total liabilities and stockholders' equity	$ 4,221,144	$ 3,962,718

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,	2018	2017	2016
		(In thousands)	
Net cash provided by operating activities	$ **294,379**	$ 284,075	$ 238,125
Investing activities:			
Capital expenditures	**(242,692)**	(146,370)	(159,570)
Net proceeds from sale or disposition of property and other	**5,032**	(5,665)	3,784
Investments in and advances to subsidiaries	**(40,000)**	(40,000)	(5,000)
Advances from subsidiaries	**70,000**	40,000	15,000
Investments	**(528)**	(468)	(129)
Net cash used in investing activities	**(208,188)**	(152,503)	(145,915)
Financing activities:			
Issuance of long-term debt	**199,422**	70,080	106,420
Repayment of long-term debt	**(125,961)**	(37,569)	(50,010)
Payments of stock issuance costs	**(10)**	—	—
Dividends paid	**(154,573)**	(150,727)	(147,156)
Redemption of preferred stock	**—**	(15,600)	—
Repurchase of common stock	**(1,920)**	(564)	—
Tax withholding on stock-based compensation	**(1,721)**	(508)	(226)
Net cash used in financing activities	**(84,763)**	(134,888)	(90,972)
Increase (decrease) in cash and cash equivalents	**1,428**	(3,316)	1,238
Cash and cash equivalents - beginning of year	**843**	4,159	2,921
Cash and cash equivalents - end of year	$ **2,271**	$ 843	$ 4,159

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 as of December 31, 2018, prior to the Holding Company Reorganization. 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 per common share Please refer to the Consolidated Statements of Income of the registrant for earnings per common share. In addition, see Item 8 - Note 1 for information on the computation of earnings per common share.

Note 2 - Debt At December 31, 2018, the Company had long-term debt maturities, excluding unamortized debt issuance costs, of $200.7 million in 2019, $700,000 in 2020, $700,000 in 2021, $700,000 in 2022, $49.2 million in 2023 and $536.7 million scheduled to mature in years after 2023.

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

Note 3 - Dividends The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $115.9 million, $116.1 million and $115.8 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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

For the years ended December 31, 2018, 2017 and 2016

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:					
2018	**$ 8,069**	**$ 7,532**	**$ 1,121**	**$ 7,872**	**$ 8,850**
2017	10,479	7,024	989	10,423	8,069
2016	9,835	8,302	851	8,509	10,479

* 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.

3. Exhibits

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
2(d)	Agreement and Plan of Merger, dated December 31, 2018, by and among MDU Resources Group, Inc., MDUR Newco, Inc. MDU Newco Sub, Inc.		8-K		2(a)	1/2/19	1-03480
3(a)	Certificate of Merger, dated December 31, 2018		8-K		3(a)	1/2/19	1-03480
3(b)	Amended and Restated Certificate of Incorporation of MDU Resources Group, Inc.		8-K		3(a)	1/2/19	1-03480
3(c)	Amended and Restated Bylaws of MDU Resources Group, Inc.		8-K		3.1	2/15/19	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

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
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
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)	First Amendment to the Fourth Amended and Restated Credit Agreement, dated as of October 26, 2018, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto	X					1-03480
4(m)	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(n)	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(o)	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(p)	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(q)	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

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
4(r)	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
4(s)	MDU Resources Group, Inc. Credit Agreement, dated June 8, 2018, among MDU Resources Group, Inc, Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	6/30/18	4(a)	8/3/18	1-03480
+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 November 15, 2018	X					1-03480
+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 10, 2016		8-K		10.3	2/18/16	1-03480
+10(i)	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(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.1	2/21/18	1-03480
+10(k)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2019	X					1-03480
+10(l)	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(m)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.3	2/21/18	1-03480
+10(n)	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(o)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(p)	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(q)	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(r)	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(s)	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

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference: Form	Period Ended	Exhibit	Filing Date	File Number
+10(t)	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(u)	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(v)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(w)	Jason L. Vollmer Offer Letter, dated March 7, 2016		8-K		10.2	3/8/16	1-03480
+10(x)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
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					
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 22, 2019	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 22, 2019
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 22, 2019
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 22, 2019
/s/ Harry J. Pearce Harry J. Pearce (Chair of the Board)	Director	February 22, 2019
/s/ Thomas Everist Thomas Everist	Director	February 22, 2019
/s/ Karen B. Fagg Karen B. Fagg	Director	February 22, 2019
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 22, 2019
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 22, 2019
/s/ William E. McCracken William E. McCracken	Director	February 22, 2019
/s/ Patricia L. Moss Patricia L. Moss	Director	February 22, 2019
/s/ Edward A. Ryan Edward A. Ryan	Director	February 22, 2019
/s/ David M. Sparby David M. Sparby	Director	February 22, 2019
/s/ John K. Wilson John K. Wilson	Director	February 22, 2019

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Section 2: EX-4.L (MDU RESOURCES FIRST AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT)

FIRST AMENDMENT

THIS FIRST AMENDMENT dated as of October 26, 2018 (this "Amendment") amends the Fourth Amended and Restated Credit Agreement dated as of September 23, 2016 (the "Credit Agreement") among Centennial Energy Holdings, Inc. (the "Company"), various financial institutions (the "Banks") and U.S. Bank National Association, as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used but not otherwise defined herein have the respective meanings given to them in the Credit Agreement.

WHEREAS, the Company, the Banks and the Administrative Agent have entered into the Credit Agreement; and

WHEREAS, the parties hereto desire to amend the Credit Agreement as set forth herein;

NOW, THEREFORE, the parties hereto agree as follows:

SECTION 1. Amendments. Subject to the satisfaction of the conditions precedent set forth in Section 3,

1.1 Section 1.01 of the Credit Agreement is amended to add the following definitions in proper alphabetical order.

"Investment Grade Rating" means a Rating of BBB- (or the equivalent) or higher from Fitch or S&P.

"Rating" means (a) the rating assigned by S&P or Fitch to the outstanding senior unsecured non-credit enhanced long term indebtedness of the Company or (b) if S&P or Fitch has not assigned a rating of the type described in clause (a), the corporate rating assigned to the Company by S&P or the issuer rating assigned to the Company by Fitch.

1.2 Section 3.04 of the Credit Agreement is amended to add the following paragraph at the end thereof:

Notwithstanding the foregoing, in the event the Administrative Agent determines (which determination shall be conclusive absent manifest error) that (A) the circumstances set forth in Section 3.04(b)(ii) have arisen and such circumstances are unlikely to be temporary, (B) ICE Benchmark Administration Limited (or any Person that takes over the administration of such rate) discontinues its administration and publication of interest settlement rates for deposits in Dollars, or (C) the supervisor for the administrator of the interest settlement rate described in clause (B) of this Section 3.04 or a Governmental Authority having jurisdiction over the Administrative Agent has made a public statement identifying a specific date after which such interest settlement rate shall no longer be used for determining interest rates for loans, then the Administrative Agent and the Company shall seek to jointly agree upon an alternate rate of interest to the Eurodollar Base Rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time, and the Administrative Agent and the Company shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable. Notwithstanding anything to the contrary in Section 10.01, such amendment shall become effective without any further action or consent of any other party to this Agreement so long as the Administrative Agent shall not have received, within five Business Days of the date notice of such amendment is provided to the Banks, a written notice from the Majority Banks stating that such Majority Banks object to such amendment (which such notice shall note with specificity the particular provisions of the amendment to which such Majority Banks object). Until an alternate rate of interest shall be determined in accordance with this Section 3.04, (x) any request pursuant to Section 2.02(d) that requests the conversion of any Advance to, or continuation of any Advance as, a Eurodollar Advance shall be ineffective and any such Advance (i) may, at the Company's option be repaid in full or (ii) if not repaid, shall be continued as or converted to, as the case may be, a Base Rate Advance, and (y) if any request pursuant to Section 2.02(c) requests a Eurodollar Advance, such Advance shall be made as a Base Rate Advance. If the alternate rate of interest determined pursuant to this paragraph of Section 3.04 shall be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement.

1.3 Section 7.08(b)(iii)(z) is amended to add the following proviso at the end thereof:

; provided that, beginning September 30, 2018, if the Company has Investment Grade Ratings from both Fitch and S&P, this clause (z) shall not apply.

Section 10.01 is amended to delete subsections (x), (y) and (z) and add the following proviso:

(w) no amendment, waiver or consent shall, unless in writing and signed by the Administrative Agent in addition to the Majority Banks or all the Banks, as the case may be, affect the rights or duties of the Administrative Agent under this Agreement or any other Loan Document, (x) no amendment of any provision of this Agreement relating to any Issuer shall be effective without the written consent of such Issuer, (y) any Fee Letter may be amended, or rights or privileges thereunder waived, in a writing executed by the respective parties thereto, and (z) the Administrative Agent and the Company may, without the consent of any Bank, enter into amendments or modifications to the Agreement or enter into any additional Loan Documents as the Administrative Agent reasonably deems appropriate in order to implement or effectuate the terms of Section 3.04 in accordance with the terms of Section 3.04.

SECTION 2. Representations and Warranties. The Company represents and warrants to the Administrative Agent and the Banks that, after giving effect to the effectiveness hereof:

(a) each representation and warranty of the Company contained in Article V of the Credit Agreement, as amended hereby (as so amended, the "Amended Credit Agreement"), is true and correct in all material respects as of the date of the execution and delivery of this

Amendment by the Company, with the same effect as if made on such date (except to the extent such representations and warranties expressly refer to an earlier date, in which case they are true and correct as of such earlier date); and

(b) no Default or Event of Default exists.

SECTION 3. Effectiveness. This Amendment shall become effective when the Administrative Agent shall have received counterparts of this Amendment executed by the Company and the Majority Banks.

SECTION 4. Miscellaneous.

4.1 Continuing Effectiveness, etc. As herein amended, the Credit Agreement shall remain in full force and effect and is hereby ratified and confirmed in all respects. After the effectiveness of this Amendment, all references in the Credit Agreement to "this Agreement" and in the other Loan Documents to the "Credit Agreement" or similar terms shall refer to the Amended Credit Agreement.

4.2 Counterparts. This Amendment may be executed in any number of counterparts and by the different parties on separate counterparts, and each such counterpart shall be deemed to be an original but all such counterparts shall together constitute one and the same Amendment. Delivery of an executed counterpart hereby by facsimile or in .pdf or similar format shall constitute delivery of an original executed counterpart hereof.

4.3 Governing Law. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE INTERNAL LAW OF THE STATE OF NEW YORK WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW (OTHER THAN TITLE 14 OF ARTICLE 5 OF THE NEW YORK GENERAL OBLIGATIONS LAW); PROVIDED THAT THE ADMINISTRATIVE AGENT AND THE BANKS SHALL RETAIN ALL RIGHTS ARISING UNDER FEDERAL LAW.

4.4 Successors and Assigns. This Amendment shall be binding upon the Company, the Banks and the Administrative Agent and their respective successors and assigns, and shall inure to the benefit of the Company, the Banks and the Administrative Agent and the respective successors and assigns of the Banks and the Administrative Agent.

Delivered as of the day and year first above written.

CENTENNIAL ENERGY HOLDINGS, INC.

By: \s\ Jason L. Vollmer
Name: Jason L. Vollmer
Title: Vice President, Chief Financial Officer and Treasurer

U.S. BANK NATIONAL ASSOCIATION, as Administrative Agent, as an Issuer and as a Bank

By: \s\ James O'Shaughnessy
Name: James O'Shaughnessy
Title: Vice President

MUFG BANK, LTD., as Syndication Agent, as an Issuer and as a Bank

By: \s\ Robert MacFarlane
Name: Robert MacFarlane
Title: Director

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

WELLS FARGO BANK, NATIONAL ASSOCIATION, as a Co-Documentation Agent, as an Issuer and as a Bank

By: \s\ Keith Luettel
Name: Keith Luettel
Title: Director

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

JPMORGAN CHASE BANK, N.A., as a Co-Documentation Agent, as an Issuer and as a Bank

By: \s\ Justin Martin
Name: Justin Martin
Title: Authorized Officer

ROYAL BANK OF CANADA, as a Co-Documentation Agent, as an Issuer and as a Bank

By: \s\ Justin Painter
Name: Justin Painter
Title: Authorized Signatory

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

TORONTO-DOMINION BANK, NEW YORK BRANCH, as a Bank

By: \s\ Annie Dorval
Name: Annie Dorval
Title: Authorized Signatory

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK BRANCH,
as a Bank

By: \s\ Anju Abraham
Name: Anju Abraham
Title: Authorized Signatory

By: \s\ Robert Casey
Name: Robert Casey
Title: Authorized Signatory

KEYBANK NATIONAL ASSOCIATION, as a Bank

By: \s\ Keven D. Smith
Name: Keven D. Smith
Title: Senior Vice President

PNC BANK, NATIONAL ASSOCIATION, as a Bank

By: \s\ Kelly R. Miller
Name: Kelly Miller
Title: Vice President

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

GOLDMAN SACHS BANK USA, as a Bank

By: \s\ Mahesh Mohan
Name: Mahesh Mohan
Title: Authorized Signatory

[Signature page to the Centennial Energy Holdings, Inc.
First Amendment]

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Section 3: EX-10.B (MDU RESOURCES DIRECTOR COMPENSATION POLICY)

MDU RESOURCES GROUP, INC.
DIRECTOR COMPENSATION POLICY

Each director of MDU Resources Group, Inc. (the "Company") who is not a full-time employee of the Company (a "Director") shall receive compensation made up of annual cash retainers and shares of the Company's common stock ("Common Stock"), as set forth in this policy.

Director Compensation

Annual Cash Retainers

Base Retainer	$70,000*
Additional Retainers:	
Non-Executive Chair of the Board	90,000
Chair of Audit Committee	15,000
Chair of Compensation Committee	10,000
Chair of Nominating and Governance Committee	10,000

* Effective June 1, 2017.

Such cash retainers shall be paid in monthly installments.

The MDU Resources Group, Inc. Deferred Compensation Plan for Directors (as amended and restated effective May 15, 2008) (the "Plan") permits a Director to defer all or any portion of the annual cash retainers. The amount deferred is recorded in each participant's deferred compensation account and credited with income in the manner prescribed in the Plan. For further details, reference is made to the Plan, a copy of which is attached.

Common Stock

Each person, other than the Non-Executive Chair of the Board, who is a Director of the Company at any time during the calendar year shall receive a $110,000 stock payment, and any person who is the Non-Executive Chair of the Board shall receive a $145,000 stock payment, on or about the Wednesday following the Board of Directors' regularly-scheduled November meeting, pursuant to the Non-Employee Director Stock Compensation Plan or the Non-Employee Director Long-Term Incentive Compensation Plan. The stock payment shall be made under the Non-Employee Director Long-Term Incentive Compensation Plan. The stock payment shall be made by providing the Director or Non-Executive Chair with the number of whole shares of Common Stock determined (i) if the shares are original issue or treasury stock, by dividing the amount of the applicable stock payment by the closing price of the Common Stock on the New York Stock Exchange on the grant date and (ii) if the shares are purchased on the open market, by dividing the amount of the applicable stock payment by the weighted average price paid to purchase shares for the Director or Non-Executive Chair for that stock payment, excluding any related brokerage commissions or other service fees. Any fractional shares shall be paid in cash. The stock payment shall be prorated for any Director or Non-Executive Chair who does not serve the entire calendar year by multiplying the applicable stock payment by a fraction, the numerator of which is the number of actual or expected months (with a partial month counted as a full month) of service on the Board during the calendar year and the denominator of which is twelve.

By written election a Director may reduce his or her annual cash retainers and have that amount applied to the purchase of additional shares of Common Stock under the Non-Employee Director Long-Term Incentive Compensation Plan. The annual election shall specify the percentage of the annual cash retainers to be applied toward the purchase of additional shares and must be received by the Company by the last business day of the year prior to the year in which the election is to be effective. No election may be changed or revoked for the current year, but may be changed for a subsequent year. The additional stock payments will be made on the last business day of March, June, September, and December. The stock payment shall be made by providing the Director with the number of whole shares of Common Stock determined (i) if the shares are original issue or treasury stock, by dividing the amount of the applicable stock payment by the closing price of the Common Stock on the New York Stock Exchange on the grant date or (ii) if the shares are purchased on the open market, by dividing the amount of the applicable stock payment by the weighted average price paid to purchase shares for the Director for that stock payment, excluding any related brokerage commissions or other service fees. No fractional shares shall be purchased and cash in lieu of any fractional shares shall be paid to the Director.

Travel Expense Reimbursement

All Directors will be reimbursed for reasonable travel expenses incurred while serving as a Director, including spouse's expenses, in connection with attendance at meetings of the Company's Board of Directors and its committees. If the travel expense is related to the reimbursement of airfare, such reimbursement will not exceed full-coach rate. Spousal travel expenses paid by the Company are treated as taxable income to the Director. See the paragraph below entitled "Code Section 409A" for further rules relating to travel expense reimbursements.

Directors' Liability

Article Seventeenth of the Company's Restated Certificate of Incorporation provides that no Director of the Company shall be liable to the Company or its stockholders for breach of fiduciary duty as a Director, with certain exceptions stated below. Section 7.07 of the Company's Bylaws requires the Company to indemnify fully a Director against expenses, attorneys fees, judgments, fines and amounts paid in settlement of any suit, action or proceeding, whether civil or criminal, arising from an action of a Director by reason of the fact that the Director was a Director of MDU Resources Group, Inc.

There are exceptions to the protections under Article Seventeenth of the Company's Restated Certificate of Incorporation: breaches of the Directors' duty of loyalty to the Company or its stockholders, acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of the law, violation of Section 174 of the Delaware General Corporation Law (relating to unlawful declaration of dividends and unlawful purchase of the Company's stock), and transactions from which the Director derived an improper personal benefit (including short-swing profits under Section 16(b) of the Securities Exchange Act of 1934).

Additional protection is provided through individual indemnification agreements with each Director.

The Company has and does maintain Directors' and Officers' liability insurance coverage with a $125 million limit.

Insurance Coverages

The Company maintains the following insurance for protection of its Directors as they carry out the business of MDU Resources Group, Inc., which shall be provided while serving as a Director:

1. General liability and automobile liability insurance:

   If driving a personal vehicle, the Directors are afforded automobile liability coverage excess of their own personal automobile insurance under a combination of policies with program limits to $100 million after a self-insured retention of $500,000. If driving a vehicle owned by the Company, personal automobile insurance does not apply.

   For general liability, coverage is provided to Directors under a combination of policies with program limits to $100 million after a self-insured retention of $500,000.

2. Fiduciary and crime insurance:

   The Directors are afforded coverage under the fiduciary and crime liability insurance policies. The fiduciary policy has a limit of $35 million and the crime policy has a limit of $10 million.

3. Aircraft liability insurance:

   The Company's existing aircraft liability insurance extends coverage while a hired, non-owned* aircraft is used by a Director in traveling to and from Director or Board committee meetings. This insurance coverage is excess of any underlying policy that may exist and provides limits of $200 million.

   *Non-owned aircraft is defined as: 1) any aircraft registered under a “standard” airworthiness certificate issued by the FAA; 2) aircraft with a seating capacity not exceeding 40 seats; 3) aircraft that are not owned by MDU Resources Group, Inc. or any of its subsidiaries; 4) aircraft that are not partly or wholly owned by or registered in the Director’s name or the name of any Director’s household member.

4. Business travel accident insurance:

   All Directors are protected by a group insurance policy with coverage of $250,000 that provides 24-hour accident protection while traveling on Company business.

   Coverage in all instances begins at the actual start of a business trip and ends when the Director returns to his/her home or regular place of employment.

   The beneficiary of the insurance will be that beneficiary recorded on a beneficiary designation provided by the Company.

5. Group life insurance:

All outside Directors are protected by a non-contributory group life insurance policy with coverage of $100,000.

The coverage begins the day the Director is elected to the Board of Directors and terminates when the Director ceases to be an outside Director.

A Certificate of Insurance shall be provided to the Director. The beneficiary of the insurance will be the beneficiary recorded on a beneficiary designation provided by the Company.

This protection is considered taxable compensation under current tax laws. Consequently, the Company will provide each Director annually on Form 1099 the amount of taxable income related to this coverage.

Hedging Stock Ownership

Directors are not permitted to hedge their ownership of Company common stock. Hedging strategies include but are not limited to zero-cost collars, equity swaps, straddles, prepaid variable forward contracts, security futures contracts, exchange funds, forward sale contracts and other financial transactions that allow the Director to benefit from devaluation of the Company's stock. Hedging strategies may allow Directors to own stock technically but without the full benefits and risks of such ownership. Therefore, Directors are prohibited from engaging in any such transactions.

Policy Regarding Margin Accounts and Pledging of Company Stock

Effective December 21, 2012, Directors and related persons are prohibited from holding Company common stock in a margin account or pledging Company securities as collateral for a loan, with certain exceptions. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge or security provisions of the customer agreement. Company common stock may be held in a cash account, which is a brokerage account that does not allow any extension of credit on securities. “Related person” means a Director’s spouse, minor child and any person (other than a tenant or domestic employee) sharing the household of a Director, as well as any entities over which a Director exercises control.

Code Section 409A

To the extent any reimbursements or in-kind benefits provided to a Director pursuant to this policy constitute “deferred compensation” under Internal Revenue Code Section 409A, any such reimbursement or in-kind benefit shall be paid in a manner consistent with Treasury Regulation Section 1.409A-3(i)(1)(iv), including the requirements that the amount of reimbursable expenses or in-kind benefits provided during a year may not affect the expenses eligible for reimbursement or in-kind benefits provided in any other year and that any reimbursement be made on or before the last day of the calendar year following the calendar year in which the expense was incurred.

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Section 4: EX-10.K (MDU RESOURCES LONG-TERM PERFORMANCE INCENTIVE PLAN)

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

PERFORMANCE SHARE AWARD AGREEMENT

February 14, 2019

{Participant Name}

In accordance with the terms of the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan (the "Plan"), pursuant to action of the Compensation Committee of the Board of Directors of MDU Resources Group, Inc. (the "Committee"), MDU Resources Group, Inc. (the "Company") hereby grants to you (the "Participant") Performance Shares (the "Award"), subject to the terms and conditions set forth in this Award Agreement (including Annexes A and B hereto and all documents incorporated herein by reference), as set forth below:

Target Award:	{No. of Shares} Performance Shares (the "Target Award")
Performance Period:	January 1, 2019 through December 31, 2021 (the "Performance Period")
Date of Grant:	February 14, 2019
Dividend Equivalents:	Yes

THESE PERFORMANCE SHARES ARE SUBJECT TO FORFEITURE AS PROVIDED HEREIN. THIS AWARD AND AMOUNTS RECEIVED IN CONNECTION WITH THIS AWARD ARE ALSO SUBJECT TO FORFEITURE, RECAPTURE OR OTHER ACTION IN THE EVENT OF AN ACCOUNTING RESTATEMENT, AS PROVIDED IN THE PLAN.

Further terms and conditions of the Award are set forth in Annexes A and B hereto, which are integral parts of this Award Agreement.

You must accept this Award Notice by logging onto your account with Fidelity Investments and accepting this grant agreement. If you fail to do so, the award will be null and void. By accepting this Award, you agree to be bound by all of the provisions set forth in this Award Notice, the Agreement, and the Plan.

Attachments:
Annex A: Performance Share Award Agreement
Annex B

ANNEX A

TO

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

PERFORMANCE SHARE AWARD AGREEMENT

It is understood and agreed that the Award of Performance Shares evidenced by the Award Agreement to which this is annexed is subject to the following additional terms and conditions.

1. Nature of Award. The Target Award represents the opportunity to receive shares of Company common stock, $1.00 par value ("Shares") and Dividend Equivalents on such Shares. The number of Shares that may be earned under this Award shall be determined pursuant to Section 4 hereof. The amount of Dividend Equivalents that may be earned under this Award shall be determined pursuant to Section 6 hereof. Except for Dividend Equivalents, which are paid in cash, Awards will be paid in Shares.

2. Performance Measures

The following performance measures will be used to determine the Payout Percentage.

- Fifty percent (50%) of the Award is based on the Company's total shareholder return ("TSR") relative to that of the Peer Group listed on Annex B (the "Percentile Rank") for the Performance Period.
- Twenty-five percent (25%) of the Award is based on the Company’s compound annual growth rate in Earnings from continuing operations before Interest, Taxes, Depreciation, Depletion and Amortization (EBITDA) for the Performance Period.
- Twenty-five percent (25%) of the Award is based on the Company’s compound annual growth rate in Earnings from continuing operations for the Performance Period.

(a) The achievement of the relative TSR performance measure will be determined in accordance with the following table:

Percentile Rank	**Payout Percentage (% of Target Award)**
[ ]th or [ ]	[ ]
[ ]th	[ ]
[ ]th	[ ]
less than [ ]th	[ ]

If the Company achieves a Percentile Rank between the [ ]th and [ ]th percentiles, the Payout Percentage shall be equal to [ ]%, plus [ ]% for each Percentile Rank whole percentage above the [ ]th percentile. If the Company achieves a Percentile Ranking between the [ ]th and [ ]th percentiles, the Payout Percentage shall be equal to [ ]%, plus [ ]% for each Percentile Rank whole percentage above the [ ]th percentile.

The Percentile Rank of a given company's TSR is defined as the percentage of the Peer Group companies' returns falling at or below the given company's TSR. The formula for calculating the Percentile Rank follows:

Percentile Rank = (n - r + 1)/n x 100

Where:

n = total number of companies in the Peer Group, including the Company

r = the numeric rank of the Company's TSR relative to the Peer Group, where the highest return in the group is ranked number 1

To illustrate, if the Company's TSR is the third highest in the Peer Group comprised of 20 companies, its Percentile Rank would be 90. The calculation is:
(20 - 3 + 1)/20 x 100 = 90.

The Percentile Rank shall be rounded to the nearest whole percentage.

If the common stock of a company in the Peer Group ceases to be traded during the Performance Period, the company will be deleted from the Peer Group. Percentile Rank will be calculated without regard to the return of the deleted company.

If the Company or a company in the Peer Group spins off a segment of its business, the shares of the spun-off entity will be treated as a cash dividend that is reinvested in the Company or the company in the Peer Group.

Total shareholder return is the percentage change in the value of an investment in the common stock of a company from the initial investment made on the last trading day in the calendar year preceding the beginning of the performance period through the last trading day in the final year of the performance period. It is assumed that dividends are reinvested in additional shares of common stock at the frequency paid.

(b) The achievement of the EBITDA growth performance measure will be determined in accordance with the following table:

EBITDA Compound Annual Growth Rate	**Payout Percentage (% of Target Award)**
Less than [ ]%	[ ]%
[ ]%	[ ]%
[ ]%	[ ]%
[ ]%	[ ]%

Payout percentages for results achieved between the stated performance levels will be determined by linear interpolation.

For purposes of calculating EBITDA, Earnings will be Income from continuing operations at the beginning and end of the performance period. Interest, taxes and depreciation, depletion, and amortization expenses used in the calculation of EBITDA will also be from continuing operations at the beginning and end of the performance period. Earnings used to determine EBITDA will be adjusted, as such adjustments are approved by the Compensation Committee, to remove:

- [ ]
- [ ]
- [ ]

For calculation of the 2019-2021 performance period, the beginning performance period EBITDA from continuing operations used in the denominator (base year) will be the 2018 EBITDA of $[ ] million. The Compensation Committee reserves the right to equitably adjust the target EBITDA annual growth rate and the beginning and end of period EBITDA to reflect the effect of business segment changes during the performance period and prevent dilution or enlargement of rights.

The EBITDA compound annual growth rate (EBITDA CAGR) for the performance period will be determined by the following formula:

$$\text{EBITDA CAGR} = (EV / BV)^{1/n} - 1$$

Where:

EV = EBITDA at the end of the performance period (12/31/2021)
BV = EBITDA at the beginning of the performance period (12/31/2018)
n = number of years in the performance period (i.e. 3)

To illustrate, if the Company's EBITDA at the end of 2018 was $600 million and the Company's EBITDA at the end of 2021 was $700 million, the compound annual growth rate at the end of the 3 year period would be 5.3%. The calculation is:

$$5.3\% = (700 / 600)^{1/3} - 1$$

(c) The achievement of the Earnings growth performance measure will be determined in accordance with the following table:

Earnings Compound Annual Growth Rate	**Payout Percentage (% of Target Award)**
Less than [ ]%	[ ]%
[ ]%	[ ]%
[ ]%	[ ]%
[ ]%	[ ]%

Payout percentages for results achieved between the stated performance levels will be determined by linear interpolation.

For purposes of calculating Earnings growth, Earnings will be Income from continuing operations at the beginning and end of the performance period. Earnings will be adjusted, as such adjustments are approved by the Compensation Committee, to remove:

- [ ]
- [ ]
- [ ]

For calculation of the 2019-2021 performance period, the beginning performance period Earnings used in the denominator (base year) will be the 2018 earnings from continuing operations of $[ ] million. The Compensation Committee reserves the right to equitably adjust the target Earnings compound annual growth rate and the Beginning and end of period Earnings to reflect the effect of business segment changes during the performance period and prevent dilution or enlargement of rights.

The Earnings compound annual growth rate (Earnings CAGR) for the performance period will be determined by the following formula:

$$\text{Earnings CAGR} = (EV / BV)^{1/n} - 1$$

Where:

EV = Earnings at the end of the performance period (12/31/2021)
BV = Earnings at the beginning of the performance period (12/31/2018)
n = number of years in the performance period (i.e. 3)

To illustrate, if the Company's Earnings at the end of 2018 was $250 million and the Company's Earnings at the end of 2021 was $300 million, the compound annual growth rate at the end of the 3 year period would be 6.3%. The calculation is:

$$6.3\% = (300 / 250)^{1/3} - 1$$

3. <u>Total Percentage Payout</u>

The Total Percentage Payout is the sum of the payout percentages for each of the performance measures multiplied by the weighting percentage for such performance measure.

i.e.

Total Percentage Payout = (50% x relative TSR payout) + (25% x EBITDA growth payout) + (25% x Earnings growth payout)

4. <u>Determination of Number of Shares Earned</u>. The number of Shares earned, if any, for the Performance Period shall be determined in accordance with the following formula:

# of Shares = Total Payout Percentage x Target Award

All Performance Shares that are not earned for the Performance Period shall be forfeited.

5. <u>Issuance of Shares and Mandatory Holding Period</u>. Subject to any restrictions on distributions of Shares under the Plan, and subject to Section 6 of this Annex A, the Shares earned under the Award, if any, shall be issued to the Participant as soon as practicable (but no later than the next March 10) following the close of the Performance Period. The Participant shall retain 50% of the net after-tax Shares that are earned under this Award until the earlier of (i) the end of the two-year period commencing

on the date any Shares earned under this Award are issued and (ii) the Participant's termination of employment. Executives are required to own Shares at designated multiples of their base salary. If a Participant has not achieved an applicable stock ownership requirement, the Company may require the Participant to hold Shares received under this award until the requirement is met.

6. Dividend Equivalents. Dividend Equivalents shall be earned with respect to any Shares issued to the Participant pursuant to this Award. The amount of Dividend Equivalents earned shall be equal to the total dividends declared on a Share for stockholders of record between the Date of Grant of this Award and the last day of the Performance Period, multiplied by the number of Shares issued to the Participant pursuant to the Award Agreement. Any Dividend Equivalents earned shall be paid in cash to the Participant when the Shares to which they relate are issued or as soon as practicable thereafter, but no later than the next March 10 following the close of the Performance Period. If the Award is forfeited or if no Shares are issued, no Dividend Equivalents shall be paid.

7. Termination of Employment.

(a) If the Participant's employment with the Company is terminated during the Performance Period (i) for "Cause" (as defined below) at any time or (ii) for any reason other than "Cause" before the Participant, as of the effective date of termination, has reached age 55 and completed 10 "Years of Service" (as defined below), all Performance Shares (and related Dividend Equivalents) shall be forfeited.

(b) If the Participant's employment with the Company is terminated for any reason other than "Cause" after the Participant, as of the effective date of termination, has reached age 55 and completed 10 "Years of Service" (i) during the first year of the Performance Period, all Performance Shares (and related Dividend Equivalents) shall be forfeited; (ii) during the second year of the Performance Period, determination of the Company's Payout Percentage for the Performance Period will be made by the Committee at the end of the Performance Period, and Shares (and related Dividend Equivalents) earned, if any, will be paid based on the Payout Percentage, prorated for the number of full months elapsed from and including the month in which the Performance Period began to and including the month in which the termination of employment occurs; and (iii) during the third year of the Performance Period, determination of the Company's Payout Percentage for the Performance Period will be made by the Committee at the end of the Performance Period, and Shares (and related Dividend Equivalents) earned, if any, will be paid based on the Payout Percentage without prorating.

(c) For purposes of the Award Agreement, the term "Cause" shall mean the Participant's fraud or dishonesty that has resulted or is likely to result in material economic damage to the Company or a Subsidiary, or the Participant's willful nonfeasance if such nonfeasance is not cured within ten days of written notice from the Company or a Subsidiary, as determined in good faith by a vote of at least two-thirds of the non-employee directors of the Company at a meeting of the Board at which the Participant is provided an opportunity to be heard. For purposes of the Award Agreement, the term "Years of Service" shall mean the years a Participant is employed by the Company and/or a Subsidiary.

8. Tax Withholding. Pursuant to Article 14 of the Plan, the Committee has the power and the right to deduct or withhold, or require the Participant to remit to the Company, an amount sufficient to satisfy any Federal, state and local taxes (including the Participant's FICA obligations) required by law to be withheld with respect to the Award and Dividend Equivalents. The Committee may condition the delivery of Shares upon the Participant's satisfaction of such withholding obligations. The withholding

requirement for Shares will be satisfied by the Company withholding Shares having a Fair Market Value equal to the minimum statutory withholding that could be imposed on the transaction (based on minimum statutory withholding rates for Federal, state and local tax purposes, as applicable, including payroll taxes, that are applicable to such supplemental taxable income) unless the Participant elects, in a manner satisfactory to the Committee, to remit an amount to satisfy the withholding requirement subject to such restrictions or limitations that the Committee, in its sole discretion, deems appropriate. Such election must be made before, and is irrevocable after December 15 of the last year of the Performance Period, and cannot be made or revoked while the Participant possesses information that will be material nonpublic information at the time the Shares are issued such that the Participant would be prohibited from trading on the Company's stock under its Insider Trading Policy.

9. Ratification of Actions. By accepting the Award or other benefit under the Plan, the Participant and each person claiming under or through him or her shall be conclusively deemed to have indicated the Participant's acceptance and ratification of, and consent to, any action taken under the Plan or the Award by the Company, its Board of Directors, or the Committee.

10. Notices. Any notice hereunder to the Company shall be addressed to its office, 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506; Attention: Corporate Secretary, and any notice hereunder to the Participant shall be addressed to him or her at the address specified on the Award Agreement, subject to the right of either party to designate at any time hereafter in writing some other address.

11. Definitions. Capitalized terms not otherwise defined herein or in the Award Agreement shall have the meanings given them in the Plan.

12. Governing Law and Severability. To the extent not preempted by Federal law, the Award Agreement will be governed by and construed in accordance with the laws of the State of Delaware, without regard to conflicts of law provisions. In the event any provision of the Award Agreement shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Award Agreement, and the Award Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

13. No Rights to Continued Employment. The Award Agreement is not a contract of employment. Nothing in the Plan or in the Award Agreement shall interfere with or limit in any way the right of the Company or any Subsidiary to terminate the Participant's employment at any time, for any reason or no reason, or confer upon the Participant the right to continue in the employ of the Company or a Subsidiary.

ANNEX B

TO

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

PERFORMANCE SHARE AWARD AGREEMENT

PEER GROUP COMPANIES

Alliant Energy Corporation
Ameren Corporation
Atmos Energy Corporation
Black Hills Corporation
CMS Energy Corporation
Dycom Industries, Inc.
EMCOR Group, Inc.
Evergy, Inc.
Granite Construction Incorporated
Jacobs Engineering Group, Inc.
KBR, Inc.
Martin Marietta Materials, Inc.
MasTec, Inc.
NiSource, Inc.
Pinnacle West Capital Corporation
Portland General Electric Company
Quanta Services, Inc.
Southwest Gas Holdings, Inc.
Summit Materials Inc.
Vulcan Materials Company
WEC Energy Group, Inc.

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Section 5: EX-21 (MDU RESOURCES SUBSIDIARIES OF MDU RESOURCES)

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective February 19, 2019)

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
ARC Fabricators, L.L.C.	South Dakota
Baldwin Contracting Company, Inc.	California
Bell Electrical Contractors, Inc.	Missouri
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 & ER Company	South Dakota
Ellis & Eastern Company	South Dakota
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 - Mountain West	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
Lone Mountain Excavation & Utilities, LLC	Nevada
Loy Clark Pipeline Co.	Oregon
LTM, Incorporated	Oregon
MDU Construction Services Group, Inc.	Delaware
MDU Energy Capital, 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
Montana-Dakota Utilities Co.	Delaware
Nevada Solar Solutions, LLC	Delaware
Nevada Valley Solar Solutions I, LLC	Delaware
Northstar Materials, Inc.	Minnesota
OEG, Inc.	Oregon
Prairie Cascade Energy Holdings, LLC	Delaware
Prairie Intermountain Energy Holdings, LLC	Delaware
Rail to Road, Inc.	South Dakota
Rocky Mountain Contractors, Inc.	Montana
Sweetman Const. Co.	South Dakota
USI Industrial Services, Inc.	Delaware
Wagner Group, Inc., The	Delaware
Wagner-Smith Company, The	Ohio
Wagner-Smith Equipment Co.	Delaware
WBI Canadian Pipeline, Ltd.	Canada
WBI Energy Midstream, LLC	Colorado
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 6: 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 22, 2019, 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, 2018.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 22, 2019

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Section 7: 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 22, 2019

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

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Section 8: 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 22, 2019

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

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Section 9: 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, 2018 (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 22nd day of February, 2019.

/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 10: 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, 2018, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(d), 110(b)(2), 107(a) or 104(e). During the twelve months ended December 31, 2018, one of the Company's operating subsidiaries received four citations and orders under Section 104(b) 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 (b) 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	—	—	$ 1,042	—	—	—
04-01698	—	—	118	—	—	—
04-05140	—	—	118	—	—	—
04-05459	—	—	118	—	—	—
10-02089	2	—	118	—	—	—
10-02170	2	—	795	—	—	—
21-02614	—	—	118	—	—	—
21-02718	1	—	352	—	—	—
21-03185	—	—	118	—	—	—
21-03248	—	—	368	1	—	—
21-03416	—	—	236	—	—	—
21-03870	—	—	354	—	—	—
21-03871	—	—	118	—	—	—
21-02936	—	—	590	—	—	—
21-03129	3	—	472	—	2	2
24-00462	—	—	826	—	—	—
24-01935	—	—	354	—	—	—
24-02022	—	—	472	—	—	—
32-00774	—	—	118	—	—	—
32-00776	—	—	118	—	—	—
32-00777	—	—	118	—	—	—
32-00950	—	—	354	—	—	—
35-00426	—	—	118	—	—	—
35-00463	—	—	118	—	—	—
35-00495	—	—	374	—	—	—
35-00512	—	—	236	—	—	—
35-02906	—	—	236	—	—	—
35-02968	—	—	354	—	—	—
35-03022	—	—	236	—	—	—
35-03131	—	—	118	—	—	—
35-03449	—	—	590	—	—	—
35-03478	—	—	118	—	—	—
35-03505	—	—	118	—	—	—
35-03558	—	—	590	—	—	—
35-03581	8	4	9,029	1	1	—
35-03590	—	—	118	—	—	—
35-03595	1	—	225	—	—	—
35-03605	—	—	590	—	—	—
35-03639	—	—	708	—	—	—
35-03667	1	—	2,042	—	—	—
35-03678	—	—	118	—	—	—
35-03752	—	—	118	—	—	—

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 104 (b) 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 (#)
41-02639	1	—	354	—	—	—
48-01383	—	—	472	—	—	—
48-01670	—	—	354	—	—	—
50-00883	—	—	354	—	—	—
50-01196	—	—	1,130	—	—	—
51-00036	3	—	4,960	—	—	8
51-00171	—	—	118	—	—	—
51-00192	—	—	118	—	—	—
51-00195	—	—	—	—	—	1
51-00241	—	—	330	—	—	1
	22	4	$ 31,739	2	3	12

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, 2018:

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
21-03248	1	—	—	—	—	—
35-03590	1	—	—	—	—	—
	2	—	—	—	—	—

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