

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

3 PU-19-132 Filed 04/15/2019 Pages: 209
FERC Financial Report Form No. 1 - (electronic only)
Montana-Dakota Utilities Co.
Tamie Aberle

3 PU-19-131 Filed 04/15/2019 Pages: 209
FERC Financial Report Form No. 1 - (electronic only)
Montana-Dakota Utilities Co.
Tamie Aberle

Exact Legal Name of Respondent (Company)

MDU Resources Group, Inc.

Year/Period of Report

End of 2018/Q4

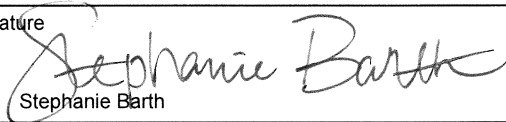
**FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION		
01 Exact Legal Name of Respondent MDU Resources Group, Inc.	02 Year/Period of Report End of <u>2018/Q4</u>	
03 Previous Name and Date of Change (if name changed during year) / /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 400 North Fourth Street, Bismarck, ND 58501		
05 Name of Contact Person Stephanie Barth	06 Title of Contact Person VP, CAO, and Controller	
07 Address of Contact Person (Street, City, State, Zip Code) 1200 West Century Ave, Bismarck, ND, 58506-5650		
08 Telephone of Contact Person, including Area Code (701) 530-1531	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2018

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Stephanie Barth	03 Signature  Stephanie Barth	04 Date Signed (Mo, Da, Yr) 4/9/19
02 Title VP, CAO, and Treasurer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	N/A
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
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7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	N/A
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	228b&229b-N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	N/A
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
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50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	N/A
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	N/A
58	Purchase and Sale of Ancillary Services	398	N/A
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

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Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input checked="" type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

*Stephanie Barth - Vice President, Chief Accounting Officer and Controller
400 North Fourth Street
Bismarck, North Dakota 58501-4092*

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Delaware - March 14, 1924

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

*Electric Service - Montana, North Dakota, South Dakota, and Wyoming
Natural Gas Service - Minnesota, Montana, North Dakota, South Dakota, and Wyoming
Propane Service - North Dakota
Nonutility Operations - Minnesota, Montana, North Dakota, South Dakota, and Wyoming
Gas Transmission - Minnesota and North Dakota*

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Centennial Energy Holdings, Inc. (1)	Holding Company	100	
2	MDU Energy Capital, LLC (1)	Holding Company	100	
3	Prairie Cascade Energy Holdings, LLC - Z	Holding Company	100	
4	Cascade Natural Gas Corporation - AH	Gas Utility Company	100	
5	Prairie Intermountain Energy Holdings, LLC - Z	Holding Company	100	
6	Intermountain Gas Company - U	Gas Utility Company	100	
7	Knife River Corporation - A	Construction Materials&Mining	100	
8	KRC Holdings, Inc. - B	Holding Company	100	
9	Alaska Basic Industries, Inc. - C	Construction Materials	100	
10	Ames Sand & Gravel, Inc. - T	Construction Materials	100	
11	Anchorage Sand and Gravel Company, Inc. - H	Construction Materials	100	
12	Baldwin Contracting Company, Inc. - C	Construction Materials	100	
13	Central Oregon Redi-Mix, LLC - O	Construction Materials	78	
14	Concrete, Inc. - C	Construction Materials	100	
15	Connolly-Pacific Co. - C	Construction Materials	100	
16	D S S Company - C	Construction Materials	100	
17	ARC Fabrications, LLC - N	Construction Materials	33.3	
18	Ellis & Eastern Company - N	Construction Materials	100	
19	Fairbanks Materials, Inc. - H	Construction Materials	100	
20	Granite City Ready Mix, Inc. - C	Construction Materials	100	
21	Hawaiian Cement - I	Construction Materials	100	
22	JTL Group, Inc. - Montana - C	Construction Materials	100	
23	JTL Group, Inc. - Wyoming - C	Construction Materials	100	
24	Jebro Incorporated - C	Construction Materials	100	
25	Kent's Oil Service - C	Construction Materials	100	
26	Knife River Corporation - North Central - C	Construction Materials	100	
27	Knife River Corporation - Northwest - C	Construction Materials	100	

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1	Knife River Corporation - South - C	Construction Materials	100	
2	Knife River Dakota, Inc. - C	Construction Materials	100	
3	Knife River Hawaii, Inc. - C	Construction Materials	100	
4	Knife River Marine, Inc. - C	Construction Materials	100	
5	Knife River Midwest, LLC - C	Construction Materials	100	
6	LTM, Incorporated - C	Construction Materials	100	
7	Northstar Materials, Inc. - C	Construction Materials	100	
8	WHC, Ltd. - C	Construction Materials	100	
9	1250 Gladding Rd, LLC - M	Construction Materials	100	
10	MDU Construction Services Group, Inc. - A	Holding Company	100	
11	MDU United Construction Solutions, Inc. - F	Holding Company	100	
12	Bell Electrical Contractors, Inc. - F	Construction Services	100	
13	Bombard Electric, LLC - F	Construction Services	100	
14	Bombard Mechanical, LLC - F	Construction Services	100	
15	Capital Electric Construction Company, Inc.-F	Construction Services	100	
16	Capital Electric Line Builders, Inc. - F	Construction Services	100	
17	Desert Fire Holdings, Inc. - F	Holding Company	100	
18	Desert Fire Protection, LLC - AN	Holding Company	100	
19	Desert Fire Protection, a Nevada Limited Partnership - AO			
20	Desert Fire Protection, Inc. - AN	Construction Services	100	
21	Duro Electric Company - S	Construction Services	100	
22	E.S.I., Inc. - P	Construction Services	100	
23	Frebco, Inc. - AM	Construction Services	100	
24	Independent Fire Fabricators, LLC - AN	Construction Services	100	
25	International Line Builders, Inc. - F	Construction Services	100	
26	Lone Mountain Excavation & Utilities, LLC - F	Construction Services	100	
27				

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1	Loy Clark Pipeline Co. - F	Construction Services	100	
2	MDU Industrial Services, Inc. - F	Holding Company	100	
3	Nevada Valley Solar Solutions I, LLC - F	Alternative Energy	100	
4	OEG, Inc. - F	Construction Services	100	
5	Rocky Mountain Contractors, Inc. - F	Construction Services	100	
6	USI Industrial Services, Inc. - AM	Construction Services	100	
7	Wagner Group, Inc., The - F	Holding Company	100	
8	Wagner Industrial Electric, Inc. - AM	Holding Company	100	
9	Wagner-Smith Company, The - P	Construction Services	100	
10	Wagner-Smith Equipment Co. - F	Construction Services	100	
11	MAAK Holdings, Inc. - F	Holding Company	100	
12	WBI Holdings, Inc. - A	Holding Company	100	
13	Fidelity Exploration & Production Company - E	Oil & Natural Gas Production	100	
14	Fidelity Oil Co. - K	Oil & Natural Gas Production	100	
15	WBI Energy, Inc. (f/k/a WBI Pipeline & Storage	Holding Company	100	
16	Group, Inc.) - E			
17	WBI Energy Transmission, Inc. (f/k/a Williston	Natural Gas Transmission	100	
18	Basin Interstate Pipeline Company) - L			
19	WBI Energy Wind Ridge Pipeline, LLC - L	Interstate Natural Gas Transp	100	
20	WBI Canadian Pipeline, Ltd. - L	Natural Gas Trans & Storage	100	
21	WBI Energy Midstream, LLC (f/k/a Bitter Creek	Natural Gas Gathering	100	
22	Pipelines, LLC) - L			
23	Centennial Holdings Capital LLC - A	Holding Company	100	
24	FutureSource Capital Corp. - R	Asset Management	100	
25	Nevada Solar Solutions, LLC - AL	Alternative Energy	100	
26	InterSource Insurance Company - R	Captive Insurance Company	100	
27	Centennial Energy Resources LLC - A	Holding Company	100	

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1	Centennial Energy Resources	Holding Company	100	
2	International, Inc. - D			
3	MDU Resources International LLC - W	Holding Company	100	
4	MDU Resources Luxembourg I LLC S.a.r.l. - W	Holding Company	100	
5	MDU Resources Luxembourg II LLC S.a.r.l. - AC	Holding Company	100	
6	(1)-Direct subsidiary of MDU Resources			
7	Group, Inc.			
8	A-100% held by Centennial Energy Holdings, Inc			
9	B-100% held by Knife River Corporation			
10	C-100% held by KRC Holdings, Inc.			
11	D-100% held by Centennial Energy Resources LLC			
12	E-100% held by WBI Holdings, Inc.			
13	F-100% held by MDU Construction Services			
14	Group, Inc.			
15	G-Reserved for Future Use,			
16	H-100% held by Alaska Basic Industries, Inc.			
17	I-Partners include Knife River Hawaii, Inc.			
18	(50%) and Knife River Dakota, Inc. (50%)			
19	J-Reserved for future use			
20	K-100% held by Fidelity Exploration &			
21	Production Company			
22	L-100% held by WBI Energy, Inc.			
23	M-100% held by Baldwin Contracting			
24	Company, Inc.			
25	N-Sweetman Const. Co.			
26	O-78% held by Knife River Corporation -			
27	Northwest			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	P-100% held by The Wagner Group, Inc.			
2	Q-Reserved for Future Use			
3	R-100% held by Centennial Holdings			
4	Capital LLC			
5	S-100% held by MDU United Construction			
6	Solutions, Inc.			
7	T-100% held by Knife River Corporation -			
8	North Central			
9	U-100% held by Prairie Intermountain			
10	Energy Holdings, LLC			
11	V-Reserved for Future Use			
12	W-100% held by Centennial Energy Resources			
13	International, Inc.			
14	X-Reserved for Future Use			
15	Y-Reserved for Future Use			
16	Z-100% held by MDU Energy Capital, LLC			
17	AA-Reserved for future use			
18	AB-Reserved for future use			
19	AC-100% held by MDU Resources Luxembourg I			
20	LLC S.a.r.l.			
21	AD-Reserved for Future Use			
22	AE-Reserved for future use			
23	AF-Reserved for Future Use			
24	AG-Reserved for Future Use			
25	AH-100% held by Prairie Cascade			
26	Energy Holdings, LLC			
27	AI-Reserved for Future Use			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	AJ-Reserved for future use			
2	AK-Reserved for future use			
3	AL-100% held by FutureSource Capital Corp.			
4	AM-100% held by MDU Industrial Services, Inc.			
5	AN-100% held by Desert Fire Holdings, Inc.			
6	AO-Partners include Desert Fire Protection,			
7	LLC (1%) and Desert Fire Holdings,			
8	Inc. (99%)			
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	David L. Goodin	824,460
3			
4	President and Chief Executive Officer of Cascade	Nicole A. Kivisto	430,000
5	Natural Gas Corporation, Great Plains Natural Gas		
6	Co., Intermountain Gas Company and Montana-		
7	Dakota Utilities Co.		
8			
9	Vice President - Human Resources	Anne M. Jones	248,600
10			
11	Vice President, General Counsel and Secretary	Daniel S. Kuntz	330,000
12			
13	Vice President, Chief Financial Officer	Jason L. Vollmer	350,000
14	and Treasurer		
15			
16	Vice President, Chief Accounting Officer	Stephanie A. Barth	220,000
17	and Controller		
18			
19	Vice President and Chief Information Officer	Margaret (Peggy) A. Link	247,500
20			
21	President and Chief Executive Officer of Knife	David Barney	455,000
22	River Corporation		
23			
24	President and Chief Executive officer of WBI	Trevor J. Hastings	300,000
25	Holdings, INC.		
26			
27	President and Chief Executive Officer of MDU	Jeffrey S. Thiede	455,000
28	Construction Services Group, INC.		
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Harry J. Pearce, Chairman of the Board	Detroit, Michigan
2		
3	David L. Goodin, President and Chief Executive Officer	Bismarck, North Dakota
4		
5	Thomas Everist	Sioux Falls, South Dakota
6		
7	Karen B. Fagg	Billings, Montana
8		
9	Mark A. Hellerstein	Denver, Colorado
10		
11	Dennis W. Johnson, Vice Chair of the Board	Dickinson, North Dakota
12		
13	A. Bart Holaday	Denver, Colorado, and Grand Forks, North Dakota
14		
15	Patricia L. Moss	Bend, Oregon
16		
17	John K. Wilson	Omaha, Nebraska
18		
19	William E. McCracken	Warren, New Jersey
20		
21	David M. Sparby	Minneapolis, Minnesota
22		
23	Edward A. Ryan	Washington, D. C.
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Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 13 Column: a

A. Bart Holaday retired from the Board of Directors effective May 8, 2018.

Schedule Page: 105 Line No.: 21 Column: a

David M. Sparby joined the Board of Directors on August 16, 2018.

Schedule Page: 105 Line No.: 23 Column: a

Edward A. Ryan joined the Board of Directors on November 15, 2018.

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? Yes
 No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midcontinent Independent System Operator, Inc. -	ER11-3279-001
2	FERC Electric Tariff	
3		
4	Midwest ISO FERC Electric Tariff Fifth	ER12-312-000
5	Revised Volume No. 1 (Midwest Independent	
6	Transmission System - FERC Electric Tariff)	
7		
8	Midwest ISO FERC Electric Tariff Fifth	ER12-450-000
9	Revised Volume No. 1 (Midwest Independent	
10	Transmission System - FERC Electric Tariff)	
11		
12	Midwest ISO FERC Electric Tariff Fifth	ER12-480-000
13	Revised Volume No. 1 (Midwest Independent	
14	Transmission System - FERC Electric Tariff)	
15		
16	Midwest ISO FERC Electric Tariff Fifth	ER12-480-002
17	Revised Volume No. 1 (Midwest Independent	
18	Transmission System - FERC Electric Tariff)	
19		
20	Midwest ISO FERC Electric Tariff Fifth	ER12-480-003
21	Revised Volume No. 1 (Midwest Independent	
22	Transmission System - FERC Electric Tariff)	
23		
24	Midcontinent Independent System Operator, Inc. -	ER12-480-006
25	FERC Electric Tariff	
26		
27	Midcontinent Independent System Operator, Inc. -	ER12-480-007
28	FERC Electric Tariff	
29		
30	Midwest ISO FERC Electric Tariff Fifth	ER12-715-000
31	Revised Volume No. 1 (Midwest Independent	
32	Transmission System - FERC Electric Tariff)	
33		
34	Midwest ISO FERC Electric Tariff Fifth	ER12-715-002
35	Revised Volume No. 1 (Midwest Independent	
36	Transmission System - FERC Electric Tariff)	
37		
38	Midwest ISO FERC Electric Tariff Fifth	ER13-1169-000
39	Revised Volume No. 1 (Midwest Independent	
40	Transmission System - FERC Electric Tariff)	
41		

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
---	--

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midcontinent Independent System Operator, Inc. -	ER13-1169-001
2	FERC Electric Tariff	
3		
4	Midcontinent Independent System Operator, Inc. -	ER13-1547-000
5	FERC Electric Tariff	
6		
7	Midcontinent Independent System Operator, Inc. -	ER13-1827-000
8	FERC Electric Tariff	
9		
10	Midcontinent Independent System Operator, Inc. -	ER13-2379-000
11	FERC Electric Tariff	
12		
13	Midcontinent Independent System Operator, Inc. -	ER13-2379-003
14	FERC Electric Tariff	
15		
16	Midcontinent Independent System Operator, Inc. -	ER13-2468-004
17	FERC Electric Tariff	
18		
19	Midcontinent Independent System Operator, Inc. -	ER13-263-000
20	FERC Electric Tariff	
21		
22	Midwest ISO FERC Electric Tariff Fifth	ER13-263-001
23	Revised Volume No.1 (Midwest Independent	
24	Transmission System - FERC Electric Tariff)	
25		
26	Midwest Independent Transmission System	ER13-307-000
27	Operator, Inc. - FERC Electric Tariff 43	
28		
29	Midwest ISO FERC Electric Tariff Fifth	ER13-674-000
30	Revised Volume No.1 (Midwest Independent	
31	Transmission System - FERC Electric Tariff)	
32		
33	Midwest ISO FERC Electric Tariff Fifth	ER13-674-002
34	Revised Volume No.1 (Midwest Independent	
35	Transmission System - FERC Electric Tariff)	
36		
37	Midwest Independent Transmission System	ER13-751-001
38	Operator, Inc. - FERC Electric Tariff 44	
39		
40	Midcontinent Independent System Operator, Inc. -	ER14-102-000
41	FERC Electric Tariff	

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midcontinent Independent System Operator, Inc. -	ER14-260-000
2	FERC Electric Tariff	
3		
4	Midcontinent Independent System Operator, Inc. -	ER14-261-000
5	FERC Electric Tariff	
6		
7	Midcontinent Independent System Operator, Inc. -	ER14-421-000
8	FERC Electric Tariff	
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10	Midcontinent Independent System Operator, Inc. -	ER14-421-001
11	FERC Electric Tariff	
12		
13	Midcontinent Independent System Operator, Inc. -	ER14-649-000
14	FERC Electric Tariff	
15		
16	Midcontinent Independent System Operator, Inc. -	ER15-1067-000
17	FERC Electric Tariff	
18		
19	Midcontinent Independent System Operator, Inc. -	ER15-1067-001
20	FERC Electric Tariff	
21		
22	Midcontinent Independent System Operator, Inc. -	ER15-1210-000
23	FERC Electric Tariff	
24		
25	Midcontinent Independent System Operator, Inc. -	ER15-1210-001
26	FERC Electric Tariff	
27		
28	Midcontinent Independent System Operator, Inc. -	ER15-142-000
29	FERC Electric Tariff	
30		
31	Midcontinent Independent System Operator, Inc. -	ER15-1490-000
32	FERC Electric Tariff	
33		
34	Midcontinent Independent System Operator, Inc. -	ER15-1689-000
35	FERC Electric Tariff	
36		
37	Midcontinent Independent System Operator, Inc. -	ER15-2364-000
38	FERC Electric Tariff	
39		
40	Midcontinent Independent System Operator, Inc. -	ER15-277-000
41	FERC Electric Tariff	

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midcontinent Independent System Operator, Inc. -	ER15-358-000
2	FERC Electric Tariff	
3		
4	Midcontinent Independent System Operator, Inc. -	ER16-1313-000
5	FERC Electric Tariff	
6		
7	Midcontinent Independent System Operator, Inc. -	ER16-1322-000
8	FERC Electric Tariff	
9		
10	Midcontinent Independent System Operator, Inc. -	ER16-1333-000
11	FERC Electric Tariff	
12		
13	Midcontinent Independent System Operator, Inc. -	ER16-1534-000
14	FERC Electric Tariff	
15		
16	Midcontinent Independent System Operator, Inc. -	ER16-18-000
17	FERC Electric Tariff	
18		
19	Midcontinent Independent System Operator, Inc. -	ER16-2417-000
20	FERC Electric Tariff	
21		
22	Midcontinent Independent System Operator, Inc. -	ER16-314-000
23	FERC Electric Tariff	
24		
25	Midcontinent Independent System Operator, Inc. -	ER16-392-000
26	FERC Electric Tariff	
27		
28	Midcontinent Independent System Operator, Inc. -	ER16-197-000
29	FERC Electric Tariff	
30		
31	Midcontinent Independent System Operator, Inc. -	ER16-888-000
32	FERC Electric Tariff	
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Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2018

Year/Period of Report
End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?
 Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201603115138	03/11/2016	ER16-1140-000	Annual Informational	Montana-Dakota Utilities Co.
2				Attachment O Filing	MISO Attachments O, GG, and MM
3					
4	201703135373	03/12/2017	ER17-1181-000	Annual Informational	Montana-Dakota Utilities Co.
5				Attachment O Filing	MISO Attachments O, GG, and MM
6					
7	201803155115	03/15/2018	ER18-1115-000	Annual Informational	Montana-Dakota Utilities Co.
8				Attachment O Filing	MISO Attachments O, GG, and MM
9					
10	20180322-5264	03/21/2018	ER18-1115-000	Supplemental (update	Montana-Dakota Utilities Co.
11				to March 15 2018	MISO Attachments O, GG, and MM
12				Annual Informational	
13				Attachment O Filing	
14					
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INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	111	Comparative Balance Sheet		c 57
2	112	Comparative Balance Sheet		c 16, 18-21, 3
3	117	Statement of Income		c 62-64
4	200	Summary of Utility Plant		c 3 & 21
5	201	Summary of Utility Plant		d 3
6	205	Electric Plant in Service		g 46
7	205 & 207	Electric Plant in Service		g 5 & 99
8	207	Electric Plant in Service		g 58
9	207	Electric Plant in Service		g 75
10	216	Construction Work in Progress - Electric		b 1
11	219	Accumulated Provision for Depreciation of		c 20-24
12		Electric Utility Plant		
13	219	Accumulated Provision for Depreciation of		c 25
14		Electric Utility Plant		
15	219	Accumulated Provision for Depreciation of		c 26
16		Electric Utility Plant		
17	219	Accumulated Provision for Depreciation of		c 28
18		Electric Utility Plant		
19	227	Materials & Supplies		c 8
20	234	Accumulated Deferred Income Taxes		c 8
21		(Account 190)		
22	263	Taxes Accrued. Prepaid and Charged During Year		i 18
23	263	Taxes Accrued. Prepaid and Charged During Year		i 24
24	263.1	Taxes Accrued. Prepaid and Charged During Year		i 4
25	263.1	Taxes Accrued. Prepaid and Charged During Year		i 12
26	263.1	Taxes Accrued. Prepaid and Charged During Year		i 17-22
27	263.1	Taxes Accrued. Prepaid and Charged During Year		i 25
28	263.1	Taxes Accrued. Prepaid and Charged During Year		i 26
29	267	Accumulated Deferred Investment Tax Credit		h 8
30	273	Accumulated Deferred Income Taxes		c 19
31		Accelerated Amortization (Account 281)		
32	275	Accumulated Deferred Income Taxes - Other		k 2
33		Property (Account 282)		
34	277	Accumulated Deferred Income Taxes - Other		k 9
35		(Account 190)		
36	321	Electric Operation and Maintenance Expenses		b 96 & 112
37	323	Electric Operation and Maintenance Expenses		b 197
38	330	Transmission of Electricity for Others (Acct 456)		n
39	336	Depreciation and Amortization of Electric Plant		f 1
40	336	Depreciation and Amortization of Electric Plant		b 7
41	336	Depreciation and Amortization of Electric Plant		f 10
42	336	Depreciation and Amortization of Electric Plant		b 11
43	354	Distribution of Salaries & Wages		b 20, 21, 23-26
44	356	Common Utility Plant and Expenses		b

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 1062 Line No.: 1 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 2 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 3 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 4 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 5 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 6 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 7 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 8 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 9 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 10 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 11 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 13 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 15 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 17 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 19 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 20 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 22 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 23 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 24 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 25 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 26 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 27 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 28 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 29 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 30 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 32 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 34 Column: a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Include electric portion of FAS 109

Schedule Page: 1062 Line No.: 36 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 37 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 38 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 39 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 40 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 41 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 42 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 43 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 44 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. The Respondent renewed franchises in 2018 in Vergas, Minnesota and the following North Dakota cities: Sherwood, Ambrose, Noonan, and Ross. No consideration was given for the renewal of the franchises other than the agreement to pay franchise fees to the extent applicable.

2. Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Respondent prior to the closing of the Holding Company Reorganization, is now a wholly owned subsidiary of MDU Energy Capital, LLC as of January 1, 2019. For additional information see Note 1 in Notes to Financial Statements on page 122.

3. None.

4. None.

5. In 2014, the Respondent constructed a natural gas pipeline from a new tap off Northern Border Pipeline near St. Anthony, North Dakota to the Respondent's Heskett electric generating station north of Mandan, North Dakota. The pipeline is classified as a transmission line approximately 24 miles in length with a flowing capacity of 85,000 to 90,000 dk per day. The Respondent entered into a Fuel Supply and Management Services Agreement with Tenaska Marketing Ventures to provide the natural gas supply to the Heskett facility with an initial term of three years and successive one-year renewals following the expiration of the initial term. The Respondent regretfully submits this 2014 project at this time and asks FERC to accept this late disclosure.

6. The Respondent's short-term indebtedness totaled \$48,500,000 at December 31, 2018, consisting of no commercial paper and \$48,500,000 of outstanding debt under MDU's revolving credit facility. The issuance of commercial paper and other short-term debt is authorized pursuant to the following orders:

On September 11, 2017, the Respondent received a FERC Order authorizing the Respondent to incur short-term indebtedness in an amount not to exceed \$250 million. This authorization was granted in Docket No. ES17-40-000.

On August 8, 2017, the Respondent received the same type of authorization from the state of Montana. This order authorized the Respondent to issue up to \$250 million in short-term indebtedness. This authorization was granted in Docket No. D2017.7.59, Default Order No. 7561.

7. None.

8. Wage increases to nonunion employees averaged 3.73% in 2018. Wage increases to union employees averaged 3.10% effective 4/30/18. The estimated impact of the increases amounted to approximately \$3,015,000.00

9. See Note 17 in Notes to Financial Statements on page 122.

10. None.

11. None.

12. None.

13. A. Bart Holaday, member of the Board of Directors, retired effective May 8, 2018.
David M. Sparby was appointed to the Board of Directors effective August 16, 2018.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	12/31/2018	2018/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

13. Edward A. Ryan was appointed to the Board of Directors effective November 15, 2018.

14. Not applicable.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	2,663,919,506	2,489,791,771
3	Construction Work in Progress (107)	200-201	165,864,516	124,919,564
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,829,784,022	2,614,711,335
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	967,632,867	921,860,914
6	Net Utility Plant (Enter Total of line 4 less 5)		1,862,151,155	1,692,850,421
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,862,151,155	1,692,850,421
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		1,718,566	2,514,929
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		16,931,362	16,449,813
19	(Less) Accum. Prov. for Depr. and Amort. (122)		6,199,490	5,380,673
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,790,885,738	1,704,908,136
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		76,201,921	76,779,282
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,877,819,531	1,792,756,558
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		-273,799	619,085
36	Special Deposits (132-134)		617,411	4,603,012
37	Working Fund (135)		312,522	150,750
38	Temporary Cash Investments (136)		1,178,164	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		27,283,245	25,259,589
41	Other Accounts Receivable (143)		14,756,480	4,110,686
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		779,796	561,438
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		36,014,729	34,029,187
45	Fuel Stock (151)	227	4,784,694	4,684,911
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	21,026,434	16,837,763
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		8,508,246	9,179,608
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,480,655	5,865,158
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		47,151,553	50,091,799
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		166,060,538	154,870,110
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,581,364	2,353,114
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,508,004	2,959,651
72	Other Regulatory Assets (182.3)	232	214,409,347	206,776,202
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,112,510	1,678,581
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		11,624	7,900
75	Other Preliminary Survey and Investigation Charges (183.2)		57,531	24,835
76	Clearing Accounts (184)		-31,304	-52,274
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	28,836,015	29,033,605
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		4,154,385	4,726,100
82	Accumulated Deferred Income Taxes (190)	234	51,529,326	59,350,651
83	Unrecovered Purchased Gas Costs (191)		-2,576,502	2,175,012
84	Total Deferred Debits (lines 69 through 83)		302,592,300	309,033,377
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,210,342,090	3,952,025,395

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	196,564,907	195,843,297
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,255,155,546	1,239,981,494
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	6,579,697	6,569,697
11	Retained Earnings (215, 215.1, 216)	118-119	642,942,878	620,946,628
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	520,659,042	419,801,251
13	(Less) Reaquired Capital Stock (217)	250-251	3,625,813	3,625,813
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-38,342,046	-37,333,718
16	Total Proprietary Capital (lines 2 through 15)		2,566,774,817	2,429,043,442
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	788,725,495	714,686,250
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		788,725,495	714,686,250
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		190,410	283,024
29	Accumulated Provision for Pensions and Benefits (228.3)		41,383,945	45,731,295
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		15,514,270	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		142,922,575	127,809,107
35	Total Other Noncurrent Liabilities (lines 26 through 34)		200,011,200	173,823,426
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		48,869,177	45,904,554
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		12,438,043	7,233,715
41	Customer Deposits (235)		1,443,059	1,361,897
42	Taxes Accrued (236)	262-263	24,703,900	3,296,066
43	Interest Accrued (237)		6,739,759	8,191,173
44	Dividends Declared (238)		39,695,262	38,572,614
45	Matured Long-Term Debt (239)		0	0

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 12/31/2018	Year/Period of Report end of 2018/Q4
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,181,720	1,095,165
48	Miscellaneous Current and Accrued Liabilities (242)		31,208,839	35,763,020
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		166,279,759	141,418,204
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		20,525,735	23,674,715
57	Accumulated Deferred Investment Tax Credits (255)	266-267	3,377,889	1,830,976
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	83,378,564	87,716,626
60	Other Regulatory Liabilities (254)	278	164,617,567	172,633,655
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	854,528	536,066
63	Accum. Deferred Income Taxes-Other Property (282)		182,374,129	173,245,884
64	Accum. Deferred Income Taxes-Other (283)		33,422,407	33,416,151
65	Total Deferred Credits (lines 56 through 64)		488,550,819	493,054,073
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,210,342,090	3,952,025,395

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	621,198,166	615,177,864		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	407,117,069	392,735,858		
5	Maintenance Expenses (402)	320-323	30,161,633	30,176,522		
6	Depreciation Expense (403)	336-337	68,005,660	64,878,031		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,016,468	4,224,779		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,683	2,820		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		495,524	495,524		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		131,812	41,659		
13	(Less) Regulatory Credits (407.4)		1,342,439	1,942,438		
14	Taxes Other Than Income Taxes (408.1)	262-263	25,882,003	24,025,388		
15	Income Taxes - Federal (409.1)	262-263	-15,347,311	-17,101,437		
16	- Other (409.1)	262-263	1,606,831	-636,763		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	88,606,884	268,126,274		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	79,041,212	238,426,113		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		531,298,605	526,600,104		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		89,899,561	88,577,760		

STATEMENT OF INCOME FOR THE YEAR (Continued)

- 9. Use page 122 for important notes regarding the statement of income for any account thereof.
- 10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
- 11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
- 12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
- 13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
- 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
333,761,110	341,684,354	287,437,056	273,493,510			2
						3
178,939,882	175,605,779	228,177,187	217,130,079			4
23,690,520	24,031,577	6,471,113	6,144,945			5
49,101,906	47,009,040	18,903,754	17,868,991			6
						7
2,373,537	1,766,079	2,642,931	2,458,700			8
2,862		2,821	2,820			9
495,524	495,524					10
						11
123,943	41,659	7,869				12
1,342,439	1,825,824		116,614			13
15,176,117	14,180,612	10,705,886	9,844,776			14
-18,730,535	-16,053,336	3,383,224	-1,048,101			15
1,008,001	-521,763	598,830	-115,000			16
53,380,868	138,101,687	35,226,016	130,024,587			17
41,814,205	114,564,528	37,227,007	123,861,585			18
						19
						20
						21
						22
						23
						24
262,405,981	268,266,506	268,892,624	258,333,598			25
71,355,129	73,417,848	18,544,432	15,159,912			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		89,899,561	88,577,760		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		36,795	98,113		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		17,990	74,895		
33	Revenues From Nonutility Operations (417)		6,541,586	7,040,505		
34	(Less) Expenses of Nonutility Operations (417.1)		3,310,802	3,572,345		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	211,109,757	218,500,841		
37	Interest and Dividend Income (419)		1,331,795	1,930,376		
38	Allowance for Other Funds Used During Construction (419.1)		1,026,572	400,908		
39	Miscellaneous Nonoperating Income (421)		42,767	376,517		
40	Gain on Disposition of Property (421.1)		42,872	187,704		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		216,803,352	224,887,724		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		42,128	31,475		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		129,536	745,961		
46	Life Insurance (426.2)		1,328,943	-2,655,182		
47	Penalties (426.3)		1,516			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		156,315	186,887		
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,658,438	-1,690,859		
51	Taxes Applicable to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	49,487	117,437		
53	Income Taxes-Federal (409.2)	262-263	124,697	-2,820,520		
54	Income Taxes-Other (409.2)	262-263	-1,901,830	-743,428		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,521,095	9,230,015		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,374,916	4,004,897		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		-1,546,913	-190,592		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-34,554	1,969,199		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		215,179,468	224,609,384		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		32,672,609	31,263,411		
63	Amort. of Debt Disc. and Expense (428)		350,328	343,324		
64	Amortization of Loss on Reaquired Debt (428.1)		571,714	598,000		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		448,838	282,192		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,282,817	502,771		
70	Net Interest Charges (Total of lines 62 thru 69)		32,760,672	31,984,156		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		272,318,357	281,202,988		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		272,318,357	281,202,988		

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		620,946,628	595,204,310
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Loss on Redemption of Preferred Stock	131		(600,000)
5	OCI Stranded Taxes Adjustment	219	1,044,813	
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		1,044,813	(600,000)
10	Dividend Equivalents on Stock Based Compensation	253	-461,628	(399,593)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-461,628	(399,593)
16	Balance Transferred from Income (Account 433 less Account 418.1)		61,208,600	62,702,147
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.50%	237		(112,501)
25	4.70%	237		(58,750)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(171,251)
30	Dividends Declared-Common Stock (Account 438)			
31		238	-155,695,135	(151,360,905)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-155,695,135	(151,360,905)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		115,899,600	115,571,920
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		642,942,878	620,946,628
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		642,942,878	620,946,628
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		419,801,251	317,077,496
50	Equity in Earnings for Year (Credit) (Account 418.1)		211,109,757	218,500,841
51	(Less) Dividends Received (Debit)		115,899,600	115,571,920
52	Dividend Equivalent on Stock Based Compensation and OCI Stranded Taxes		5,647,634	(205,166)
53	Balance-End of Year (Total lines 49 thru 52)		520,659,042	419,801,251

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 52 Column: c

Dividend equivalents on stock based compensation - CEHI	\$ 217,718
Dividend equivalents on stock based compensation - MDU EC	86,117
Stranded OCI Adjustment	(6,921,003)
Adjustment to Retained Earnings due to change in Revenue Recognition	969,534
	<u>(5,647,634)</u>

Schedule Page: 118 Line No.: 52 Column: d

Dividend equivalents on stock based compensation - CEHI	\$ 133,400
Dividend equivalents on stock based compensation - MDU EC	71,766
	<u>205,166</u>

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	272,318,357	281,202,988
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	72,312,708	67,700,375
5	Amortization of		
6	Loss on Reacquired Debt, Bond Discount and Debt Exp	343,465	495,300
7			
8	Deferred Income Taxes (Net)	9,711,851	34,925,280
9	Investment Tax Credit Adjustment (Net)	1,546,913	190,592
10	Net (Increase) Decrease in Receivables	-14,436,634	-426,114
11	Net (Increase) Decrease in Inventory	-2,820,729	4,163,158
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	23,281,803	2,207,920
14	Net (Increase) Decrease in Other Regulatory Assets	8,688,521	5,923,937
15	Net Increase (Decrease) in Other Regulatory Liabilities	563	-1,212,357
16	(Less) Allowance for Other Funds Used During Construction	1,026,572	400,908
17	(Less) Undistributed Earnings from Subsidiary Companies	95,210,157	102,928,921
18	Other (provide details in footnote):		
19	Unrecovered Purchased Gas Costs	4,751,514	-300,256
20	Net Change in Other Current & Accrued Assets	7,310,350	-4,712,022
21	Other Noncurrent Changes	10,716,358	-10,829,547
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	297,488,311	275,999,425
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-233,006,571	-134,992,949
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-7,516,547	-10,709,725
29	Gross Additions to Nonutility Plant	-495,927	-408,194
30	(Less) Allowance for Other Funds Used During Construction	-1,026,572	-400,908
31	Other (provide details in footnote):		
32			
33	Customer Advances for Construction	-3,148,980	193,296
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-243,141,453	-145,516,664
35			
36	Acquisition of Other Noncurrent Assets (d)	-527,466	-468,090
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-10,000,000	-40,000,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	40,000,000	40,000,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
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 (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Depreciation of Nonutility Plant	811,995	1,064,862
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-212,856,924	-144,919,892
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	200,000,000	70,500,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Stock Expense	-10,000	
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	199,990,000	70,500,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-125,960,755	-37,568,736
74	Preferred Stock		-15,600,000
75	Common Stock		
76	Other (provide details in footnote): Repurchase of Common Stock	-1,920,095	-564,642
77	Tax Withholding on Performance Shares	-1,720,999	-508,519
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		-342,501
81	Dividends on Common Stock	-154,572,486	-150,384,383
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-84,184,335	-134,468,781
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	447,052	-3,389,248
87			
88	Cash and Cash Equivalents at Beginning of Period	769,835	4,159,083
89			
90	Cash and Cash Equivalents at End of period	1,216,887	769,835

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
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Schedule Page: 120 Line No.: 73 Column: b

Includes (b) other long-term debt and (c) commercial paper classified as long-term debt.

Schedule Page: 120 Line No.: 73 Column: c

Includes (b) other long-term debt and (c) commercial paper classified as long-term debt.

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Recquired Debt, and 257, Unamortized Gain on Recquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Definitions

The following abbreviations and acronyms used in the Notes are defined below:

AFUDC	Allowance for funds used during construction
ARAM	Average Rate Assumption Method
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
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 Station	427-MW coal fired electric generating facility near Beulah, North Dakota (25 percent ownership)
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
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 on Montana-Dakota
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
K-Plan	Company's 401(k) Retirement Plan
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
MISO	Midcontinent Independent System Operator, Inc.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
SEC	United States Securities and Exchange Commission
SDPUC	South Dakota Public Utilities Commission
SSIP	System Safety and Integrity Program
TCJA	Tax Cuts and Jobs Act
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Montana-Dakota and Great Plains are public utility divisions of the Company.

Montana-Dakota generates, transmits, and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota, and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services. The Company provides service to approximately 143,000 electric and 299,000 natural gas residential, commercial, industrial and municipal customers in 285 communities and adjacent rural areas as of December 31, 2018.

Montana-Dakota is subject to regulation by the FERC, NDPSC, MTPSC, SDPUC, and WYPSC. Great Plains is subject to regulation by the MNPUC and the NDPSC.

The Company owns two wholly owned subsidiaries, Centennial and MDU Energy Capital, as well as ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. These requirements differ from GAAP related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs. As required by the FERC for Form 1 report purposes, the Company reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by \$975.6 million; current and accrued assets would increase by \$1.0 billion; deferred debits would increase by \$784.1 million; long-term debt would increase by \$1.1 billion; other noncurrent liabilities and current and accrued liabilities would increase by \$619.8 million; and deferred credits would increase by \$1.1 billion as of December 31, 2018. Furthermore, operating revenues would

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NOTES TO FINANCIAL STATEMENTS (Continued)			

increase by \$3.9 billion and operating expenses, excluding income taxes, would increase by \$3.6 billion for the twelve months ended December 31, 2018. In addition, net cash provided by operating activities would increase by \$202.4 million; net cash used in investing activities would increase by \$498.1 million; net cash used in financing activities would decrease by \$314.6 million; the effect of exchange rate changes on cash would decrease by \$1,000; and the net change in cash and cash equivalents would be an increase of \$18.9 million for the twelve months ended December 31, 2018. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Notes to Financial Statements accompanying this FERC Form No. 1 relate to the nonconsolidated parent company and its two public utility divisions. For information on disclosures of the subsidiary companies, refer to the Company's Form 10-K.

Montana-Dakota and Great Plains are regulated businesses which 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 5 for more information regarding the nature and amounts of these regulatory deferrals.

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 jurisdictions in which the Company provides 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 16.

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

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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. The total balance of receivables past due 90 days or more was \$640,000 and \$690,000 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 \$780,000 and \$561,000, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota was \$47.2 million and \$50.1 million at December 31, 2018 and 2017, respectively.

Inventories and natural gas in storage

Natural gas in storage is carried at 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)	
Plant materials and operating supplies	\$ 21,026	\$ 16,838
Gas stored underground-current	8,508	9,179
Fuel stock	4,785	4,685
Total	\$ 34,319	\$ 30,702

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was \$1.7 million and \$2.5 million at December 31, 2018 and 2017, respectively.

Investments

The Company's investments include its investment in subsidiary companies, the cash surrender value of life insurance policies, an insurance contract, and other miscellaneous investments. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Statement of Income. The Company has not elected the fair value option for its other investments. For more information, see Notes 6 and 14.

Property, plant and equipment

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

	2018	2017
	(In thousands)	
AFUDC - borrowed	\$ 1,283	\$ 503
AFUDC - equity	\$ 1,027	\$ 401

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Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets. The Company collects removal costs for plant assets in regulated utility rates. These amounts are included in accumulated provision for depreciation, amortization and depletion.

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

	2018	2017	Weighted Average Depreciable Life in Years
(Dollars in thousands, where applicable)			
Electric:			
Generation	\$ 1,131,484	\$ 1,034,765	49
Distribution	430,750	415,543	46
Transmission	302,315	296,941	64
Construction in progress	161,742	117,922	-
Other	117,133	112,301	13
Natural gas distribution:			
Distribution	547,788	506,539	46
Construction in progress	4,122	6,998	-
Other	134,450	123,702	12
Less accumulated depreciation, depletion and amortization	967,633	921,861	
Net utility plant	\$ 1,862,151	\$ 1,692,850	
Nonutility property	\$ 16,931	\$ 16,450	
Less accumulated depreciation, depletion and amortization	6,199	5,381	
Net nonutility property	\$ 10,732	\$ 11,069	

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No impairment losses were recorded in 2018 and 2017. 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. 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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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 and 2017, there were no impairment losses recorded. At December 31, 2018, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value. For more information on goodwill, see Note 4.

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 of 5.0 percent, and a long-term growth rate projection of 3.5 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 Company generates revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. The Company establishes 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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

tariff, payment terms are net 30 days. At this time, the Company has 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 regulatory asset or liability. For more information on asset retirement obligations, see Note 8.

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 recoverable (refundable) through rate adjustments were (\$2.6) million and \$2.2 million at December 31, 2018 and 2017, respectively, and included in unrecovered purchased gas costs.

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 performs 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 and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by the Company, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. The Company makes a similar allocation for state income taxes paid in connection with combined state filings. 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

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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. Taxes recoverable from customers have been recorded as regulatory assets. Taxes refundable to customers and excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as regulatory liabilities. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates 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 interest and penalties, respectively.

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; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; 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

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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.

For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance.

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.

In December 2017, the FERC issued guidance to provide clarification of whether and how to apply this ASU for purposes of regulatory accounting and reporting. The FERC concluded that pension and postretirement benefit cost, in its entirety without separation of the various components, be recorded in operating expenses. Regarding capitalization, companies

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may continue to capitalize the service cost component and non-service cost component or elect to capitalize only the service cost component as prescribed by ASU No. 2017-07.

The Company has elected to capitalize only the service cost component as prescribed by ASU No. 2017-07 as of January 1, 2018. This change in accounting practice will not have a material effect on the Company's results of operations, cash flows or disclosures, nor will it have a material effect on rates, rate base or current period expenses.

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).

In November 2018, the FERC issued an Order granting blanket approval for certain public utilities to reclassify the stranded tax effects caused by the reduction in corporate tax rate by the TCJA, from Account 219 to Account 439, in keeping with FASB's guidance for public utilities that include both accumulated other comprehensive income and retained earnings in their capital structures for ratemaking purposes. The approval was granted provided the transfer from accumulated other comprehensive income to retained earnings will not affect rates.

The Company early adopted the guidance on January 1, 2018, for its GAAP financial statements 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, including \$6.9 million related to the stranded tax expense of subsidiaries. As the Company's capital structure for ratemaking purposes would not be impacted, following the FERC's Order, the Company reclassified the stranded income taxes in its FERC financial statements from Account 219 to Account 439 as of December 31, 2018. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

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 for its GAAP financial statements on January 1, 2019.

In December 2018, the FERC issued guidance to provide clarity on how regulated entities can implement the lease accounting guidance within the framework and regulatory intent of the FERC's existing requirements for lease accounting. The FERC guidance permits entities to record operating leases that may be capitalized under ASU No. 2016-02 in the FERC balance sheet accounts that have already been established for capital lease assets and liabilities. All other provisions of lease accounting are not affected by this accounting guidance, and the accounting guidance is intended to have no impact on the existing ratemaking treatment or practices. For entities that elect this option, additional disclosures would be required within their FERC filings. The Company has elected to not

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record operating leases on its FERC financial statements. Therefore, this standard will not have an impact on the Company's FERC financial statements or disclosures.

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 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

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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 for its GAAP financial statements effective January 1, 2019, on a prospective basis. For FERC financial statements, the Company will functionalize these costs within the FERC plant accounts or in miscellaneous intangible plant, if appropriate. Additionally, the amortization of these costs will be reported as depreciation and amortization. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

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 postretirement liability adjustments and other comprehensive income (loss) recorded by its subsidiaries.

The postretirement liability adjustment in other comprehensive income was \$1.0 million and \$(517,000), net of tax of \$(323,000) and \$315,000, for the years ended December 31, 2018 and 2017, respectively.

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31, 2018	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
	(In thousands)		
Balance at December 31, 2017	\$ (4,803)	\$ (32,531)	\$ (37,334)
Other comprehensive income before reclassifications	903	3,333	4,236
Amounts reclassified from accumulated other comprehensive loss	99	2,616	2,715
Net current-period other comprehensive income	1,002	5,949	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(1,045)	(6,914)	(7,959)
Balance at December 31, 2018	\$ (4,846)	\$ (33,496)	\$ (38,342)

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Twelve Months Ended December 31, 2017	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
(In thousands)			
Balance at December 31, 2016	\$ (4,287)	\$ (31,446)	\$ (35,733)
Other comprehensive loss before reclassifications	(599)	(1,358)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	83	1,416	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	---	(1,143)	(1,143)
Net current-period other comprehensive income loss	(516)	(1,085)	(1,601)
Balance at December 31, 2017	\$ (4,803)	\$ (32,531)	\$ (37,334)

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 Statement of Income. The reclassifications were as follows:

Twelve Months Ended December 31,	2018	2017	Location on Statement of Income
(In thousands)			
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	\$ (131)	\$ (133)	(a)
	32	50	Income taxes
	(99)	(83)	
Subsidiary reclassifications out of accumulated other comprehensive loss	(2,616)	(1,416)	Equity in earnings of Subsidiary Companies
Total reclassifications	\$ (2,715)	\$ (1,499)	

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

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.

Year Ended December 31, 2018	Electric	Natural Gas Distribution	Total
(In thousands)			
Residential utility sales	\$ 121,477	\$ 160,022	\$ 281,499
Commercial utility sales	136,236	109,631	245,867
Industrial utility sales	34,353	5,672	40,025
Other utility sales	7,556	---	7,556
Natural gas transportation	---	6,423	6,423
Other	31,568	9,431	40,999
Revenues from contracts with customers	331,190	291,179	622,369
Revenues out of scope	3,933	1,475	5,408
Total external operating revenues	\$ 335,123	\$ 292,654	\$ 627,777

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Note 3 - Acquisitions

During 2018, a subsidiary of the Company completed four acquisitions of construction materials and contracting businesses in Oregon, Minnesota, and 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. 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 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.

Note 4 - Goodwill and Other Intangible Assets

The carrying amount of goodwill, which is related to the natural gas distribution business, remained unchanged at \$4.8 million for the years ended December 31, 2018 and 2017. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 5 - 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)	(h)	\$ 96,595	\$ 95,806
Asset retirement obligations (a) (b)	Over plant lives	13,763	12,036
Taxes recoverable from customers (a)	Over plant lives	8,179	8,253
Unamortized loss on required debt	Up to 8 years	4,154	4,726
Costs related to identifying generation development (c)	Up to 8 years	2,508	2,960
Unrecovered purchased gas costs	Up to 1 year	(2,577)	2,175
Other (a) (d) (e)	Up to 20 years	13,832	14,283
Total regulatory assets		136,454	140,239
Regulatory liabilities:			
Taxes refundable to customers (f)		148,015	155,329
Plant removal and decommissioning costs (b) (f)		56,095	55,519
Accumulated provision for rate refunds		15,514	---
Pension and postretirement benefits (f)		10,309	11,056
Other (f) (g)		6,209	3,214
Total regulatory liabilities		236,142	225,118
Net regulatory position		\$ (99,688)	\$ (84,879)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.

(a) Included in other regulatory assets on the Comparative Balance Sheet.

(b) Included in accumulated provision for depreciation, amortization and depletion on the Comparative Balance Sheet.

(c) Included in unrecovered plant and regulatory study costs on the Comparative Balance Sheet.

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- (d) Included in prepayments on the Comparative Balance Sheet.
- (e) Included in miscellaneous deferred debits on the Comparative Balance Sheet.
- (f) Included in other regulatory liabilities on the Comparative Balance Sheet.
- (g) Included in accumulated deferred investment tax credits on the Comparative Balance Sheet.
- (h) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2018 and 2017, approximately \$119.4 million and \$118.5 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 \$7.4 million in taxes recoverable from customers and an increase of \$149.8 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. For more information on the various rate cases, see Note 16. 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 business ceases 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 6 - 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 plan 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 \$49.2 million and \$51.6 million as of December 31, 2018 and 2017, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized loss on these investments for the year ended December 31, 2018, was \$2.4 million. The net unrealized gain on these investments for the year ended December 31, 2017, was \$6.5 million. The change in fair value, which is considered part of the cost of the plan, is classified in Other Income and Deductions as Life Insurance on the Statement of Income.

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

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active markets, or using other known 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				Balance at December 31, 2018
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)		
(In thousands)					
Assets:					
Money market funds	\$	—	\$	5,045	\$ 5,045
Insurance contract*		—	49,213	—	49,213
Total assets measured at fair value	\$	—	\$	54,258	\$ 54,258

*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				Balance at December 31, 2017
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)		
(In thousands)					
Assets:					
Money market funds	\$	—	\$	3,762	\$ 3,762
Insurance contract*		—	51,578	—	51,578
Total assets measured at fair value	\$	—	\$	55,340	\$ 55,340

*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.

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The Company's long-term debt is not measured at fair value on the Comparative Balance Sheet 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	\$ 788,725	\$ 795,113	\$ 714,686	\$ 752,311

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

Note 7 - Debt

Certain debt instruments of the Company, including those discussed later, contain restrictive covenants and provisions. In order to borrow under the respective credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. At December 31, 2018, the Company complied with all applicable financial covenants and restrictions. In the event the Company does 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:

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
(Dollars in millions)						
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a) \$ 175.0	\$ 48.5	(b) \$ 73.8	(b) \$ —	6/8/23

(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 included in other long-term debt on the Comparative Balance Sheet.

The Company's commercial paper program is supported by a revolving credit agreement. While the amount of commercial paper outstanding does not reduce available capacity under the revolving credit agreement, the Company does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

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

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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.

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

	2018	2017
	(In thousands)	
Senior Notes at a weighted average rate of 4.12%, due on dates ranging from October 17, 2019 to November 21, 2046	\$ 739,800	\$ 640,500
Commercial paper at an interest rate of 2.83%, supported by revolving credit agreement	48,500	73,750
Other note at a rate of 6.0%, due on November 30, 2038	425	436
Total long-term debt	\$ 788,725	\$ 714,686

Schedule of Debt Maturities Long-term debt maturities 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	\$200,711	\$712	\$713	\$714	\$49,214	\$536,661

Note 8 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, decommissioning of certain electric generating facilities, 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 for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
Balance at beginning of year	\$ 127,809	\$ 119,521
Liabilities incurred	6,293	4,559
Liabilities settled	(1,006)	(2,509)
Accretion expense *	6,690	6,277
Revisions in estimates	3,137	(39)
Balance at end of year	\$ 142,923	\$ 127,809

* Includes \$6.7 million and \$6.3 million in 2018 and 2017, respectively, related to regulatory assets.

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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.

Note 9 - 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. 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 10 - Common Stock

For the years 2018 and 2017, dividends declared on common stock were \$.7950 and \$.7750 per common share, respectively.

The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2018 and 2017, 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.

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 11 - 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.

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Total stock-based compensation expense (after tax), excluding the amount recognized by the Company's subsidiaries, was \$1.2 million and \$805,000 in 2018 and 2017, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company's subsidiaries, related to stock-based compensation was approximately \$2.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 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 and 40,572 shares with a fair value of \$1.1 million issued to non-employee directors during the years ended December 31, 2018 and 2017, 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 and its subsidiaries 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 and 2017 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

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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 year ended December 31, 2017, was \$9.6 million.

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 12 - Income Taxes

Income before income taxes for the years ended December 31, 2018 and 2017, respectively was \$57.0 million and \$76.5 million.

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

	2018	2017
	(In thousands)	
Current:		
Federal	\$ (15,223)	\$ (19,922)
State	(295)	(1,380)
	(15,518)	(21,302)
Deferred:		
Income taxes:		
Federal	8,835	32,335
State	877	2,590
Investment tax credit - net	1,547	191
	11,259	35,116
Total income tax expense (benefit)	\$ (4,259)	\$ 13,814

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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 associated with the non-regulated operations 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 expense of \$2.9 million for the year ended December 31, 2017. Included in the tax expense was \$1.0 million related to amounts in accumulated other comprehensive loss.

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 5 and 16. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of \$157.2 million in the fourth quarter of 2017. 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.

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.

Based on the Company's estimate of the amount of excess deferred income taxes that would be used to reduce future customer rates, the Company recorded an increase in regulatory liabilities of approximately \$149.8 million and a reduction in regulatory assets of \$7.4 million, including gross ups, to reflect the future revenue reduction required to return previously collected income taxes to customers.

The accounts that increased and (decreased) in the 2017 remeasurement of deferred income taxes are reflected below (in millions):

FERC Account	254	182.3	190	281	282	283
Excess Deferred Income Taxes:						
Electric*	\$122.5		\$(1.7)	\$(0.5)	\$(120.3)	\$(3.4)
Gas	27.3		(3.1)		(26.3)	(4.1)
Regulatory Asset and Deferred Taxes associated with AFUDC:						
Electric*		\$(6.8)			(3.2)	(3.6)
Gas		(0.6)			(0.3)	(0.3)
Total	\$149.8	\$(7.4)	\$(4.8)	\$(0.5)	\$(150.1)	\$(11.4)

*Deferred income taxes for the Company's electric integrated system, including excess deferred income taxes and those associated with AFUDC, are included in the MISO attachment 0 formula rate template based on an allocation percentage of transmission-related assets to total integrated system-related assets for each given year. For the years ended

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December 31, 2018 and 2017, the allocation percentage for transmission-related assets to total integrated-system related assets was 18.92% and 15.83%, respectively.

Total plant-related excess deferred taxes, those originating in FERC accounts 281 or 282, as of December 31, 2017, were \$147.1 million, and were largely considered protected. The Company has proposed in all of its state jurisdictions to amortize both protected and non-protected plant-related excess deferred taxes on an ARAM basis which is based on plant lives. See Note 1 for more information on the Company's weighted average depreciable lives. All state jurisdictions which have approved rates related to TCJA have approved this treatment and the Company is awaiting final orders in the remaining jurisdictions.

Net non-plant-related excess deferred taxes, those originating in FERC accounts 190 and 283, as of December 31, 2017 were \$2.7 million. These excess deferred taxes are being amortized on a straight-line basis over periods ranging from 1-10 years as approved by the respective state jurisdictions which have approved rates related to TCJA.

Deferred taxes associated with AFUDC, recorded in FERC account 282 and 283, and the related regulatory asset, recorded in FERC account 182.3 were reduced by \$7.4 million as of December 31, 2017 reflecting the reduction in future revenue requirement required to be collected from customers.

Amortization of the excess deferred taxes are being recorded to FERC Accounts 410.1 and 411.1 as appropriate. For the year ended December 31, 2018, the amortization of excess deferred taxes, including gross ups, has reduced the related regulatory liabilities by \$7.3 million.

In November 2018, MISO submitted revisions to the generic rate template in attachment O of its Open Access Transmission, Energy and Operating Reserve Markets Tariff and to company-specific formula rate templates of several MISO transmission owners, including the Company's (FERC Docket No. ER19-249-000). The revisions add two income tax items to the generic rate template and the company-specific formula rates regarding the allowance for funds used during construction and a provision to return (or recover) excess (or deficient) accumulated deferred income taxes resulting from tax law or rate changes. In December 2018, the submittal was approved by the FERC for filing effective January 1, 2019.

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

	2018	2017
	(In thousands)	
Deferred tax assets:		
Postretirement	\$ 23,695	\$ 26,021
Production Tax Credits	8,015	19,367
Compensation-related	7,903	5,294
Customer advances	4,988	5,762
Other	6,928	2,907
Total deferred tax assets	51,529	59,351
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	183,229	173,782
Postretirement	26,206	25,745
Cost recovery mechanisms	1,688	2,285
Other	5,528	5,386
Total deferred tax liabilities	216,651	207,198
Net deferred income tax liability	\$ (165,122)	\$ (147,847)

As of December 31, 2018 and 2017, the Company had a federal income tax credit carryforward of \$8.0 million and \$19.4 million, respectively. The federal income tax credit carryforwards will expire in 2037 and 2038 if not utilized. As of December 31, 2018 and 2017, no valuation allowances have been recorded associated with previously identified deferred tax assets. Changes in tax regulations or assumptions regarding current and future taxable income could require valuation allowances in the future.

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	\$ 17,275
Deferred taxes associated with TCJA enactment for regulated activities	(5,364)
Deferred taxes associated with other comprehensive income (loss)	(323)
Other	(329)
Deferred income tax expense for the period	\$ 11,259

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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	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	\$ 11,959	21.0	\$ 26,781	35.0
Increases (reductions) resulting from:				
Production tax credit	(11,759)	(20.6)	(13,958)	(18.2)
Excess deferred income tax amortization	(5,364)	(9.4)	---	---
Amortization and deferral of investment tax credit	(120)	(0.2)	(171)	(0.2)
R&D tax credit	(669)	(1.2)	---	---
Deductible K-Plan dividends	(644)	(1.1)	(1,092)	(1.4)
AFUDC equity	(215)	(0.4)	(140)	(0.2)
State income taxes, net of federal income tax	2,163	3.8	1,923	2.5
Nonqualified benefit plan TCJA revaluation	182	0.3	(2,342)	(3.1)
TCJA revaluation related to accumulated other comprehensive income	---	---	1,890	2.5
Other	208	0.3	(122)	(0.2)
Total income tax expense (benefit)	\$ (4,259)	(7.5)	\$ 13,814	18.1

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The Company is no longer subject to U.S. federal 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
	(In thousands)	
Balance at beginning of year	\$ ---	\$ ---
Additions based on tax positions related to current year	39	---
Additions for tax positions of prior years	100	---
Balance at end of year	\$ 139	---

For the years ended December 31, 2018 and 2017, the Company recognized approximately \$59,000 and \$14,000, respectively, of interest income, related to income taxes. At December 31, 2018 and 2017, the Company had no accrued receivables for interest.

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Note 13 - Cash Flow Information

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

	2018	2017
	(In thousands)	
Interest, net of AFUDC – borrowed of \$1,283 and \$503 in 2018 and 2017, respectively	\$ 32,841	\$ 30,101
Income taxes refunded, net	\$ (36,926)	\$ (7,885)

Noncash investing transactions at December 31 were as follows:

	2018	2017
	(In thousands)	
Property, plant and equipment additions in accounts payable	\$ 12,907	\$ 12,324
Issuance of common stock in connection with acquisition by a subsidiary	\$ 18,186	\$ ---

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. Other postretirement plans presented here include certain of the Company's subsidiaries.

Prior to 2017, all of the Company's defined benefit pension plans were 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.

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.

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Changes in benefit obligation and plan assets for the years ended December 31, 2018 and 2017, and amounts recognized in the Comparative Balance Sheet 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	\$ 250,889	\$ 245,858	\$ 40,128	\$ 40,267
Service cost	---	---	621	616
Interest cost	8,183	9,090	1,257	1,443
Plan participants' contributions	---	---	731	804
Actuarial (gain) loss	(17,944)	10,543	(4,389)	260
Benefits paid	(21,159)	(14,602)	(2,749)	(3,262)
Benefit obligation at end of year	219,969	250,889	35,599	40,128
Change in net plan assets:				
Fair value of plan assets at beginning of year	192,712	182,213	50,531	47,253
Actual gain (loss) on plan assets	(11,422)	24,679	(1,551)	5,645
Employer contribution	7,200	422	70	91
Plan participants' contributions	---	---	731	804
Benefits paid	(21,159)	(14,602)	(2,749)	(3,262)
Fair value of net plan assets at end of year	167,331	192,712	47,032	50,531
Funded status – over (under)	\$ (52,638)	\$ (58,177)	\$ 11,433	\$ 10,403
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	\$ (52,638)	\$ (58,177)	\$ 11,433	\$ 10,403
Net amount recognized	\$ (52,638)	\$ (58,177)	\$ 11,433	\$ 10,403
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	\$ 103,455	\$ 102,514	\$ 599	\$ 683
Prior service credit	---	---	(7,253)	(8,228)
Total	\$ 103,455	\$ 102,514	\$ (6,654)	\$ (7,545)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. 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 5.

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.

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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	\$ 219,969	\$ 250,889
Accumulated benefit obligation	\$ 219,969	\$ 250,889
Fair value of plan assets	\$ 167,331	\$ 192,712

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	2018	2017
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	\$ ---	\$ ---	\$ 621	\$ 616
Interest cost	8,183	9,090	1,257	1,443
Expected return on assets	(11,352)	(11,222)	(2,754)	(2,651)
Amortization of prior service credit	---	---	(976)	(976)
Recognized net actuarial loss	3,890	3,554	---	---
Net periodic benefit cost (credit), including amount capitalized	721	1,422	(1,852)	(1,568)
Less amount capitalized	---	294	119	(360)
Net periodic benefit cost (credit)	721	1,128	(1,971)	(1,208)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities):				
Net (gain) loss	4,831	(2,915)	(84)	(2,733)
Amortization of actuarial loss	(3,890)	(3,554)	---	---
Amortization of prior service credit	---	---	976	976
Total recognized in accumulated other comprehensive (income) loss and regulatory assets (liabilities)	941	(6,469)	892	(1,757)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss and regulatory assets (liabilities)	\$ 1,662	\$ (5,341)	\$ (1,079)	\$ (2,965)

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 \$3.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost (credit) in 2019 are \$0 and \$976,000, 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	4.02%	3.37%	4.03%	3.38%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%

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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 %	3.82%	3.38 %	3.83 %
Expected return on plan assets	6.75 %	6.75%	5.75 %	5.75 %

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	8.0 %	7.5 %
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	\$ 42	\$ (36)
Effect on postretirement benefit obligation	\$ 925	\$ (806)

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

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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.

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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			Balance at December 31, 2018
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
(In thousands)				
Assets:				
Cash equivalents	\$ —	\$ 2,680	\$ —	\$ 2,680
Equity securities:				
U.S. companies	6,000	—	—	6,000
International companies	---	526	—	526
Collective and mutual funds *	79,347	28,051	—	107,398
Corporate bonds	—	39,744	—	39,744
Municipal bonds	—	5,775	—	5,775
U.S. Government securities	261	3,205	—	3,466
Total assets measured at fair value	\$ 85,608	\$ 79,981	\$ —	\$ 165,589

*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			Balance at December 31, 2017
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
(In thousands)				
Assets:				
Cash equivalents	\$ —	\$ 2,074	\$ —	\$ 2,074
Equity securities:				
U.S. companies	7,257	—	—	7,257
International companies	960	—	—	960
Collective and mutual funds *	93,436	36,842	—	130,278
Corporate bonds	—	40,761	—	40,761
Municipal bonds	—	4,647	—	4,647
U.S. Government securities	564	4,510	—	5,074
Total assets measured at fair value	\$ 102,217	\$ 88,834	\$ —	\$ 191,051

*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.

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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			Balance at December 31, 2018
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	(In thousands)			
Assets:				
Cash equivalents	\$ —	\$ 2,187	\$ —	\$ 2,187
Equity securities:				
U.S. companies	841	—	—	841
Insurance contract*	—	44,004	—	44,004
Total assets measured at fair value	\$ 841	\$ 46,191	\$ —	\$ 47,032

*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.

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	Fair Value Measurements at December 31, 2017, Using			Balance at December 31, 2017
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
(In thousands)				
Assets:				
Cash equivalents	\$ —	\$ 2,738	\$ —	\$ 2,738
Equity securities:				
U.S. companies	1,074	—	—	1,074
Insurance contract*	—	46,719	—	46,719
Total assets measured at fair value	\$ 1,074	\$ 49,457	\$ —	\$ 50,531

*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 \$2.8 million to its defined benefit pension plans in 2019. The Company does not expect to contribute 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	\$ 13,893	\$ 2,653	\$ 91
2020	13,992	2,544	87
2021	14,138	2,486	82
2022	14,305	2,476	76
2023	14,377	2,445	70
2024–2028	70,899	11,592	249

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	\$ 47,176	\$ 51,388
Accumulated benefit obligation	\$ 47,176	\$ 51,388

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

	2018	2017
(In thousands)		
Components of net periodic benefit cost:		
Service cost	\$ 185	\$ 221
Interest cost	1,586	1,769
Recognized net actuarial loss	290	214
Net periodic benefit cost	\$ 2,061	\$ 2,204

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	3.85%	3.18%
Benefit obligation rate of compensation increase	N/A	N/A
Net periodic benefit cost discount rate	3.18%	3.54%
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	\$ 4,263	\$ 4,525	\$ 4,620	\$ 3,914	\$ 4,035	18,272

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018 and 2017 were \$96,000 and \$167,000, respectively.

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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*	\$ 49,213	\$ 51,578
Life insurance**	19,122	19,399
Other	5,054	3,765
Total investments	\$ 73,389	\$ 74,742

* For more information on the insurance contract, see Note 6.

**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 costs incurred under these plans were \$10.6 million in 2018 and \$11.1 million in 2017.

Note 15 - Jointly Owned Facilities

The 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 Statement of Income.

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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 16 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details 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. The MNPUC is scheduled to address the compliance filing on April 18, 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

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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. The TCJA refund was issued to customers on March 29, 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. On March 7, 2019, the MTPSC issued an interim order authorizing an interim increase of \$7.9 million or 12.8% to be effective April 1, 2019. The interim increase is subject to refund depending on the final outcome of the rate case. 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. The interim refund was issued to customers on March 1, 2019.

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. The TCJA refund was issued to customers on March 12, 2019.

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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. New rates were implemented on February 1, 2019. The refund is scheduled to be issued to customers on April 12, 2019.

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. The TCJA refund was issued to customers on February 15, 2019.

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. On March 19, 2019, the WYPSC ruled to approve Montana-Dakota's requested decrease in electric rates and required a refund to customers for the period of January 1, 2018, through the date prior to the implementation of rates within 90 days of the effective date of new rates. Compliance electric rates were submitted to the WYPSC on April 4, 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

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formula rate under the MISO tariff for the multivalued project for \$12.5 million, which is effective January 1, 2019.

Note 17 - Commitments and Contingencies

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of \$190,000 and \$283,000 which have not been discounted, for contingencies related to litigation as of December 31, 2018 and 2017, respectively. 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. Legal costs are expensed as they are incurred.

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	\$1,802	\$1,738	\$1,610	\$1,386	\$1,340	\$27,122

Rent expense was \$1.9 million and \$2.7 million for the years ended December 31, 2018 and 2017, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 22 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
(In thousands)						
Purchase commitments	\$167,413	\$89,378	\$61,099	\$20,883	\$18,401	\$22,298

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2018 and 2017, were \$292.6 million and \$256.7 million, respectively.

Note 18 - 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. 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.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	(62,886)	(33,220,342)		(149,194)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	120,447	(130,512)		
3	Preceding Quarter/Year to Date Changes in Fair Value	(139,146)	(1,813,479)		(5,756)
4	Total (lines 2 and 3)	(18,699)	(1,943,991)		(5,756)
5	Balance of Account 219 at End of Preceding Quarter/Year	(81,585)	(35,164,333)		(154,950)
6	Balance of Account 219 at Beginning of Current Year	(81,585)	(35,164,333)		(154,950)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(143,727)	4,440,688		(61,062)
8	Current Quarter/Year to Date Changes in Fair Value	113,929	(5,346,123)		216,012
9	Total (lines 7 and 8)	(29,798)	(905,435)		154,950
10	Balance of Account 219 at End of Current Quarter/Year	(111,383)	(36,069,768)		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(2,300,322)		(35,732,744)		
2	367,472		357,407		
3			(1,958,381)		
4	367,472		(1,600,974)		(1,600,974)
5	(1,932,850)		(37,333,718)		
6	(1,932,850)		(37,333,718)		
7			4,235,899		
8	(228,045)		(5,244,227)		
9	(228,045)		(1,008,328)		(1,008,328)
10	(2,160,895)		(38,342,046)		

**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,441,019,287	1,691,798,611
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	212,334,613	201,385,454
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,653,353,900	1,893,184,065
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	165,864,516	157,910,407
12	Acquisition Adjustments	10,565,606	10,468,340
13	Total Utility Plant (8 thru 12)	2,829,784,022	2,061,562,812
14	Accum Prov for Depr, Amort, & Depl	967,632,867	636,929,476
15	Net Utility Plant (13 less 14)	1,862,151,155	1,424,633,336
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	918,984,066	623,443,481
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	38,177,136	3,086,461
22	Total In Service (18 thru 21)	957,161,202	626,529,942
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	10,471,665	10,399,534
33	Total Accum Prov (equals 14) (22,26,30,31,32)	967,632,867	636,929,476

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
612,400,624				136,820,052	3
					4
					5
9,554,360				1,394,799	6
					7
621,954,984				138,214,851	8
					9
					10
1,666,554				6,287,555	11
97,266					12
623,718,804				144,502,406	13
271,390,587				59,312,804	14
352,328,217				85,189,602	15
					16
					17
268,305,998				27,234,587	18
					19
					20
3,012,458				32,078,217	21
271,318,456				59,312,804	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
72,131					32
271,390,587				59,312,804	33

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	5,401,996	2,174,294
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	5,401,996	2,174,294
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,015,062	
9	(311) Structures and Improvements	80,423,573	25,213,013
10	(312) Boiler Plant Equipment	342,486,035	-22,104,423
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	84,826,180	1,712,850
13	(315) Accessory Electric Equipment	20,054,504	5,049,723
14	(316) Misc. Power Plant Equipment	19,206,192	3,378,555
15	(317) Asset Retirement Costs for Steam Production	7,370,483	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	555,382,029	13,249,718
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	38,533	
38	(341) Structures and Improvements	8,419,480	27,552,392
39	(342) Fuel Holders, Products, and Accessories	2,116,203	
40	(343) Prime Movers		
41	(344) Generators	429,305,494	23,714,906
42	(345) Accessory Electric Equipment	16,665,158	35,798,943
43	(346) Misc. Power Plant Equipment	1,774,648	83,033
44	(347) Asset Retirement Costs for Other Production	10,674,612	7,698,722
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	468,994,128	94,847,996
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,024,376,157	108,097,714

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
				2
				3
			7,576,290	4
			7,576,290	5
				6
				7
			1,015,062	8
942,396		-331,991	104,362,199	9
6,390,868			313,990,744	10
				11
660,031		331,991	86,210,990	12
221,179			24,883,048	13
648,635		52,839	21,988,951	14
		-54,204	7,316,279	15
8,863,109		-1,365	559,767,273	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
			38,533	37
20,091		701,334	36,653,115	38
50,037		-87,778	1,978,388	39
				40
1,238,830		-2,820,765	448,960,805	41
797,852		2,207,209	53,873,458	42
39,254			1,818,427	43
421,284		54,204	18,006,254	44
2,567,348		54,204	561,328,980	45
11,430,457		52,839	1,121,096,253	46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	4,858,679	20,348
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	146,635,867	6,836,150
51	(354) Towers and Fixtures	4,992,886	
52	(355) Poles and Fixtures	79,567,203	-962,574
53	(356) Overhead Conductors and Devices	55,837,776	4,933,857
54	(357) Underground Conduit	1,944,583	
55	(358) Underground Conductors and Devices	3,101,857	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	797	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	296,941,437	10,827,781
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,039,020	72,458
61	(361) Structures and Improvements		
62	(362) Station Equipment	76,847,322	5,758,846
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	43,143,824	2,101,497
65	(365) Overhead Conductors and Devices	33,380,886	1,036,184
66	(366) Underground Conduit	235,918	
67	(367) Underground Conductors and Devices	117,907,485	6,733,515
68	(368) Line Transformers	73,289,457	3,119,483
69	(369) Services	37,273,186	945,062
70	(370) Meters	18,580,478	260,820
71	(371) Installations on Customer Premises	2,916,488	269,970
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	7,888,805	1,883,533
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	415,542,617	22,181,368
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	38,850	
87	(390) Structures and Improvements	1,518,094	14,947
88	(391) Office Furniture and Equipment	458,297	7,424
89	(392) Transportation Equipment	8,248,100	840,820
90	(393) Stores Equipment	14,774	
91	(394) Tools, Shop and Garage Equipment	4,301,391	671,168
92	(395) Laboratory Equipment	720,963	
93	(396) Power Operated Equipment	14,162,109	1,312,257
94	(397) Communication Equipment	1,222,854	622,325
95	(398) Miscellaneous Equipment	58,769	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	30,744,201	3,468,941
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	30,744,201	3,468,941
100	TOTAL (Accounts 101 and 106)	1,773,006,408	146,750,098
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	1,773,006,408	146,750,098

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
9,007			4,870,020	48
			1,789	49
3,541,333		-464,131	149,466,553	50
			4,992,886	51
627,544		-99,575	77,877,510	52
727,343		-66,520	59,977,770	53
			1,944,583	54
			3,101,857	55
				56
			797	57
4,905,227		-630,226	302,233,765	58
				59
			4,111,478	60
				61
4,311,802		480,841	78,775,207	62
				63
239,654		69,532	45,075,199	64
168,928		25,717	34,273,859	65
			235,918	66
839,548			123,801,452	67
450,044		-844	75,958,052	68
142,000			38,076,248	69
112,796			18,728,502	70
156,664			3,029,794	71
				72
1,127,626			8,644,712	73
			39,748	74
7,549,062		575,246	430,750,169	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			38,850	86
908			1,532,133	87
238,022		18,574	246,273	88
546,469		-78,267	8,464,184	89
			14,774	90
65,256			4,907,303	91
60,618			660,345	92
1,511,769		-210,819	13,751,778	93
2,609		10,609	1,853,179	94
			58,769	95
2,425,651		-259,903	31,527,588	96
				97
				98
2,425,651		-259,903	31,527,588	99
26,310,397		-262,044	1,893,184,065	100
				101
				102
				103
26,310,397		-262,044	1,893,184,065	104

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Construct BSSE 345kV Transmission Line	105,845,864
2	Construct Ellendale 345kV Substation	16,386,297
3	Construct 230/34.5kV Watford City Substation	5,930,802
4	Construct new Bowdle Substation	5,193,796
5	Construct new Leola Substation - 115kV portion	2,414,516
6	Install 34.5kV Line around Watford City	2,337,385
7	Install 115kV Line SD Section of Ellendale to Leola	2,151,334
8	Rebuild North 10 Miles of the Glendive-Baker 60kV Line	1,712,238
9	Purchase Landworks Software	1,558,210
10	Construct Reactor at Ellendale 345kV Substation	1,435,162
11	GIS Field Verification Pilot Project	1,433,901
12	Add Coal Combustion Residuals Slag Pond Liner at Coyote Station	1,217,207
13		
14		
15		
16		
17		
18		
19	Minor Projects less than \$1,000,000:	
20	Steam Production	2,358,064
21		
22	Other Production	20,757
23		
24	Transmission	2,396,107
25		
26	Distribution	3,429,011
27		
28	General	502,369
29		
30	Intangible	1,587,387
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	157,910,407

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	596,868,751	596,868,751		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	49,101,906	49,101,906		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,193,272	1,193,272		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-1,098,327	-1,098,327		
9		1,391,566	1,391,566		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	50,588,417	50,588,417		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	26,310,397	26,310,397		
13	Cost of Removal	-572,250	-572,250		
14	Salvage (Credit)	1,683,671	1,683,671		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	24,054,476	24,054,476		
16	Other Debit or Cr. Items (Describe, details in footnote):	40,789	40,789		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	623,443,481	623,443,481		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	253,625,574	253,625,574		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	100,460,225	100,460,225		
25	Transmission	109,638,612	109,638,612		
26	Distribution	149,503,985	149,503,985		
27	Regional Transmission and Market Operation				
28	General	10,215,085	10,215,085		
29	TOTAL (Enter Total of lines 20 thru 28)	623,443,481	623,443,481		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 8 Column: c

Common plant depreciation expense charged to electric operations

Schedule Page: 219 Line No.: 9 Column: c

SFAS ARO depreciation expense reclassified to a regulatory asset

Schedule Page: 219 Line No.: 16 Column: c

Reserve reclassifications between utility segments and net gains and losses on depreciable plant

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	CENTENNIAL ENERGY HOLDINGS, INC. (100% OWNED)	12/88		
3	Capital investment in subsidiaries			781,612,455
4				
5	Equity in undistributed subsidiary earnings since acquisition			393,861,660
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			503,494,430
10				
11	Equity in undistributed subsidiary earnings since acquisition			25,939,591
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
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38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	1,790,885,738	TOTAL	1,704,908,136

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		732,282,521		3
				4
187,586,887	-98,517,317	482,931,230		5
				6
				7
				8
		543,895,644		9
				10
23,522,870	-17,686,116	31,776,343		11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
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				40
				41
211,109,757	-116,203,433	1,790,885,738		42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,684,911	4,784,694	Electric & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,206,532	16,965,194	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,005,304	2,967,108	Electric
8	Transmission Plant (Estimated)	163,200	109,400	Electric
9	Distribution Plant (Estimated)	1,704,552	1,780,372	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-241,825	-795,640	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	16,837,763	21,026,434	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	21,522,674	25,811,128	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 11 Column: b

Allowance for inventory shrinkage - materials and supplies.

Schedule Page: 227 Line No.: 11 Column: c

Allowance for inventory shrinkage - materials and supplies.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	65,101.00		11,607.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	5,187.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Lewis & Clark to WygenIII	48.00			
23	RM Heskett to Wygen III	48.00			
24					
25					
26					
27					
28	Total	96.00			
29	Balance-End of Year	59,818.00		11,607.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	168.00		168.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	168.00			
40	Balance-End of Year			168.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	168.00	10		
45	Gains	168.00	10		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfersors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
11,607.00		11,607.00		266,961.00		366,883.00		1
								2
								3
				11,607.00		11,607.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						5,187.00		18
								19
								20
								21
						48.00		22
						48.00		23
								24
								25
								26
								27
						96.00		28
11,607.00		11,607.00		278,568.00		373,207.00		29
								30
								31
								32
								33
								34
								35
168.00		168.00		5,659.00		6,331.00		36
				168.00		168.00		37
								38
				168.00		336.00		39
168.00		168.00		5,659.00		6,163.00		40
								41
								42
								43
				168.00	3	336.00		13 44
				168.00	3	336.00		13 45
								46

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Electric Generation Development	1,718,605		407	171,860	429,651
22	Costs: ND Public Service					
23	Commission authorization granted					
24	6/8/11 due to cancellation of					
25	construction; North Dakota					
26	electric amortization over					
27	120 months					
28						
29	Electric Generation Development	3,424,185			198,351	1,467,584
30	Costs: MT Public Service					
31	Commission authorization granted					
32	8/2/11 due to cancellation of					
33	construction; Montana electric					
34	amortization over 180 months					
35						
36	Electric Generation Development	814,359		407	81,436	610,769
37	Costs: SD Public Utility					
38	Commission authorization					
39	granted 6/15/16 due to					
40	cancellation of construction;					
41	South Dakota electric					
42	amortization over 120 months					
43						
44						
45						
46						
47						
48						
49	TOTAL	5,957,149			451,647	2,508,004

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 29 Column: d

407	\$242,228
419	<u>(43,877)</u>
	\$198,351

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	Unamortized Regulatory Commission Expense:	1,468,659	583,449		652,468	1,399,640
2	South Dakota gas amortization over 36 months					
3	ending 6/19; Montana gas amortization over					
4	36 months ending 6/21; Wyoming gas amortization					
5	over 60 months ending 5/20; Minnesota gas					
6	amortization over 48 months ending 12/20;					
7	North Dakota gas amortization over 36 months					
8	ending 11/21; Montana electric amortization					
9	over 36 months ending 3/19; North Dakota					
10	electric amortization over 36 months ending					
11	8/20; South Dakota electric amortization over					
12	60 months ending 6/21; Wyoming electric					
13	amortization over 60 months ending 2/22.					
14						
15	Asset Retirement Obligations, recovered over	91,493,656	8,595,559	230	1,861,651	98,227,564
16	plant lives					
17						
18	Deferred Fuel and Purchased Power Costs -					
19	North Dakota - Electric	(2,801,149)	4,793,343		1,712,416	279,778
20	Wyoming - Electric	(222,195)	212,516		905,181	-914,860
21	Montana - Electric	(620,641)	1,369,518		814,429	-65,552
22	South Dakota - Electric	(67,572)	265,947	555	149,027	49,348
23						
24	Deferred Pension, recovered as expense is	95,588,919	968,427	253	173,344	96,384,002
25	incurred					
26						
27	Regulatory Matters -Deferred Tax Related,	8,253,225	1,095,422		1,169,798	8,178,849
28	recovered over plant lives					
29						
30	ND Transmission Cost Recovery Adjustment -	3,447,458	739,241		3,245,984	940,715
31	[Case No. PU-11-672]					
32						
33	Montana Public Service Commission/Montana	421,493	30,573	408.1	311,999	140,067
34	Consumer Counsel tax deferral [Docket No.					
35	D2014.8.72, D2015.9.67, D2015.9.68 and					
36	D2015.6.51]					
37						
38	ND Environmental Cost Recovery Rider	2,485,753	22,685		2,508,438	
39	[Case No. PU-18-89]					
40						
41	WY Renewable Energy Rider	(223)		142	119	-342
42	[Docket No. 20004-128-EA-18]					
43						

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	Manufactured Gas Plant Site - Billings, MT, not	483,905	80,406			564,311
2	yet being amortized [Docket No. D2014.11.95]					
3						
4	Deferred Pension Expense - ND Gas,	216,705		920	6,020	210,685
5	amortization over 3 years ending 11/21					
6	[Case No. PU-17-295]					
7						
8	ND Generation Resource Recovery Rider	1,538,950	188,574		1,727,524	
9	[Case No. PU-17-469]					
10						
11	ND Renewable Resource Cost Adjustment	(635,943)	4,041,764		1,227,628	2,178,193
12	[Case No. PU-18-82]					
13						
14	Loss on Buildings - North Dakota, amortization	2,838,647	32,953	407.3	108,479	2,763,121
15	over 20 years ending 11/38 [Case No. PU-16					
16	-666 and Case No. PU-17-295]					
17						
18	SD Transmission Rider	61,539	39,931		135,639	-34,169
19	[Docket No. EL15-024]					
20						
21	SD Infrastructure Rider	65,836	175,761		148,042	93,555
22	[Docket No. EL15-024]					
23						
24	MN Revenue Decoupling	545,857	628,587		1,174,444	
25	[Docket No. G-004/GR-15-879]					
26						
27	Preferred Stock Premium, amortization over 15	600,000			23,333	576,667
28	years ending 5/33 [Docket No. D2017.9.79]					
29						
30	MT Ad Valeorem Tax Tracker	1,214,523	1,354,494			2,569,017
31	[Docket No. 2016.12.96]					
32						
33	MN Gas Utility Infrastructure Cost Adjustment	398,800	367,436		70,903	695,333
34	[Docket No. G-004/M-16-1066]					
35						
36	MT Gas Conservation Program Tracking Mechanism		254,685		81,260	173,425
37	[Docket No. D2017.3.27]					
38						
39	Unless otherwise noted, amortization period					
40	for regulatory assets above are over a 12					
41	month period					
42						
43						
44	TOTAL :	206,776,202	25,841,271		18,208,126	214,409,347

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 1 Column: d

928 (Electric)	276,745
928 (Gas)	375,723
	<u>652,468</u>

Schedule Page: 232 Line No.: 19 Column: d

229	83
419	41
431	13,917
555	1,698,375
	<u>1,712,416</u>

Schedule Page: 232 Line No.: 20 Column: d

182.3	596
419	(5,783)
431	6,214
555	904,154
	<u>905,181</u>

Schedule Page: 232 Line No.: 21 Column: d

182.3	19,495
431	24,042
555	770,892
	<u>814,429</u>

Schedule Page: 232 Line No.: 27 Column: d

282	738,297
283	431,501
	<u>1,169,798</u>

Schedule Page: 232 Line No.: 30 Column: d

229	858,036
400	2,386,357
419	1,591
	<u>3,245,984</u>

Schedule Page: 232 Line No.: 38 Column: d

229	1,011,025
400	1,495,553
419	1,860
	<u>2,508,438</u>

Schedule Page: 232.1 Line No.: 8 Column: d

229	483,319
400	1,243,744
419	461
	<u>1,727,524</u>

Schedule Page: 232.1 Line No.: 11 Column: d

400	1,214,852
431	12,776
	<u>1,227,628</u>

Schedule Page: 232.1 Line No.: 18 Column: d

400	133,226
431	2,413
	<u>135,639</u>

Schedule Page: 232.1 Line No.: 21 Column: d

400	147,119
431	923
	<u>148,042</u>

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 232.1	Line No.: 24	Column: d
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400	1,388,008
489	<u>(213,564)</u>
	1,174,444

Schedule Page: 232.1	Line No.: 27	Column: d
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407.3	10,000
407.4	<u>13,333</u>
	23,333

Schedule Page: 232.1	Line No.: 33	Column: d
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400	67,802
489	<u>3,101</u>
	70,903

Schedule Page: 232.1	Line No.: 36	Column: d
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488	16,624
495	64,316
908	<u>320</u>
	81,260

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Deferred capital stock expense		587,539		587,539	
2						
3	Conservation programs	-970,715	14,075,416		14,546,672	-1,441,971
4						
5	Advance to FutureSource Capital	1,241,157	60,334			1,301,491
6	Corp. for land					
7						
8	Goodwill - Great Plains Natural	4,812,244				4,812,244
9	Gas Co.					
10						
11	Subsidiary post-retirement	13,547,923	206,365	228.3	1,022,628	12,731,660
12	trust assets					
13						
14	Post-retirement Benefit Costs	10,402,996	1,906,509		876,914	11,432,591
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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32						
33						
34						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	29,033,605				28,836,015

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 233	Line No.: 1	Column: d
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181	\$	545,004
237		<u>42,535</u>
	\$	587,539

Schedule Page: 233	Line No.: 3	Column: d
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142	\$	1,510,947
182.3		9,675,485
186		89,010
456		1,067,883
495		154,416
908		<u>2,048,931</u>
	\$	14,546,672

Schedule Page: 233	Line No.: 14	Column: d
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131	\$	77,597
186		60,157
254		<u>739,160</u>
	\$	876,914

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pension Expense	5,268,939	4,862,793
3	Compensation-related	2,930,019	4,647,677
4	Customer Advances	1,220,815	1,038,304
5	Postretirement Benefit Costs	1,152,213	1,063,284
6	Production Tax Credit Carryforward	19,366,967	8,015,316
7	Other	1,952,548	4,888,160
8	TOTAL Electric (Enter Total of lines 2 thru 7)	31,891,501	24,515,534
9	Gas		
10	Pension Expense	7,070,120	6,089,486
11	Customer Advances	4,541,677	3,949,955
12	Compensation-related	2,364,362	3,255,137
13	Postretirement Benefit Costs	1,544,792	1,451,409
14	Uniform Capitalization	232,000	228,000
15	Other	-433,585	383,359
16	TOTAL Gas (Enter Total of lines 10 thru 15)	15,319,366	15,357,346
17	Other (Specify) *	12,139,784	11,656,446
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	59,350,651	51,529,326

Notes

	Balance at Beginning of Year	Balance at End of Year
*Non-Utility		
C.I.A.C.'s	647,745	719,406
Charitable Contributions	197,393	-
ITC - State	286,850	686,105
SISP Expense	10,985,212	10,228,351
State Credit Carryforward	22,584	22,584
Total Non-Utility	12,139,784	11,656,446

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock	500,000,000	1.00	
3	Total Account 201	500,000,000		
4				
5	Account 204			
6	Preferred Stock	500,000	100.00	
7	4.50% Cumulative			
8	4.70% Cumulative			
9				
10	Total Account 204	500,000		
11				
12	Preferred Stock A - Cumulative	1,000,000		
13				
14	Preference Stock - Cumulative	500,000		
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
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41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
196,564,907	196,564,907	538,921	3,625,813			2
196,564,907	196,564,907	538,921	3,625,813			3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						31
						32
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						39
						40
						41
						42

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 250 Line No.: 2 Column: a

See Note 10 in Notes To Financial Statements beginning on page 122.

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2018

Year/Period of Report

End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

- 1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
- 2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2	Common Stock, \$1.00 par value	6,579,697
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	6,579,697

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 (None)		
2	Account 222 (None)		
3	Account 223 (None)		
4	Account 224		
5	Unsecured Senior Note		
6	6.33%	100,000,000	344,061
7	6.04%	100,000,000	362,431
8	3.36%	20,000,000	86,071
9	3.73%	40,000,000	173,637
10	5.98%	30,000,000	624,465
11	5.18%	50,000,000	239,178
12	4.24%	60,000,000	291,263
13	4.34%	40,000,000	197,042
14	3.78%	87,000,000	471,997
15	4.03%	52,000,000	286,355
16	4.87%	11,000,000	59,461
17	4.15%	40,000,000	226,084
18	2.00%	10,500,000	6,029
19	SUBTOTAL	640,500,000	3,368,074
20			
21	Term Loan	70,000,000	
22	Commercial Paper - 2.284% average for 2018		655,377
23	Minot Air Force Base Note Payable	509,197	
24	LIBOR Floating Rate Note	100,000,000	34,692
25	LIBOR Floating Rate Note	100,000,000	
26	SUBTOTAL	270,509,197	690,069
27			
28			
29			
30			
31			
32			
33	TOTAL	911,009,197	4,058,143

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
						4
						5
082406	082426	082406	082426	100,000,000	6,330,000	6
091608	091608	091608	091618		4,295,111	7
032117	032132	032117	032132	20,000,000	672,000	8
032117	032137	032117	032137	40,000,000	1,492,000	9
121503	121533	121503	121533	30,000,000	1,794,000	10
041514	041544	041514	041544	50,000,000	2,590,000	11
071514	071524	071514	071524	60,000,000	2,544,000	12
071514	071526	071514	071526	40,000,000	1,736,000	13
102915	103025	102915	103025	87,000,000	3,288,600	14
121015	121030	121015	121030	52,000,000	2,095,600	15
102915	103045	102915	103045	11,000,000	535,700	16
112116	112146	112116	112146	40,000,000	1,660,000	17
090517	090332	090517	090332	9,800,000	296,839	18
				539,800,000	29,329,850	19
						20
122018	060823			48,500,000	101,805	21
					1,743,044	22
092308	113038			425,495	25,881	23
091718	101719	091718	101719	100,000,000	859,479	24
101818	111819	101818	111819	100,000,000	612,550	25
				248,925,495	3,342,759	26
						27
						28
						29
						30
						31
						32
				788,725,495	32,672,609	33

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 22 Column: i

This amount includes a commitment fee of \$221,788

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	272,318,357
2		
3		
4	Taxable Income Not Reported on Books	
5	Dividends Received from Subsidiary Companies	115,899,600
6	See Footnote	21,631,887
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	73,124,704
11	Unamortized Loss on Reacquired Debt	571,714
12	Bad Debts	218,358
13	See Footnote	17,634,251
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	211,109,757
16	AFUDC Equity	1,026,572
17	See Footnote	3,290,306
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	111,743,492
21	Dividends Received From Subsidiaries	115,899,600
22	Federal Income Tax Provision	6,387,682
23	Supplemental Income Security Plan	911,206
24	401(k) Dividend Deduction	3,066,056
25	State Income Tax Deduction	61,242
26	See Footnote	11,961,958
27	Federal Tax Net Income	35,941,000
28	Show Computation of Tax:	
29	Federal Tax @ 21% of line 30	7,547,610
30	Other Credits and Adjustments	-20,171
31	Research & Development Tax Credit	-257,969
32	Wind Production Tax Credit	-25,874,000
33	Closing/Filing True-Up & Out of Period Adjustments	3,381,916
34		
35		
36	TOTAL	-15,222,614
37		
38	Response to Instruction #2 - See Footnote	
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 6 Column: b

Taxable Income Not Reported on Books:	
Contributions in Aid of Construction	\$ 2,933,140
Cost Recovery Mechanisms	2,618,449
Minnesota Decoupling	545,857
Reserved Revenues	15,514,270
Fuel Tax Credit	20,171
Total	<u>\$21,631,887</u>

Schedule Page: 261 Line No.: 13 Column: b

Deductions Recorded on Books Not Deducted for Return:	
State Income Tax Provision	\$ 2,128,833
Regulatory Commission Expense	69,019
Unrecovered Purchased Gas Cost	1,697,523
Disallowed Meals and Entertainment	234,472
Penalties	200
Qualified Transportation Fringe - Parking	100,672
Lobbying Expenses	156,316
Vacation Accrual	323,167
Prepaid Demand Charges	506,240
Deferred Compensation - Directors	432,153
Management Incentive	696,837
Performance Share Program	3,410,988
Bonus Accrual & 401(k) Profit Sharing	6,585,151
Preferred Stock Redemption Amortization	23,333
Loss on Buildings	14,343
Montana PSC/MCC Tax Deferral	194,011
Abandoned Power Plant Cost Recovery	451,648
Sundry Reserves	609,345
Total	<u>\$17,634,251</u>

Schedule Page: 261 Line No.: 17 Column: b

Income Recorded on Books Not Included in Return:	
Customer Advances	\$3,159,185
Mor-Gran-Sou Capacity Revenue	81,806
WAPA Fiber Demand Revenue	49,315
Total	<u>\$3,290,306</u>

Schedule Page: 261 Line No.: 26 Column: b

Deductions on Return Not Charged Against Book Income:	
Charitable Contributions	\$ 1,299,081
Contingency Reserve	70,743
Pension Expense	6,474,269
Post Retirement Benefits	1,851,373
Board of Directors - Retirement Benefits	19,165
Deferred Medicare Part D	299,823
Retired Power Plant	60,853
Prepaid Expenses	58,533
Capitalized Overheads	17,156
F&PP Deferral	329,125
Montana Decommissioning	1,342,439
Manufactured Gas Plant	80,406
Miscellaneous	58,992
Total	<u>\$11,961,958</u>

Schedule Page: 261 Line No.: 38 Column: a

The Respondent files a consolidated return; however, the information above has been prepared on a separate return basis. The consolidated group elected to allocate tax liabilities in accordance with method #2 under Internal Revenue Code Section 1552 (Earnings and Profits). The 2018 federal tax provisions were:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4
FOOTNOTE DATA			

Centennial Energy Holdings, Inc.	26,858,356
MDU Energy Capital	<u>(3,257,812)</u>
	\$23,600,544

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	CORPORATE INCOME					
2	Federal	-9,698,065		-15,222,614	-34,215,854	-175,801
3	State	-722,696		-294,998	-2,711,239	175,109
4	SUBTOTAL	-10,420,761		-15,517,612	-36,927,093	-692
5						
6	UNEMPLOYMENT					
7	Federal	33,097		54,880	57,551	
8	Arizona					
9	Idaho	14,132		49,968	56,037	
10	Minnesota	493		3,082	3,083	
11	Montana	6,316		37,325	38,974	
12	Texas	102		166	243	
13	North Dakota	23,103		146,499	140,946	
14	Oregon			1,638	1,292	
15	South Dakota	1,123		3,835	3,752	
16	Washington	874		7,313	6,850	
17	Wyoming	619		2,566	2,876	
18	SUBTOTAL	79,859		307,272	311,604	
19						
20	GROSS REVENUE					
21	Montana	90,339		365,162	388,275	
22	South Dakota			98,624	98,624	
23	Wyoming	53,241		95,433	100,958	
24	SUBTOTAL	143,580		559,219	587,857	
25						
26	USE					
27	Minnesota	1,324		17,749	19,020	
28	North Dakota	-21,395		707,258	555,116	
29	South Dakota	59,011		207,029	258,968	
30	Washington	3,374		3,768	3,374	
31	Wyoming	872		29,969	30,636	
32	Idaho	-2,685		8,498	5,671	
33	Iowa					
34	Nebraska					
35	SUBTOTAL	40,501		974,271	872,785	
36						
37	PROPERTY					
38	Minnesota (GPNG)	773,000		842,417	769,417	
39	Montana	5,033,216		11,240,538	11,009,295	
40	North Dakota	4,124,427		4,325,241	4,131,399	
41	TOTAL	3,296,066		14,660,032	-6,748,494	-692

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (i) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
9,119,374		-18,730,535			3,507,921	2
1,868,654		1,008,001			-1,302,999	3
10,988,028		-17,722,534			2,204,922	4
						5
						6
30,426		15,339			39,541	7
						8
8,063		5,070			44,898	9
492		37			3,045	10
4,667		15,484			21,841	11
25		30			136	12
28,656		45,943			100,556	13
346					1,638	14
1,206		716			3,119	15
1,337		83			7,230	16
309		828			1,738	17
75,527		83,530			223,742	18
						19
						20
67,226		289,514			75,648	21
		23,234			75,390	22
47,716		60,815			34,618	23
114,942		373,563			185,656	24
						25
						26
53					17,749	27
130,747					707,258	28
7,072					207,029	29
3,768					3,768	30
205					29,969	31
142					8,498	32
						33
						34
141,987					974,271	35
						36
						37
846,000					842,417	38
5,264,459		6,223,932			5,016,606	39
4,318,269		2,849,307			1,475,934	40
24,703,900		-2,546,417			17,206,449	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	North Dakota (GPNG)	36,236		36,967	36,236	
2	South Dakota	1,186,017		1,456,548	1,187,311	
3	Wyoming	133,284		290,826	278,697	
4	SUBTOTAL	11,286,180		18,192,537	17,412,355	
5						
6						
7	FRANCHISE					
8	Delaware	106,100		250,000	356,100	
9	Wyoming	145,167		297,830	297,309	
10	Hettinger, ND	1,685		14,747	14,813	
11						
12	SUBTOTAL	252,952		562,577	668,222	
13						
14						
15						
16	MISCELLANEOUS					
17	Federal-FICA	1,335,419		7,887,754	8,195,420	
18	Federal-Highway Use			8,611	8,611	
19	Montana WET Tax	28,553		121,699	120,774	
20	Montana-Electric License	9,887		66,693	55,200	
21	ND-Coal Conversion-Heskett	34,674		419,900	417,711	
22	ND-Generation Tax	487,222		487,930	975,152	
23	ND-Coal Conversion-Coyote			545,408	545,408	
24	Secretaries of State					
25	(annual filing fees)			2,546	2,546	
26	Fort Peck Tribal	6,000		29,227	4,954	
27	Crow Agency Tribal	12,000		12,000		
28	Federal CNG Tax					
29	Montana CNG Tax					
30	North Dakota CNG Tax					
31	South Dakota CNG Tax					
32	SUBTOTAL	1,913,755		9,581,768	10,325,776	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,296,066		14,660,032	-6,748,494	-692

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
36,967					36,967	1
1,455,254		866,492			590,056	2
145,413		218,644			72,182	3
12,066,362		10,158,375			8,034,162	4
						5
						6
						7
		149,750			100,250	8
145,688		188,249			109,581	9
1,619					14,747	10
						11
147,307		337,999			224,578	12
						13
						14
						15
						16
1,027,753		2,543,772			5,343,982	17
		6,496			2,115	18
29,478		121,699				19
21,380		66,693				20
36,863		419,900				21
		487,930				22
		545,408				23
						24
		1,525			1,021	25
30,273		29,227				26
24,000					12,000	27
						28
						29
						30
						31
1,169,747		4,222,650			5,359,118	32
						33
						34
						35
						36
						37
						38
						39
						40
24,703,900		-2,546,417			17,206,449	41

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 3 Column: a

Idaho, Minnesota, Montana, and North Dakota state income taxes.

Schedule Page: 262 Line No.: 6 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262 Line No.: 20 Column: a

Allocated on a gross revenue ratio by state.

Schedule Page: 262 Line No.: 26 Column: a

Charged directly to various inventory and construction accounts.

Schedule Page: 262 Line No.: 37 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 8 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 9 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 10 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 17 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262.1 Line No.: 18 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 24 Column: a

Allocated on a corporate overhead ratio basis.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		1,830,976	420	1,774,584	420	227,671	
8	TOTAL	1,830,976		1,774,584		227,671	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	GAS UTILITY						
11	4%						
12	10%						
13	8%						
14	SUBTOTAL						
15							
16	COMMON UTILITY						
17	4%						
18	10%						
19	8%						
20	SUBTOTAL						
21							
22							
23							
24	TOTAL OTHER UTILITY						
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
3,377,889	25 YEARS		7
3,377,889			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Accrued pension expense	58,176,716		7,579,202	2,040,204	52,637,718
2						
3	Accrued and deferred benefit					
4	compensation plans	8,582,889		1,847,039	2,903,776	9,639,626
5						
6	Intercompany portion of					
7	Supplemental Income					
8	Security Program trust assets	18,513,158	131	1,033,191	1,290,073	18,770,040
9						
10	Gas affordability tracker	7,528	131	32,560	50,998	25,966
11						
12	Capacity rights contracts	2,021,785	454	131,121		1,890,664
13						
14						
15						
16	MISO MVP Reserve	414,550				414,550
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	87,716,626		10,623,113	6,285,051	83,378,564

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 1 Column: c

131	7,200,692
182	173,344
186	24,250
920	180,916
	<u>7,579,202</u>

Schedule Page: 269 Line No.: 4 Column: c

131	120,073
242	1,063,544
253	66,961
930	596,461
	<u>1,847,039</u>

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	536,066	349,949	35,088
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	536,066	349,949	35,088
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	536,066	349,949	35,088
18	Classification of TOTAL			
19	Federal Income Tax	461,505	290,621	20,032
20	State Income Tax	74,561	59,328	15,056
21	Local Income Tax			

NOTES

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2018

Year/Period of Report

End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
		254	273,026	254	276,627	854,528	4
							5
							6
							7
			273,026		276,627	854,528	8
							9
							10
							11
							12
							13
							14
							15
							16
			273,026		276,627	854,528	17
							18
			246,770		250,349	735,673	19
			26,256		26,278	118,855	20
							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	258,530,090	13,325,466	7,008,968
3	Gas	57,879,259	3,475,447	4,798,963
4	Utility	-145,750,839		
5	TOTAL (Enter Total of lines 2 thru 4)	170,658,510	16,800,913	11,807,931
6	Non-Utility	2,587,374		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	173,245,884	16,800,913	11,807,931
10	Classification of TOTAL			
11	Federal Income Tax	148,919,323	13,597,809	9,972,546
12	State Income Tax	24,326,561	3,203,104	1,835,385
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		282	619,819	282	638,484	264,865,253	2
		282	203,228	282	184,562	56,537,077	3
			19,618,545		23,885,813	-141,483,571	4
			20,441,592		24,708,859	179,918,759	5
117,481	249,485					2,455,370	6
							7
							8
117,481	249,485		20,441,592		24,708,859	182,374,129	9
							10
90,468	204,113		17,837,361		22,186,424	156,780,004	11
27,013	45,372		2,604,231		2,522,435	25,594,125	12
							13

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 4 Column: a

Utility definition includes Regulatory Matters (excess deferred taxes recoverable/refundable to customers).

Schedule Page: 274 Line No.: 4 Column: b

Regulatory Matters - 254	\$(151,990,873)
Regulatory Matters - 182.3	<u>6,240,034</u>
	\$(145,750,839)

Schedule Page: 274 Line No.: 4 Column: h

Regulatory Matters - 254	\$18,880,248
Regulatory Matters - 182.3	<u>738,297</u>
	\$19,618,545

Schedule Page: 274 Line No.: 4 Column: j

Regulatory Matters - 254	\$23,203,750
Regulatory Matters - 182.3	<u>682,063</u>
	\$23,885,813

Schedule Page: 274 Line No.: 4 Column: k

Regulatory Matters - 254	\$(147,667,371)
Regulatory Matters - 182.3	<u>6,183,800</u>
	\$(141,483,571)

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Fuel & Purch. Power Deferral		388,627	309,985
4	Def. Pension Exp - Reg Asset	10,236,070	6,682,484	6,598,119
5	Unamort Loss on Required Debt	920,877	573,080	684,293
6				
7	Unrecovered Plant Costs	731,326	438,091	549,366
8	Other - Electric	6,552,878	4,500,860	7,348,957
9	TOTAL Electric (Total of lines 3 thru 8)	18,441,151	12,583,142	15,490,720
10	Gas			
11	Unrecovered Purch. Gas Costs	789,309	1,428,954	1,887,555
12	Regulatory Commission Expense	205,529	262,966	255,924
13	Unamort Loss on Required Debt	231,950	143,046	171,291
14	Def. Pension Exp - Reg Asset	13,080,718	8,119,583	8,010,005
15				
16	Other - Gas	6,404,663	5,966,110	6,197,459
17	TOTAL Gas (Total of lines 11 thru 16)	20,712,169	15,920,659	16,522,234
18	Other	-5,737,169		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	33,416,151	28,503,801	32,012,954
20	Classification of TOTAL			
21	Federal Income Tax	28,691,276	26,045,038	29,394,905
22	State Income Tax	4,724,875	2,458,763	2,618,049
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
						78,642	1
							2
							3
		283	137,590	283	44,323	10,227,168	4
		283	2,946	283	1,415	808,133	5
							6
						620,051	7
		283	27,580	283	35,282	3,712,483	8
			168,116		81,020	15,446,477	9
							10
						330,708	11
						212,571	12
		283	2,524	283	4,055	205,236	13
		283	19,108	283	112,375	13,283,563	14
							15
			934,656		37,125	5,275,783	16
			956,288		153,555	19,307,861	17
48,197	18,925		34,390,437		38,766,403	-1,331,931	18
48,197	18,925		35,514,841		39,000,978	33,422,407	19
							20
42,002	16,801		31,097,024		34,427,956	28,697,542	21
6,195	2,124		4,417,817		4,573,022	4,724,865	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 8 Column: b

UTILITY: Other - Electric	
Contingency Reserve	\$ 1,678
Excess Deferred Income Taxes	2,631,844
Loss on Buildings	497,496
MT Ad Valorem Tax Tracker	94,474
MT PSC/MCC Tax Deferral	91,432
ND Environmental Cost Recovery Rider	606,646
ND Generation Resource Recovery Rider	375,579
ND Transmission Tracker	841,349
Postretirement Benefit Costs	1,025,321
Preferred Stock Redemption Amort	117,808
Prepaid Expense	80,640
Property Insurance Recovery	4,059
Regulatory Commission Expense	157,803
SD Infrastructure Rider	13,826
SD Transmission Cost Recovery Rider	12,923
	\$ 6,552,878

Schedule Page: 276 Line No.: 8 Column: c

UTILITY: Other - Electric	
Contingency Reserve	\$ 1,004
Loss on Buildings	309,994
MT Ad Valorem Tax Tracker	379,781
MT PSC/MCC Tax Deferral	151,901
ND Environmental Cost Recovery Rider	385,503
ND Generation Resource Recovery Rider	274,194
ND Renewable Resource Recovery Rider	551,301
ND Transmission Tracker	799,525
Postretirement Benefit Costs	1,000,259
Preferred Stock Redemption Amort	141,457
Prepaid Expense	286,557
Property Insurance Recovery	3,442
Regulatory Commission Expense	162,912
SD Infrastructure Rider	33,961
SD Transmission Cost Recovery Rider	19,069
	\$ 4,500,860

Schedule Page: 276 Line No.: 8 Column: d

UTILITY: Other - Electric	
Contingency Reserve	\$ 1,004
Excess Deferred Income Taxes	2,093,098
Loss on Buildings	327,613
MT Ad Valorem Tax Tracker	121,160
MT PSC/MCC Tax Deferral	183,431
ND Environmental Cost Recovery Rider	992,149
ND Generation Resource Recovery Rider	649,773
ND Renewable Resource Recovery Rider	19,715
ND Transmission Tracker	1,411,293
Postretirement Benefit Costs	875,385
Preferred Stock Redemption Amort	146,039
Prepaid Expense	278,273
Property Insurance Recovery	7,467
Regulatory Commission Expense	182,425
SD Infrastructure Rider	28,140
SD Transmission Cost Recovery Rider	31,992
	\$ 7,348,957

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 8 Column: k

UTILITY: Other - Electric	
Contingency Reserve	\$ 1,678
Excess Deferred Income Taxes	538,747
Loss on Buildings	479,877
MT Ad Valorem Tax Tracker	353,095
MT PSC/MCC Tax Deferral	59,902
ND Renewable Resource Recovery Rider	531,586
ND Transmission Tracker	229,581
Postretirement Benefit Costs	1,157,930
Preferred Stock Redemption Amort	113,226
Prepaid Expense	88,924
Regulatory Commission Expense	138,290
SD Infrastructure Rider	19,647
	\$ 3,712,483

Schedule Page: 276 Line No.: 16 Column: b

UTILITY: Other - Gas	
Contingency Reserve	\$ 97,772
Def Pension Exp - ND Gas - Reg Asset	52,887
Excess Deferred Income Taxes	3,115,811
Loss on Buildings	195,273
Manufactured Gas Plant Site - Billings	127,423
MN Revenue Decoupling	156,890
MN Infrastructure Rider	114,623
MT Ad Valorem Tax Tracker	225,338
MT PSC/MCC Tax Deferral	19,557
Postretirement Benefit Costs	1,349,519
Preferred Stock Redemption Amort	28,493
Prepaid Demand	866,264
Prepaid Expenses	53,537
Property Insurance Recovery	1,276
	\$ 6,404,663

Schedule Page: 276 Line No.: 16 Column: c

UTILITY: Other - Gas	
Contingency Reserve	\$ 65,181
Def Pension Exp - ND Gas - Reg Asset	41,129
Loss on Buildings	118,964
Manufactured Gas Plant Site - Billings	110,476
MN Revenue Decoupling	134,985
MN Infrastructure Rider	237,236
MT Ad Valorem Tax Tracker	359,108
MT Conservation Tracking Adjustment	59,220
MT PSC/MCC Tax Deferral	30,981
Postretirement Benefit Costs	1,267,209
Preferred Stock Redemption Amort	34,113
Prepaid Demand	3,312,984
Prepaid Expenses	192,915
Property Insurance Recovery	1,609
	\$ 5,966,110

Schedule Page: 276 Line No.: 16 Column: d

UTILITY: Other - Gas	
Contingency Reserve	\$ 65,181
Def Pension Exp - ND Gas - Reg Asset	42,598
Excess Deferred Income Taxes	1,205,956
Loss on Buildings	119,777
Manufactured Gas Plant Site - Billings	89,303
MN Revenue Decoupling	291,875

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MDU Resources Group, Inc.			
FOOTNOTE DATA			

MN Infrastructure Rider	152,006
MT Ad Valorem Tax Tracker	261,058
MT Conservation Tracking Adjustment	28,254
MT PSC/MCC Tax Deferral	50,538
Postretirement Benefit Costs	1,122,795
Preferred Stock Redemption Amort	35,221
Prepaid Demand	2,543,057
Prepaid Expenses	186,922
Property Insurance Recovery	2,918
	\$ 6,197,459

Schedule Page: 276 Line No.: 16 Column: g

283	\$ 15,204
190	919,452
	\$ 934,656

Schedule Page: 276 Line No.: 16 Column: i

283	\$ 7,503
190	29,622
	\$ 37,125

Schedule Page: 276 Line No.: 16 Column: k

UTILITY: Other - Gas	
Contingency Reserve	\$ 97,772
Def Pension Exp - ND Gas - Reg Asset	51,418
Excess Deferred Income Taxes	1,909,855
Loss on Buildings	194,460
Manufactured Gas Plant Site - Billings	148,596
MN Infrastructure Rider	199,853
MT Ad Valorem Tax Tracker	323,388
MT Conservation Tracking Adjustment	30,966
Postretirement Benefit Costs	1,486,199
Preferred Stock Redemption Amort	27,385
Prepaid Demand	746,361
Prepaid Expenses	59,530
	\$ 5,275,783

Schedule Page: 276 Line No.: 18 Column: b

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 1,857,081
Regulatory Matters - 182.3 - Gas	156,109
Regulatory Matters - 254 - Electric	(3,499,525)
Regulatory Matters - 254 - Gas	(4,304,440)
Total Utility Other	\$(5,790,775)

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 53,606
Total Non-Utility	\$ 53,606

TOTAL OTHER \$(5,737,169)

Schedule Page: 276 Line No.: 18 Column: e

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 48,197

Schedule Page: 276 Line No.: 18 Column: f

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 18,925

Schedule Page: 276 Line No.: 18 Column: h

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 351,185

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4
FOOTNOTE DATA			

Regulatory Matters - 182.3 - Gas	80,315
Regulatory Matters - 254 - Electric	15,325,771
Regulatory Matters - 254 - Gas	<u>18,633,166</u>
Total Utility Other	<u>\$34,390,437</u>

Schedule Page: 276 Line No.: 18 Column: j

UTILITY: Other

Regulatory Matters - 182.3 - Electric	\$ 332,152
Regulatory Matters - 182.3 - Gas	81,207
Regulatory Matters - 254 - Electric	18,070,134
Regulatory Matters - 254 - Gas	<u>20,282,910</u>
Total Utility Other	<u>\$38,766,403</u>

Schedule Page: 276 Line No.: 18 Column: k

UTILITY: Other

Regulatory Matters - 182.3 - Electric	\$ 1,838,048
Regulatory Matters - 182.3 - Gas	157,001
Regulatory Matters - 254 - Electric	(755,162)
Regulatory Matters - 254 - Gas	<u>(2,654,696)</u>
Total Utility Other	<u>\$(1,414,809)</u>

NON UTILITY: Other

Partnership Ordinary Gain/(Loss)	<u>\$ 82,878</u>
Total Non-Utility	<u>\$ 82,878</u>

TOTAL OTHER \$(1,331,931)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Regulatory matters - Deferred Tax Related	155,328,635		95,371,141	88,057,806	148,015,300
2						
3	Retired Power Plant - amortizations over	242,298	405	60,854		181,444
4	120 months beginning 7/11 in North Dakota					
5	9/11 in Montana, and 7/16 in South Dakota.					
6	[ND Case No. PU-10-124, MT Docket No. D2010.8.82,					
7	SD Docket No. EI 15-024]					
8						
9	Deferred Other Postretirement	10,759,874	186	739,160		10,020,714
10						
11	Grain Drying Margin Sharing - North Dakota,	237,512	496	344,524	322,807	215,795
12	South Dakota Gas [Case No. PU-13-803] &					
13	[Docket No. NG12-008]					
14						
15	Gain on Building Sale - North Dakota	854,891	405	43,618		811,273
16	Electric [Case No. PU-16-666]					
17						
18	Gain on Building Sale; North Dakota	290,296	405	17,564		272,732
19	Gas - Amortization over 240 months ending					
20	6/34 [Case No. PU-13-803]					
21						
22	Deferred Post-Retirement Expense;	296,747	920	8,242		288,505
23	North Dakota - Gas [Case No. PU-15-90]					
24						
25	Decommissioning cost amortization - Montana	4,623,402	407	1,342,439		3,280,963
26	over 60 months beginning 4/16					
27	[Docket No. D2015.6.51]					
28						
29	SD Conservation Program Tracking Mechanism		495	53,548	129,708	76,160
30	[Docket No. NG18-002]					
31						
32	MN Conservation Improvement Program		495	110,720	941,524	830,804
33	[Docket No. G004/GR-15-879]					
34						
35	MN Revenue Decoupling				623,877	623,877
36	[Docket No. G-004/GR-15-879]					
37						
38						
39						
40						
41	TOTAL	172,633,655		98,091,810	90,075,722	164,617,567

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 278	Line No.: 1	Column: c
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190	35,779,614
282	23,480,378
283	36,111,149
	95,371,141

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	126,172,875	121,171,353
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	141,961,125	140,855,736
5	Large (or Ind.) (See Instr. 4)	36,081,553	34,416,931
6	(444) Public Street and Highway Lighting	2,400,148	2,750,525
7	(445) Other Sales to Public Authorities	4,847,694	4,897,425
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	633,925	627,567
10	TOTAL Sales to Ultimate Consumers	312,097,320	304,719,537
11	(447) Sales for Resale	1,039,756	839,721
12	TOTAL Sales of Electricity	313,137,076	305,559,258
13	(Less) (449.1) Provision for Rate Refunds	15,345,655	2,833,912
14	TOTAL Revenues Net of Prov. for Refunds	297,791,421	302,725,346
15	Other Operating Revenues		
16	(450) Forfeited Discounts	401,237	387,461
17	(451) Miscellaneous Service Revenues	226,874	165,165
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,345,855	4,383,756
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,368,373	2,416,677
22	(456.1) Revenues from Transmission of Electricity of Others	28,627,350	31,605,949
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	35,969,689	38,959,008
27	TOTAL Electric Operating Revenues	333,761,110	341,684,354

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
1,196,619	1,153,484	118,426	118,379	2
				3
1,513,911	1,513,068	22,756	22,764	4
551,000	539,877	236	242	5
26,899	30,838	587	570	6
59,883	63,087	748	748	7
				8
6,089	6,116	269	198	9
3,354,401	3,306,470	143,022	142,901	10
45,974	39,971			11
3,400,375	3,346,441	143,022	142,901	12
				13
3,400,375	3,346,441	143,022	142,901	14

Line 12, column (b) includes \$ -2,066,188 of unbilled revenues.
 Line 12, column (d) includes -23,212 MWH relating to unbilled revenues

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 5 Column: b

Basis of classification - Industrial Customers

Schedule Page: 300 Line No.: 5 Column: c

Basis of classification - Industrial Customers

Schedule Page: 300 Line No.: 1 Column: \$

Unbilled revenue includes over/under related to trackers.

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Montana					
3	10-Residential Electric Service	188,913	17,802,064	20,083	9,407	0.0942
4	20-Small General Electric Service	2,438	227,625	255	9,561	0.0934
5	52-Outdoor Lighting Service	729	93,096	906	805	0.1277
6	North Dakota					
7	10-Residential Electric Service	784,411	84,162,442	78,456	9,998	0.1073
8	13-Optional Residential Thermal E	163	12,330	4	40,750	0.0756
9	16-Optional Time-of-Day Service	105	10,134	7	15,000	0.0965
10	20-Small General Electric Service	4,983	681,503	698	7,139	0.1368
11	25-Irrigation Power Service	1	601	1	1,000	0.6010
12	30-General Electric Service	6,438	661,828	85	75,741	0.1028
13	32-General Electric Space Heating	2,423	185,453	27	89,741	0.0765
14	52-Outdoor Lighting Service	1,138	118,388	1,163	979	0.1040
15	South Dakota					
16	10-Residential Electric Service	64,963	7,320,661	6,519	9,965	0.1127
17	20-Small General Electric Service	525	55,071	36	14,583	0.1049
18	24-Outdoor Lighting Service	183	17,305	258	709	0.0946
19	53-Special Residential Dual Fuel	6,359	426,651	350	18,169	0.0671
20	Wyoming					
21	10-Residential Electric Service	129,399	15,040,316	13,417	9,644	0.1162
22	11-Special Residential Controlled	9,252	577,658	709	13,049	0.0624
23	20-Small General Electric Service	935	122,585	164	5,701	0.1311
24	24-Outdoor Lighting Service	450	27,788	597	754	0.0618
25	Unbilled-Net	-7,189	-1,370,624			0.1907
26	Adjustment for Duplicate Customer			-5,408		
27	Subtotal Residential	1,196,619	126,172,875	118,327	10,113	0.1054
28	Small Commercial-442					
29	Montana					
30	20-Small General Electric Service	107,702	9,691,619	5,363	20,082	0.0900
31	25-Irrigation Power Service	3,889	298,837	145	26,821	0.0768
32	32-General Electric Space Heating	2,898	187,434	15	193,200	0.0647
33	52-Outdoor Lighting Service	1,926	250,783	822	2,343	0.1302
34	North Dakota					
35	20-Small General Electric Service	87,568	10,840,798	8,971	9,761	0.1238
36	25-Irrigation Power Service	1,056	89,114	38	27,789	0.0844
37	26-Optional Time-of-Day Small Gen	1,357	193,591	249	5,450	0.1427
38	30-General Electric Service	419,635	42,108,293	3,005	139,646	0.1003
39	32-General Electric Space Heating	47,805	3,784,571	492	97,165	0.0792
40	40-Small Municipal Electric Servi	1	587	2	500	0.5870
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	52-Outdoor Lighting Service	4,747	493,751	1,254	3,785	0.1040
2	South Dakota					
3	20-Small General Electric Service	31,560	3,449,190	1,932	16,335	0.1093
4	24-Outdoor Lighting Service	439	41,531	262	1,676	0.0946
5	25-Irrigation Power Service	217	15,597	7	31,000	0.0719
6	26-Optional Time-of-Day General E	131	16,097	24	5,458	0.1229
7	32-General Electric Space Heating	6,786	432,618	151	44,940	0.0638
8	Wyoming					
9	20-Small General Electric Service	49,156	4,811,467	2,490	19,741	0.0979
10	22-Special General Controlled Ele	240	15,093	18	13,333	0.0629
11	24-Outdoor Lighting Service	907	56,674	316	2,870	0.0625
12	25-Irrigation Power Service	2,457	279,955	76	32,329	0.1139
13	26-Irrigation Power Service Optio	57	11,776	8	7,125	0.2066
14	Unbilled-Net	-5,935	-491,465			0.0828
15	Adjustment for Duplicate Customer			-4,405		
16	Subtotal Small Commercial	764,599	76,577,911	21,235	36,007	0.1002
17						
18	Large Commercial-442					
19	Montana					
20	25-Irrigation Power Service	484	35,639	11	44,000	0.0736
21	30-Large General Electric Service	159,013	12,583,689	256	621,145	0.0791
22	31-Optional Time-of-Day Large Gen	345	47,984	1	345,000	0.1391
23	52-Outdoor Lighting Service	453	59,141	77	5,883	0.1306
24	North Dakota					
25	20-Small General Electric Service	247	27,083	16	15,438	0.1096
26	25-Irrigation Power Service	33	3,247	2	16,500	0.0984
27	30-General Electric Service	406,112	37,696,150	1,225	331,520	0.0928
28	31-Optional Time-of-Day General S	28,193	2,574,201	65	433,738	0.0913
29	32-General Electric Space Heating	13,239	1,035,072	46	287,804	0.0782
30	34-Firm Service Economic Developm	778	69,967	1	778,000	0.0899
31	38-Interruptible Large Power Dema	32,307	2,332,425	3	10,769,000	0.0722
32	52-Outdoor Lighting Service	378	39,312	107	3,533	0.1040
33	South Dakota					
34	24-Outdoor Lighting Service	138	13,104	32	4,313	0.0950
35	30-Large General Electric Service	28,320	2,619,580	110	257,455	0.0925
36	Wyoming					
37	24-Outdoor Lighting Service	57	3,532	16	3,563	0.0620
38	26-Optional Time-of-Day Irrigatio	3	351			0.1170
39	39-Large General Electric Service	85,483	6,506,560	152	562,388	0.0761
40	Unbilled-Net	-6,271	-263,823			0.0421
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Adjustment for Duplicate Customer			-476		
2	Subtotal Large Commercial	749,312	65,383,214	1,644	455,786	0.0873
3						
4	Small Industrial-442					
5	Montana					
6	20-Small General Electric Service	4,801	412,941	84	57,155	0.0860
7	31-Optional Time-of-Day Large Gen	10,671	777,135	4	2,667,750	0.0728
8	35-Contract Service	6,595	373,057	1	6,595,000	0.0566
9	52-Outdoor Lighting Service	3	366	3	1,000	0.1220
10	North Dakota					
11	20-Small General Electric Service	242	27,386	19	12,737	0.1132
12	30-General Electric Service	2,341	299,933	37	63,270	0.1281
13	32-General Electric Space Heating	908	69,315	4	227,000	0.0763
14	52-Outdoor Lighting Service	32	3,349	8	4,000	0.1047
15	South Dakota					
16	20-Small General Electric Service	42	4,609	4	10,500	0.1097
17	24-Outdoor Lighting Service	10	965	3	3,333	0.0965
18	Wyoming					
19	20-Small General Electric Service	312	30,614	10	31,200	0.0981
20	24-Outdoor Lighting Service	2	102	2	1,000	0.0510
21	Unbilled-Net	-2,184	-92,234			0.0422
22	Adjustment for Duplicate Customer			-29		
23	Subtotal Small Industrial	23,775	1,907,538	150	158,500	0.0802
24						
25	Large Industrial-442					
26	Montana					
27	30-Large General Electric Service	88,685	6,109,167	24	3,695,208	0.0689
28	31-Optional Time-of-Day Large Gen	1,922	209,801	4	480,500	0.1092
29	35-Contract Service	218,750	12,397,317	12	18,229,167	0.0567
30	52-Outdoor Lighting Service	1	192	3	333	0.1920
31	North Dakota					
32	30-General Electric Service	200,590	13,791,025	45	4,457,556	0.0688
33	31-Optional Time-of-Day General E	4,268	439,264	9	474,222	0.1029
34	32-General Electric Space Heating	51	4,514	1	51,000	0.0885
35	38-Interruptible Large Power Dema	4,140	203,965	1	4,140,000	0.0493
36	52-Outdoor Lighting Service	9	922	3	3,000	0.1024
37	South Dakota					
38	24-Outdoor Lighting Service	8	784	2	4,000	0.0980
39	30-Large General Electric Service	7,822	621,884	6	1,303,667	0.0795
40	Wyoming					
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	37-Large Power Standby Service	16	4,103	1	16,000	0.2564
2	39-Large General Electric Service	1,416	158,552	5	283,200	0.1120
3	Unbilled-Net	-453	232,525			-0.5133
4	Adjustment for Duplicate Customer			-26		
5	Subtotal Large Industrial	527,225	34,174,015	90	5,858,056	0.0648
6						
7	Public Street and Highway - 444					
8	Montana					
9	20-Small General Electric Service	115	10,454	5	23,000	0.0909
10	41-Municipal Lighting Service	4,251	371,278	92	46,207	0.0873
11	52-Outdoor Lighting Service	85	11,182	7	12,143	0.1316
12	North Dakota					
13	20-Small General Electric Service	384	53,524	57	6,737	0.1394
14	40-Small Municipal Electric Servi	27	2,266	1	27,000	0.0839
15	41-Municipal Lighting Service	19,034	1,630,014	619	30,750	0.0856
16	52-Outdoor Lighting Service	125	12,949	29	4,310	0.1036
17	South Dakota					
18	24-Outdoor Lighting Service	6	585	3	2,000	0.0975
19	41-Street Lighting Service	2,455	249,135	53	46,321	0.1015
20	Wyoming					
21	20-Small General Electric Service	9	2,003	4	2,250	0.2226
22	24-Outdoor Lighting Service	3	203	2	1,500	0.0677
23	41-Municipal Lighting Service	1,031	96,523	4	257,750	0.0936
24	Unbilled-Net	-626	-39,968			0.0638
25	Adjustment for Duplicate Customer			-298		
26	Subtotal Public Street and Highwa	26,899	2,400,148	578	46,538	0.0892
27						
28	Other Sales to Public Authorities					
29	Montana					
30	48-Municipal Pumping Service	5,753	449,348	108	53,269	0.0781
31	North Dakota					
32	20-Small General Electric Service	382	52,826	54	7,074	0.1383
33	30-General Electric Service	1,718	175,077	11	156,182	0.1019
34	32-General Electric Space Heating	297	22,102	6	49,500	0.0744
35	40-Small Municipal Electric Servi	3,724	386,872	284	13,113	0.1039
36	48-Municipal Pumping Service	47,081	3,676,596	322	146,214	0.0781
37	South Dakota					
38	48-Municipal Pumping Service	1,435	121,573	49	29,286	0.0847
39	Unbilled-Net	-507	-36,700			0.0724
40	Adjustment for Duplicate Customer			-82		
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Subtotal Other Sales	59,883	4,847,694	752	79,632	0.0810
2						
3	Interdepartmental-448					
4	Montana					
5	Billed	550	61,218	95	5,789	0.1113
6	North Dakota					
7	Billed	5,075	513,732	152	33,388	0.1012
8	South Dakota					
9	Billed	298	34,684	10	29,800	0.1164
10	Wyoming					
11	Billed	213	28,190	31	6,871	0.1323
12	Unbilled-Net	-47	-3,899			0.0830
13	Adjustment for Duplicate Customer			-17		
14	Subtotal Interdepartmental Sales	6,089	633,925	271	22,469	0.1041
15						
16	Total	3,354,401	312,097,320	143,047	23,450	0.0930
17						
18	Fuel Clause Adjustment					
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4
FOOTNOTE DATA			

Schedule Page: 304.4 Line No.: 18 Column: a

Revenue Billed Pursuant to Fuel Clause Adjustment (FCA) (Included in revenue amounts on pages 304-304.4)

Residential-440

Montana

10-Residential Electric Service	4,588,966
20-Small General Electric Service	59,622
52-Outdoor Lighting Service	17,689

North Dakota

10-Residential Electric Service	18,277,274
13-Optional Residential Thermal Energy Storage	3,827
16-Optional Time-of-Day Residential Electric Service	2,483
20-Small General Electric Service	116,706
25-Irrigation Power Service	13
30-General Electric Service	150,644
32-General Electric Space Heating Service	57,450
52-Outdoor Lighting Service	26,533

South Dakota

10-Residential Electric Service	1,486,212
20-Small General Electric Service	12,026
24-Outdoor Lighting Service	4,179
53-Special Residential Electric Dual Fuel Space Heating Service	144,933

Wyoming

10-Residential Electric Service	4,508,626
11-Special Residential Controlled Electric Service	325,084
20-Small General Electric Service	32,666
24-Outdoor Lighting Service	15,630
Unbilled-net	(17,287)
Subtotal Residential	29,813,276

Small Commercial-442

Montana

20-Small General Electric Service	2,618,925
25-Irrigation Power Service	89,241
32-General Electric Space Heating Service	71,946
52-Outdoor Lighting Service	46,771

North Dakota

20-Small General Electric Service	2,043,529
25-Irrigation Power Service	23,512
26-Optional Time-of-Day Small General Electric Service	31,608
30-General Electric Service	9,732,321
32-General Electric Space Heating Service	1,128,064
40-Small Municipal Electric Service	35
52-Outdoor Lighting Service	110,899

South Dakota

20-Small General Electric Service	720,436
24-Outdoor Lighting Service	10,017
25-Irrigation Power Service	4,711
26-Optional Time-of-Day Small General Electric Service	3,005
32-General Electric Space Heating Service	157,398

Wyoming

20-Small General Electric Service	1,710,336
22-Special General Controlled Electric Service	8,464
24-Outdoor Lighting Service	33,450

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.		12/31/2018	2018/Q4
FOOTNOTE DATA			

25-Irrigation Power Service	83,878
26-Irrigation Power Service Optional Time-of-Day	1,942
Unbilled-net	(33,260)
Subtotal Small Commercial	18,597,228

Large Commercial-442

Montana

25-Irrigation Power Service	11,059
30-Large General Electric Service	3,851,145
31-Optional Time-of-Day Large General Electric Service	8,576
52-Outdoor Lighting Service	10,995

North Dakota

20-Small General Electric Service	5,770
25-Irrigation Power Service	728
30-General Electric Service	9,377,231
31-Optional Time-of-Day General Electric Service	652,395
32-General Electric Space Heating Service	311,824
38-Interruptible Large Power Demand Response	18,011
52-Outdoor Lighting Service	724,607
34-Firm Service Economic Development Rate	8,799

South Dakota

24-Outdoor Lighting Service	3,162
30-Large General Electric Service	647,129

Wyoming

24-Outdoor Lighting Service	1,986
26-Optional Time-of-Day Irrigation Service	91
39-Large General Electric Service	2,921,707
Unbilled-net	(57,584)
Subtotal Large Commercial	18,497,631

Small Industrial-442

Montana

20-Small General Electric Service	116,862
31-Optional Time-of-Day Large General Electric Service	255,635
35-Contract Service Rate	155,804
52-Outdoor Lighting Service	68

North Dakota

20-Small General Electric Service	5,689
30-General Electric Service	54,473
32-General Electric Space Heating Service	21,356
52-Outdoor Lighting Service	749

South Dakota

20-Small General Electric Service	953
24-Outdoor Lighting Service	233

Wyoming

20-Small General Electric Service	10,851
24-Outdoor Lighting Service	57
Unbilled-net	(51,048)
Subtotal Small Industrial	571,682

Large Industrial-442

Montana

30-General Electric Service	2,150,976
31-Optional Time-of-Day Large General Electric Service	45,481

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.		12/31/2018	2018/Q4
FOOTNOTE DATA			

35-Contract Service	5,168,190
52-Outdoor Lighting Service	36
North Dakota	
30-General Electric Service	4,514,216
31-Optional Time-of-Day General Electric Service	99,249
32-General Electric Space Heating Service	1,198
38-Interruptible Large Power Demand Response	93,569
52-Outdoor Lighting Service	206
South Dakota	
24-Outdoor Lighting Service	189
30-Large General Electric Service	178,284
Wyoming	
37-Large Power Standby Service	583
39-Large General Service	49,288
Unbilled-net	23,402
Subtotal Large Industrial	12,324,867

Public Street and Highway Lighting-444	
Montana	
20-Small General Service	2,797
41-Municipal Lighting Service	104,166
52-Outdoor Lighting Service	2,150
North Dakota	
20-Small General Service	8,975
40-Small Municipal Electric Service	641
41-Municipal Lighting Service	443,513
52-Outdoor Lighting Service	3,020
South Dakota	
24-Outdoor Lighting Service	142
41-Street Lighting Service	56,202
Wyoming	
20-Small General Electric Service	316
24-Outdoor Lighting Service	116
41-Municipal Lighting Service	35,851
Unbilled-net	(11,193)
Subtotal Public Street and Highway Lighting	646,696

Other Sales to Public Authorities-446	
Montana	
48-Municipal Pumping Service	138,596
North Dakota	
20-Small General Electric Service	8,919
30-General Electric Service	40,014
32-General Electric Space Heating Service	7,070
40-Small Municipal Electric Service	86,885
48-Municipal Pumping Service	1,071,867
South Dakota	
48-Municipal Pumping Service	32,784
Unbilled-net	(3,536)
Subtotal Other Sales	1,382,599

Interdepartmental Sales-448	
Montana	13,382
North Dakota	118,237

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

South Dakota	6,841
Wyoming	7,420
Unbilled-Net	(245)
Subtotal Interdepartmental	145,635
Total Fuel Clause Adjustment	81,979,614

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Midwest Independent Transmission					
2	System Operator (MISO)	OS	MISO	N/A	N/A	N/A
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
45,974		1,039,756		1,039,756	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
45,974	0	1,039,756	0	1,039,756	
45,974	0	1,039,756	0	1,039,756	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 2 Column: b

Respondent began participation in the Midwest Independent System Operator (MISO) RTO in April 2005.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,385,247	2,600,569
5	(501) Fuel	54,995,192	50,398,536
6	(502) Steam Expenses	7,928,936	7,277,004
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,060,269	1,986,679
10	(506) Miscellaneous Steam Power Expenses	4,174,418	3,774,691
11	(507) Rents	854,259	784,469
12	(509) Allowances	84	83
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	72,398,405	66,822,031
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,395,980	1,468,840
16	(511) Maintenance of Structures	790,065	823,893
17	(512) Maintenance of Boiler Plant	7,331,912	6,749,753
18	(513) Maintenance of Electric Plant	2,150,943	1,805,872
19	(514) Maintenance of Miscellaneous Steam Plant	1,833,788	1,864,900
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	13,502,688	12,713,258
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	85,901,093	79,535,289
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	293,990	298,564
63	(547) Fuel	3,732,798	3,702,906
64	(548) Generation Expenses	3,459,514	2,385,188
65	(549) Miscellaneous Other Power Generation Expenses	846,164	579,104
66	(550) Rents	635,529	595,708
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,967,995	7,561,470
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	126,295	103,014
70	(552) Maintenance of Structures	20,448	26,209
71	(553) Maintenance of Generating and Electric Plant	622,541	1,388,180
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	76,567	92,806
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	845,851	1,610,209
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	9,813,846	9,171,679
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	21,984,234	24,622,906
77	(556) System Control and Load Dispatching	1,961,434	2,029,849
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	23,945,668	26,652,755
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	119,660,607	115,359,723
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,682,170	3,597,743
84			
85	(561.1) Load Dispatch-Reliability	465,367	464,518
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,005,314	997,082
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	563,644	575,086
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	41,709	41,893
93	(562) Station Expenses	590,513	610,716
94	(563) Overhead Lines Expenses	284,218	279,892
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	24,809,164	26,478,895
97	(566) Miscellaneous Transmission Expenses	109,580	62,167
98	(567) Rents	112,419	766,185
99	TOTAL Operation (Enter Total of lines 83 thru 98)	31,664,098	33,874,177
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	117,651	79,437
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	891,366	1,010,386
108	(571) Maintenance of Overhead Lines	1,073,888	1,895,638
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,082,905	2,985,461
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	33,747,003	36,859,638

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	544,865	463,367
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	544,865	463,367
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	544,865	463,367
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,938,901	1,714,944
135	(581) Load Dispatching		
136	(582) Station Expenses	589,271	874,586
137	(583) Overhead Line Expenses	748,462	441,286
138	(584) Underground Line Expenses	1,313,221	1,359,519
139	(585) Street Lighting and Signal System Expenses	46,680	97,672
140	(586) Meter Expenses	1,234,272	1,102,848
141	(587) Customer Installations Expenses	290,187	173,326
142	(588) Miscellaneous Expenses	3,269,976	3,314,478
143	(589) Rents	154,124	153,001
144	TOTAL Operation (Enter Total of lines 134 thru 143)	9,585,094	9,231,660
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	786,138	643,070
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	288,724	259,453
149	(593) Maintenance of Overhead Lines	3,542,223	3,088,029
150	(594) Maintenance of Underground Lines	792,466	869,819
151	(595) Maintenance of Line Transformers	181,157	164,790
152	(596) Maintenance of Street Lighting and Signal Systems	149,033	162,896
153	(597) Maintenance of Meters	61,235	21,269
154	(598) Maintenance of Miscellaneous Distribution Plant	913,164	914,042
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,714,140	6,123,368
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	16,299,234	15,355,028
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	137,761	157,613
160	(902) Meter Reading Expenses	500,074	508,504
161	(903) Customer Records and Collection Expenses	2,431,281	2,713,167
162	(904) Uncollectible Accounts	1,427,226	1,015,295
163	(905) Miscellaneous Customer Accounts Expenses	185,940	163,521
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	4,682,282	4,558,100

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	29,723	49,386
168	(908) Customer Assistance Expenses	61,090	64,844
169	(909) Informational and Instructional Expenses	118,787	125,741
170	(910) Miscellaneous Customer Service and Informational Expenses	9,801	4,734
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	219,401	244,705
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	-1,347	1,110
175	(912) Demonstrating and Selling Expenses	70,984	86,549
176	(913) Advertising Expenses	23,845	15,891
177	(916) Miscellaneous Sales Expenses	7,662	7,652
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	101,144	111,202
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	8,473,516	7,764,717
182	(921) Office Supplies and Expenses	4,893,624	4,053,892
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	715,234	391,241
185	(924) Property Insurance	1,064,394	1,046,451
186	(925) Injuries and Damages	2,181,229	2,119,873
187	(926) Employee Pensions and Benefits	7,014,333	7,933,305
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	631,080	846,071
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	87,661	69,837
192	(930.2) Miscellaneous General Expenses	906,594	690,074
193	(931) Rents	863,265	1,170,851
194	TOTAL Operation (Enter Total of lines 181 thru 193)	26,830,930	26,086,312
195	Maintenance		
196	(935) Maintenance of General Plant	544,936	599,281
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	27,375,866	26,685,593
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	202,630,402	199,637,356

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Black Hills Power & Light Co.	RQ	BHPL #42	49	49	49
2	Beckton Hydro-Energy	LU				
3	Western Area Power Admin - Ft. Peck	LF	19			
4	Midcontinent Independent					
5	System Operator (MISO)	EX	MISO			
6	Customer Owned Generation	OS				
7	Deferral per tariff					
8	Enerwise Global Technologies, Inc.	OS				
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555), (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
84,372			3,717,427	2,889,140	55,000	6,661,567	1
			9,126	9,020		18,146	2
14,301				343,229		343,229	3
							4
732,366			-13,190	16,336,651		16,323,461	5
			421,200			421,200	6
					-3,091,217	-3,091,217	7
			1,307,848			1,307,848	8
							9
							10
							11
							12
							13
							14
831,039			5,442,411	19,578,040	-3,036,217	21,984,234	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 6 Column: b

Other Service classification includes purchases during periods of generation and economical reasons.

Schedule Page: 326 Line No.: 8 Column: b

Other Service classification includes purchases during periods of generation and economical reasons.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Midcontinent Independent			
2	System Operator (MISO)	MISO participants	MISO participants	OS
3				
4	MISO	MISO participants	MISO participants	NF
5				
6	MISO	MISO participants	MISO participants	OS
7				
8	Southwest Power Pool	Southwest Power Pool	Southwest Power Pool	OS
9				
10	MISO	MISO participants	MISO participants	OS
11				
12	MISO	MISO participants	MISO participants	OS
13				
14	MISO	MISO participants	MISO participants	OS
15				
16	MISO	MISO participants	MISO participants	OS
17				
18	MISO	MISO participants	MISO participants	OS
19				
20	Basin Electric Co-Op	Basin Electric Co-Op	Basin Electric Co-Op	OS
21				
22	Southwest Water Authority	Western Area Power Administration	Southwest Water Authority	OS
23				
24	Powder River Energy Corp	Powder River Energy Corp	Powder River Energy Corp	OLF
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
						1
7	Various	Various				2
						3
8	Various	Various				4
						5
9	Various	Various	1,445			6
						7
9	Various	Various				8
						9
24	Various	Various		1,159,848	1,137,106	10
						11
26	Various	Various				12
						13
26A	Various	Various				14
						15
37	Various	Various				16
						17
38	Various	Various				18
						19
Facility Sharing	Various	Various				20
						21
	Dickinson	Dickinson		3,511	3,442	22
						23
5	Sheridan	Various		10,262	10,262	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,445	1,173,621	1,150,810	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
				1
		1,357,557	1,357,557	2
				3
		32,915	32,915	4
				5
3,291,862			3,291,862	6
				7
		10,324,229	10,324,229	8
				9
		765,718	765,718	10
				11
		980,290	980,290	12
				13
		11,576,568	11,576,568	14
				15
		10,282	10,282	16
				17
		12,796	12,796	18
				19
		244,000	244,000	20
				21
	28,935		28,935	22
				23
	2,198		2,198	24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
3,291,862	31,133	25,304,355	28,627,350	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 24 Column: c

Sheridan-Johnson REA contract is perpetual. Agreement amended 4/1/18. MDU no longer charges Powder River for wheeling. MDU will continue to charge Powder River for facility use.

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	DELIVERED POWER TO AND							
2	RECEIVED POWER FROM							
3	WHEELER							
4	Mor Gran Sou Elec Coop	LFP	1,569	1,694				
5	Grand Elec Coop	LFP	601	651		3,678		3,678
6	Midcontinent							
7	Independent							
8	System Operator (MISO)	OS					7,557,435	7,557,435
9	Southwest Power Pool	FNS				17,248,051		17,248,051
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,170	2,345		17,251,729	7,557,435	24,809,164

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	399,331
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Directors Fees and Expense	507,263
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	906,594

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

- Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			670,409		670,409
2	Steam Production Plant	14,335,748				14,335,748
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	18,133,601			-104,471	18,029,130
7	Transmission Plant	5,091,345				5,091,345
8	Distribution Plant	9,975,446				9,975,446
9	Regional Transmission and Market Operation					
10	General Plant	467,439				467,439
11	Common Plant-Electric	1,098,327		1,807,599		2,905,926
12	TOTAL	49,101,906		2,478,008	-104,471	51,475,443

B. Basis for Amortization Charges

Range from five year, 20% to ten year, 10% Straight Line Amortization for computer software.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13							
14	311	104,362					
15	312	313,991					
16	314	86,211					
17	315	24,883					
18	316	21,989					
19	317.0	7,316					
20	Subtotal	558,752					
21							
22	OTHER PRODUCTION						
23							
24	341	36,653					
25	342	1,978					
26	344	448,961					
27	345	53,874					
28	346	1,818					
29	347.0	18,006					
30	Subtotal	561,290					
31							
32	TRANSMISSION PLANT						
33							
34	350.2	3,192					
35	352	2					
36	353	149,466					
37	354	4,993					
38	355	77,877					
39	356	59,978					
40	357	1,945					
41	358	3,102					
42	359.1	1					
43	Subtotal	300,556					
44							
45	DISTRIBUTION PLANT						
46							
47	360.2	961					
48	362	78,775					
49	364	45,075					
50	365	34,274					

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	366	236					
13	367	123,801					
14	368	75,958					
15	369	38,076					
16	370	18,729					
17	371	3,030					
18	373	8,645					
19	374.0	40					
20	Subtotal	427,600					
21							
22	GENERAL PLANT						
23							
24	303	7,576					
25	390	1,532					
26	391	246					
27	392	8,464					
28	393	15					
29	394	4,907					
30	395	661					
31	396	13,752					
32	397	1,853					
33	398	59					
34	Subtotal	39,065					
35							
36	Total	1,887,263					
37	FOOTNOTE						
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 19 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336 Line No.: 29 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336 Line No.: 42 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 19 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 37 Column: a

Column (b) - 12/31/18 depreciable sub-plant account balances

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State Commission Regulatory Expense Amortized				
2	Over Various 12 Month Periods				
3					
4	MONTANA				
5	Electric				118,761
6					
7	Gas				31,850
8					
9					
10	NORTH DAKOTA				
11	Electric				325,041
12					
13	Gas				221,632
14					
15					
16	SOUTH DAKOTA				
17	Electric				136,634
18					
19	Gas				140,121
20					
21					
22					
23					
24					
25					
26	WYOMING				
27	Electric				87,946
28					
29	Gas				36,511
30					
31					
32	MINNESOTA				
33	Gas				360,163
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				10,000
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				1,468,659

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
							4
Electric	928	79,633	180,570	928	94,102	205,229	5
							6
Gas	928	25,394	185,628	928	39,296	178,182	7
							8
							9
							10
Electric	928	217,654		928	125,042	199,999	11
							12
Gas	928	54,827	130,809	928	12,528	339,913	13
							14
							15
							16
Electric	928	26,130		928	34,925	101,709	17
							18
Gas	928	1,897	2,238	928	94,906	47,453	19
							20
							21
							22
							23
							24
							25
							26
Electric	928	32,487		928	21,107	66,839	27
							28
Gas	928	26,682		928	15,108	21,403	29
							30
							31
							32
Gas	928	174,862		928	131,250	228,913	33
							34
							35
							36
Gas	928	600		928		10,000	37
							38
							39
							40
							41
							42
							43
							44
							45
		640,166	499,245		568,264	1,399,640	46

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	4,451,661		
49	Administrative and General	180,702		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,632,363		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	565,759		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	16,254,189		
58	Customer Accounts (Line 37)	3,912,341		
59	Customer Service and Informational (Line 38)	361,993		
60	Sales (Line 39)	246,333		
61	Administrative and General (Lines 40 and 49)	4,876,078		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	26,216,693	735,808	26,952,501
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	59,877,940	1,680,558	61,558,498
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,506,274	294,873	10,801,147
69	Gas Plant	8,182,697	229,659	8,412,356
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	18,688,971	524,532	19,213,503
72	Plant Removal (By Utility Departments)			
73	Electric Plant	623,077	17,488	640,565
74	Gas Plant	485,277	13,620	498,897
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,108,354	31,108	1,139,462
77	Other Accounts (Specify, provide details in footnote):			
78	183 - Preliminary Survey & Investigation	19,299		19,299
79	184 - Clearing Accounts	366,916		366,916
80	416 - Cost/Expense of Mech Job and Contr.	11,923		11,923
81	417 - Expense for Non-Utility Operations	515,492		515,492
82	121 - Non Utility	39,695		39,695
83	146 - Accounts Receivable from Associated Companies	6,243,102		6,243,102
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,196,427		7,196,427
96	TOTAL SALARIES AND WAGES	86,871,692	2,236,198	89,107,890

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of <u>2018/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account No.	Utility Plant	Accumulated Depreciation	Depreciation Expense
PLANT IN SERVICE			
303 Misc. Intangible Plant	61,618,605	32,078,217	3,923,983
389 Land and Land Rights	3,082,569	0	0
390 Structures and Improvements	49,285,342	16,756,062	590,427
391 Office Furniture & Equipment	5,638,581	2,516,491	723,875
392 Transportation Equipment	12,685,210	5,271,044	613,643
393 Stores Equipment	108,528	36,825	3,231
394 Miscellaneous Tools	795,492	391,321	44,469
396 Power Operated Equipment	0	0	0
397 Communication Equipment	3,768,265	1,636,455	295,587
398 Miscellaneous Equipment	1,232,259	614,761	61,494
3991 Asset Retirement Obligations	0	0	0
	138,214,851	59,301,176	6,256,709
WORK IN PROGRESS			
	6,287,555	11,628	0
	144,502,406	59,312,804	6,256,709
Allocation of Common Utility Plant			
Electric Department	81,866,090	33,403,764	2,905,926
Natural Gas Department	62,636,316	25,909,040	2,941,312
Clearing Accounts			409,471
	144,502,406	59,312,804	6,256,709

Basis of Allocation

- (1) General Office common plant and depreciation are allocated based on net plant and employee ratios.
- (2) Other common plant and depreciation are directly assigned or allocated based on the ratio of electric transmission and distribution and gas distribution gross plant investment by state or employee ratios.
- (3) Expenses other than depreciation are not shown above but are allocated on net plant in service and number of employee ratios.

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: INTEGRATED

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	778	16	900	565	213				
2	February	740	12	1000	541	199				
3	March	633	8	900	467	166				
4	Total for Quarter 1				1,573	578				
5	April	649	6	900	470	179				
6	May	598	26	1800	464	134				
7	June	677	28	1700	533	144				
8	Total for Quarter 2				1,467	457				
9	July	720	10	1700	572	148				
10	August	733	10	1800	567	166				
11	September	585	7	1700	453	132				
12	Total for Quarter 3				1,592	446				
13	October	550	15	900	413	137				
14	November	653	9	900	478	175				
15	December	696	31	1900	506	190				
16	Total for Quarter 4				1,397	502				
17	Total Year to Date/Year				6,029	1,983				

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: SHERIDAN

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	57	16	900	55	2				
2	February	55	19	2000	53	2				
3	March	49	4	2000	47	2				
4	Total for Quarter 1				155	6				
5	April	47	2	2200	46	1				
6	May	41	25	1800	40	1				
7	June	53	28	1800	52	1				
8	Total for Quarter 2				138	3				
9	July	65	10	1800	64	1				
10	August	62	12	1900	60	2				
11	September	46	10	1800	44	2				
12	Total for Quarter 3				168	5				
13	October	42	10	900	41	1				
14	November	46	15	1900	44	2				
15	December	53	8	1900	51	2				
16	Total for Quarter 4				136	5				
17	Total Year to Date/Year				597	19				

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2018

Year/Period of Report
End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	3,354,401
3	Steam	2,235,939	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	45,974
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	604,414	27	Total Energy Losses	293,828
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,694,203
9	Net Generation (Enter Total of lines 3 through 8)	2,840,353			
10	Purchases	831,039			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,173,621			
17	Delivered	1,150,810			
18	Net Transmission for Other (Line 16 minus line 17)	22,811			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,694,203			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: INTEGRATED

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	331,591	938	565	16	900
30	February	315,240	337	541	12	1000
31	March	291,743	4,234	467	8	900
32	April	252,718	690	470	6	900
33	May	250,024	3,658	464	26	1800
34	June	264,175	6,447	533	28	1700
35	July	288,403	3,059	572	10	1700
36	August	285,152	958	567	10	1800
37	September	244,532	3,199	453	7	1700
38	October	255,385	2,314	413	15	900
39	November	296,599	3,483	478	9	900
40	December	324,989	16,657	506	31	1900
41	TOTAL	3,400,551	45,974			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 29 Column: b

MONTHLY PEAKS AND OUTPUT
Name of System: Sheridan

Line #	Month (a)	Total Mo. Energy (b)	Megawatts (d)	Day (e)	Hour (f)
29	Jan	29,297	55	16	900
30	Feb	28,135	53	19	2000
31	Mar	25,489	47	4	2000
32	Apr	22,379	46	2	2200
33	May	20,518	40	25	1800
34	Jun	20,881	52	28	1800
35	Jul	26,655	64	10	1800
36	Aug	24,243	60	12	1900
37	Sep	20,505	44	10	1800
38	Oct	22,474	41	15	900
39	Nov	25,052	44	8	1900
40	Dec	28,024	51	31	1900
41	Total	293,652			

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>R.M. Heskett</i> (b)	Plant Name: <i>R.M. Heskett</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler					
3	Year Originally Constructed	1954					
4	Year Last Unit was Installed	1963					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	86.00	0.00				
6	Net Peak Demand on Plant - MW (60 minutes)	102	0				
7	Plant Hours Connected to Load	8603	0				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	97	0				
10	When Limited by Condenser Water	89	0				
11	Average Number of Employees	50	0				
12	Net Generation, Exclusive of Plant Use - KWh	504356600	0				
13	Cost of Plant: Land and Land Rights	242583	0				
14	Structures and Improvements	27912665	0				
15	Equipment Costs	94337813	0				
16	Asset Retirement Costs	1181551	0				
17	Total Cost	123674612	0				
18	Cost per KW of Installed Capacity (line 17/5) Including	1438.0769	0				
19	Production Expenses: Oper, Supv, & Engr	699102	0				
20	Fuel	19568448	0				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	3083142	0				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	936771	0				
26	Misc Steam (or Nuclear) Power Expenses	916597	0				
27	Rents	0	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	476863	0				
30	Maintenance of Structures	192500	0				
31	Maintenance of Boiler (or reactor) Plant	1387022	0				
32	Maintenance of Electric Plant	494940	0				
33	Maintenance of Misc Steam (or Nuclear) Plant	820669	0				
34	Total Production Expenses	28576054	0				
35	Expenses per Net KWh	0.0567	0.0000				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal-Lignite	Coal-Sub Bit	Tires	Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Tons	Tons	Mcf		
38	Quantity (Units) of Fuel Burned	466871	0	2885	227	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6899	8735	15918	1163	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.024	0.000	81.953	5.056	0.000	0.000
41	Average Cost of Fuel per Unit Burned	41.414	0.000	81.960	5.056	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.001	0.000	2.574	4.347	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.039	0.000	0.033	0.056	0.000	0.000
44	Average BTU per KWh Net Generation	12955.114	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: Miles City (d)			Plant Name: Big Stone (e)			Plant Name: WY Gen III (f)			Line No.
Gas Turbine			Steam			Steam			1
Conventional			Conventional			Conventional			2
1972			1975			2010			3
1972			1975			2010			4
23.75			94.11			28.00			5
26			108			28			6
19			6730			8398			7
0			0			0			8
22			108			28			9
22			104			28			10
0			83			17			11
273000			521187530			209280000			12
609			150559			0			13
223817			33326609			3592777			14
4449212			115104034			61639259			15
0			824105			0			16
4673638			149405307			65232036			17
196.7848			1587.5604			2329.7156			18
30531			310620			567557			19
44950			10625020			2078112			20
0			0			0			21
0			1083750			547606			22
0			0			0			23
0			0			0			24
79514			360317			125625			25
0			819326			216994			26
0			0			846418			27
0			0			84			28
16158			177925			248432			29
692			189520			137777			30
0			1950643			574646			31
59327			776719			139277			32
0			142548			15583			33
231172			16436388			5498111			34
0.8468			0.0315			0.0263			35
Gas	Fuel Oil		Coal-SubBit	Fuel Oil		Coal-SubBit			36
Mcf	Bbl		Tons	Bbl		Tons			37
3351	5337	0	327876	66109	0	148994	0	0	38
1104	140000	0	8238	140000	0	8056	0	0	39
9.221	0.000	0.000	30.771	103.022	0.000	12.957	0.000	0.000	40
9.221	110.639	0.000	31.968	91.209	0.000	13.948	0.000	0.000	41
8.352	18.805	0.000	1.940	15.512	0.000	0.866	0.000	0.000	42
0.136	0.306	0.000	0.020	0.161	0.000	0.010	0.000	0.000	43
16288.190	0.000	0.000	10382.712	0.000	0.000	11470.715	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Glendive	Coyote				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Gas Turbine	Steam				
3	Year Originally Constructed	1979	1981				
4	Year Last Unit was Installed	2003	1981				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	75.52	103.65				
6	Net Peak Demand on Plant - MW (60 minutes)	76	107				
7	Plant Hours Connected to Load	133	7855				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	74	108				
10	When Limited by Condenser Water	71	81				
11	Average Number of Employees	4	80				
12	Net Generation, Exclusive of Plant Use - KWh	2734171	765232779				
13	Cost of Plant: Land and Land Rights	37924	519148				
14	Structures and Improvements	1504563	29107073				
15	Equipment Costs	26596032	108393961				
16	Asset Retirement Costs	0	1704873				
17	Total Cost	28138519	139725055				
18	Cost per KW of Installed Capacity (line 17/5) Including	372.5969	1348.0468				
19	Production Expenses: Oper, Supv, & Engr	49421	514608				
20	Fuel	299007	15924764				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	0	1615921				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	222655	511487				
26	Misc Steam (or Nuclear) Power Expenses	0	1346470				
27	Rents	0	5591				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	26006	206945				
30	Maintenance of Structures	1719	204190				
31	Maintenance of Boiler (or reactor) Plant	0	1951365				
32	Maintenance of Electric Plant	170222	155741				
33	Maintenance of Misc Steam (or Nuclear) Plant	0	271322				
34	Total Production Expenses	769030	22708404				
35	Expenses per Net KWh	0.2813	0.0297				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Fuel Oil	Coal-Lignite	Fuel Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Bbl	Tons	Bbl		
38	Quantity (Units) of Fuel Burned	28346	48350	0	623679	201806	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1040	140000	0	6959	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.390	88.876	0.000	24.562	92.478	0.000
41	Average Cost of Fuel per Unit Burned	7.390	87.458	0.000	24.830	91.366	0.000
42	Average Cost of Fuel Burned per Million BTU	7.106	14.871	0.000	1.784	15.539	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.094	0.197	0.000	0.020	0.177	0.000
44	Average BTU per KWh Net Generation	13257.708	0.000	0.000	11380.350	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Heskett III</i> (d)			Plant Name: <i>Lewis & Clark II</i> (e)			Plant Name: <i>Lewis & Clark</i> (f)			Line No.
	Gas Turbine			Internal Combustion			Steam		1
	Conventional			Conventional			Outdoor Boiler		2
	2014			2015			1958		3
	2014			2015			1958		4
	89.00			18.70			44.00		5
	99			19			51		6
	164			668			6608		7
	0			0			0		8
	84			19			52		9
	62			17			50		10
	0			0			30		11
	3981000			8497000			235882341		12
	0			0			80862		13
	62248			0			10423074		14
	53440031			44752564			67598669		15
	3134674			0			3605750		16
	56636953			44752564			81708355		17
	636.3703			2393.1852			1857.0081		18
	60147			40804			293360		19
	2717539			327275			6798848		20
	0			0			0		21
	0			0			1598517		22
	0			0			0		23
	0			0			0		24
	58652			376853			126069		25
	0			0			875031		26
	0			0			2250		27
	0			0			0		28
	0			22568			285815		29
	3010			14089			66078		30
	0			0			1468236		31
	71202			106582			584266		32
	0			0			583666		33
	2910550			888171			12682136		34
	0.7311			0.1045			0.0538		35
Gas			Gas			Coal-Lignite	Coal-Sub	Gas	36
Mcf			Mcf			Tons	Tons	Mcf	37
66347	0	0	62261	0	0	232542	776	20136	38
1085	0	0	1209	0	0	6681	8152	1195	39
40.827	0.000	0.000	4.892	0.000	0.000	27.311	0.000	6.568	40
40.827	0.000	0.000	4.892	0.000	0.000	28.581	24.309	6.568	41
37.628	0.000	0.000	4.046	0.000	0.000	2.139	1.491	5.496	42
0.680	0.000	0.000	0.036	0.000	0.000	0.029	0.020	0.073	43
18082.570	0.000	0.000	8858.838	0.000	0.000	13328.426	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 403 Line No.: -1 Column: d

Plant is designed for peak load service.

Schedule Page: 403 Line No.: -1 Column: e

Plant is 22.7% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 403 Line No.: -1 Column: f

Plant is 25.0% owned by Respondent. Statistics represent Respondent's share of plant cost, production expenses and other data.

Schedule Page: 402 Line No.: 5 Column: b

Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: d

Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: e

Statistics reflect 22.7% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 403 Line No.: 5 Column: f

Statistics reflect 25% of Maximum Turbine Name Plate Rating of 112

Schedule Page: 403 Line No.: 10 Column: d

Limited by ambient air temperature

Schedule Page: 402.1 Line No.: -1 Column: b

Plant is designed for peak load service.

Schedule Page: 402.1 Line No.: -1 Column: c

Plant is 25% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 402.1 Line No.: 5 Column: b

Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 5 Column: c

Statistics reflect 25% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 403.1 Line No.: 5 Column: d

Maximum Turbine Name Plate Rating

Schedule Page: 403.1 Line No.: 5 Column: e

Maximum Turbine Name Plate Rating

Schedule Page: 403.1 Line No.: 5 Column: f

Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 10 Column: b

Limited by ambient air temperature

Schedule Page: 403.1 Line No.: 10 Column: d

Limited by ambient air temperature

Schedule Page: 403.1 Line No.: 10 Column: e

Limited by fuel quality.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees shared by and included in R. M. Heskett.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees shared by and included in Lewis & Clark.

Schedule Page: 402 Line No.: 43 Column: b1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: d1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: f1

Average cost of all fuels burned per net kWh generated.

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: 44 Column: b1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402 Line No.: 44 Column: c1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402 Line No.: 44 Column: d1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402 Line No.: 44 Column: e1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402 Line No.: 44 Column: f1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402.1 Line No.: 43 Column: b1 Average cost of all fuels burned per net kWh generated.
Schedule Page: 402.1 Line No.: 43 Column: c1 Average cost of all fuels burned per net kWh generated.
Schedule Page: 402.1 Line No.: 43 Column: d1 Average cost of all fuels burned per net kWh generated.
Schedule Page: 402.1 Line No.: 43 Column: e1 Average cost of all fuels burned per net kWh generated.
Schedule Page: 402.1 Line No.: 43 Column: f1 Average cost of all fuels burned per net kWh generated.
Schedule Page: 402.1 Line No.: 44 Column: b1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402.1 Line No.: 44 Column: c1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402.1 Line No.: 44 Column: d1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402.1 Line No.: 44 Column: e1 Average Btu per net kWh generated for all fuels.
Schedule Page: 402.1 Line No.: 44 Column: f1 Average Btu per net kWh generated for all fuels.

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	OIL					
2	Portable Generators	2012	3.65	4.0	5,943	2,010,820
3						
4	WIND					
5	Diamond Willow	2007	30.00	30.2	86,103,380	64,539,472
6	Cedar Hills	2010	19.50	19.5	49,932,640	46,374,529
7	Thunder Spirit	2015	155.50	144.0	407,947,000	299,095,519
8	WASTE HEAT					
9	Ormat Facility	2009	7.50	7.7	44,939,890	15,073,480
10						
11						
12						
13						
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46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
	23,681		15,033	Oil		2
						3
						4
	409,421		177,708	Wind		5
	313,333		89,873	Wind		6
	3,033,853		49,150	Wind		7
						8
	880,359		22,512	Waste Heat		9
						10
						11
						12
						13
						14
						15
						16
						17
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						19
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						21
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						45
						46

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 2 Column: c
Maximum Turbine Name Plate Rating

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	AVS	Charlie Creek	345.00	345.00	3	26.57		1
2	Coyote	Center	345.00	345.00	2	11.43		1
3	Coyote Switch Yard		345.00	345.00	2	1.04		1
4	Center	Jamestown	345.00	345.00	2	10.69		1
5	Big Stone Plant	Sisseton	230.00	230.00	2	47.55		1
6	Heskett Station	East Bismarck	230.00	230.00	2	10.49		1
7	Bismarck	Wishek	230.00	230.00	2	67.41		1
8	Wishek	Ellendale	230.00	230.00	2	54.88		1
9	Heskett Station	WAPA Tie	230.00	230.00	2	1.15		1
10	Montana Border	South Dakota Border	230.00	230.00	2	86.19		1
11	Merricourt Windfarm	Ellendale	230.00	230.00	2	29.71		1
12	Thunder Spirit Interconnect		230.00	230.00	2	0.55		1
13								
14	Lines Below 132 Kilovolts		115.00	115.00	2	626.86	4.12	
15			69.00	69.00	Various	96.19	1.33	1
16			41.60	69.00	2	86.44	17.19	1
17			57.00	69.00	2	3.34		1
18			57.00	60.00	Various	907.42	0.89	1
19			33.00	60.00	1	18.38		1
20			57.00	57.00	1	2.61		2
21			41.60		Various	1,042.45	27.69	
22			33.00	35.00	1	28.99		1
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,160.34	51.22	20

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2306.2 KcMIL								1
2-954 MCM								2
2-954 MCM								3
2-1272 MCM								4
954 MCM								5
795 MCM								6
795 MCM								7
795 MCM								8
954 MCM								9
954 MCM								10
954 MCM								11
795MCM								12
								13
Various								14
Various								15
4/0 ACSR								16
4/0 ACSR								17
Various								18
4/0 ACSR								19
4/0 ACSR								20
Various								21
Various								22
								23
	3,248,524	147,825,065	151,073,589	6,152,002	1,191,539	112,419	7,455,960	24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	3,248,524	147,825,065	151,073,589	6,152,002	1,191,539	112,419	7,455,960	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 4 Column: b

Respondent, Otter Tail Power Company, Northern Municipal Power Agency (NMPA) and Northwestern Public Service share ownership of 10.69 miles of transmission line. Respondent's ownership share is 6.25%. NMPA pays all operating and maintenance expenses and they are shared based on mileage percentage. Respondent's expenses are reflected in accounts 562 and 570.

Schedule Page: 422 Line No.: 14 Column: h

Various

Schedule Page: 422 Line No.: 21 Column: d

Various

Schedule Page: 422 Line No.: 21 Column: h

Various

Schedule Page: 422 Line No.: 24 Column: j

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 24 Column: k

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 24 Column: l

Cost by transmission line not available. Total costs for all transmission lines.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	MWEC 115kV Sub Tap		1.09	SP	17.00	1	1
2							
3	Stanley Jct	Stanley	5.35	SP	17.00	1	1
4			-5.30	Retired			
5							
6	Williston Water Plant Tap		2.22	SP	18.00	1	1
7							
8	Glen Ullin Jct	Hebron Jct	0.21	SP	19.00	1	1
9			-0.25	Retired			
10							
11	Hettinger	Lemmon	10.68	SP	16.00	1	1
12			-10.69	Retired			
13							
14	Lemmon NW Sub Tap		-0.01	Retired			
15							
16	Beach Tap		0.71	SP	20.00	1	1
17							
18							
19	Crosby	Kincaid	0.05	SP	36.00	1	1
20							
21	Little Muddy Sub	Williston	0.15	SP	20.00	2	2
22			-0.12	Retired			
23							
24	Wishek	Ellendale	0.08	SP	26.00	1	1
25			-0.19	Retired			
26							
27	Merricourt WF	Ellendale	0.07	SP	14.00	1	1
28			-0.05	Retired			
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		4.00		203.00	11	11

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
336	MCMACSR	TP-115DC-PEL	69			260,000		260,000	1
									2
336	MCMACSR	T-69-A	69			50,946		50,946	3
									4
									5
336	MCMACSR	T-60-A-1	60	14,292	941,304	255,254		1,210,850	6
									7
4/0	ACSR	T-46-A	42		18,446	12,487		30,933	8
							2,642	2,642	9
									10
336	MCMACSR	T-46-A-1 MOD	42		861,637	2,256,364		3,118,001	11
							184,024	184,024	12
									13
			42				190	190	14
									15
4/0	ACSR	T-60-B	60		269,894	7,634		277,528	16
							2,901	2,901	17
									18
4/0	ACSR	T-60-E	60			80,116		80,116	19
									20
477	MCMACSR	T-60-HAI DBL	57	18,817	502,631	127,003		648,451	21
							16,770	16,770	22
									23
795	MCMACSR	T-230-A	230		187,708	36,257		223,965	24
									25
									26
954	MCMACSR	T-230-A	230		145,303	76,637		221,940	27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				33,109	2,926,923	3,162,698	206,527	6,329,257	44

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MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 424 Line No.: 1 Column: j

9' X 9' Vertical

Schedule Page: 424 Line No.: 1 Column: o

No charges due to being a trade with Mountrail Williams Electric Cooperative for Right-of-Ways; \$260,000 is an estimated cost

Schedule Page: 424 Line No.: 3 Column: j

8' x 8' Vertical

Schedule Page: 424 Line No.: 3 Column: o

No retirement costs recorded yet

Schedule Page: 424 Line No.: 6 Column: j

86" x 73" x 103" Triangular

Schedule Page: 424 Line No.: 8 Column: j

86" x 86" x 86" Triangular

Schedule Page: 424 Line No.: 8 Column: k

46 KV Design

Schedule Page: 424 Line No.: 11 Column: j

86" x 61" x 95" Triangular

Schedule Page: 424 Line No.: 11 Column: k

46 KV Design

Schedule Page: 424 Line No.: 14 Column: k

46 KV Design

Schedule Page: 424 Line No.: 16 Column: j

86" x 73" x 103" Triangular

Schedule Page: 424 Line No.: 19 Column: j

7' x 7' Vertical

Schedule Page: 424 Line No.: 21 Column: j

8' x 8' Vertical

Schedule Page: 424 Line No.: 21 Column: k

60 KV Design

Schedule Page: 424 Line No.: 24 Column: j

19'6" x 19'6" Horizontal

Schedule Page: 424 Line No.: 24 Column: o

WO not Unitized/In-service, no retirement done yet

Schedule Page: 424 Line No.: 27 Column: j

19'6" x 19'6" Horizontal

Schedule Page: 424 Line No.: 27 Column: o

WO not Unitized/In-service, no retirement done yet

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	22.90	
2	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	118.00	13.80
3	Cedar Hills, ND	Trans at Plant	58.20	34.50	
4	Coyote Station, ND (25% Interest)	Trans at Plant	345.00	22.90	
5	Coyote Station, ND (25% Interest)	Trans at Plant	115.00	13.80	
6	Coyote Station, ND	Trans at Plant	345.00	115.00	13.80
7	Diamond Willow, MT	Trans at Plant	57.20	34.50	
8	Glen Ullin, ND (Ormat)	Trans at Plant	41.60	12.47	
9	Glendive, MT (Turbine)	Trans at Plant	115.00	13.20	
10	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
11	Heskett Station, ND	Trans at Plant	230.00	115.00	13.80
12	Heskett Station, ND	Trans at Plant	116.00	13.20	
13	Heskett Station, ND	Trans at Plant	115.00	13.20	
14	Heskett Station, ND	Trans at Plant	115.00	41.60	
15	Heskett Station, ND	Trans at Plant	115.00	69.00	
16	Lewis & Clark Station, MT	Trans at Plant	115.00	13.80	
17	Lewis & Clark Station, MT	Trans at Plant	57.00	13.80	
18	Lewis & Clark Station, MT	Trans at Plant	115.00	60.00	
19	Miles City, MT (Turbine)	Trans at Plant	57.00	13.80	
20	Thunder Spirit, ND	Trans at Plant	230.00	34.50	
21	Substations under 10,000 KVA (0)				
22	SUBTOTAL		2917.00	835.17	41.40
23					
24	Baker, MT	Trans Unattended	115.00	57.00	
25	Baker, MT	Trans Unattended	230.00	115.00	14.10
26	Baker, MT Cabin Creek Jct	Trans Unattended	115.00	57.20	
27	Beulah Jct., ND	Trans Unattended	115.00	41.60	
28	Bismarck Jct., ND (E. Bismarck)	Trans Unattended	115.00	41.60	
29	Bismarck, ND NW	Trans Unattended	115.00	41.60	
30	Bismarck, ND Sweet Ave.	Trans Unattended	115.00	41.60	
31	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
32	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
33	Bowman, ND	Trans Unattended	230.00	41.60	
34	Dickinson, ND	Trans Unattended	115.00	41.60	
35	Dickinson, ND	Trans Unattended	115.00	41.60	
36	Ellendale Jct., ND	Trans Unattended	230.00	115.00	13.80
37	Ellendale Jct., ND	Trans Unattended	115.00	41.60	
38	Elgin, ND	Trans Unattended	69.00	41.60	
39	Gascoyne Jct., ND	Trans Unattended	115.00	41.60	
40	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
104	1					1
52	1					2
28	2					3
120	1					4
21	1					5
168	1					6
28	2					7
11	1					8
40	1					9
87	2					10
112	1					11
94	1	1				12
28	1					13
34	1					14
45	1			1		4 15
53	1					16
20	1					17
47	1					18
31	1					19
						20
						21
1123	22	1		1		4 22
						23
40	1			1		4 24
112	1					25
83	1					26
45	1					27
80	2			2		8 28
47	1			1		4 29
56	1					30
20	1			1		2 31
						32
						33
75	1					34
93	1					35
100	1					36
37	1					37
15	1					38
11	1			1		1 39
30	1			1		3 40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
2	Halliday, ND	Trans Unattended	115.00	41.60	
3	Hettinger Jct., ND	Trans Unattended	115.00	41.60	
4	Hettinger Jct., ND	Trans Unattended	230.00	115.00	14.10
5	Kenmare Jct., ND	Trans Unattended	115.00	57.00	
6	Lignite, ND	Trans Unattended	115.00	57.00	
7	Linton Jct., ND	Trans Unattended	115.00	41.60	
8	Mandan, ND 230	Trans Unattended	230.00	115.00	13.80
9	Mandan, ND Collins	Trans Unattended	115.00	41.60	
10	McIntosh Jct., SD	Trans Unattended	115.00	41.60	
11	Miles City, MT	Trans Unattended	230.00	115.00	13.80
12	Miles City, MT	Trans Unattended	115.00	57.00	13.80
13	Mohall, ND	Trans Unattended	115.00	57.00	
14	New England, ND	Trans Unattended	115.00	41.60	
15	Plentywood Jct., MT	Trans Unattended	115.00	57.00	
16	Poplar Jct., MT	Trans Unattended	115.00	57.00	
17	Ray, ND Jct.	Trans Unattended	115.00	57.00	
18	Rosebud Creek, MT	Trans Unattended	230.00	60.00	13.80
19	Selby, SD	Trans Unattended	41.60	12.47	
20	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
21	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
22	Stanley Jct., ND	Trans Unattended	115.00	69.00	12.47
23	Tioga, ND	Trans Unattended	230.00	115.00	
24	Tioga Jct., ND	Trans Unattended	115.00	57.00	
25	Wibaux, MT	Trans Unattended	115.00	60.00	
26	Wishek Jct., ND	Trans Unattended	115.00	41.60	
27	Wishek Jct., ND	Trans Unattended	230.00	115.00	13.80
28	Zahl, ND	Trans Unattended	57.00	13.20	
29	Substations under 10,000 KVA (10)				
30	SUBTOTAL		6492.60	2693.47	206.67
31					
32	Substations under 10,000 KVA Distrib at Plant (2)				
33	SUBTOTAL				
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
56	1					1
20	1			1		2
25	1			1		3
112	1					4
30	1			1		5
75	1					6
15	1			1		7
224	1					8
30	1					9
13	1			1		10
100	1					11
56	1					12
74	1			1		13
22	1			1		14
47	1					15
37	1					16
75	1					17
40	1					18
						19
57	2					20
75	1					21
22	1			1		22
112	1					23
75	1					24
						25
30	1			1		26
112	1					27
				3		28
30	14	1		3		29
2408	56	1		22		30
						31
8	2			3		32
8	2			3		33
						34
						35
						36
						37
						38
						39
						40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Beulah, ND Coyote Creek	Distrib Unattended	115.00	22.90	
2	Beulah, ND W. M. Port 1	Distrib Unattended	115.00	6.90	
3	Beulah, ND W. M. Port 2	Distrib Unattended	115.00	6.90	
4	Baker, MT Lookout Butte	Distrib Unattended	57.20	12.47	
5	Baker, MT Pine Unit #1	Distrib Unattended	57.00	12.47	
6	Bismarck, ND Kirkwood	Distrib Unattended	115.00	12.47	
7	Bismarck, ND SE Expressway	Distrib Unattended	115.00	12.47	
8	Bismarck, ND NW (Century)	Distrib Unattended	115.00	12.47	
9	Bismarck, ND NE	Distrib Unattended	115.00	12.47	
10	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
11	Bismarck, ND Turnpike	Distrib Unattended	115.00	12.47	
12	Bismarck, ND South 9th St.	Distrib Unattended	41.60	12.47	
13	Bismarck, ND Sunrise	Distrib Unattended	115.00	12.47	
14	Bismarck, ND 26th & D	Distrib Unattended	115.00	12.47	
15	Dayton, WY Smith Creek	Distrib Unattended			
16	Dayton, WY Tongue River	Distrib Unattended			
17	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
18	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
19	Dickinson, ND NE	Distrib Unattended	41.60	12.47	
20	Dickinson, ND Refinery	Distrib Unattended	41.60	12.47	
21	Dickinson, ND 21st	Distrib Unattended	41.60	12.47	
22	Dickinson, ND West	Distrib Unattended	41.60	12.47	
23	Fullerton, ND	Distrib Unattended	41.60	12.47	
24	Glendive, MT	Distrib Unattended	57.00	12.47	
25	Glendive, MT West	Distrib Unattended	57.00	12.47	
26	Glendive, MT	Distrib Unattended	57.00	12.47	
27	Hague, ND	Distrib Unattended			
28	Hazelton, ND	Distrib Unattended			
29	Kintyre, ND	Distrib Unattended			
30	Lignite, ND	Distrib Unattended	57.00	2.40	
31	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
32	Mandan, ND Collins Ave	Distrib Unattended	115.00	12.47	
33	Mandan, ND Midway	Distrib Unattended	41.60	12.47	
34	Mandan, ND	Distrib Unattended	115.00	12.47	
35	Miles City, MT Greenstar	Distrib Unattended	57.00	12.47	
36	Miles City, MT 8th St	Distrib Unattended	57.00	12.47	
37	Miles City, MT South	Distrib Unattended	57.00	12.47	
38	Mobridge, SD	Distrib Unattended	115.00	12.47	
39	Pollock, SD	Distrib Unattended			
40	Ranchester, WY Wolf Creek	Distrib Unattended			

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
10	1					2
11	1					3
11	1					4
11	1			3	1	5
28	1			6	2	6
53	2			9	4	7
22	1			3	2	8
28	1			6	2	9
94	2			27	8	10
56	2			9	3	11
30	1			9	3	12
28	1			6	2	13
42	2			9	3	14
				2		15
				1		16
14	1			3	1	17
14	1			3	1	18
14	1			3	1	19
14	1					20
11	1			3	1	21
14	1			6	2	22
				3		23
14	1			3	1	24
11	1			3	1	25
11	1			3	1	26
				3		27
				3		28
				3		29
12	4			3	1	30
14	1			3	1	31
28	1					32
28	1			6	2	33
50	2			9	3	34
10	1			3	1	35
11	1			3	1	36
11	1			6	2	37
22	1			9	2	38
				3		39
				1		40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
2	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
3	Sheridan, WY Soldier Creek	Distrib Unattended	41.60	12.47	
4	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
5	Sheridan, WY West	Distrib Unattended	41.60	12.47	
6	Sheridan, WY Decker Road	Distrib Unattended			
7	Sidney, MT	Distrib Unattended	57.00	12.47	
8	Sidney, MT	Distrib Unattended	57.00	12.47	
9	Stanley, ND	Distrib Unattended	69.00	12.47	
10	Stanley, ND Enbridge	Distrib Unattended	69.00	12.47	
11	Story, WY	Distrib Unattended			
12	Watford City, ND South Park	Distrib Unattended	34.50	7.20	
13	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
14	Williston, ND Harvest Hills	Distrib Unattended	57.00	12.47	
15	Williston, ND NE	Distrib Unattended	57.00	12.47	
16	Williston, ND NW North	Distrib Unattended	57.00	12.47	
17	Williston, ND NW South	Distrib Unattended	57.00	12.47	
18	Williston, ND Sabin Metals	Distrib Unattended	57.00	13.80	
19	Williston, ND Water Plant	Distrib Unattended	57.00	4.16	
20	Williston, ND Oasis	Distrib Unattended	57.00	12.47	
21	Zeeland, ND	Distrib Unattended			
22	Substations Under 10,000 KVA (233)				
23	SUBTOTAL		3489.70	612.94	
24					
25	GRAND TOTAL		12899.30	4141.58	248.07
26					
27					
28	FOOTNOTES				
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
24	2			6	3	1
11	1			3	2	2
14	1			3	2	3
11	1			3	2	4
11	1			3	2	5
				3		6
11	1			3	1	7
14	1			3	1	8
14	1			3	1	9
14	1			3	1	10
				3		11
11	1			3	1	12
11	1			3	1	13
22	2			3	1	14
10	1			3	1	15
14	1			3	1	16
14	1			3	1	17
10	1					18
				3	1	19
11	1			3	1	20
				3		21
679	387			453	59	22
1647	446			691	134	23
						24
5186	526	2		717	181	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 426.1 Line No.: 2 Column: a

See (C) and (D) of footnotes

Schedule Page: 426.1 Line No.: 11 Column: a

See (G) of footnotes

Schedule Page: 426.1 Line No.: 12 Column: a

See (E) and (F) of footnotes

Schedule Page: 426.1 Line No.: 18 Column: a

See (A) and (B) of footnotes

Schedule Page: 426.3 Line No.: 28 Column: a

FOOTNOTES:

- (A) Mid-Yellowstone Electric Cooperative, Inc. has a 14,911 KVA capacity interest.
- (B) Respondent and Mid-Yellowstone Electric Cooperative, Inc. shared the facilities construction expense and available capacity in the respective percentages of 63% and 37%. All maintenance and operating expenses are shared in the same percentage. Respondent expenses are reflected in accounts 570 and 562. Mid-Yellowstone Electric Cooperative, Inc. is not an associated company.
- (C) Upper Missouri G&T Electric Cooperative, Inc. has a 15,300 KVA capacity interest.
- (D) Upper Missouri G&T Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (E) Western Area Power Administration (WAPA) has a 9,500 KVA capacity interest.
- (F) WAPA does routine maintenance at their expense and major repairs are divided 19% WAPA and 81% Respondent.
- (G) WAPA has a 25,000 KVA capacity interest.

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Insurance	CHCC	401,165,184,228	4,531,659
3	Cost of Service	CHCC	401,165,184,228	1,177,532
4	Contract Services	CHCC	184	467,939
5	Contract Services	WBIH		293,392
6	Contract Services	MDU CSG	401,402,417,107	1,472,585
7				
8				
9	Total			7,943,107
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Cost of Service for Facilities Used	KRC	454,493	653,742
22	Cost of Service for Facilities Used	MDU CSG	454,493	251,759
23	Cost of Service for Facilities Used	MDU EC	454,493	2,025,240
24	Cost of Service for Facilities Used	WBIH	454,493	84,776
25				
26	Total			3,015,517
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2018

Year/Period of Report

End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
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20	Non-power Goods or Services Provided for Affiliate			
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report 2018/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column: b

Company Abbreviations used in Column (b)

CHCC Centennial Holdings Capital LLC
KRC Knife River Corporation
MDU CSG MDU Construction Services Group, Inc.
MDU EC MDU Energy Capital, LLC
WBIH WBI Holdings, Inc.

Schedule Page: 429 Line No.: 5 Column: c

107,146,184,401,402,417