

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

- 2 PU-18-123 Filed 04/20/2018 Pages: 205
2017 FERC Form 1 - electronic only
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
- 2 PU-18-122 Filed 04/20/2018 Pages: 205
2017 FERC Form 1 - electronic only
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

Exact Legal Name of Respondent (Company)

MDU Resources Group, Inc.

Year/Period of Report

End of 2017/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>2017/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) 12/31/2017

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) <u>4/18</u>
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
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12	Notes to Financial Statements	122-123	
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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	
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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
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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	
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40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
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45	Sales for Resale	310-311	
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47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
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50	Transmission of Electricity by Others	332	
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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) 12/31/2017	Year/Period of Report End of <u>2017/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	MDU Holdings, LLC (1)	Holding Company	100	
4	Prairie Cascade Energy Holdings, LLC - Z	Holding Company	100	
5	Cascade Natural Gas Corporation - AH	Gas Utility Company	100	
6	Prairie Intermountain Energy Holdings, LLC - Z	Holding Company	100	
7	Intermountain Gas Company - U	Gas Utility Company	100	
8	Knife River Corporation - A	Construction Materials&Mining	100	
9	KRC Holdings, Inc. - B	Holding Company	100	
10	Alaska Basic Industries, Inc. - C	Construction Materials	100	
11	Ames Sand & Gravel, Inc. - T	Construction Materials	100	
12	Anchorage Sand and Gravel Company, Inc. - H	Construction Materials	100	
13	Baldwin Contracting Company, Inc. - C	Construction Materials	100	
14	Central Oregon Redi-Mix, LLC - O	Construction Materials	78	
15	Concrete, Inc. - C	Construction Materials	100	
16	Connolly-Pacific Co. - C	Construction Materials	100	
17	D S S Company - C	Construction Materials	100	
18	Fairbanks Materials, Inc. - H	Construction Materials	100	
19	Granite City Ready Mix, Inc. - C	Construction Materials	100	
20	Hawaiian Cement - I	Construction Materials	100	
21	JTL Group, Inc. - Montana - C	Construction Materials	100	
22	JTL Group, Inc. - Wyoming - C	Construction Materials	100	
23	Jebro Incorporated - C	Construction Materials	100	
24	Kent's Oil Service - C	Construction Materials	100	
25	Knife River Corporation - North Central - C	Construction Materials	100	
26	Knife River Corporation - Northwest - C	Construction Materials	100	
27	Knife River Corporation - South - C	Construction Materials	100	

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

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

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1	FutureSource Capital Corp. - R	Asset Management	100	
2	Nevada Solar Solutions, LLC - AL	Alternative Energy	100	
3	InterSource Insurance Company - R	Captive Insurance Company	100	
4	Centennial Energy Resources LLC - A	Holding Company	100	
5	Centennial Energy Resources	Holding Company	100	
6	International, Inc. - D			
7	MDU Resources International LLC - W	Holding Company	100	
8	MDU Resources Luxembourg I LLC S.a.r.l. - W	Holding Company	100	
9	MDU Resources Luxembourg II LLC S.a.r.l. - AC	Holding Company	100	
10	MDU Brasil Ltda. - X	Holding Company	100	
11	(1)-Direct subsidiary of MDU Resources			
12	Group, Inc.			
13	A-100% held by Centennial Energy Holdings, Inc			
14	B-100% held by Knife River Corporation			
15	C-100% held by KRC Holdings, Inc.			
16	D-100% held by Centennial Energy Resources LLC			
17	E-100% held by WBI Holdings, Inc.			
18	F-100% held by MDU Construction Services			
19	Group, Inc.			
20	G-100% held by International Line Builders,			
21	Inc.			
22	H-100% held by Alaska Basic Industries, Inc.			
23	I-Partners include Knife River Hawaii, Inc.			
24	(50%) and Knife River Dakota, Inc. (50%)			
25	J-100% held by WBI Energy Services, Inc.			
26	K-100% held by Fidelity Exploration &			
27	Production Company			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	L-100% held by WBI Energy, Inc.			
2	M-100% held by Baldwin Contracting			
3	Company, Inc.			
4	N-Reserved for future use			
5	O-78% held by Knife River Corporation -			
6	Northwest			
7	P-100% held by The Wagner Group, Inc.			
8	Q-100% held by Rocky Mountain			
9	Contractors, Inc.			
10	R-100% held by Centennial Holdings			
11	Capital LLC			
12	S-100% held by MDU United Construction			
13	Solutions, Inc.			
14	T-100% held by Knife River Corporation -			
15	North Central			
16	U-100% held by Prairie Intermountain			
17	Energy Holdings, LLC			
18	V-Equity interest held by Fidelity Exploration			
19	& Production Company - 75%			
20	W-100% held by Centennial Energy Resources			
21	International, Inc.			
22	X-99.9999% held by MDU Resources Luxembourg			
23	II LLC S.a.r.l. and .0001% held by			
24	Centennial Energy Resources International,			
25	Inc.			
26	Y-Entity was dissolved through merger with			
27	affiliate or dissolution			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Z-100% held by MDU Energy Capital, LLC			
2	AA-Reserved for future use			
3	AB-Reserved for future use			
4	AC-100% held by MDU Resources Luxembourg I			
5	LLC S.a.r.l.			
6	AD-100% held by Cascade Natural			
7	Gas Corporation			
8	AE-100% held by Prairielands Energy Marketing,			
9	Inc.			
10	AF-100% held by LME&U Holdings, LLC			
11	AG-100% held by BEH Electric Holdings, LLC			
12	AH-100% held by Prairie Cascade			
13	Energy Holdings, LLC			
14	AI-100% held by BMH Mechanical Holdings, LLC			
15	AJ-Reserved for future use			
16	AK-Reserved for future use			
17	AL-100% held by FutureSource Capital Corp.			
18	AM-100% held by MDU Industrial Services, Inc.			
19	AN-100% held by Desert Fire Holdings, Inc.			
20	AO-Partners include Desert Fire Protection,			
21	LLC (1%) and Desert Fire Holdings,			
22	Inc. (99%)			
23				
24				
25				
26				
27				

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	792,750
3			
4	President and Chief Executive Officer of Cascade	Nicole A. Kivisto	378,000
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	226,000
10			
11	Vice President, General Counsel and Secretary	Daniel S. Kuntz	300,000
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	188,095
17	and Controller		
18			
19	Vice President and Chief Financial Officer	Doran N. Schwartz	315,548
20			
21	Executive Vice President - Business Development	Dennis L. Haider	141,342
22			
23	Chief Information Officer	Margaret (Peggy) A. Link	225,000
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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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 13 Column: b

Jason L. Vollmer was named Vice President, Chief Financial Officer and Treasurer, effective September 30, 2017 to replace Doran N. Schwartz who resigned.

Schedule Page: 104 Line No.: 16 Column: b

Stephanie A. Barth was named Vice President, Chief Accounting Officer and Controller of MDU Resources effective September 30, 2017, upon Jason L. Vollmer's Promotion to Vice President, Chief Financial Officer and Treasurer.

Schedule Page: 104 Line No.: 19 Column: b

Doran N. Schwartz resigned effective September 29, 2017.

Schedule Page: 104 Line No.: 21 Column: b

Dennis L. Haider retired effective June 12, 2017.

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
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19	William E. McCracken	Warren, New Jersey
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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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 11 Column: a
Dennis W. Johnson, member of the Board of Directors, was elected to Vice Chair of the Board effective February 15, 2018.

INFORMATION ON FORMULA RATES
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. -	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? 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. -	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	
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16	Midcontinent Independent System Operator, Inc. -	ER13-2379-004
17	FERC Electric Tariff	
18		
19	Midcontinent Independent System Operator, Inc. -	ER13-2468-000
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	
9		
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? 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. -	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)
12/31/2017

Year/Period of Report
End of 2017/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	03/13/2017	ER17-1181-000	Annual Informational	Montana-Dakota Utilities Co.
5				Attachment O Filing	MISO Attachments O, GG, and MM
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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 283)		
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) 12/31/2017	Year/Period of Report 2017/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
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Schedule Page: 1062 Line No.: 15 Column: a
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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
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Schedule Page: 1062 Line No.: 27 Column: a
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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) 12/31/2017	Year/Period of Report 2017/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 12/31/2017	Year/Period of Report End of <u>2017/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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. The Respondent renewed franchises in 2017 in Redwood Falls, Minnesota, Camp Crook, South Dakota, Piedmont, South Dakota, Sheridan, Wyoming and the following North Dakota cities: Belfield, Burlington, Crosby, Hazen, South Heart, and Stanley. No consideration was given for the renewal of the franchises other than the agreement to pay franchise fees to the extent applicable.

2. None.

3. None.

4. None.

5. None.

6. The Respondent's short-term indebtedness was \$73,750,000 at December 31, 2017. 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 3.65% in 2017. Wage increases to union employees averaged 3.25% effective 5/1/17. The estimated impact of the increases amounted to approximately \$2,917,000.

9. See Note 15 in Notes To Financial Statements beginning on page 122.

10. None.

11. None.

12. None.

13. Jason L. Vollmer was named Vice President, Chief Financial Officer and Treasurer, effective September 30, 2017.

Stephanie A. Barth was named Vice President, Chief Accounting officer and Controller, effective September 30, 2017.

Doran N. Schwartz, Vice President, and Chief Financial Officer resigned effective as of the end of the day on September 29, 2017.

Dennis L. Haider, Executive Vice President of Business Development, retired effective June 12, 2017.

Dennis W. Johnson, member of the Board of Directors, was elected to Vice Chair of the Board effective February 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	2,489,791,771	2,418,364,465
3	Construction Work in Progress (107)	200-201	124,919,564	67,808,467
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,614,711,335	2,486,172,932
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	921,860,914	878,703,820
6	Net Utility Plant (Enter Total of line 4 less 5)		1,692,850,421	1,607,469,112
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)		1,692,850,421	1,607,469,112
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,514,929	2,692,161
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		16,449,813	16,090,676
19	(Less) Accum. Prov. for Depr. and Amort. (122)		5,380,673	4,352,234
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,704,908,136	1,603,873,802
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)		76,779,282	70,369,897
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)		1,792,756,558	1,685,982,141
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		619,085	3,946,952
36	Special Deposits (132-134)		4,603,012	2,279,900
37	Working Fund (135)		150,750	212,131
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		25,259,589	24,806,476
41	Other Accounts Receivable (143)		4,110,686	3,663,520
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		561,438	481,777
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		34,029,187	34,423,691
45	Fuel Stock (151)	227	4,684,911	4,528,869
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	16,837,763	17,336,690
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)		9,179,608	12,822,648
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,865,158	5,936,055
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)		50,091,799	47,631,992
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)		154,870,110	157,107,147
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,353,114	2,276,700
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,959,651	3,406,606
72	Other Regulatory Assets (182.3)	232	206,776,202	217,540,263
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,678,581	948,016
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		7,900	12,888
75	Other Preliminary Survey and Investigation Charges (183.2)		24,835	0
76	Clearing Accounts (184)		-52,274	-35,372
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	29,033,605	26,117,491
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)		4,726,100	5,297,814
82	Accumulated Deferred Income Taxes (190)	234	59,350,651	87,892,895
83	Unrecovered Purchased Gas Costs (191)		2,175,012	1,874,756
84	Total Deferred Debits (lines 69 through 83)		309,033,377	345,332,057
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,952,025,395	3,798,582,618

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) 12/31/2017	Year/Period of Report end of 2017/Q4
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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	195,843,297	195,843,297
3	Preferred Stock Issued (204)	250-251	0	15,000,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,239,981,494	1,239,047,477
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	6,569,697	6,569,697
11	Retained Earnings (215, 215.1, 216)	118-119	620,946,628	595,204,310
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	419,801,251	317,077,496
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)	-37,333,718	-35,732,744
16	Total Proprietary Capital (lines 2 through 15)		2,429,043,442	2,316,244,326
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	714,686,250	681,754,986
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)		714,686,250	681,754,986
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)		283,024	122,938
29	Accumulated Provision for Pensions and Benefits (228.3)		45,731,295	46,541,513
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	1,343,280
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)		127,809,107	119,521,302
35	Total Other Noncurrent Liabilities (lines 26 through 34)		173,823,426	167,529,033
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		45,904,554	36,758,884
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		7,233,715	5,591,989
41	Customer Deposits (235)		1,361,897	1,425,667
42	Taxes Accrued (236)	262-263	3,296,066	14,992,270
43	Interest Accrued (237)		8,191,173	7,531,734
44	Dividends Declared (238)		38,572,614	37,767,342
45	Matured Long-Term Debt (239)		0	0

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)		1,095,165	937,989
48	Miscellaneous Current and Accrued Liabilities (242)		35,763,020	30,518,735
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)		141,418,204	135,524,610
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		23,674,715	23,481,419
57	Accumulated Deferred Investment Tax Credits (255)	266-267	1,830,976	1,640,385
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	87,716,626	91,493,076
60	Other Regulatory Liabilities (254)	278	172,633,655	22,896,238
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	536,066	499,023
63	Accum. Deferred Income Taxes-Other Property (282)		173,245,884	297,349,295
64	Accum. Deferred Income Taxes-Other (283)		33,416,151	60,170,227
65	Total Deferred Credits (lines 56 through 64)		493,054,073	497,529,663
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,952,025,395	3,798,582,618

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	615,177,864	552,791,714		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	392,735,858	346,893,487		
5	Maintenance Expenses (402)	320-323	30,176,522	27,549,761		
6	Depreciation Expense (403)	336-337	64,878,031	65,925,578		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,224,779	4,095,801		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	2,820	2,820		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-1,405,255	-552,023		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	24,025,388	21,813,906		
15	Income Taxes - Federal (409.1)	262-263	-17,101,437	-5,061,445		
16	- Other (409.1)	262-263	-636,763	-896,217		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	268,126,274	68,117,857		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	238,426,113	55,003,060		
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)		526,600,104	472,886,465		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		88,577,760	79,905,249		

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)	
341,684,354	321,162,370	273,493,510	231,629,344			2
						3
175,605,779	168,442,439	217,130,079	178,451,048			4
24,031,577	22,320,344	6,144,945	5,229,417			5
47,009,040	48,934,860	17,868,991	16,990,718			6
						7
1,766,079	1,620,991	2,458,700	2,474,810			8
		2,820	2,820			9
-1,288,641	-552,023	-116,614				10
						11
						12
						13
14,180,612	12,747,568	9,844,776	9,066,338			14
-16,053,336	-12,175,706	-1,048,101	7,114,261			15
-521,763	-1,575,121	-115,000	678,904			16
138,101,687	51,253,120	130,024,587	16,864,737			17
114,564,528	34,830,630	123,861,585	20,172,430			18
						19
						20
						21
						22
						23
						24
268,266,506	256,185,842	258,333,598	216,700,623			25
73,417,848	64,976,528	15,159,912	14,928,721			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)		88,577,760	79,905,249		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		98,113	100,033		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		74,895	71,515		
33	Revenues From Nonutility Operations (417)		7,040,505	6,686,433		
34	(Less) Expenses of Nonutility Operations (417.1)		3,572,345	3,546,711		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	218,500,841	8,611,755		
37	Interest and Dividend Income (419)		1,930,376	2,679,301		
38	Allowance for Other Funds Used During Construction (419.1)		400,908	-3,391		
39	Miscellaneous Nonoperating Income (421)		376,517	503,222		
40	Gain on Disposition of Property (421.1)		187,704	6,613		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		224,887,724	14,965,740		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		31,475	177,706		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		745,961	174,287		
46	Life Insurance (426.2)		-2,655,182	-1,052,133		
47	Penalties (426.3)			2,209		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		186,887	117,353		
49	Other Deductions (426.5)			1,352		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-1,690,859	-579,226		
51	Taxes Applicable to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	117,437	300,545		
53	Income Taxes-Federal (409.2)	262-263	-2,820,520	-712,193		
54	Income Taxes-Other (409.2)	262-263	-743,428	-760,954		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	9,230,015	1,639,201		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,004,897	856,545		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		-190,592	111,917		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,969,199	-501,863		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		224,609,384	16,046,829		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		31,263,411	30,559,947		
63	Amort. of Debt Disc. and Expense (428)		343,324	337,723		
64	Amortization of Loss on Reaquired Debt (428.1)		598,000	670,246		
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)		282,192	308,257		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		502,771	356,915		
70	Net Interest Charges (Total of lines 62 thru 69)		31,984,156	31,519,258		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		281,202,988	64,432,820		
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)		281,202,988	64,432,820		

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		595,204,310	570,240,768
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Loss on Redemption of Preferred Stock		-600,000	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-600,000	
10	Dividend Equivalents on Stock Based Compensation		-399,593	(232,375)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-399,593	(232,375)
16	Balance Transferred from Income (Account 433 less Account 418.1)		62,702,147	55,821,065
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%		-112,501	(450,003)
25	4.70%		-58,750	(235,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-171,251	(685,003)
30	Dividends Declared-Common Stock (Account 438)			
31			-151,360,905	(147,454,825)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-151,360,905	(147,454,825)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		115,571,920	117,514,680
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		620,946,628	595,204,310
	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)		620,946,628	595,204,310
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		317,077,496	426,114,449
50	Equity in Earnings for Year (Credit) (Account 418.1)		218,500,841	8,611,755
51	(Less) Dividends Received (Debit)		115,571,920	117,514,680
52			-205,166	(134,028)
53	Balance-End of Year (Total lines 49 thru 52)		419,801,251	317,077,496

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

Dividend equivalents on stock based compensation - CEHI	\$133,400
Dividend equivalents on stock based compensation - MDU EC	\$ 71,766

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

Dividend equivalents on stock based compensation - CEHI	\$104,278
Dividend equivalents on stock based compensation - MDU EC	\$ 29,750

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)	281,202,988	64,432,820
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	67,700,375	69,472,176
5	Amortization of		
6	Loss on Reacquired Debt, Bond Discount and Debt Exp	495,300	1,007,968
7			
8	Deferred Income Taxes (Net)	34,925,280	13,897,453
9	Investment Tax Credit Adjustment (Net)	190,592	-111,916
10	Net (Increase) Decrease in Receivables	-426,114	-4,875,815
11	Net (Increase) Decrease in Inventory	4,163,158	932,859
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	2,207,920	13,130,347
14	Net (Increase) Decrease in Other Regulatory Assets	5,923,937	-16,088,758
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,212,357	-1,050,586
16	(Less) Allowance for Other Funds Used During Construction	400,908	-3,391
17	(Less) Undistributed Earnings from Subsidiary Companies	102,928,921	-108,902,925
18	Other (provide details in footnote):		
19	Unrecovered Purchased Gas Costs	-300,256	-5,544,820
20	Net Change in Other Current & Accrued Assets	-4,712,022	-10,882,352
21	Other Noncurrent changes	-10,829,547	7,576,883
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	275,999,425	240,802,575
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-134,992,949	-154,154,491
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-10,709,725	-5,828,349
29	Gross Additions to Nonutility Plant	-408,194	-449,925
30	(Less) Allowance for Other Funds Used During Construction	-400,908	3,391
31	Other (provide details in footnote):		
32			
33	Customer Advances for Construction	193,296	1,292,262
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-145,516,664	-159,143,894
35			
36	Acquisition of Other Noncurrent Assets (d)	-468,090	-128,825
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-40,000,000	-5,000,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	40,000,000	15,000,000
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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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	1,064,862	680,706
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-144,919,892	-148,592,013
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	70,500,000	106,419,500
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Repurchase of Common Stock	-564,642	
69	Tax Withholding on Performance Shares	-508,519	-226,301
70	Cash Provided by Outside Sources (Total 61 thru 69)	69,426,839	106,193,199
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-37,568,736	-50,009,533
74	Preferred Stock	-15,600,000	
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-342,501	-685,003
81	Dividends on Common Stock	-150,384,383	-146,471,060
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-134,468,781	-90,972,397
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,389,248	1,238,165
87			
88	Cash and Cash Equivalents at Beginning of Period	4,159,083	2,920,918
89			
90	Cash and Cash Equivalents at End of period	769,835	4,159,083

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 12/31/2017	Year/Period of Report End of <u>2017/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) 12/31/2017	Year/Period of Report 2017/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
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)
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Company	MDU Resources Group, Inc.
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
IFRS	International Financial Reporting Standards
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
MISO	Midcontinent Independent System Operator, Inc.
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
SEC	United States Securities and Exchange Commission
SDPUC	South Dakota Public Utilities Commission
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016

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MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 297,000 natural gas residential, commercial, industrial and municipal customers in 278 communities and adjacent rural areas as of December 31, 2017.

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 \$728.7 million; current and accrued assets would increase by \$915.1 million; deferred debits would increase by \$738.8 million; long-term debt would increase by \$851.7 million; other noncurrent liabilities and current and accrued liabilities would increase by \$497.6 million; and deferred credits would increase by \$1.0 billion as of December 31, 2017. Furthermore, operating revenues would increase by \$3.8 billion and operating expenses, excluding income taxes, would increase by \$3.5 billion for the twelve months ended December 31, 2017. In addition, net cash provided by operating activities would increase by \$172.0 million; net cash used in investing activities would increase by \$69.2 million; net cash used in financing activities would increase by \$110.9 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 a decrease of \$8.1 million for the twelve months ended December 31, 2017. 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Management has also evaluated the impact of events occurring after December 31, 2017, up to the date of issuance of these financial statements.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. In accordance with the accounting guidance on accounting for income taxes, entities must account for the effects of the change in tax laws or rates in the period of enactment. In the fourth quarter of 2017, the period of enactment, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent effective January 1, 2018. For more information on the impacts of the TCJA on the year ended December 31, 2017, see Notes 3 and 10. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company's consolidated financial statements and related disclosures for 2018 and thereafter.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount. The total balance of receivables past due 90 days or more was \$690,000 and \$856,000 at December 31, 2017 and 2016, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2017 and 2016 was \$561,000 and \$482,000, 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:

	2017	2016
	(In thousands)	
Plant materials and operating supplies	\$ 16,838	\$ 17,337
Gas stored underground-current	9,179	12,822
Fuel stock	4,685	4,529
Total	\$ 30,702	\$ 34,688

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was \$2.5 million and \$2.7

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NOTES TO FINANCIAL STATEMENTS (Continued)			

million at December 31, 2017 and 2016, 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 4 and 12.

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:

	2017	2016
	(In thousands)	
AFUDC - borrowed	\$ 503	\$ 357
AFUDC - equity	\$ 401	\$ (3)

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:

	2017	2016	Weighted Average Depreciable Life in Years
(Dollars in thousands, where applicable)			
Electric:			
Generation	\$ 1,034,765	\$ 1,036,373	39
Distribution	415,543	398,382	44
Transmission	296,941	284,048	57
Construction in progress	117,922	62,110	-
Other	112,301	103,107	15
Natural gas distribution:			
Distribution	506,539	481,727	46
Construction in progress	6,998	5,698	-
Other	123,702	114,728	13
Less accumulated depreciation, depletion and amortization	921,861	878,704	
Net utility plant	\$ 1,692,850	\$ 1,607,469	
Nonutility property	\$ 16,450	\$ 16,091	
Less accumulated depreciation, depletion and amortization	5,381	4,352	
Net nonutility property	\$ 11,069	\$ 11,739	

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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 2017 and 2016. 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 recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2017 and 2016, there were no impairment losses recorded. At December 31, 2017, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value. For more information on goodwill, see Note 2.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital of 4.9 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 2017. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued utility revenues represent revenues recognized in excess of amounts billed. Accrued utility revenues were \$50.1 million and \$47.6 million at December 31, 2017 and 2016, respectively. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

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 6.

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 through rate adjustments were \$2.2 million and \$1.9 million at December 31, 2017 and 2016, respectively, which is included in unrecovered purchased gas costs.

Stock-based compensation

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also 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 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance affects the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. The Company adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The adoption of the guidance impacted the Statement of Income and the Comparative Balance Sheet in the first quarter of 2017 due to the taxes related to the stock-based compensation award that vested in February 2017 being recognized as income tax expense as compared to a reduction to additional paid-in capital under the previous guidance. Adoption of the guidance also increased the number of shares included in the diluted earnings per share calculation due to the exclusion of tax benefits in the incremental shares calculation. The change in the weighted average common shares outstanding - diluted did not result in a material effect on the earnings per common share - diluted.

Recently issued accounting standards not yet adopted

Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was effective for the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

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

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance was effective for the Company on January 1, 2018. The guidance was to be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which should be applied prospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures and does not anticipate a material impact.

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Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. The guidance requires the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net benefit costs shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance allows only the service cost component to be eligible for capitalization.

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 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 is evaluating the adoption of the guidance in the first quarter of 2018. The guidance will not have a material impact on the Company's results of operations, financial position, cash flows or disclosures.

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

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

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

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

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company is evaluating adoption of the guidance in the first quarter of 2018. At December 31, 2017, the Company had \$7.7 million of stranded tax effects in the accumulated other comprehensive loss balance, including \$6.7 million related to the stranded tax effects of subsidiaries.

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 \$(517,000) and \$1.7 million, net of tax of \$315,000 and \$(1.0) million, for the years ended December 31, 2017 and 2016, respectively.

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

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)

Twelve Months Ended December 31, 2016	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
(In thousands)			
Balance at December 31, 2015	\$ (5,952)	\$ (31,196)	\$ (37,148)
Other comprehensive income (loss) before reclassifications	310	(1,911)	(1,601)
Amounts reclassified from accumulated other comprehensive loss	1,355	1,661	3,016
Net current-period other comprehensive income (loss)	1,665	(250)	1,415
Balance at December 31, 2016	\$ (4,287)	\$ (31,446)	\$ (35,733)

Reclassifications out of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31,	2017	2016	Location on Statement of Income
(In thousands)			
Amortization of postretirement liability losses included in net periodic benefit cost credit	\$ (133)	\$ (2,182)	(a)
	50	827	Income taxes
	(83)	(1,355)	
Subsidiary reclassifications out of accumulated other comprehensive loss	(1,416)	(1,661)	Equity in earnings of Subsidiary Companies
Total reclassifications	\$ (1,499)	\$ (3,016)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 12.

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Note 2 - 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, 2017 and 2016. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 3 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period*	2017	2016
(In thousands)			
Regulatory assets:			
Pension and postretirement benefits (a)	(h)	\$ 95,806	\$ 101,611
Asset retirement obligations (a) (b)	-	12,036	9,437
Taxes recoverable from customers (a)	Over plant lives	8,253	15,989
Unamortized loss on required debt	Up to 9 years	4,726	5,298
Costs related to identifying generation development (c)	Up to 9 years	2,960	3,407
Unrecovered purchased gas costs	Up to 1 year	2,175	1,875
Other (a) (d) (e)	Up to 20 years	14,283	18,754
Total regulatory assets		140,239	156,371
Regulatory liabilities:			
Taxes refundable to customers (f)		155,329	6,177
Plant removal and decommissioning costs (b) (f)		55,519	57,363
Pension and postretirement benefits (f)		11,056	9,099
Accumulated provision for rate refunds		---	1,343
Other (f) (g)		3,214	2,992
Total regulatory liabilities		225,118	76,974
Net regulatory position		\$ (84,879)	\$ 79,397

* 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.
- (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, 2017 and 2016, approximately \$118.5 million and \$121.2 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

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TCJA. The revaluation of the Company's regulatory deferred tax assets and liabilities are being deferred as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Note 14. 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. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

If, for any reason, the Company's regulated 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 4 - 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 \$51.6 million and \$47.9 million as of December 31, 2017 and 2016, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized gains on these investments for the years ended December 31, 2017 and 2016, were \$6.5 million and \$2.3 million, respectively. 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 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, 2017 and 2016, there were no transfers between Levels 1 and 2.

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

	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.

	Fair Value Measurements at December 31, 2016, Using			Balance at December 31, 2016
	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	\$ —	\$ 513	\$ —	\$ 513
Insurance contract*	—	47,861	—	47,861
Total assets measured at fair value	\$ —	\$ 48,374	\$ —	\$ 48,374

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

The Company'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:

	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(In thousands)				
Long-term debt	\$ 714,686	\$ 752,311	\$ 681,755	\$ 717,599

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

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Note 5 - 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. 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, 2017	Amount Outstanding at December 31, 2016	Letters of Credit at December 31, 2017	Expiration Date
(Dollars in millions)						
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a) \$ 175.0	\$ 73.8	(b) \$ 111.0	(b) \$ —	5/8/19

- (a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of \$225.0 million). There were no amounts outstanding under the revolving credit agreement.
- (b) Amount outstanding under commercial paper program 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 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

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

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

	2017	2016
	(In thousands)	
Senior Notes at a weighted average rate of 4.84%, due on dates ranging from September 16, 2018 to November 21, 2046	\$ 640,500	\$ 570,000
Commercial paper at an interest rate of 1.68%, supported by revolving credit agreement	73,750	111,000
Other note at a rate of 6.0%, due on November 30, 2038	436	755
Total long-term debt	\$ 714,686	\$ 681,755

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

	2018	2019	2020	2021	2022	Thereafter
	(In thousands)					
Long-term debt maturities	\$100,011	\$74,461	\$712	\$713	\$714	\$538,075

Note 6 - 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:

	2017	2016
	(In thousands)	
Balance at beginning of year	\$ 119,521	\$ 103,737
Liabilities incurred	4,559	10,834
Liabilities settled	(2,509)	(995)
Accretion expense *	6,277	5,976
Revisions in estimates	(39)	(31)
Balance at end of year	\$ 127,809	\$ 119,521

* Includes \$6.3 million and \$6.0 million in 2017 and 2016, respectively, related to regulatory assets.

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

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Note 7 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2017		2016
(In thousands, except shares and per share amounts)			
Authorized:			
Preferred -			
500,000 shares, cumulative, par value \$100, issuable in series			
Preferred stock A -			
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)			
Preference -			
500,000 shares, cumulative, without par value, issuable in series (none outstanding)			
Outstanding:			
4.50% Series - 100,000 shares	\$	---	\$ 10,000
4.70% Series - 50,000 shares		---	5,000
Total preferred stocks	\$	---	\$ 15,000

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

Note 8 - Common Stock

For the years 2017 and 2016, dividends declared on common stock were \$.7750 and \$.7550 per common share, respectively.

The Company's Stock Purchase Plan provided interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan provides participants the option to invest in the Company's common stock. From January 2015 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, purchased shares of authorized but unissued common stock from the Company. From September 2015 through December 2017, the K-Plan purchased shares of common stock on the open market. At December 31, 2017, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From September 2015 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan were de-registered.

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

Pursuant to a covenant under a credit agreement, Centennial may only declare or pay distributions if as of the last day of any fiscal quarter, the ratio of Centennial's average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial's Consolidated EBITDA does not exceed 3 to 1; and after giving effect to such distribution, all distributions made during the

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12-month period ending on the last day of the fiscal quarter in which such distribution is made will not exceed the remainder of Centennial's Consolidated EBITDA minus Centennial's capital expenditures less the net cash proceeds from all sales of capital assets from continuing operations, for the immediately preceding 12-month period. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately \$1.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2017. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately \$384 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2017. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 9 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2017, there were 5.1 million remaining shares available to grant under these plans. The Company generally purchases shares on the open market for non-employee director stock awards. The Company purchased shares on the open market for the employee performance shares that vested in 2017. The Company anticipates future employee performance share awards will continue to be satisfied by purchasing shares on the open market.

Total stock-based compensation expense (after tax), excluding the amount recognized by the Company's subsidiaries, was \$805,000 and \$808,000 in 2017 and 2016, respectively.

As of December 31, 2017, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company's subsidiaries, related to stock-based compensation was approximately \$1.5 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

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

Performance share awards

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

Target grants of performance shares outstanding at December 31, 2017, were as follows:

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

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2017 and 2016 were:

	2017		2016	
Weighted average grant-date fair value	\$ 24.31		\$ 14.60	
Blended volatility range	22.70 %	- 25.56 %	29.25 %	- 32.51 %
Risk-free interest rate range	.69 %	- 1.61 %	.47 %	- 0.92 %
Weighted average discounted dividends per share	\$ 1.70		\$ 1.56	

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

A summary of the status of the performance share awards for the year ended December 31, 2017, was as follows:

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

Note 10 - Income Taxes

Income before income taxes for the years ended December 31, 2017 and 2016, respectively was \$76.5 million and \$62.2 million.

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

	2017		2016	
	(In thousands)			
Current:				
Federal	\$ (19,922)		\$ (5,774)	
State	(1,380)		(1,657)	
	(21,302)		(7,431)	
Deferred:				
Income taxes:				
Federal	32,335		11,595	
State	2,590		2,303	
Investment tax credit - net	191		(112)	
	35,116		13,786	
Total income tax expense	\$ 13,814		\$ 6,355	

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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 on a plan for amounts expected to be returned to customers, as discussed in Notes 3 and 14. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of \$157.2 million in the fourth quarter of 2017. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

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

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

	2017	2016
	(In thousands)	
Deferred tax assets:		
Postretirement	\$ 26,021	\$ 41,319
Production Tax Credits	19,367	16,944
Compensation-related	5,294	13,049
Customer advances	5,762	8,852
Other	2,907	7,729
Total deferred tax assets	59,351	87,893
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	173,782	297,848
Postretirement	25,745	41,039
Cost recovery mechanisms	2,285	4,635
Other	5,386	14,497
Total deferred tax liabilities	207,198	358,019
Net deferred income tax liability	\$ 147,847	\$ 270,126

As of December 31, 2017 and 2016, the Company had a federal income tax credit carryforward of \$19.4 million and \$16.9 million respectively. The federal income tax credit carryforwards will expire in 2036 and 2037 if not utilized. As of December 31, 2017 and 2016, 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, 2016, to December 31, 2017, to deferred income tax expense:

	2017
	(In thousands)
Change in net deferred income tax liability from the preceding table	\$ (122,279)
Deferred taxes associated with TCJA enactment for regulated activities	157,157
Deferred taxes associated with other comprehensive income	315
Other	(77)
Deferred income tax expense for the period	\$ 35,116

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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,	2017		2016	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	\$ 26,781	35.0	\$ 21,762	35.0
Increases (reductions) resulting from:				
Production tax credit	(13,958)	(18.2)	(13,544)	(21.8)
Deductible K-Plan dividends	(1,092)	(1.4)	(1,180)	(1.9)
Nonqualified benefit plan	(2,342)	(3.1)	(1,085)	(1.7)
Amortization and deferral of investment tax credit	(171)	(0.2)	(73)	(0.1)
AFUDC equity	(140)	(0.2)	1	0.0
State income taxes, net of federal income tax	1,923	2.5	1,183	1.9
TCJA revaluation	1,890	2.5	---	---
TCJA revaluation related to accumulated other comprehensive loss balance	1,045	1.4	---	---
Other	(122)	(0.2)	(709)	(1.2)
Total income tax expense	\$ 13,814	18.1	\$ 6,355	10.2

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

The Company had no unrecognized tax benefits for the years ended December 31, 2017 and 2016.

For the year ended December 31, 2017, the Company recognized approximately \$14,000 of interest income, related to income taxes. At December 31, 2016, the Company had accrued assets of approximately \$18,000 for the receipt of interest income.

Note 11 - Cash Flow Information

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

	2017	2016
	(In thousands)	
Interest, net of AFUDC – borrowed of \$503 and \$357 in 2017 and 2016, respectively	\$ 30,101	\$ 30,867
Income taxes refunded, net	\$ (7,885)	\$ (8,641)

Noncash investing transactions at December 31 were as follows:

	2017	2016
	(In thousands)	
Property, plant and equipment additions in accounts payable	\$ 12,324	\$ 9,495

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Note 12 - 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 2016, all of the Company's defined pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits.

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

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, 2017 and 2016, and amounts recognized in the Comparative Balance Sheet at December 31, 2017 and 2016, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
(In thousands)				
Change in benefit obligation:				
Benefit obligation at beginning of year	\$ 245,858	\$ 251,676	\$ 40,267	\$ 46,752
Service cost	—	—	616	716
Interest cost	9,090	9,679	1,443	1,749
Plan participants' contributions	—	—	804	825
Actuarial (gain) loss	10,543	(99)	260	(6,444)
Benefits paid	(14,602)	(15,398)	(3,262)	(3,331)
Benefit obligation at end of year	250,889	245,858	40,128	40,267
Change in net plan assets:				
Fair value of plan assets at beginning of year	182,213	183,045	47,253	47,449
Actual gain on plan assets	24,679	14,566	5,645	2,274
Employer contribution	422	—	91	36
Plan participants' contributions	—	—	804	825
Benefits paid	(14,602)	(15,398)	(3,262)	(3,331)
Fair value of net plan assets at end of year	192,712	182,213	50,531	47,253
Funded status – over (under)	\$ (58,177)	\$ (63,645)	\$ 10,403	\$ 6,986
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	\$ (58,177)	\$ (63,645)	\$ 10,403	\$ 6,986
Net amount recognized	\$ (58,177)	\$ (63,645)	\$ 10,403	\$ 6,986
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	\$ 102,514	\$ 108,983	\$ 683	\$ 3,416
Prior service credit	—	—	(8,228)	(9,204)
Total	\$ 102,514	\$ 108,983	\$ (7,545)	\$ (5,788)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. The above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 3.

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

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

	2017	2016
(In thousands)		
Projected benefit obligation	\$ 250,889	\$ 245,858
Accumulated benefit obligation	\$ 250,889	\$ 245,858
Fair value of plan assets	\$ 192,712	\$ 183,213

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

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
(In thousands)				
Components of net periodic benefit cost (credit):				
Service cost	\$ —	\$ —	\$ 616	\$ 716
Interest cost	9,090	9,679	1,443	1,749
Expected return on assets	(11,222)	(11,467)	(2,651)	(2,591)
Amortization of prior service credit	—	—	(976)	(976)
Recognized net actuarial loss	3,554	3,535	—	502
Net periodic benefit cost (credit), including amount capitalized	1,422	1,747	(1,568)	(600)
Less amount capitalized	294	374	(360)	(152)
Net periodic benefit cost (credit)	1,128	1,373	(1,208)	(448)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities):				
Net gain	(2,915)	(3,198)	(2,733)	(6,127)
Amortization of actuarial loss	(3,554)	(3,535)	—	(502)
Amortization of prior service credit	—	—	976	976
Total recognized in accumulated other comprehensive income and regulatory liabilities	(6,469)	(6,733)	(1,757)	(5,653)
Total recognized in net periodic benefit credit and accumulated other comprehensive income and regulatory liabilities	\$ (5,341)	\$ (5,360)	\$ (2,965)	\$ (6,101)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory asset into net periodic benefit cost in 2018 is \$3.9 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 asset into net periodic benefit cost in 2018 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	
	2017	2016	2017	2016
Discount rate	3.37%	3.81%	3.38%	3.83%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Discount rate	3.82%	3.98%	3.83%	4.04%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%

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The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2017, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 20 percent to 25 percent equity securities and 75 percent to 80 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

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

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2017:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	\$ 58	\$ (47)
Effect on postretirement benefit obligation	\$ 1,289	\$ (1,113)

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

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

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

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

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2017 and 2016, there were no transfers between Levels 1 and 2.

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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, 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	—	9,157	—	9,157
U.S. Government securities	564	—	—	564
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.

	Fair Value Measurements at December 31, 2016, Using			Balance at December 31, 2016
	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	\$ —	\$ 3,467	\$ —	\$ 3,467
Equity securities:				
U.S. companies	6,200	—	—	6,200
International companies	866	—	—	866
Collective and mutual funds *	88,539	34,995	—	123,534
Corporate bonds	—	37,522	—	37,522
Municipal bonds	—	6,011	—	6,011
U.S. Government securities	2,377	1,117	—	3,494
Total assets measured at fair value	\$ 97,982	\$ 83,112	\$ —	\$ 181,094

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2017 and 2016, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2017, Using			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.

	Fair Value Measurements at December 31, 2016, Using			Balance at December 31, 2016
	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	\$ —	\$ 101	\$ —	\$ 101
Equity securities:				
U.S. companies	1,040	—	—	1,040
Insurance contract*	—	46,112	—	46,112
Total assets measured at fair value	\$ 1,040	\$ 46,213	\$ —	\$ 47,253

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

The Company expects to contribute approximately \$12.1 million to its defined benefit pension plans in 2018. The Company does not expect to contribute to its postretirement benefit plans in 2018.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2018	\$ 14,763	\$ 2,809	\$ 120
2019	14,764	2,765	116
2020	14,876	2,640	111
2021	14,950	2,594	104
2022	15,071	2,597	97
2023– 2027	74,531	12,349	357

Nonqualified benefit plans

In addition to the qualified defined pension benefit plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was \$2.2 million and \$509,000 in 2017 and 2016, respectively, which reflects a curtailment gain of \$2.2 million in the first quarter of 2016. The total projected benefit obligation for these plans was \$52.3 million and \$59.1 million at December 31, 2017 and 2016, respectively. The accumulated benefit obligation for these plans was \$52.3 million and \$59.1 million at December 31, 2017 and 2016, respectively. A discount rate of 3.18 percent and 3.54 percent at December 31, 2017 and 2016, respectively, was used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2017 and 2016, due to the plans being frozen. A discount rate of 3.54 percent and 3.76 percent for the years ended December 31, 2017 and 2016, respectively, and a rate of compensation increase of 4.00 percent for the year ended December 31, 2016, were used to determine net periodic benefit cost. No rate of compensation increase was used to determine net periodic benefit cost at December 31, 2017, due to the plans being frozen.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate \$3.6 million in 2018; \$3.7 million in 2019; \$3.9 million in 2020; \$4.0 million in 2021, \$3.6 million in 2022 and \$19.3 million for the years 2023 through 2027.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2017 and 2016 were \$167,000 and \$33,000, respectively.

The Company had investments of \$74.7 million and \$68.2 million at December 31, 2017 and 2016, respectively, consisting of equity securities of \$45.5 million and \$42.2 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of \$20.8 million and \$20.4 million, respectively, and other investments of \$8.4 million and \$5.6 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees, and costs incurred under these plans were \$11.1 million in 2017 and \$10.7 million in 2016.

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MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Note 13 - Jointly Owned Facilities

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

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

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

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

Note 14 - Regulatory Matters and Revenues Subject to Refund

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

MNPUC

On December 21, 2016, Great Plains filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff of approximately \$456,000 annually. The tariff will allow Great Plains to recover infrastructure investments, not previously included in rates, mandated by federal or state agencies associated with Great Plains' pipeline integrity programs. On October 6, 2017, the MNPUC approved the implementation of the natural gas utility infrastructure cost tariff to collect an annual increase of approximately \$456,000. Great Plains submitted a compliance filing on October 10, 2017, and the rates were implemented for service rendered on and after November 1, 2017.

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Great Plains provided preliminary impacts of the TCJA by January 30, 2018. A commission planning

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NOTES TO FINANCIAL STATEMENTS (Continued)			

meeting was held on February 6, 2018, to discuss the impacts of the TCJA. Initial filings addressing the impacts of the TCJA were submitted on March 2, 2018. This matter is pending before the MNPUC.

MTPSC

On September 25, 2017, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase of approximately \$2.8 million annually or approximately 4.1 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately \$1.6 million or approximately 2.3 percent, subject to refund. On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA for the natural gas segment within the natural gas rate case. On January 12, 2018, Montana-Dakota filed a revised interim increase of approximately \$764,000, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. The interim request for rate relief was denied by the MTPSC on March 6, 2018. A hearing is scheduled for April 26, 2018. This matter is pending before the MTPSC.

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

NDPSC

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

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately \$5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately \$4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On January 12, 2018, Montana-Dakota requested a delay of the rate case as a result of the enactment of the TCJA to allow the Company time to investigate the implications of the TCJA on the rate case. On February 14, 2018, the NDPSC approved the delay of hearing and scheduled it to begin on May 30, 2018. Also on February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately \$2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. Updated interim rates were implemented on March 1, 2018. A hearing is scheduled to begin on May 30, 2018. This matter is pending before the NDPSC.

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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

and natural gas utilities. On March 9, 2018, Montana-Dakota submitted a request to decrease electric rates by \$7.2 million or 3.9 percent annually. This matter is pending before the NDPSC.

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.

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 of the TCJA on rates by March 30, 2018. Montana-Dakota submitted its initial assessment on March 30, 2018. This matter is pending before the WYPSC.

FERC

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

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. If the waiver is granted, MISO expects to implement new rates reflecting the reduction in the tax rate beginning with services rendered on March 1, 2018, and will re-bill January and February 2018 services to reflect the new rates. The FERC approved the waiver request on March 15, 2018, and new rates reflecting the effects of the TCJA were implemented by MISO on March 1, 2018. The total revenue requirement for the Company's multivalue project was reduced to \$12.0 million.

Note 15 - 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 \$283,000 and \$1.7 million, which have not been discounted, for contingencies related to litigation as of December 31, 2017 and 2016, respectively. The

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FOOTNOTE DATA			

Schedule Page: 120 Line No.: 61 Column: b

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

Schedule Page: 120 Line No.: 61 Column: c

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

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.

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	(23,843)	(34,256,532)		(200,236)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	142,820	2,505,904		
3	Preceding Quarter/Year to Date Changes in Fair Value	(181,863)	(1,469,714)		51,042
4	Total (lines 2 and 3)	(39,043)	1,036,190		51,042
5	Balance of Account 219 at End of Preceding Quarter/Year	(62,886)	(33,220,342)		(149,194)
6	Balance of Account 219 at Beginning of Current Year	(62,886)	(33,220,342)		(149,194)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	120,447	(130,512)		
8	Current Quarter/Year to Date Changes in Fair Value	(139,146)	(1,813,479)		(5,756)
9	Total (lines 7 and 8)	(18,699)	(1,943,991)		(5,756)
10	Balance of Account 219 at End of Current Quarter/Year	(81,585)	(35,164,333)		(154,950)

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	(2,667,563)		(37,148,174)		
2	367,241		3,015,965		
3			(1,600,535)		
4	367,241		1,415,430		1,415,430
5	(2,300,322)		(35,732,744)		
6	(2,300,322)		(35,732,744)		
7	367,472		357,407		
8			(1,958,381)		
9	367,472		(1,600,974)		(1,600,974)
10	(1,932,850)		(37,333,718)		

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)	2,037,046,734	1,352,039,065
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	442,260,128	420,967,343
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,479,306,862	1,773,006,408
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	124,919,564	116,083,188
12	Acquisition Adjustments	10,484,909	10,387,643
13	Total Utility Plant (8 thru 12)	2,614,711,335	1,899,477,239
14	Accum Prov for Depr, Amort, & Depl	921,860,914	609,672,446
15	Net Utility Plant (13 less 14)	1,692,850,421	1,289,804,793
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	878,371,214	596,868,751
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	33,032,748	2,416,052
22	Total In Service (18 thru 21)	911,403,962	599,284,803
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	10,456,952	10,387,643
33	Total Accum Prov (equals 14) (22,26,30,31,32)	921,860,914	609,672,446

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
552,389,410				132,618,259	3
					4
					5
18,189,485				3,103,300	6
					7
570,578,895				135,721,559	8
					9
					10
5,874,134				2,962,242	11
97,266					12
576,550,295				138,683,801	13
257,799,869				54,388,599	14
318,750,426				84,295,202	15
					16
					17
255,268,098				26,234,365	18
					19
					20
2,462,462				28,154,234	21
257,730,560				54,388,599	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
69,309					32
257,799,869				54,388,599	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	3,734,605	1,667,391
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	3,734,605	1,667,391
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,015,062	
9	(311) Structures and Improvements	76,112,102	3,869,385
10	(312) Boiler Plant Equipment	347,507,053	-1,769,165
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	85,846,939	157,969
13	(315) Accessory Electric Equipment	20,502,449	578,908
14	(316) Misc. Power Plant Equipment	19,716,842	875,251
15	(317) Asset Retirement Costs for Steam Production	5,186,357	2,184,126
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	555,886,804	5,896,474
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	6,931,800	289,150
39	(342) Fuel Holders, Products, and Accessories	3,228,338	-30,038
40	(343) Prime Movers		
41	(344) Generators	430,516,149	1,891,493
42	(345) Accessory Electric Equipment	16,096,152	141,965
43	(346) Misc. Power Plant Equipment	1,230,675	506,346
44	(347) Asset Retirement Costs for Other Production	12,057,345	15,939
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	470,098,992	2,814,855
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,025,985,796	8,711,329

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
			5,401,996	4
			5,401,996	5
				6
				7
			1,015,062	8
408,023		850,109	80,423,573	9
3,413,371		161,518	342,486,035	10
				11
1,178,728			84,826,180	12
709,211		-317,642	20,054,504	13
691,916		-693,985	19,206,192	14
			7,370,483	15
6,401,249			555,382,029	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
			38,533	37
		1,198,530	8,419,480	38
5,473		-1,076,624	2,116,203	39
				40
2,124,450		-977,698	429,305,494	41
420,858		847,899	16,665,158	42
5,619		43,246	1,774,648	43
1,398,672			10,674,612	44
3,955,072		35,353	468,994,128	45
10,356,321		35,353	1,024,376,157	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	4,706,327	152,352
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	140,805,815	6,429,603
51	(354) Towers and Fixtures	4,992,886	
52	(355) Poles and Fixtures	74,523,444	5,182,694
53	(356) Overhead Conductors and Devices	53,970,387	1,959,424
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)	284,047,885	13,724,073
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,993,157	45,863
61	(361) Structures and Improvements		
62	(362) Station Equipment	71,309,793	6,045,874
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	41,806,886	1,593,196
65	(365) Overhead Conductors and Devices	33,163,458	371,279
66	(366) Underground Conduit	223,988	
67	(367) Underground Conductors and Devices	112,615,689	6,153,584
68	(368) Line Transformers	70,186,608	3,527,634
69	(369) Services	36,224,503	1,211,341
70	(370) Meters	18,300,268	361,993
71	(371) Installations on Customer Premises	2,856,228	150,853
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	7,662,005	354,579
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	398,382,331	19,816,196
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	1,402,232	128,449
88	(391) Office Furniture and Equipment	469,010	12,261
89	(392) Transportation Equipment	8,494,099	763,549
90	(393) Stores Equipment	14,774	
91	(394) Tools, Shop and Garage Equipment	3,862,519	512,774
92	(395) Laboratory Equipment	730,054	4,915
93	(396) Power Operated Equipment	13,522,064	1,434,247
94	(397) Communication Equipment	610,149	600,087
95	(398) Miscellaneous Equipment	58,769	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	29,202,520	3,456,282
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)	29,202,520	3,456,282
100	TOTAL (Accounts 101 and 106)	1,741,353,137	47,375,271
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)	1,741,353,137	47,375,271

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
			4,858,679	48
			1,789	49
599,551			146,635,867	50
			4,992,886	51
138,935			79,567,203	52
92,035			55,837,776	53
			1,944,583	54
			3,101,857	55
				56
			797	57
830,521			296,941,437	58
				59
			4,039,020	60
				61
481,419	-1	-26,925	76,847,322	62
				63
259,914	-1	3,657	43,143,824	64
156,558		2,707	33,380,886	65
		11,930	235,918	66
849,817	-41	-11,930	117,907,485	67
424,828	43		73,289,457	68
162,658			37,273,186	69
81,783			18,580,478	70
90,593			2,916,488	71
				72
127,779			7,888,805	73
			39,748	74
2,635,349		-20,561	415,542,617	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			38,850	86
12,587			1,518,094	87
22,974			458,297	88
898,695		-110,853	8,248,100	89
			14,774	90
23,606		-50,296	4,301,391	91
14,006			720,963	92
842,237		48,035	14,162,109	93
86,682		99,300	1,222,854	94
			58,769	95
1,900,787		-13,814	30,744,201	96
				97
				98
1,900,787		-13,814	30,744,201	99
15,722,978		978	1,773,006,408	100
				101
				102
				103
15,722,978		978	1,773,006,408	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 345kV Transmission Line at Big Stone South to Ellendale, ND	89,261,966
2	Construct the Ellendale 345kV Substation	9,049,070
3	Construct 230/34.5kV Substation in Watford City, ND	3,314,915
4	Construct New Leola Junction Substation	3,030,379
5	Replace Dickinson Basin Transformer	1,939,898
6	Relocate 10 miles of TL212-1 for SDDOT Highway 12 Expansion between Hettinger and Lemmon	1,647,879
7	Install 34.5kV Line around Watford City, ND	1,510,545
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19	Minor Projects less than \$1,000,000:	
20	Steam Production	1,799,984
21		
22	Other Production	-194,287
23		
24	Transmission	-334,199
25		
26	Distribution	2,990,716
27		
28	General	417,822
29		
30	Intangible	1,648,500
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	116,083,188

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	570,038,828	570,038,828		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	47,009,040	47,009,040		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,157,102	1,157,102		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-1,197,503	-1,197,503		
9		1,937,648	1,937,648		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	48,906,287	48,906,287		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	15,722,978	15,722,978		
13	Cost of Removal	7,670,838	7,670,838		
14	Salvage (Credit)	1,361,970	1,361,970		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	22,031,846	22,031,846		
16	Other Debit or Cr. Items (Describe, details in footnote):	-44,518	-44,518		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	596,868,751	596,868,751		

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

20	Steam Production	248,465,144	248,465,144		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	83,815,779	83,815,779		
25	Transmission	105,443,351	105,443,351		
26	Distribution	148,903,508	148,903,508		
27	Regional Transmission and Market Operation				
28	General	10,240,969	10,240,969		
29	TOTAL (Enter Total of lines 20 thru 28)	596,868,751	596,868,751		

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			821,876,154
4				
5	Equity in undistributed subsidiary earnings since acquisition			291,525,852
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			464,920,152
10				
11	Equity in undistributed subsidiary earnings since acquisition			25,551,644
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
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36				
37				
38				
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40				
41				
42	Total Cost of Account 123.1 \$	1,704,908,136	TOTAL	1,603,873,802

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
		781,612,455		3
				4
198,841,128	-96,505,320	393,861,660		5
				6
				7
				8
		503,494,430		9
				10
19,659,713	-19,271,766	25,939,591		11
				12
				13
				14
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				31
				32
				33
				34
				35
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				39
				40
				41
218,500,841	-115,777,086	1,704,908,136		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)	4,528,869	4,684,911	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)	13,266,709	12,206,532	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,874,413	3,005,304	Electric
8	Transmission Plant (Estimated)	91,892	163,200	Electric
9	Distribution Plant (Estimated)	1,318,107	1,704,552	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-214,431	-241,825	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	17,336,690	16,837,763	
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)	21,865,559	21,522,674	

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) 12/31/2017	Year/Period of Report 2017/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		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	58,589.00		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	5,041.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Lewis & Clark to WygenIII	27.00			
23	RM Heskett to Wygen III	27.00			
24					
25					
26					
27					
28	Total	54.00			
29	Balance-End of Year	53,494.00		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	11		
45	Gains	168.00	11		
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.

2019		2020		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		360,371.00		1
								2
								3
				11,607.00		11,607.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						5,041.00		18
								19
								20
								21
						27.00		22
						27.00		23
								24
								25
								26
								27
						54.00		28
11,607.00		11,607.00		278,568.00		366,883.00		29
								30
								31
								32
								33
								34
								35
242.00		268.00		5,994.00		6,840.00		36
								37
								38
				67.00		235.00		39
242.00		268.00		5,927.00		6,605.00		40
								41
								42
								43
				67.00	3	235.00		14 44
				67.00	3	235.00		14 45
								46

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2017

Year/Period of Report

End of 2017/Q4

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	171,861	601,511
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			193,658	1,665,935
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	692,205
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			446,955	2,959,651

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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

407	\$242,228
419	<u>(48,570)</u>
	\$193,658

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) 12/31/2017	Year/Period of Report End of <u>2017/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:	735,357	970,755		514,967	1,191,145
2	Montana gas amortization over 36 months					
3	ending 1/17; South Dakota gas amortization					
4	over 36 months ending 6/19; North Dakota					
5	gas amortization over 36 months ending 1/18;					
6	Wyoming gas amortization over 60 months ending 5/20					
7	Minnesota gas amortization over 48 months ending					
8	12/20; Montana electric amortization over 36 months					
9	ending 3/19; North Dakota electric amortization					
10	over 36 months ending 8/20; South Dakota electric					
11	amortization over 60 months ending 6/21.					
12						
13	Accumulated costs associated with gas rate	1,040,106	426,978	182.3	1,189,570	277,514
14	cases in Montana, North Dakota, and Minnesota					
15	and electric rate cases in Montana and South Dakota					
16						
17	Asset Retirement Obligations	85,207,805	8,794,824		2,508,973	91,493,656
18						
19	Deferred Fuel and Purchased Power Costs -					
20	North Dakota - Electric	(2,769,168)	2,204,350		2,236,331	-2,801,149
21	Wyoming - Electric	247,940	442,795	555	912,930	-222,195
22	Montana - Electric	(762,185)	741,381		599,837	-620,641
23	South Dakota - Electric	(78,715)	296,917		285,774	-67,572
24						
25	Deferred Pension	101,458,393		253	5,869,474	95,588,919
26						
27						
28	Manufactured Gas Plant Site - Bismarck, ND	90,753		928	90,753	
29	amortization over 120 months ending 12/17					
30	Regulatory Matters -Deferred Tax Related	15,989,236	7,434,924		15,170,935	8,253,225
31						
32	ND Transmission Cost Recovery Adjustment -	4,931,041	1,518,624		3,002,207	3,447,458
33	[Case No. PU-11-672]					
34						
35	Montana Public Service Commission/Montana	374,509	193,959	408.1	146,975	421,493
36	Consumer Counsel tax deferral [Docket No.					
37	D2014.8.72, D2015.9.67, D2015.9.68 and					
38	D2015.6.51]					
39						
40	ND Environmental Cost Recovery Rider	3,176,199	16,961		707,407	2,485,753
41	[Case No. PU-13-85]					
42						
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) 12/31/2017	Year/Period of Report End of <u>2017/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	WY Renewable Energy Rider	(197)	68	142	94	-223
2	[Docket No. 20004-108-ET-14]					
3						
4	Manufactured Gas Plant Site - Billings, MT	381,345	102,560			483,905
5	[Docket No. D2014.11.95]					
6						
7	Deferred Pension Expense - ND Gas	152,144	64,561			216,705
8	[Case No. PU-15-90]					
9						
10	ND Generation Resource Recovery Rider	2,460,587	47,899		969,536	1,538,950
11	[Case No. PU-15-704]					
12						
13	ND Renewable Resource Cost Adjustment	1,446,222	319,885		2,402,050	-635,943
14	[Case No. PU-15-703]					
15						
16	Loss on Buildings - North Dakota	2,829,847	50,459	407.3	41,659	2,838,647
17						
18	SD Transmission Rider	78,036	79,829	400	96,326	61,539
19	[Docket No. EL15-024]					
20						
21	SD Infrastructure Rider	184,772	47,314		166,250	65,836
22	[Docket No. EL15-024]					
23						
24	MN Revenue Decoupling	366,236	440,103		260,482	545,857
25	[Docket No. G-004/GR-15-879]					
26						
27	Preferred Stock Premium		600,000			600,000
28						
29	MT Ad Valeorem Tax Tracker		1,214,523			1,214,523
30	[Docket No. 2016.12.96]					
31						
32	MN Gas Utility Infrastructure Cost Adjustment		398,800			398,800
33	[Docket No. G-004/M-16-1066]					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL :	217,540,263	26,408,469		37,172,530	206,776,202

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 232	Line No.: 1	Column: d
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928 (Electric)	196,700
928 (Gas)	318,267
	<u>514,967</u>

Schedule Page: 232	Line No.: 17	Column: d
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421.1	78,388
230	2,430,585
	<u>2,508,973</u>

Schedule Page: 232	Line No.: 20	Column: d
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555	2,210,677
419	330
431	14,508
229	10,816
	<u>2,236,331</u>

Schedule Page: 232	Line No.: 22	Column: d
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555	579,272
419	1,240
431	19,325
	<u>599,837</u>

Schedule Page: 232	Line No.: 23	Column: d
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555	273,683
431	6
449	12,085
	<u>285,774</u>

Schedule Page: 232	Line No.: 30	Column: d
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282	7,352,567
283	7,818,368
	<u>15,170,935</u>

Schedule Page: 232	Line No.: 32	Column: d
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229	352,894
400	2,643,237
419	6,076
	<u>3,002,207</u>

Schedule Page: 232	Line No.: 40	Column: d
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400	706,501
419	906
	<u>707,407</u>

Schedule Page: 232.1	Line No.: 10	Column: d
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400	305,940
229	663,037
419	559
	<u>969,536</u>

Schedule Page: 232.1	Line No.: 13	Column: d
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400	979,071
229	1,411,942
419	11,037
	<u>2,402,037</u>

Schedule Page: 232.1	Line No.: 21	Column: d
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400	165,633
419	617
	<u>166,250</u>

Schedule Page: 232.1	Line No.: 24	Column: d
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400	186,740
489	73,742
	<u>260,482</u>

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		439,852		439,852	
2						
3	Conservation programs	-241,096	2,887,457		3,617,076	-970,715
4						
5	Advance to FutureSource Capital	1,129,108	112,049			1,241,157
6	Corp. for land					
7						
8	Goodwill - Great Plains Natural	4,812,244				4,812,244
9	Gas Co.					
10						
11	Subsidiary post-retirement	13,431,310	820,107		703,494	13,547,923
12	trust assets					
13						
14	Post-retirement Benefit Costs	6,985,925	3,502,134	131	85,063	10,402,996
15						
16						
17						
18						
19						
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43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	26,117,491				29,033,605

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 1 Column: d

181	\$ 419,738
428	20,114
	<u>\$ 439,852</u>

Schedule Page: 233 Line No.: 3 Column: d

142	\$3,610,040
143	6,388
419	648
	<u>\$3,617,076</u>

Schedule Page: 233 Line No.: 11 Column: d

186	\$ 104,047
253	599,447
	<u>\$ 703,494</u>

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	8,801,848	5,268,939
3	Compensation-related	7,390,427	2,930,019
4	Customer Advances	1,904,888	1,220,815
5	Postretirement Benefit Costs	1,458,716	1,152,213
6	Production Tax Credit Carryforward	16,943,932	19,366,967
7	Other	4,632,089	1,952,548
8	TOTAL Electric (Enter Total of lines 2 thru 7)	41,131,900	31,891,501
9	Gas		
10	Pension Expense	11,764,197	7,070,120
11	Customer Advances	6,947,238	4,541,677
12	Compensation-related	5,658,436	2,364,362
13	Postretirement Benefit Costs	1,989,828	1,544,792
14	Uniform Capitalization	410,603	232,000
15	Other	747,259	-433,585
16	TOTAL Gas (Enter Total of lines 10 thru 15)	27,517,561	15,319,366
17	Other (Specify) *	19,243,434	12,139,784
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	87,892,895	59,350,651

Notes

	Balance at Beginning of Year	Balance at End of Year
*Non-Utility		
C.I.A.C.'s	938,822	647,745
Charitable Contributions	329,615	197,393
ITC - State	648,020	286,850
SISP Expense	17,304,339	10,985,212
State Credit Carryforward	22,584	22,584
Bad Debts Expense	54	-
Total Non-Utility	19,243,434	12,139,784

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				
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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
195,843,297	195,843,297	538,921	3,625,813			2
195,843,297	195,843,297	538,921	3,625,813			3
						4
						5
						6
						7
						8
						9
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						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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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

See Note 8 in Notes To Financial Statements beginning on page 122.

Schedule Page: 250 Line No.: 7 Column: f

The Respondent retired all outstanding shares of 4.5% Series preferred stock April 1, 2017.

Schedule Page: 250 Line No.: 8 Column: f

The Respondent retired all outstanding shares of 4.7% Series preferred stock April 1, 2017.

Schedule Page: 250 Line No.: 10 Column: f

The Respondent retired all outstanding shares of preferred stock April 1, 2017.

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2017

Year/Period of Report

End of 2017/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	6,569,697
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	6,569,697

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	86,065
9	3.73%	40,000,000	173,631
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	
19	SUBTOTAL	640,500,000	3,362,033
20			
21	5.1% Preferred Stock, Cumulative, subject to redemption	5,000,000	
22	Commercial Paper - 1.273% average for 2017		641,077
23	Minot Air Force Base Note Payable	509,197	
24	SUBTOTAL	5,509,197	641,077
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	646,009,197	4,003,110

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	100,000,000	6,040,000	7
032117	032132	032117	032132	20,000,000	520,800	8
032117	032137	032117	032137	40,000,000	1,156,300	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	10,500,000	67,667	18
				640,500,000	30,358,667	19
						20
052361					3,934	21
				73,750,000	874,310	22
092308	113038			436,250	26,500	23
				74,186,250	904,744	24
						25
						26
						27
						28
						29
						30
						31
						32
				714,686,250	31,263,411	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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 21 Column: e

The Respondent retired all outstanding shares of 5.1% Series preferred stock April 1, 2017.

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)	281,202,988
2		
3		
4	Taxable Income Not Reported on Books	
5	Dividends Received from Subsidiary Companies	115,571,920
6	See Footnote	3,322,327
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	68,765,237
11	Unamortized Loss on Required Debt	571,714
12	Bad Debts	79,661
13	See Footnote	19,098,698
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	218,500,841
16	AFUDC Equity	400,908
17	See Footnote	2,029,348
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	132,320,091
21	Dividends Received From Subsidiaries	115,571,920
22	Supplemental Income Security Plan	13,915,945
23	Prepaid Demand Charges	26,906
24	Unrecovered Purchased Gas Cost	945,255
25	See Footnote	21,510,239
26		
27	Federal Tax Net Income	-16,608,908
28	Show Computation of Tax:	
29	Federal Tax @ 35% of line 30	-5,813,118
30	Other Credits and Adjustments	-21,832
31	Wind Production Credit	-11,500,000
32	Closing/Filing True-Up & Out of Period Adjustments	-2,587,007
33		
34		
35	TOTAL	-19,921,957
36		
37	Response to Instruction #2 - See Footnote	
38		
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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

Taxable Income Not Reported on Books:	
Cost Recovery Mechanisms	\$3,063,997
Customer Advances	236,498
Fuel Tax Credit	21,832
Total	<u>\$3,332,327</u>

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

Deductions Recorded on Books Not Deducted for Return:	
Federal Income Tax Provision	\$12,399,998
State Income Tax Provision	1,400,461
State Income Tax Deduction	922,950
Regulatory Commission Expense	306,804
Disallowed Meals and Entertainment Exp.-50%	221,121
Preferred Stock Expense	3,935
Vacation Accrual	369,760
Management Incentive	529,166
Pension Expense	1,357,598
Contingency Reserve	684,153
Lobbying Expenses	186,887
Abandoned Power Plant Cost Recovery	446,955
F&PP Deferral	247,940
Sundry Reserves	20,970
Total	<u>\$19,098,698</u>

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

Income Recorded on Books Not Included in Return:	
Reserved Revenues	\$1,343,280
MISO MVP Reserve	269,762
Contributions in Aid of Construction	105,564
Mor-Gran-Sou Capacity Revenue	81,806
WAPA Fiber Demand Revenue	49,315
Minnesota Decoupling	179,621
Total	<u>\$2,029,348</u>

Schedule Page: 261 Line No.: 25 Column: b

Deductions on Return Not Charged Against Book Income:	
Dividend Paid Deduction	\$ 90,001
401(k) Dividend Deduction	3,119,867
Bonus Accrual & 401k Profit Sharing	9,058,708
Performance Share Program	4,640,988
Post Retirement Benefits	1,355,380
Preferred Stock Redemption Amortization	600,000
Deferred Compensation - Directors	197,352
Board of Directors - Retirement Benefits	20,013
Deferred Medicare Part D	198,556
Retired Power Plant	60,853
Loss on Buildings	43,835
Prepaid Expenses	550,067
Capitalized Overheads	133,413
Montana Decommissioning	1,342,439
Montana PSC/MCC Tax Deferral	46,362
Manufactured Gas Plant	11,806
Miscellaneous	40,599
Total	<u>\$21,510,239</u>

Schedule Page: 261 Line No.: 37 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

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

and Profits). The 2017 federal tax provisions were:

Centennial Energy Holdings, Inc.	90,210,712
MDU Energy Capital	3,997,028
	\$94,207,740

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	-1,488,797		-19,921,958	-11,725,952	-13,262
3	State	4,498,113		-1,380,191	3,840,325	-293
4	SUBTOTAL	3,009,316		-21,302,149	-7,885,627	-13,555
5						
6	UNEMPLOYMENT					
7	Federal	31,908		57,032	55,843	
8	Arizona					
9	Idaho	16,485		75,007	77,360	
10	Minnesota	529		3,983	4,019	
11	Montana	2,043		14,382	10,109	
12	Texas			102		
13	North Dakota	20,042		129,019	125,958	
14	Oregon					
15	South Dakota	1,586		4,503	4,966	
16	Washington	1,157		4,514	4,797	
17	Wyoming	761		3,581	3,723	
18	SUBTOTAL	74,511		292,123	286,775	
19						
20	GROSS REVENUE					
21	Montana	133,812		592,353	635,826	
22	South Dakota			85,760	85,760	
23	Wyoming	45,610		106,483	98,852	
24	SUBTOTAL	179,422		784,596	820,438	
25						
26	USE					
27	Minnesota	310		25,253	24,239	
28	North Dakota	34,901		365,219	421,515	
29	South Dakota	2,425		125,677	69,091	
30	Washington	918		3,374	918	
31	Wyoming	4,330		14,422	17,880	
32	Idaho	1,739		20,047	24,471	
33	Iowa					
34	Nebraska					
35	SUBTOTAL	44,623		553,992	558,114	
36						
37	PROPERTY					
38	Minnesota (GPNG)	689,000		786,953	702,953	
39	Montana	4,746,004		10,068,872	9,781,660	
40	North Dakota	3,493,152		4,124,663	3,493,388	
41	TOTAL	14,992,270		6,696,170	18,378,819	-13,555

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)	
						1
-9,698,065		-16,053,336			-3,868,622	2
-722,696		-521,763			-858,428	3
-10,420,761		-16,575,099			-4,727,050	4
						5
						6
33,097		14,996			42,036	7
						8
14,132		9,281			65,726	9
493		48			3,935	10
6,316		5,622			8,760	11
102		11			91	12
23,103		43,870			85,149	13
						14
1,123		837			3,666	15
874		139			4,375	16
619		1,213			2,368	17
79,859		76,017			216,106	18
						19
						20
90,339		318,373			273,980	21
		22,945			62,815	22
53,241		70,461			36,022	23
143,580		411,779			372,817	24
						25
						26
1,324					25,253	27
-21,395					365,219	28
59,011					125,677	29
3,374					3,374	30
872					14,422	31
-2,685					20,047	32
						33
						34
40,501					553,992	35
						36
						37
773,000					786,953	38
5,033,216		5,535,094			4,533,778	39
4,124,427		2,737,781			1,386,882	40
3,296,066		-2,394,487			9,090,657	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)	32,397		36,236	32,397	
2	South Dakota	1,013,874		1,180,143	1,008,000	
3	Wyoming	130,889		266,568	264,173	
4	SUBTOTAL	10,105,316		16,463,435	15,282,571	
5						
6						
7	FRANCHISE					
8	Delaware	36,050		250,100	180,050	
9	Wyoming	123,302		294,089	272,224	
10	Hettinger, ND	1,160		9,444	8,919	
11						
12	SUBTOTAL	160,512		553,633	461,193	
13						
14						
15						
16	MISCELLANEOUS					
17	Federal-FICA	1,041,584		7,731,265	7,437,430	
18	Federal-Highway Use			7,162	7,162	
19	Montana WET Tax	28,381		120,987	120,815	
20	Montana-Electric License	20,158		66,247	76,518	
21	ND-Coal Conversion-Heskett	36,593		407,415	409,334	
22	ND-Generation Tax	274,337		487,222	274,337	
23	ND-Coal Conversion-Coyote			517,117	517,117	
24	Secretaries of State					
25	(annual filing fees)			2,635	2,635	
26	Fort Peck Tribal	12,000		-1,171	4,829	
27	Crow Agency Tribal	5,178		12,000	5,178	
28	Federal CNG Tax	6		-6		
29	Montana CNG Tax	437		-437		
30	North Dakota CNG Tax	-104		104		
31	South Dakota CNG Tax					
32	SUBTOTAL	1,418,570		9,350,540	8,855,355	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	14,992,270		6,696,170	18,378,819	-13,555

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 (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)	
36,236					36,236	1
1,186,017		655,688			524,455	2
133,284		201,817			64,751	3
11,286,180		9,130,380			7,333,055	4
						5
						6
						7
106,100		150,310			99,790	8
145,167		184,632			109,457	9
1,685					9,444	10
						11
252,952		334,942			218,691	12
						13
						14
						15
						16
1,335,419		2,622,645			5,108,620	17
		5,448			1,714	18
28,553		120,987				19
9,887		66,247				20
34,674		407,415				21
487,222		487,222				22
		517,117				23
						24
		1,584			1,051	25
6,000		-1,171				26
12,000					12,000	27
					-6	28
					-437	29
					104	30
						31
1,913,755		4,227,494			5,123,046	32
						33
						34
						35
						36
						37
						38
						39
						40
3,296,066		-2,394,487			9,090,657	41

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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

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		1,640,385	420	295,219	420	104,628	
8	TOTAL	1,640,385		295,219		104,628	
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
1,830,976	25 YEARS		7
1,830,976			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	63,645,493		6,917,702	1,448,925	58,176,716
2						
3	Accrued and deferred benefit					
4	compensation plans	8,253,490		1,403,581	1,732,980	8,582,889
5						
6	Intercompany portion of					
7	Supplemental Income					
8	Security Program trust assets	16,752,105			1,761,053	18,513,158
9						
10	Gas affordability tracker	4,771	131	7,596	10,353	7,528
11						
12	Capacity rights contracts	2,152,906	454	131,121		2,021,785
13						
14						
15						
16	MISO MVP Reserve	684,311		269,761		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	91,493,076		8,729,761	4,953,311	87,716,626

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

131	\$ 422,015
182	5,869,474
184	26,766
186	599,447
	<u>\$6,917,702</u>

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

131	\$ 193,440
184	249,687
216	32,673
242	927,781
	<u>\$1,403,581</u>

Schedule Page: 269 Line No.: 16 Column: c

456	\$ 162,465
232	107,296
	<u>\$ 269,761</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 rating 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	499,023	548,605	33,548
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	499,023	548,605	33,548
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)	499,023	548,605	33,548
18	Classification of TOTAL			
19	Federal Income Tax	460,837	486,159	10,515
20	State Income Tax	38,186	62,446	23,033
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)

12/31/2017

Year/Period of Report

End of 2017/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	505,640	254	27,626	536,066	4
							5
							6
							7
			505,640		27,626	536,066	8
							9
							10
							11
							12
							13
							14
							15
							16
			505,640		27,626	536,066	17
							18
			478,636		3,660	461,505	19
			27,004		23,966	74,561	20
							21

NOTES (Continued)

ACCUMULATED DEFFERED 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	234,752,746	33,857,759	10,473,169
3	Gas	54,622,480	6,688,672	3,039,139
4	Utility	3,627,643		
5	TOTAL (Enter Total of lines 2 thru 4)	293,002,869	40,546,431	13,512,308
6	Non-Utility	4,346,426		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	297,349,295	40,546,431	13,512,308
10	Classification of TOTAL			
11	Federal Income Tax	274,186,158	35,525,141	10,729,377
12	State Income Tax	23,163,137	5,021,290	2,782,931
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	1,494,274	282	1,887,028	258,530,090	2
		282	1,243,813	282	851,059	57,879,259	3
			173,283,736		23,905,254	-145,750,839	4
			176,021,823		26,643,341	170,658,510	5
301,912	2,060,964					2,587,374	6
							7
							8
301,912	2,060,964		176,021,823		26,643,341	173,245,884	9
							10
132,366	1,944,156		165,313,570		17,062,761	148,919,323	11
169,546	116,808		10,708,253		9,580,580	24,326,561	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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

Utility definition includes Regulatory Matters.

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

Regulatory Matters - 254	\$ (6,301,635)
Regulatory Matters - 182.3	9,929,278
	<u>\$ 3,627,643</u>

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

Regulatory Matters - 254	\$ 165,931,169
Regulatory Matters - 182.3	7,352,567
	<u>\$ 173,283,736</u>

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

Regulatory Matters - 254	\$ 20,241,931
Regulatory Matters - 182.3	3,663,323
	<u>\$ 23,905,254</u>

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

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

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	86,779	178,230	265,009
4	Def. Pension Exp - Reg Asset	16,498,237	29,478,600	35,740,767
5	Unamort Loss on Required Debt	1,596,843	2,589,736	3,265,702
6	Reg Assets Awaiting Recovery			
7	Unrecovered Plant Costs	1,292,475	2,028,940	2,590,089
8	Other - Electric	7,339,947	15,943,115	16,730,184
9	TOTAL Electric (Total of lines 3 thru 8)	26,814,281	50,218,621	58,591,751
10	Gas			
11	Unrecovered Purch. Gas Costs	749,169	4,340,483	4,300,343
12	Regulatory Commission Expense	336,139	662,851	793,461
13	Unamort Loss on Required Debt	415,777	649,253	833,080
14	Def. Pension Exp - Reg Asset	22,048,938	36,551,037	45,519,257
15	Reg Assets Awaiting Recovery	12	1	13
16	Other - Gas	3,804,948	18,205,961	14,220,917
17	TOTAL Gas (Total of lines 11 thru 16)	27,354,983	60,409,586	65,667,071
18	Other	6,000,963		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	60,170,227	110,628,207	124,258,822
20	Classification of TOTAL			
21	Federal Income Tax	55,307,881	92,125,716	106,545,461
22	State Income Tax	4,862,346	18,502,491	17,713,361
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)		
							1
							2
							3
						10,236,070	4
						920,877	5
							6
						731,326	7
		283	1,043,335	283	1,043,335	6,552,878	8
			1,043,335		1,043,335	18,441,151	9
							10
						789,309	11
						205,529	12
						231,950	13
						13,080,718	14
							15
			1,808,696		423,367	6,404,663	16
			1,808,696		423,367	20,712,169	17
22,600	33,241		45,656,045		33,928,554	-5,737,169	18
22,600	33,241		48,508,076		35,395,256	33,416,151	19
							20
18,637	31,817		40,994,745		28,811,065	28,691,276	21
3,963	1,424		7,513,331		6,584,191	4,724,875	22
							23

NOTES (Continued)

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) 12/31/2017	2017/Q4
FOOTNOTE DATA			

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

UTILITY: Other - Electric	
Contingency Reserve	\$ 2,637
Regulatory Commission Expense	340,503
MT PSC/MCC Tax Deferral	147,755
ND Environmental Cost Recovery Rider	1,200,984
Postretirement Benefit Costs	1,042,064
Property Insurance	156,619
Transmission Cost Adj	1,864,007
Loss on Buildings	772,659
ND Generation Resource Recovery Rider	930,139
ND Renewable Resource Recovery Rider	546,694
Prepaid Expenses	243,903
SD Infrastructure Rider	64,670
SD Transmission Cost Recovery Rider	27,313
	\$ 7,339,947

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

UTILITY: Other - Electric	
Contingency Reserve	\$ 4,688
Excess Deferred Income Taxes	2,631,844
Loss on Buildings	1,398,648
MT Ad Valorem Tax Tracker	405,153
MT PSC/MCC Tax Deferral	278,834
ND Environmental Cost Recovery Rider	1,697,997
ND Generation Resource Recovery Rider	1,157,883
ND Renewable Resource Recovery Rider	21,816
ND Transmission Tracker	3,104,732
Postretirement Benefit Costs	3,429,016
Preferred Stock Redemption Amort	517,735
Prepaid Expense	657,097
Property Insurance Recovery	24,094
Regulatory Commission Expense	498,909
SD Infrastructure Rider	53,604
SD Transmission Cost Recovery Rider	60,965
	\$ 7,339,947

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

UTILITY: Other - Electric	
Contingency Reserve	\$ 5,647
Excess Deferred Income Taxes	1,673,811
MT Ad Valorem Tax Tracker	310,679
MT PSC/MCC Tax Deferral	335,257
ND Environmental Cost Recovery Rider	2,292,335
ND Generation Resource Recovery Rider	1,712,443
ND Renewable Resource Recovery Rider	568,510
ND Transmission Tracker	4,127,390
Postretirement Benefit Costs	3,445,759
Preferred Stock Redemption Amort	399,927
Prepaid Expense	820,360
Property Insurance Recovery	176,654
Regulatory Commission Expense	681,609
SD Infrastructure Rider	104,448
SD Transmission Cost Recovery Rider	75,355
	\$16,730,184

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

UTILITY: Other - Electric	
Contingency Reserve	\$ 1,678

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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.: 16 Column: b

UTILITY: Other - Gas	
Contingency Reserve	\$ 162,953
MT PSC/MCC Tax Deferral	(245)
Postretirement Benefit Costs	1,392,665
Prepaid Demand	1,341,882
Property Insurance	49,694
Def Pension Exp - ND Gas - Reg Asset	57,513
Manufactured Gas Plant Site - Billings	150,202
Loss on Buildings	297,065
Manufactured Gas Plant Site - Bismarck	34,306
MN Revenue Decoupling	151,512
Prepaid Expenses	167,401
	\$ 3,804,948

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

UTILITY: Other - Gas	
Contingency Reserve	\$ 288,959
Def Pension Exp - ND Gas - Reg Asset	172,485
Def Postretirement Exp - ND Gas - Reg Asset	121,858
Excess Deferred Income Taxes	3,115,811
Loss on Buildings	548,773
Manufactured Gas Plant Site - Billings	388,776
Manufactured Gas Plant Site - Bismarck	1,369
MN Revenue Decoupling	529,861
MN Infrastructure Rider	478,947
MT Ad Valorem Tax Tracker	966,370
MT PSC/MCC Tax Deferral	91,490
Postretirement Benefit Costs	4,491,289
Preferred Stock Redemption Amort	125,103
Prepaid Demand	6,434,885
Prepaid Expenses	442,395
Property Insurance Recovery	7,590
	\$18,205,961

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

UTILITY: Other - Gas	
Contingency Reserve	\$ 354,140
Def Pension Exp - ND Gas - Reg Asset	177,111
Def Postretirement Exp - ND Gas - Reg Asset	121,858
Loss on Buildings	650,565
Manufactured Gas Plant Site - Billings	411,555
Manufactured Gas Plant Site - Bismarck	35,675
MN Revenue Decoupling	524,483

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			

FOOTNOTE DATA

MN Infrastructure Rider	364,324
MT Ad Valorem Tax Tracker	741,032
MT PSC/MCC Tax Deferral	71,688
Postretirement Benefit Costs	4,534,435
Preferred Stock Redemption Amort	96,610
Prepaid Demand	5,525,174
Prepaid Expenses	556,259
Property Insurance Recovery	56,008
	<u>\$14,220,917</u>

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

283	\$ 374,263
190	1,434,433
	<u>\$ 1,808,696</u>

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

283	\$ 374,263
190	49,104
	<u>\$ 423,367</u>

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

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
	<u>\$ 6,404,663</u>

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 5,565,796
Regulatory Matters - 182.3 - Gas	494,162
Regulatory Matters - 254 - Electric	(10,574)
Regulatory Matters - 254 - Gas	(112,668)
Total Utility Other	<u>\$ 5,936,716</u>

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 64,247
Total Non-Utility	<u>\$ 64,247</u>

TOTAL OTHER \$ 6,000,963

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

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 22,600

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

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 33,241

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

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

UTILITY: Other

Regulatory Matters - 182.3 - Electric	\$ 6,931,177
Regulatory Matters - 182.3 - Gas	887,192
Regulatory Matters - 254 - Electric	17,060,871
Regulatory Matters - 254 - Gas	<u>20,776,805</u>
Total Utility Other	\$45,656,045

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

UTILITY: Other

Regulatory Matters - 182.3 - Electric	\$ 3,222,462
Regulatory Matters - 182.3 - Gas	549,139
Regulatory Matters - 254 - Electric	13,571,920
Regulatory Matters - 254 - Gas	<u>16,585,033</u>
Total Utility Other	\$33,928,554

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

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	<u>(4,304,440)</u>
Total Utility Other	\$(5,790,775)

NON UTILITY: Other

Partnership Ordinary Gain/(Loss)	\$ 53,606
Total Non-Utility	<u>\$ 53,606</u>

TOTAL OTHER \$(5,737,169)

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	6,176,596		85,247,603	234,399,642	155,328,635
2						
3	Retired Power Plant - amortizations over	303,151	405	60,853		242,298
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	8,992,740	496		1,767,134	10,759,874
10						
11	Grain Drying Margin Sharing - North Dakota	91,607	496	125,629	187,568	153,546
12	Gas [Case No. PU-13-803]					
13						
14	Grain Drying Margin Sharing - South Dakota	79,842	496	101,617	105,741	83,966
15	Gas [Docket No. NG-12-008]					
16						
17	Gain on Building Sale - North Dakota	872,362	405	17,471		854,891
18	Electric [Case No. PU-16-666]					
19						
20	Gain on Building Sale; North Dakota -Gas	307,861	405	17,565		290,296
21	Amortization over 240 months ending 6/34					
22	[Case No. PU-13-803]					
23						
24	Deferred Post-Retirement Expense;	106,238			190,509	296,747
25	North Dakota - Gas [Case No. PU-15-90]					
26						
27	Decommissioning cost amortization - Montana	5,965,841	407	1,342,439		4,623,402
28	over 60 months beginning 4/16					
29	[Docket No. D2015.6.51]					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	22,896,238		86,913,177	236,650,594	172,633,655

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 1 Column: c

190	\$ 36,208,869
282	20,269,556
283	28,769,178
	<u>\$ 85,247,603</u>

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	121,171,353	117,014,058
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	140,855,736	135,389,644
5	Large (or Ind.) (See Instr. 4)	34,416,931	31,913,313
6	(444) Public Street and Highway Lighting	2,750,525	2,749,398
7	(445) Other Sales to Public Authorities	4,897,425	4,209,854
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	627,567	620,578
10	TOTAL Sales to Ultimate Consumers	304,719,537	291,896,845
11	(447) Sales for Resale	839,721	1,026,988
12	TOTAL Sales of Electricity	305,559,258	292,923,833
13	(Less) (449.1) Provision for Rate Refunds	2,833,912	1,619,235
14	TOTAL Revenues Net of Prov. for Refunds	302,725,346	291,304,598
15	Other Operating Revenues		
16	(450) Forfeited Discounts	387,461	668,846
17	(451) Miscellaneous Service Revenues	165,165	152,566
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,383,756	4,138,819
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,416,677	19,344,847
22	(456.1) Revenues from Transmission of Electricity of Others	31,605,949	5,552,694
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	38,959,008	29,857,772
27	TOTAL Electric Operating Revenues	341,684,354	321,162,370

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
1,153,484	1,132,571	118,379	118,483	2
				3
1,513,068	1,491,763	22,764	22,693	4
539,877	544,207	242	244	5
30,838	31,143	570	565	6
63,087	52,840	748	762	7
				8
6,116	6,013	198	201	9
3,306,470	3,258,537	142,901	142,948	10
39,971	45,018			11
3,346,441	3,303,555	142,901	142,948	12
				13
3,346,441	3,303,555	142,901	142,948	14

Line 12, column (b) includes \$ 2,829,430 of unbilled revenues.
 Line 12, column (d) includes 18,956 MWH relating to unbilled revenues

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) 12/31/2017	Year/Period of Report 2017/Q4
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	185,452	17,272,561	20,077	9,237	0.0931
4	20-Small General Electric Service	2,546	230,239	256	9,945	0.0904
5	52-Outdoor Lighting Service	745	93,836	897	831	0.1260
6	North Dakota					
7	10-Residential Electric Service	739,805	79,382,866	78,274	9,451	0.1073
8	13-Optional Residential Thermal E	133	10,040	4	33,250	0.0755
9	16-Optional Time-of-Day Service	112	10,677	8	14,000	0.0953
10	20-Small General Electric Service	4,734	638,182	669	7,076	0.1348
11	25-Irrigation Power Service	1	417	1	1,000	0.4170
12	30-General Electric Service	6,460	672,220	86	75,116	0.1041
13	32-General Electric Space Heating	2,045	163,786	25	81,800	0.0801
14	52-Outdoor Lighting Service	1,110	119,619	1,169	950	0.1078
15	South Dakota					
16	10-Residential Electric Service	60,901	6,873,911	6,533	9,322	0.1129
17	20-Small General Electric Service	484	50,857	35	13,829	0.1051
18	24-Outdoor Lighting Service	189	17,697	261	724	0.0936
19	53-Special Residential Dual Fuel	5,491	367,121	344	15,962	0.0669
20	Wyoming					
21	10-Residential Electric Service	127,869	14,542,496	13,231	9,664	0.1137
22	11-Special Residential Controlled	8,871	512,647	708	12,530	0.0578
23	20-Small General Electric Service	968	123,219	168	5,762	0.1273
24	24-Outdoor Lighting Service	468	28,071	612	765	0.0600
25	Unbilled-Net	5,100	60,891			0.0119
26	Adjustment for Duplicate Customer			-4,979		
27	Subtotal Residential	1,153,484	121,171,353	118,379	9,744	0.1050
28	Small Commercial-442					
29	Montana					
30	20-Small General Electric Service	105,076	9,291,971	5,320	19,751	0.0884
31	25-Irrigation Power Service	7,409	491,782	142	52,176	0.0664
32	30-General Electric Service					
33	32-General Electric Space Heating	1,752	111,296	15	116,800	0.0635
34	52-Outdoor Lighting Service	1,879	238,694	807	2,328	0.1270
35	North Dakota					
36	20-Small General Electric Service	87,560	10,654,867	9,029	9,698	0.1217
37	25-Irrigation Power Service	1,324	97,638	37	35,784	0.0737
38	26-Optional Time-of-Day Small Gen	1,350	190,651	247	5,466	0.1412
39	30-General Electric Service	417,950	42,269,677	2,917	143,281	0.1011
40	32-General Electric Space Heating	41,350	3,368,824	482	85,788	0.0815
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.
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	40-Small Municipal Electric Servi	1	441	1	1,000	0.4410
2	52-Outdoor Lighting Service	4,830	520,988	1,237	3,905	0.1079
3	South Dakota					
4	20-Small General Electric Service	30,585	3,329,670	1,924	15,897	0.1089
5	24-Outdoor Lighting Service	450	42,049	260	1,731	0.0934
6	25-Irrigation Power Service	258	17,756	7	36,857	0.0688
7	26-Optional Time-of-Day General E	132	15,900	24	5,500	0.1205
8	32-General Electric Space Heating	5,714	362,155	148	38,608	0.0634
9	Wyoming					
10	20-Small General Electric Service	49,138	4,764,595	2,448	20,073	0.0970
11	22-Special General Controlled Ele	233	13,307	18	12,944	0.0571
12	24-Outdoor Lighting Service	981	58,669	315	3,114	0.0598
13	25-Irrigation Power Service	2,997	320,362	76	39,434	0.1069
14	26-Irrigation Power Service Optio	75	12,725	7	10,714	0.1697
15	Unbilled-Net	4,070	-330,888			-0.0813
16	Adjustment for Duplicate Customer			-4,257		
17	Subtotal Small Commercial	765,114	75,843,129	21,204	36,083	0.0991
18						
19	Large Commercial-442					
20	Montana					
21	25-Irrigation Power Service	1,067	69,037	11	97,000	0.0647
22	30-Large General Electric Service	155,719	12,272,771	272	572,496	0.0788
23	31-Optional Time-of-Day Large Gen	464	60,668	1	464,000	0.1308
24	52-Outdoor Lighting Service	462	58,700	80	5,775	0.1271
25	North Dakota					
26	20-Small General Electric Service	223	22,889	12	18,583	0.1026
27	25-Irrigation Power Service	68	5,152	2	34,000	0.0758
28	30-General Electric Service	395,263	37,286,683	1,193	331,319	0.0943
29	31-Optional Time-of-Day General S	28,511	2,433,399	60	475,183	0.0853
30	32-General Electric Space Heating	11,885	935,385	46	258,370	0.0787
31	34-Firm Service Economic Developm	610	54,697	1	610,000	0.0897
32	38-Interruptible Large Power Dema	34,064	2,459,418	3	11,354,667	0.0722
33	52-Outdoor Lighting Service	391	42,146	108	3,620	0.1078
34	South Dakota					
35	24-Outdoor Lighting Service	137	12,813	30	4,567	0.0935
36	30-Large General Electric Service	27,717	2,529,685	108	256,639	0.0913
37	Wyoming					
38	24-Outdoor Lighting Service	59	3,533	16	3,688	0.0599
39	26-Optional Time-of-Day Irrigatio	3	344			0.1147
40	39-Large General Electric Service	85,371	6,373,705	147	580,755	0.0747
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.
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	Unbilled-Net	5,940	391,582			0.0659
2	Adjustment for Duplicate Customer			-530		
3	Subtotal Large Commercial	747,954	65,012,607	1,560	479,458	0.0869
4						
5	Small Industrial-442					
6	Montana					
7	20-Small General Electric Service	4,641	398,934	81	57,296	0.0860
8	31-Optional Time-of-Day Large Gen	10,119	739,777	4	2,529,750	0.0731
9	35-Contract Service	2,716	151,974			0.0560
10	52-Outdoor Lighting Service	3	354	3	1,000	0.1180
11	North Dakota					
12	20-Small General Electric Service	290	31,822	20	14,500	0.1097
13	30-General Electric Service	29,802	2,336,835	39	764,154	0.0784
14	32-General Electric Space Heating	685	53,197	4	171,250	0.0777
15	52-Outdoor Lighting Service	32	3,468	9	3,556	0.1084
16	South Dakota					
17	20-Small General Electric Service	37	4,180	4	9,250	0.1130
18	24-Outdoor Lighting Service	10	942	3	3,333	0.0942
19	Wyoming					
20	20-Small General Electric Service	309	30,570	11	28,091	0.0989
21	24-Outdoor Lighting Service	2	100	2	1,000	0.0500
22	Unbilled-Net	242	-32,500			-0.1343
23	Adjustment for Duplicate Customer			-30		
24	Subtotal Small Industrial	48,888	3,719,653	150	325,920	0.0761
25						
26	Large Industrial-442					
27	Montana					
28	30-Large General Electric Service	88,291	5,958,140	26	3,395,808	0.0675
29	31-Optional Time-of-Day Large Gen	3,086	235,278	4	771,500	0.0762
30	35-Contract Service	220,046	11,847,361	12	18,337,167	0.0538
31	52-Outdoor Lighting Service	1	187	3	333	0.1870
32	North Dakota					
33	30-General Electric Service	159,432	11,057,947	45	3,542,933	0.0694
34	31-Optional Time-of-Day General E	4,319	421,626	14	308,500	0.0976
35	32-General Electric Space Heating	46	4,343	1	46,000	0.0944
36	38-Interruptible Large Power Dema	3,897	198,238	1	3,897,000	0.0509
37	52-Outdoor Lighting Service	9	952	3	3,000	0.1058
38	South Dakota					
39	24-Outdoor Lighting Service	12	1,080	2	6,000	0.0900
40	30-Large General Electric Service	7,681	604,652	6	1,280,167	0.0787
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.
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	Wyoming					
2	39-Large General Electric Service	1,560	169,788	5	312,000	0.1088
3	Unbilled-Net	2,609	197,686			0.0758
4	Adjustment for Duplicate Customer			-30		
5	Subtotal Large Industrial	490,989	30,697,278	92	5,336,837	0.0625
6						
7	Public Street and Highway - 444					
8	Montana					
9	20-Small General Electric Service	110	10,006	5	22,000	0.0910
10	41-Municipal Lighting Service	6,798	582,441	98	69,367	0.0857
11	52-Outdoor Lighting Service	127	16,099	15	8,467	0.1268
12	North Dakota					
13	20-Small General Electric Service	219	36,787	52	4,212	0.1680
14	40-Small Municipal Electric Servi	27	2,284	1	27,000	0.0846
15	41-Municipal Lighting Service	19,516	1,724,112	607	32,152	0.0883
16	52-Outdoor Lighting Service	280	30,049	37	7,568	0.1073
17	South Dakota					
18	24-Outdoor Lighting Service	9	875	6	1,500	0.0972
19	41-Street Lighting Service	2,478	248,587	54	45,889	0.1003
20	Wyoming					
21	20-Small General Electric Service	10	2,198	5	2,000	0.2198
22	24-Outdoor Lighting Service	6	383	2	3,000	0.0638
23	41-Municipal Lighting Service	1,076	97,784	4	269,000	0.0909
24	Unbilled-Net	182	-1,080			-0.0059
25	Adjustment for Duplicate Customer			-316		
26	Subtotal Public Street and Highwa	30,838	2,750,525	570	54,102	0.0892
27						
28	Other Sales to Public Authorities					
29	Montana					
30	48-Municipal Pumping Service	6,890	507,988	109	63,211	0.0737
31	North Dakota					
32	20-Small General Electric Service	365	52,663	56	6,518	0.1443
33	30-General Electric Service	1,679	173,517	10	167,900	0.1033
34	32-General Electric Space Heating	255	19,186	6	42,500	0.0752
35	40-Small Municipal Electric Servi	3,657	372,508	285	12,832	0.1019
36	48-Municipal Pumping Service	48,002	3,675,457	329	145,903	0.0766
37	South Dakota					
38	48-Municipal Pumping Service	1,483	125,041	50	29,660	0.0843
39	Unbilled-Net	756	-28,935			-0.0383
40	Adjustment for Duplicate Customer			-97		
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.
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	Subtotal Other Sales	63,087	4,897,425	748	84,341	0.0776
2						
3	Interdepartmental-448					
4	Montana					
5	Billed	519	57,588	94	5,521	0.1110
6	North Dakota					
7	Billed	5,063	516,376	149	33,980	0.1020
8	South Dakota					
9	Billed	269	32,763	10	26,900	0.1218
10	Wyoming					
11	Billed	207	27,306	31	6,677	0.1319
12	Unbilled-Net	58	-6,466			-0.1115
13	Adjustment for Duplicate Customer			-86		
14	Subtotal Interdepartmental Sales	6,116	627,567	198	30,889	0.1026
15						
16	Total	3,306,470	304,719,537	142,901	23,138	0.0922
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) 12/31/2017	2017/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	4,435,994
20-Small General Electric Service	61,293
52-Outdoor Lighting Service	17,832

North Dakota

10-Residential Electric Service	16,949,433
13-Optional Residential Thermal Energy Storage	3,107
16-Optional Time-of-Day Residential Electric Service	2,607
20-Small General Electric Service	109,144
25-Irrigation Power Service	14
30-General Electric Service	149,200
32-General Electric Space Heating Service	48,163
52-Outdoor Lighting Service	25,328

South Dakota

10-Residential Electric Service	1,353,158
20-Small General Electric Service	10,768
24-Outdoor Lighting Service	4,198
53-Special Residential Electric Dual Fuel Space Heating Service	124,001

Wyoming

10-Residential Electric Service	3,488,155
11-Special Residential Controlled Electric Service	202,201
20-Small General Electric Service	24,382
24-Outdoor Lighting Service	13,578
Unbilled-net	405,757
Subtotal Residential	27,428,313

Small Commercial-442

Montana

20-Small General Electric Service	2,515,249
25-Irrigation Power Service	168,840
32-General Electric Space Heating Service	42,849
52-Outdoor Lighting Service	44,955

North Dakota

20-Small General Electric Service	2,009,325
25-Irrigation Power Service	28,439
26-Optional Time-of-Day Small General Electric Service	30,775
30-General Electric Service	9,499,276
32-General Electric Space Heating Service	963,689
40-Small Municipal Electric Service	26
52-Outdoor Lighting Service	110,845

South Dakota

20-Small General Electric Service	678,474
24-Outdoor Lighting Service	9,955
25-Irrigation Power Service	5,426
26-Optional Time-of-Day Small General Electric Service	2,914
32-General Electric Space Heating Service	129,815

Wyoming

20-Small General Electric Service	1,384,045
22-Special General Controlled Electric Service	4,557
24-Outdoor Lighting Service	28,126

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.		12/31/2017	2017/Q4
FOOTNOTE DATA			

25-Irrigation Power Service	106,582
26-Irrigation Power Service Optional Time-of-Day	2,666
Unbilled-net	181,879
Subtotal Small Commercial	17,948,707

Large Commercial-442

Montana

25-Irrigation Power Service	24,269
30-Large General Electric Service	3,704,476
31-Optional Time-of-Day Large General Electric Service	11,322
52-Outdoor Lighting Service	11,048

North Dakota

20-Small General Electric Service	5,121
25-Irrigation Power Service	1,451
30-General Electric Service	8,952,343
31-Optional Time-of-Day General Electric Service	645,969
32-General Electric Space Heating Service	276,155
38-Interruptible Large Power Demand Response	746,741
52-Outdoor Lighting Service	8,923
34-Firm Service Economic Development Rate	13,628

South Dakota

24-Outdoor Lighting Service	3,041
30-Large General Electric Service	617,215

Wyoming

24-Outdoor Lighting Service	1,733
26-Optional Time-of-Day Irrigation Service	95
39-Large General Electric Service	2,384,117
Unbilled-net	297,451
Subtotal Large Commercial	17,705,098

Small Industrial-442

Montana

20-Small General Electric Service	111,370
31-Optional Time-of-Day Large General Electric Service	239,164
35-Contract Service Rate	60,055
52-Outdoor Lighting Service	67

North Dakota

20-Small General Electric Service	6,681
30-General Electric Service	657,793
32-General Electric Space Heating Service	15,893
52-Outdoor Lighting Service	734

South Dakota

20-Small General Electric Service	832
24-Outdoor Lighting Service	224

Wyoming

20-Small General Electric Service	8,628
24-Outdoor Lighting Service	50
Unbilled-net	5,369
Subtotal Small Industrial	1,106,860

Large Industrial-442

Montana

30-General Electric Service	2,105,363
31-Optional Time-of-Day Large General Electric Service	69,950

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.		12/31/2017	2017/Q4
FOOTNOTE DATA			

35-Contract Service	4,786,222
52-Outdoor Lighting Service	35
North Dakota	
30-General Electric Service	3,527,336
31-Optional Time-of-Day General Electric Service	98,119
32-General Electric Space Heating Service	1,071
38-Interruptible Large Power Demand Response	86,034
52-Outdoor Lighting Service	202
South Dakota	
24-Outdoor Lighting Service	256
30-Large General Electric Service	170,295
Wyoming	
39-Large General Service	45,887
Unbilled-net	62,705
Subtotal Large Industrial	10,953,475
Public Street and Highway Lighting-444	
Montana	
20-Small General Service	2,634
41-Municipal Lighting Service	162,662
52-Outdoor Lighting Service	3,096
North Dakota	
20-Small General Service	4,984
40-Small Municipal Electric Service	624
41-Municipal Lighting Service	446,501
52-Outdoor Lighting Service	6,479
South Dakota	
24-Outdoor Lighting Service	208
41-Street Lighting Service	55,056
Wyoming	
20-Small General Electric Service	274
24-Outdoor Lighting Service	180
41-Municipal Lighting Service	31,227
Unbilled-net	6,074
Subtotal Public Street and Highway Lighting	719,999
Other Sales to Public Authorities-446	
Montana	
48-Municipal Pumping Service	162,878
North Dakota	
20-Small General Electric Service	8,356
30-General Electric Service	38,424
32-General Electric Space Heating Service	6,051
40-Small Municipal Electric Service	83,779
48-Municipal Pumping Service	1,069,180
South Dakota	
48-Municipal Pumping Service	32,932
Unbilled-net	16,551
Subtotal Other Sales	1,418,151
Interdepartmental Sales-448	
Montana	12,435
North Dakota	115,446
South Dakota	6,058

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Wyoming	5,260
Unbilled-Net	1,606
Subtotal Interdepartmental	140,805
Total Fuel Clause Adjustment	77,421,408

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
39,971		839,721		839,721	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
39,971	0	839,721	0	839,721	
39,971	0	839,721	0	839,721	

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) 12/31/2017	Year/Period of Report 2017/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	2,600,569	2,618,096
5	(501) Fuel	50,398,536	46,240,749
6	(502) Steam Expenses	7,277,004	6,947,055
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,986,679	1,951,390
10	(506) Miscellaneous Steam Power Expenses	3,774,691	4,126,322
11	(507) Rents	784,469	713,336
12	(509) Allowances	83	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	66,822,031	62,596,948
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,468,840	1,142,004
16	(511) Maintenance of Structures	823,893	750,942
17	(512) Maintenance of Boiler Plant	6,749,753	7,285,766
18	(513) Maintenance of Electric Plant	1,805,872	1,528,588
19	(514) Maintenance of Miscellaneous Steam Plant	1,864,900	1,909,230
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,713,258	12,616,530
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	79,535,289	75,213,478
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	298,564	220,454
63	(547) Fuel	3,702,906	3,996,875
64	(548) Generation Expenses	2,385,188	2,038,164
65	(549) Miscellaneous Other Power Generation Expenses	579,104	403,682
66	(550) Rents	595,708	604,408
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,561,470	7,263,583
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	103,014	74,571
70	(552) Maintenance of Structures	26,209	6,396
71	(553) Maintenance of Generating and Electric Plant	1,388,180	685,251
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	92,806	8,788
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,610,209	775,006
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	9,171,679	8,038,589
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	24,622,906	25,274,022
77	(556) System Control and Load Dispatching	2,029,849	2,034,033
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	26,652,755	27,308,055
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	115,359,723	110,560,122
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,597,743	3,935,353
84			
85	(561.1) Load Dispatch-Reliability	464,518	482,245
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	997,082	966,483
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	575,086	525,385
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	41,893	38,272
93	(562) Station Expenses	610,716	695,575
94	(563) Overhead Lines Expenses	279,892	315,799
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	26,478,895	25,069,506
97	(566) Miscellaneous Transmission Expenses	62,167	43,107
98	(567) Rents	766,185	94,729
99	TOTAL Operation (Enter Total of lines 83 thru 98)	33,874,177	32,166,454
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	79,437	31,596
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	1,010,386	826,487
108	(571) Maintenance of Overhead Lines	1,895,638	992,769
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,985,461	1,850,852
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	36,859,638	34,017,306

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	463,367	433,705
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	463,367	433,705
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)	463,367	433,705
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,714,944	1,467,425
135	(581) Load Dispatching		
136	(582) Station Expenses	874,586	615,486
137	(583) Overhead Line Expenses	441,286	668,727
138	(584) Underground Line Expenses	1,359,519	1,562,352
139	(585) Street Lighting and Signal System Expenses	97,672	113,309
140	(586) Meter Expenses	1,102,848	1,074,010
141	(587) Customer Installations Expenses	173,326	170,320
142	(588) Miscellaneous Expenses	3,314,478	3,275,619
143	(589) Rents	153,001	196,213
144	TOTAL Operation (Enter Total of lines 134 thru 143)	9,231,660	9,143,461
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	643,070	499,277
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	259,453	217,128
149	(593) Maintenance of Overhead Lines	3,088,029	3,423,623
150	(594) Maintenance of Underground Lines	869,819	917,863
151	(595) Maintenance of Line Transformers	164,790	198,463
152	(596) Maintenance of Street Lighting and Signal Systems	162,896	170,329
153	(597) Maintenance of Meters	21,269	11,678
154	(598) Maintenance of Miscellaneous Distribution Plant	914,042	1,037,100
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,123,368	6,475,461
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,355,028	15,618,922
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	157,613	136,392
160	(902) Meter Reading Expenses	508,504	480,206
161	(903) Customer Records and Collection Expenses	2,713,167	3,127,062
162	(904) Uncollectible Accounts	1,015,295	1,018,726
163	(905) Miscellaneous Customer Accounts Expenses	163,521	135,074
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	4,558,100	4,897,460

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	49,386	45,841
168	(908) Customer Assistance Expenses	64,844	61,222
169	(909) Informational and Instructional Expenses	125,741	148,001
170	(910) Miscellaneous Customer Service and Informational Expenses	4,734	453
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	244,705	255,517
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,110	345
175	(912) Demonstrating and Selling Expenses	86,549	81,070
176	(913) Advertising Expenses	15,891	17,759
177	(916) Miscellaneous Sales Expenses	7,652	7,345
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	111,202	106,519
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	7,764,717	6,917,097
182	(921) Office Supplies and Expenses	4,053,892	3,696,945
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	391,241	659,030
185	(924) Property Insurance	1,046,451	1,074,272
186	(925) Injuries and Damages	2,119,873	1,672,344
187	(926) Employee Pensions and Benefits	7,933,305	7,554,178
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	846,071	720,658
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	69,837	81,269
192	(930.2) Miscellaneous General Expenses	690,074	859,084
193	(931) Rents	1,170,851	1,035,860
194	TOTAL Operation (Enter Total of lines 181 thru 193)	26,086,312	24,270,737
195	Maintenance		
196	(935) Maintenance of General Plant	599,281	602,495
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	26,685,593	24,873,232
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	199,637,356	190,762,783

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	Minnesota Power	OS				
3	Western Area Power Admin - Ft. Peck	LF	19			
4	Western Area Power Administration	EX	19			
5	Midcontinent Independent					
6	System Operator (MISO)	EX	MISO			
7	Customer Owned Generation	OS				
8	Deferral per tariff					
9	Enerwise Global Technologies, Inc.	OS				
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)	
103,207			3,522,392	3,341,116	51,266	6,914,774	1
			39,240			39,240	2
14,301				404,009		404,009	3
					80,838	80,838	4
838,179							5
			-7,351	15,911,770		15,904,419	6
			418,850			418,850	7
					292,553	292,553	8
			568,223			568,223	9
							10
							11
							12
							13
							14
955,687			4,541,354	19,656,895	424,657	24,622,906	

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 2 Column: a

Minnesota Power purchased power contract ended May 2017.

Schedule Page: 326 Line No.: 2 Column: b

Other Service classification includes purchases for scheduled outages, operational control, general purpose, emergencies, interruptible load replacement and economical reasons.

Schedule Page: 326 Line No.: 7 Column: b

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

Schedule Page: 326 Line No.: 9 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	1,437			6
						7
9	Various	Various				8
						9
24	Various	Various		1,189,689	1,156,156	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		2,896	2,820	22
						23
5	Sheridan	Various		8,648	8,648	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,437	1,201,233	1,167,624	

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
		1,021,681	1,021,681	2
				3
		-79,261	-79,261	4
				5
4,118,687			4,118,687	6
				7
		13,361,469	13,361,469	8
				9
		660,983	660,983	10
				11
		1,828,080	1,828,080	12
				13
		10,381,895	10,381,895	14
				15
		18,181	18,181	16
				17
		21,315	21,315	18
				19
		244,000	244,000	20
				21
	22,433		22,433	22
				23
	6,486		6,486	24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
4,118,687	28,919	27,458,343	31,605,949	

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 24 Column: c
 Sheridan-Johnson REA contract is perpetual

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	1,486	1,605				
5	Grand Elec Coop	LFP	614	665		4,261		4,261
6	Midcontinent							
7	Independent							
8	System Operator (MISO)	OS					6,941,048	6,941,048
9	Southwest Power Pool	FNS				19,533,586		19,533,586
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,100	2,270		19,537,847	6,941,048	26,478,895

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	350,133
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	339,941
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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45		
46	TOTAL	690,074

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

1. 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).
2. 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.
3. 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.
4. 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			359,444		359,444
2	Steam Production Plant	13,795,795				13,795,795
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,147,450			-78,324	17,069,126
7	Transmission Plant	4,827,663				4,827,663
8	Distribution Plant	9,646,648				9,646,648
9	Regional Transmission and Market Operation					
10	General Plant	393,981				393,981
11	Common Plant-Electric	1,197,503		1,484,959		2,682,462
12	TOTAL	47,009,040		1,844,403	-78,324	48,775,119

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	80,424	63.00		2.86	R2.5	16.60
15	312	342,486	45.00		2.42	R0.5	17.80
16	314	84,826	45.00		2.63	R0.5	21.20
17	315	20,055	50.00		1.56	R2.5	21.80
18	316	19,206	30.00		4.33	R0.5	12.20
19	317.0	7,370					
20	Subtotal	554,367					
21							
22	OTHER PRODUCTION						
23							
24	341	8,419	70.00		4.77	R1	12.60
25	342	2,116	43.00		3.13	R5	21.40
26	344	429,306	55.00		3.70	R3	19.00
27	345	16,665	28.00		4.73	L2	12.40
28	346	1,775	28.00		3.08	S1	21.40
29	347.0	10,675					
30	Subtotal	468,956					
31							
32	TRANSMISSION PLANT						
33							
34	350.2	3,181	50.00		1.36	R3	25.60
35	352	2	45.00		1.10	R2.5	4.70
36	353	146,636	60.00	-10.00	1.81	R3	45.20
37	354	4,993	55.00	-5.00	1.65	R5	24.90
38	355	79,567	50.00	-35.00	2.41	R3	36.00
39	356	55,838	65.00	-15.00	1.34	R3	45.20
40	357	1,944	50.00		2.01	R3	43.60
41	358	3,102	50.00		2.01	R3	43.60
42	359.1	1					
43	Subtotal	295,264					
44							
45	DISTRIBUTION PLANT						
46							
47	360.2	957	50.00		1.35	R2	25.60
48	362	76,847	50.00	-5.00	1.78	R2.5	37.60
49	364	43,144	50.00	-70.00	3.99	R1	37.60
50	365	33,381	55.00	-70.00	3.68	R1	43.30

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	50.00		1.86	R3	29.60
13	367	117,908	40.00	-15.00	2.96	R2	32.00
14	368	73,289	55.00	-10.00	2.22	R3	40.80
15	369	37,273	45.00	-27.00	1.97	R3	31.40
16	370	18,580	20.00	-5.00	4.23	L3	14.90
17	371	2,916	22.00	-15.00	5.11	R0.5	15.60
18	373	7,889	43.00	-40.00	3.46	R1	28.00
19	374.0	40					
20	Subtotal	412,460					
21							
22	GENERAL PLANT						
23							
24	303	5,402			8.72	NA	11.50
25	390	1,518	29.00	25.00	3.12	L2	18.20
26	391	458			19.44	NA	
27	392	8,248	11.00	20.00	4.53	L3	6.19
28	393	15	30.00		3.33	NA	
29	394	4,301	20.00		4.94	NA	
30	395	721	20.00		4.86	NA	
31	396	14,162	9.00	20.00	5.55	L0	8.77
32	397	1,223			12.30	NA	
33	398	59	25.00		4.00	NA	
34	Subtotal	36,107					
35							
36	Total	1,767,154					
37	FOOTNOTE						
38							
39							
40							
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43							
44							
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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) 12/31/2017	Year/Period of Report 2017/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.: 24 Column: c

Various

Schedule Page: 336.1 Line No.: 26 Column: c

Various

Schedule Page: 336.1 Line No.: 26 Column: g

N/A

Schedule Page: 336.1 Line No.: 28 Column: g

N/A

Schedule Page: 336.1 Line No.: 29 Column: g

N/A

Schedule Page: 336.1 Line No.: 30 Column: g

N/A

Schedule Page: 336.1 Line No.: 32 Column: c

Various

Schedule Page: 336.1 Line No.: 32 Column: g

N/A

Schedule Page: 336.1 Line No.: 33 Column: g

N/A

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

Column (b) - 12/31/17 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				212,862
6					
7	Gas				5,162
8					
9					
10	NORTH DAKOTA				
11	Electric				441,679
12					
13	Gas				67,316
14					
15					
16	SOUTH DAKOTA				
17	Electric				171,560
18					
19	Gas				235,027
20					
21					
22					
23					
24					
25					
26	WYOMING				
27	Electric				83,720
28					
29	Gas				70,692
30					
31					
32	MINNESOTA				
33	Gas				487,445
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				1,775,463

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	139,781		928	94,101	118,761	5
							6
Gas	928	35,327	31,850	928	5,162	31,850	7
							8
							9
							10
Electric	928	429,362	-66,554	928	50,084	325,041	11
							12
Gas	928	11,891	218,816	928	64,500	221,632	13
							14
							15
							16
Electric	928	19,041		928	34,926	136,634	17
							18
Gas				928	94,906	140,121	19
							20
							21
							22
							23
							24
							25
							26
Electric	928	61,187	21,815	928	17,589	87,946	27
							28
Gas	928	37,082	-19,073	928	15,108	36,511	29
							30
							31
							32
Gas	928	162,554	3,968	928	131,250	360,163	33
							34
							35
							36
Gas	928	1,250	10,000			10,000	37
							38
							39
							40
							41
							42
							43
							44
							45
		897,475	200,822		507,626	1,468,659	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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 350 Line No.: 11 Column: i

Includes rate case expenses written off \$154,603.

Schedule Page: 350 Line No.: 29 Column: i

Includes rate case expenses written off \$19,362.

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	4,092,698		
49	Administrative and General	265,273		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,357,971		
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)	566,980		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	15,228,155		
58	Customer Accounts (Line 37)	3,942,149		
59	Customer Service and Informational (Line 38)	415,520		
60	Sales (Line 39)	189,301		
61	Administrative and General (Lines 40 and 49)	4,545,037		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	24,887,142	2,869,340	27,756,482
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	57,336,072	6,610,509	63,946,581
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	9,977,785	1,150,380	11,128,165
69	Gas Plant	7,527,101	867,830	8,394,931
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	17,504,886	2,018,210	19,523,096
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,077,602	124,241	1,201,843
74	Gas Plant	812,927	93,726	906,653
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,890,529	217,967	2,108,496
77	Other Accounts (Specify, provide details in footnote):			
78	183 - Preliminary Survey & Investigation	77,240		77,240
79	184 - Clearing Accounts	248,484		248,484
80	416 - Cost/Expense of Mech Job & Constr.	30,028		30,028
81	417 - Expense for Non-Utility Operations	493,397		493,397
82	426 - Misc Non Operating Exp.	18,996		18,996
83	121 - Non Utility	25,957		25,957
84	146 - Accounts Receivable From Associated Companies	5,287,186		5,287,186
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,181,288		6,181,288
96	TOTAL SALARIES AND WAGES	82,912,775	8,846,686	91,759,461

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) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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	Depreciaton Expense
PLANT IN SERVICE			
303 Misc. Intangible Plant	60,724,913	28,154,234	3,440,906
389 Land and Land Rights	2,445,129	0	0
390 Structures and Improvements	48,643,888	16,359,280	535,992
391 Office Furniture & Equipment	5,414,188	2,417,137	1,000,868
392 Transportation and Equipment	12,499,346	5,051,689	573,247
393 Stores Equipment	93,255	33,593	3,019
394 Miscellaneous Tools	813,383	368,553	41,368
396 Power Operated Equipment	0	0	0
397 Communication Equipment	3,871,531	1,434,925	239,825
398 Miscellaneous Equipment	1,215,926	558,221	60,276
3991 Asset Retirement Obligations	0	0	0
	135,721,559	54,377,632	5,895,501
WORK IN PROGRESS			
	2,962,242	10,967	0
	138,683,801	54,388,599	5,895,501
Allocation of Common Utility Plant			
Electric Department	77,993,527	30,959,154	2,682,462
Natural Gas Department	60,690,274	23,429,445	2,813,145
Clearing Accounts			399,894
	138,683,801	54,388,599	5,895,501

Basis of Allocation

- General Office common plant and depreciation are allocated based on net plant and employee ratios.
- 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.
- 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	783	12	1900	562	221				
2	February	744	8	900	533	211				
3	March	690	13	900	490	200				
4	Total for Quarter 1				1,585	632				
5	April	548	25	1200	397	151				
6	May	520	12	1700	398	122				
7	June	667	9	1700	511	156				
8	Total for Quarter 2				1,306	429				
9	July	749	5	1700	579	170				
10	August	682	28	1800	538	144				
11	September	650	12	1700	506	144				
12	Total for Quarter 3				1,623	458				
13	October	578	31	1000	433	145				
14	November	642	9	900	477	165				
15	December	766	30	2000	556	210				
16	Total for Quarter 4				1,466	520				
17	Total Year to Date/Year				5,980	2,039				

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	59	4	1900	57	2				
2	February	56	3	900	54	2				
3	March	45	1	900	44	1				
4	Total for Quarter 1				155	5				
5	April	40	9	2200	39	1				
6	May	40	31	1900	39	1				
7	June	53	8	1800	51	2				
8	Total for Quarter 2				129	4				
9	July	62	13	1800	60	2				
10	August	58	1	1800	57	1				
11	September	55	12	1800	53	2				
12	Total for Quarter 3				170	5				
13	October	42	31	900	42	1				
14	November	48	6	1900	46	1				
15	December	55	31	1900	54	1				
16	Total for Quarter 4				142	3				
17	Total Year to Date/Year				596	17				

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)	3,306,470
3	Steam	1,991,881	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	39,971
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	638,759	27	Total Energy Losses	273,495
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,619,936
9	Net Generation (Enter Total of lines 3 through 8)	2,630,640			
10	Purchases	955,687			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,201,233			
17	Delivered	1,167,624			
18	Net Transmission for Other (Line 16 minus line 17)	33,609			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,619,936			

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) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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	338,806	40	562	12	1900
30	February	273,749	1,712	533	8	900
31	March	290,174	2,623	490	13	900
32	April	234,598	1,090	397	25	1200
33	May	239,077	8,359	398	12	1700
34	June	248,949	2,998	511	9	1700
35	July	307,187	2,335	579	5	1700
36	August	261,619	3,375	538	28	1800
37	September	245,521	8,947	506	12	1700
38	October	262,938	6,645	433	31	1000
39	November	292,589	1,847	477	9	900
40	December	331,538		556	30	2000
41	TOTAL	3,326,745	39,971			

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) 12/31/2017	Year/Period of Report 2017/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	31,815	57	4	1900
30	Feb	25,044	54	3	900
31	Mar	23,973	44	1	900
32	Apr	21,181	39	9	2200
33	May	20,581	39	31	1900
34	Jun	21,659	51	8	1800
35	Jul	28,635	60	13	1800
36	Aug	24,015	57	1	1800
37	Sep	21,204	53	12	1800
38	Oct	21,739	42	31	900
39	Nov	24,517	46	6	1900
40	Dec	28,828	54	31	1900
41	Total	293,191	596		

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	8729	0				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	99	0				
10	When Limited by Condenser Water	90	0				
11	Average Number of Employees	52	0				
12	Net Generation, Exclusive of Plant Use - KWh	454134100	0				
13	Cost of Plant: Land and Land Rights	242583	0				
14	Structures and Improvements	27595552	0				
15	Equipment Costs	93569153	0				
16	Asset Retirement Costs	1235755	0				
17	Total Cost	122643043	0				
18	Cost per KW of Installed Capacity (line 17/5) Including	1426.0819	0				
19	Production Expenses: Oper, Supv, & Engr	968424	0				
20	Fuel	16143627	0				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	2688580	0				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	896701	0				
26	Misc Steam (or Nuclear) Power Expenses	1169701	0				
27	Rents	0	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	534664	0				
30	Maintenance of Structures	167686	0				
31	Maintenance of Boiler (or reactor) Plant	1702214	0				
32	Maintenance of Electric Plant	740084	0				
33	Maintenance of Misc Steam (or Nuclear) Plant	948928	0				
34	Total Production Expenses	25960609	0				
35	Expenses per Net KWh	0.0572	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	427654	0	2363	1174	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	7026	8735	15918	1124	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	35.981	0.000	82.012	5.095	0.000	0.000
41	Average Cost of Fuel per Unit Burned	37.285	0.000	81.993	5.095	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.653	0.000	2.575	4.533	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.036	0.000	0.035	0.061	0.000	0.000
44	Average BTU per KWh Net Generation	13401.200	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
23.15			94.11			28.00			5
25			108			27			6
28			7799			7806			7
0			0			0			8
22			109			27			9
22			102			27			10
0			18			5			11
405840			469708700			189984000			12
609			150559			0			13
223817			9592516			3563861			14
4330963			140397519			61350148			15
0			824105			0			16
4555389			150964699			64914009			17
196.7771			1604.1303			2318.3575			18
15711			281293			529392			19
81904			11498882			2028332			20
0			0			0			21
18570			999659			492517			22
0			0			0			23
0			0			0			24
55919			349873			120052			25
0			779139			227726			26
0			0			775417			27
0			0			83			28
17518			158017			272919			29
1938			280175			78237			30
797294			1229381			580515			31
1979			183018			235380			32
0			141036			6040			33
990833			15900473			5346610			34
2.4414			0.0339			0.0281			35
Gas	Fuel Oil		Coal-SubBit	Fuel Oil		Coal-SubBit			36
Mcf	Bbl		Tons	Bbl		Tons			37
4629	297	0	308142	886	0	136766	0	0	38
1114	140000	0	8255	140000	0	7967	0	0	39
10.526	91.770	0.000	36.354	71.845	0.000	13.200	0.000	0.000	40
10.526	111.818	0.000	37.117	69.552	0.000	14.831	0.000	0.000	41
9.449	19.041	0.000	2.248	11.826	0.000	0.931	0.000	0.000	42
0.161	0.324	0.000	0.024	0.128	0.000	0.011	0.000	0.000	43
17003.809	0.000	0.000	10842.114	0.000	0.000	11470.595	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)	Gas Turbine	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional				
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)	78	107				
7	Plant Hours Connected to Load	116	7451				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	72	107				
10	When Limited by Condenser Water	69	83				
11	Average Number of Employees	3	21				
12	Net Generation, Exclusive of Plant Use - KWh	2333400	652070490				
13	Cost of Plant: Land and Land Rights	37924	519148				
14	Structures and Improvements	1504563	28550616				
15	Equipment Costs	26169810	109011842				
16	Asset Retirement Costs	0	1704873				
17	Total Cost	27712297	139786479				
18	Cost per KW of Installed Capacity (line 17/5) Including	366.9531	1348.6395				
19	Production Expenses: Oper, Supv, & Engr	45974	504230				
20	Fuel	235964	15208938				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	32811	1488912				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	116052	427034				
26	Misc Steam (or Nuclear) Power Expenses	0	487719				
27	Rents	0	52				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	31581	212449				
30	Maintenance of Structures	2257	188287				
31	Maintenance of Boiler (or reactor) Plant	105365	1912240				
32	Maintenance of Electric Plant	1217	209040				
33	Maintenance of Misc Steam (or Nuclear) Plant	0	296649				
34	Total Production Expenses	571221	20935550				
35	Expenses per Net KWh	0.2448	0.0321				
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	24508	623	0	535514	6427	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1104	140000	0	6939	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.676	87.255	0.000	27.743	71.777	0.000
41	Average Cost of Fuel per Unit Burned	5.676	90.103	0.000	27.570	69.222	0.000
42	Average Cost of Fuel Burned per Million BTU	5.142	15.320	0.000	1.987	11.773	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.068	0.202	0.000	0.023	0.135	0.000
44	Average BTU per KWh Net Generation	13165.729	0.000	0.000	11455.283	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			Gas Turbine			Steam		1
	Conventional			Conventional			Outdoor Boiler		2
	2014			2015			1958		3
	2014			2015			1958		4
	89.00			18.70			44.00		5
	89			19			52		6
	162			415			6283		7
	0			0			0		8
	84			19			52		9
	59			16			51		10
	0			0			32		11
	3400145			5453000			225983577		12
	0			0			80862		13
	62249			0			11121028		14
	53438713			45091421			62244249		15
	0			0			3605749		16
	53500962			45091421			77051888		17
	601.1344			2411.3059			1751.1793		18
	54342			17867			317230		19
	2854324			191991			5518757		20
	0			0			0		21
	60732			140628			1607336		22
	0			0			0		23
	0			0			0		24
	8632			135903			193019		25
	0			0			1110406		26
	0			0			9000		27
	0			0			0		28
	0			12095			290791		29
	3596			16549			109508		30
	77392			104229			1325403		31
	0			35467			438350		32
	0			0			472247		33
	3059018			654729			11392047		34
	0.8997			0.1201			0.0504		35
Gas			Gas			Coal-Lignite	Coal-Sub	Gas	36
Mcf			Mcf			Tons	Tons	Mcf	37
65342	0	0	40185	0	0	215275	1761	9569	38
1063	0	0	1194	0	0	6697	8152	1193	39
43.818	0.000	0.000	4.863	0.000	0.000	23.831	0.000	9.122	40
43.818	0.000	0.000	4.863	0.000	0.000	25.010	24.307	9.122	41
41.221	0.000	0.000	4.073	0.000	0.000	1.867	1.491	7.646	42
0.842	0.000	0.000	0.036	0.000	0.000	0.024	0.019	0.099	43
20428.116	0.000	0.000	8798.990	0.000	0.000	12936.869	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)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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) 12/31/2017	Year/Period of Report 2017/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.: 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, including Heskett III.

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.

Schedule Page: 402 Line No.: 44 Column: b1

Average Btu per net kWh generated for all fuels including Heskett III.

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) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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, including Lewis & Clark II.
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 including Lewis & Clark II.

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	5.50	6.0	9,429	2,259,046
3						
4	WIND					
5	Diamond Willow	2007	30.00	30.2	93,696,000	63,727,669
6	Cedar Hills	2010	19.50	19.5	59,385,390	46,426,524
7	Thunder Spirit	2015	107.50	107.0	428,528,000	210,422,310
8	WASTE HEAT					
9	Ormat Facility	2009	7.50	6.6	45,548,210	15,265,025
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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
	20,631		16,616	Oil		2
						3
						4
	389,812		123,416	Wind		5
	207,332		159,929	Wind		6
	2,298,405		68,088	Wind		7
						8
	577,966		33,683	Waste Heat		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
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						39
						40
						41
						42
						43
						44
						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) 12/31/2017	Year/Period of Report 2017/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	54.99		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	29.69		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	95.06	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	904.41	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	1,042.50	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	3,156.34	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
	3,237,183	145,294,067	148,531,250	6,018,381	1,975,075	766,185	8,759,641	24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	3,237,183	145,294,067	148,531,250	6,018,381	1,975,075	766,185	8,759,641	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) 12/31/2017	Year/Period of Report 2017/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	Thunder Spirit Interconnect Ln		0.55	H-Frame	7.00	1	1
2							
3	Sidney Loop Line		3.46	SP	23.00	1	1
4	Sidney	Shell Oil	-2.91	Retired			
5							
6	Beaver Hill Tap Line		0.52	SP	23.00	1	1
7			-0.01	Retired			
8	Heil Jct	Elgin Sub	-7.14	Retired			
9			-0.80	Retired UB			
10	Miles City Loop Line		0.02	SP	130.00	1	1
11							
12	Dickinson North	Green River	7.30	SP	18.00	1	1
13							
14	Hettinger	Bowman	3.95	SP	13.00	1	1
15			3.95	SP	13.00	1	1
16	South 9th Street Tap		0.75	SP	20.00	1	1
17	Sweet Ave	South 9th	0.69	UB on 149-2 SP	20.00	1	1
18	Sweet Ave	South 9th	-0.69	Retired	20.00	1	1
19	Dickinson North 41.6kV		2.35	SP	17.00	1	1
20			4.52	UB on 169-1 SP	18.00	1	1
21	Collins Sub	Tesoro 46kV	1.45	SP	23.00	1	1
22							
23	Heskett Station	Refinery	0.13	SP	31.00	1	1
24			-0.04	Retired UB			
25	Jct TL039-Century-CPEC Line		2.28	SP	17.00	1	1
26							
27	Heskett Station	Jct TL403-1 & TL405-1	-4.08	Retired			
28							
29	Dickinson NW Sub	Dickinson North Sub	1.72	SP	19.00	1	1
30			-0.36	Correction			
31	West Dickinson Tap Line		0.01	SP		1	1
32			-0.01	UB on 137-1			
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		17.61		412.00	17	17

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)	
795	MCMACSR	T-230-A	230		424,706	222,971		647,677	1
									2
336	MCMACSR	T-60-A-SW	57		2,645,340			2,645,340	3
			57						4
									5
336	MCMACSR	T-60-B-1	57	4,998	112,048	36,417		153,463	6
									7
			42						8
			42				34,167	34,167	9
336	MCMACSR	T-46-E	57		28,726	74,577		103,303	10
							13,417	13,417	11
954	MCMACSR	TP-DDCW	115			148,088		148,088	12
									13
4/0	ACSR	T-60-A	42		11,023	7,789		18,812	14
4/0	ACSR	T-60-A	57						15
336	MCMACSR	T-115-P1	115		233,656	233,536		467,192	16
336	MCMACSR	T-46-HUB2	42						17
336	MCMACSR	T-46-HUB2	42						18
477	MCMACSR	T-46-A	42			42,008		42,008	19
477	MCMACSR	TP-DDCW	42						20
336	MCMACSR	T-46-HA1	42			789,661		789,661	21
									22
336	MCMACSR	T-46-E	42		382	118,452		118,834	23
							14,149	14,149	24
954	MCMACSR	T-115-P	115		47,476	78,594		126,070	25
									26
			42						27
									28
954	MCMACSR	T-46-A	42			36,887		36,887	29
			115						30
477	MCMACSR	T-46-A	42						31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				4,998	3,503,357	1,788,980	61,733	5,359,068	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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 424	Line No.: 1	Column: j
19'6" x 19'6" Horizontal		
Schedule Page: 424	Line No.: 3	Column: j
8' x 7' x 7' Vertical		
Schedule Page: 424	Line No.: 3	Column: k
60 KV Design		
Schedule Page: 424	Line No.: 4	Column: k
60 KV Design		
Schedule Page: 424	Line No.: 6	Column: j
8' x 8' Vertical		
Schedule Page: 424	Line No.: 6	Column: k
60 KV Design		
Schedule Page: 424	Line No.: 8	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 9	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 10	Column: j
6' x 6' Vertical		
Schedule Page: 424	Line No.: 10	Column: k
60 KV Design		
Schedule Page: 424	Line No.: 12	Column: j
10' x 10' Vertical		
Schedule Page: 424	Line No.: 14	Column: j
86" x 86" x 86" Triangular		
Schedule Page: 424	Line No.: 14	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 15	Column: j
86" x 86" x 86" Triangular		
Schedule Page: 424	Line No.: 15	Column: k
60 KV Design		
Schedule Page: 424	Line No.: 16	Column: j
11' x 11' x 10' Vertical		
Schedule Page: 424	Line No.: 17	Column: j
6' x 6' x 10' Vertical		
Schedule Page: 424	Line No.: 17	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 18	Column: j
6' x 6' x 10' Vertical		
Schedule Page: 424	Line No.: 18	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 19	Column: j
86" x 86" x 86" Triangular		
Schedule Page: 424	Line No.: 19	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 20	Column: j
10' x 10' Vertical		
Schedule Page: 424	Line No.: 20	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 21	Column: j
6' x 6' x 10' Vertical		
Schedule Page: 424	Line No.: 21	Column: k
46 KV Design		
Schedule Page: 424	Line No.: 23	Column: j

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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

6' x 6' Vertical

Schedule Page: 424 Line No.: 23 Column: k

46 KV Design

Schedule Page: 424 Line No.: 25 Column: j

11' x 11' x 10' Vertical

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

46 KV Design

Schedule Page: 424 Line No.: 29 Column: j

86" x 86" x 86" Triangular

Schedule Page: 424 Line No.: 29 Column: k

46 KV Design

Schedule Page: 424 Line No.: 31 Column: j

86" x 86" x 86" Triangular

Schedule Page: 424 Line No.: 31 Column: k

46 KV Design

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	Substations under 10,000 KVA (0)				
21	SUBTOTAL		2687.00	800.67	41.40
22					
23	Baker, MT	Trans Unattended	115.00	57.00	
24	Baker, MT	Trans Unattended	230.00	115.00	14.10
25	Baker, MT Cabin Creek Jct	Trans Unattended	115.00	57.20	
26	Beulah Jct., ND	Trans Unattended	115.00	41.60	
27	Bismarck Jct., ND (E. Bismarck)	Trans Unattended	115.00	41.60	
28	Bismarck, ND NW	Trans Unattended	115.00	41.60	
29	Bismarck, ND Sweet Ave.	Trans Unattended	115.00	41.60	
30	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
31	Dickinson, ND	Trans Unattended	115.00	41.60	
32	Dickinson, ND	Trans Unattended	115.00	41.60	
33	Dunning, ND	Trans Unattended	115.00	57.00	
34	Ellendale Jct., ND	Trans Unattended	230.00	115.00	13.80
35	Ellendale Jct., ND	Trans Unattended	115.00	41.60	
36	Elgin, ND	Trans Unattended	69.00	41.60	
37	Gascoyne Jct., ND	Trans Unattended	115.00	41.60	
38	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
39	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
40	Halliday, ND	Trans Unattended	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		15
53	1					16
20	1					17
47	1					18
31	1					19
						20
1123	22	1		1	4	21
						22
40	1			1	4	23
112	1					24
83	1					25
45	1					26
80	2			2	8	27
47	1			1	4	28
56	1					29
20	1			1	2	30
75	1					31
93	1					32
20	1			1	2	33
100	1					34
37	1					35
15	1					36
11	1			1	1	37
30	1			1	3	38
56	1					39
20	1			1	2	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	Hettinger Jct., ND	Trans Unattended	115.00	41.60	
2	Hettinger Jct., ND	Trans Unattended	230.00	115.00	14.10
3	Kenmare Jct., ND	Trans Unattended	115.00	57.00	
4	Linton Jct., ND	Trans Unattended	115.00	41.60	
5	Mandan, ND 230	Trans Unattended	230.00	115.00	13.80
6	Mandan, ND Collins	Trans Unattended	115.00	41.60	
7	McIntosh Jct., SD	Trans Unattended	115.00	41.60	
8	Miles City, MT	Trans Unattended	230.00	115.00	13.80
9	Miles City, MT	Trans Unattended	115.00	57.00	13.80
10	New England, ND	Trans Unattended	115.00	41.60	
11	Plentywood Jct., MT	Trans Unattended	115.00	57.00	
12	Poplar Jct., MT	Trans Unattended	115.00	57.00	
13	Ray, ND Jct.	Trans Unattended	115.00	57.00	
14	Rosebud Creek, MT	Trans Unattended	230.00	60.00	13.80
15	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
16	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
17	Stanley Jct., ND	Trans Unattended	115.00	69.00	12.47
18	Tioga, ND	Trans Unattended	230.00	115.00	
19	Tioga Jct., ND	Trans Unattended	115.00	57.00	
20	Wishek Jct., ND	Trans Unattended	115.00	41.60	
21	Wishek Jct., ND	Trans Unattended	230.00	115.00	13.80
22	Substations under 10,000 KVA (8)				
23	SUBTOTAL		5819.00	2467.60	206.67
24					
25	Substations under 10,000 KVA Distrib at Plant (2)				
26	SUBTOTAL				
27					
28					
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)	
25	1			1	2	1
112	1					2
30	1			1	3	3
15	1			1	2	4
224	1					5
30	1					6
13	1			1	1	7
100	1					8
56	1					9
22	1			1	2	10
47	1					11
37	1					12
75	1					13
40	1					14
57	2					15
75	1					16
22	1			1	2	17
112	1					18
75	1					19
30	1			1	3	20
112	1					21
21	13	1		3		22
2270	54	1		19	41	23
						24
8	2			3	1	25
8	2			3	1	26
						27
						28
						29
						30
						31
						32
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						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	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
16	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
17	Dickinson, ND NE	Distrib Unattended	41.60	12.47	
18	Dickinson, ND Refinery	Distrib Unattended	41.60	12.47	
19	Dickinson, ND 21st	Distrib Unattended	41.60	12.47	
20	Dickinson, ND West	Distrib Unattended	41.60	12.47	
21	Glendive, MT	Distrib Unattended	57.00	12.47	
22	Glendive, MT West	Distrib Unattended	57.00	12.47	
23	Glendive, MT	Distrib Unattended	57.00	12.47	
24	Lignite, ND	Distrib Unattended	57.00	2.40	
25	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
26	Mandan, ND Collins Ave	Distrib Unattended	115.00	12.47	
27	Mandan, ND Midway (New)	Distrib Unattended	41.60	12.47	
28	Mandan, ND	Distrib Unattended	115.00	12.47	
29	Miles City, MT Greenstar	Distrib Unattended	57.00	12.47	
30	Miles City, MT 8th St	Distrib Unattended	57.00	12.47	
31	Miles City, MT South	Distrib Unattended	57.00	12.47	
32	Mobridge, SD	Distrib Unattended	115.00	12.47	
33	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
34	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
35	Sheridan, WY Soldier Creek	Distrib Unattended	41.60	12.47	
36	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
37	Sheridan, WY West	Distrib Unattended	41.60	12.47	
38	Sidney, MT	Distrib Unattended	57.00	12.47	
39	Sidney, MT	Distrib Unattended	57.00	12.47	
40	Stanley, ND	Distrib Unattended	69.00	12.47	

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
10	1					4
10	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	7	10
56	2			9	3	11
41	2			6	3	12
28	1			6	2	13
42	2			9	3	14
14	1			3	1	15
14	1			3	1	16
14	1			3	1	17
14	1					18
11	1			3	1	19
14	1			6	2	20
14	1			3	1	21
10	1			3	1	22
11	1			3	1	23
12	4			3	1	24
14	1			3	1	25
28	1					26
28	1			6	2	27
50	2			9	3	28
10	1			3	1	29
11	1			3	1	30
11	1			6	2	31
22	1			9	2	32
24	2			6	3	33
11	1			3	2	34
14	1			3	2	35
11	1			3	2	36
11	1			3	1	37
11	1			3	1	38
14	1			3	1	39
14	1			3	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	Stanley, ND Enbridge	Distrib Unattended	69.00	12.47	
2	Watford City, ND South Park	Distrib Unattended	34.50	7.20	
3	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
4	Williston, ND NE	Distrib Unattended	57.00	12.47	
5	Williston, ND NW North	Distrib Unattended	57.00	12.47	
6	Williston, ND NW South	Distrib Unattended	57.00	12.47	
7	Williston, ND Sabin Metals	Distrib Unattended	57.00	13.80	
8	Williston, ND Oasis	Distrib Unattended	57.00	12.47	
9	Substations Under 10,000 KVA (231)				
10	SUBTOTAL		3334.10	583.84	
11					
12	GRAND TOTAL		11840.10	3852.11	248.07
13					
14					
15	FOOTNOTES				
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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			3	1	1
11	1			3	1	2
11	1			3	1	3
10	1			3	1	4
14	1			3	1	5
14	1			3	1	6
10	1					7
11	1			3	1	8
647	392			439	58	9
1601	450			640	129	10
						11
5002	528	2		663	175	12
						13
						14
						15
						16
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						18
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						22
						23
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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) 12/31/2017	Year/Period of Report 2017/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 27 Column: a
See (A) and (B) of footnotes
Schedule Page: 426 Line No.: 28 Column: a
See (B) and (C) of footnotes
Schedule Page: 426 Line No.: 33 Column: a
See (J) and (K) of footnotes
Schedule Page: 426 Line No.: 36 Column: a
See (N) and (O) of footnotes
Schedule Page: 426 Line No.: 40 Column: a
See (H) and (I) of footnotes
Schedule Page: 426.1 Line No.: 8 Column: a
See (P) of footnotes
Schedule Page: 426.1 Line No.: 9 Column: a
See (L) and (M) of footnotes
Schedule Page: 426.1 Line No.: 14 Column: a
See (D) and (E) of footnotes
Schedule Page: 426.1 Line No.: 21 Column: a
See (F) and (G) of footnotes
Schedule Page: 426.3 Line No.: 15 Column: a

FOOTNOTES:

- (A) Capital Electric Cooperative, Inc. has a 25 MVA capacity interest.
- (B) Capital Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (C) Capital Electric Cooperative, Inc. has a 10 MVA capacity interest.
- (D) Mid-Yellowstone Electric Cooperative, Inc. has a 14,911 KVA capacity interest.
- (E) 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.
- (F) KEM Electric Cooperative, Inc. has a 59,136 KVA capacity interest.
- (G) KEM Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (H) Upper Missouri G&T Electric Cooperative, Inc. has a 15,300 KVA capacity interest.
- (I) Upper Missouri G&T Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (J) Central Power and Upper Missouri G&T Electric Cooperative, Inc. have a 9,420 KVA capacity interest.
- (K) Central Power pays for all expenses relating to equipment owned by them and is not an associated company. The Respondent pays for all expenses relating to transformer and regulator equipment owned by Respondent.
- (L) Western Area Power Administration (WAPA) has a 9,500 KVA capacity interest.
- (M) WAPA does routine maintenance at their expense and major repairs are divided 19% WAPA and 81% Respondent.
- (N) Mor-Gran-Sou Electric Cooperative has a 4,560 KVA capacity interest.
- (O) Mor-Gran-Sou Electric Cooperative pays for all expenses relating to equipment owned by them and is not an associated company.
- (P) 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	2,774,037
3	Cost of Service	CHCC	401,165,184,228	1,543,802
4	Contract Services	CHCC	184	419,314
5	Contract Services	WBIH		787,128
6	Contract Services	MDU CSG	401,402,417,107	1,190,101
7				
8				
9	Total			6,714,382
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	791,944
22	Cost of Service for Facilities Used	MDU CSG	454,493	228,461
23	Cost of Service for Facilities Used	MDU EC	454,493	1,727,225
24	Cost of Service for Facilities Used	WBIH	454,493	147,973
25				
26	Total			2,895,603
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)
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42				
1	Non-power Goods or Services Provided by Affiliated			
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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)

12/31/2017

Year/Period of Report

End of 2017/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)
5				
6				
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20	Non-power Goods or Services Provided for Affiliate			
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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) 12/31/2017	Year/Period of Report 2017/Q4
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