

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

Exact Legal Name of Respondent (Company)

MDU Resources Group, Inc.

Year/Period of Report

End of 2016/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>2016/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 Jason Vollmer		06 Title of Contact Person VP, CAO, and Treasurer	
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) 530-1755	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) 12/31/2016

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 Jason Vollmer	03 Signature  Jason Vollmer	04 Date Signed (Mo, Da, Yr) <u>1/5/2017</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
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	N/A
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	228b&229b-N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	N/A
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	N/A
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	N/A
58	Purchase and Sale of Ancillary Services	398	N/A
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/Q4

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)
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	

Stockholders' Reports Check appropriate box:

Two copies will be submitted

No annual report to stockholders is prepared

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) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

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.

Jason Vollmer - Vice President, Chief Accounting officer, and Treasurer
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	

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	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	Continental Line Builders, Inc. - F	Construction Services	100	
19	Coordinating and Planning Services, Inc. - F	Construction Services	100	
20	Desert Fire Holdings, Inc. - F	Holding Company	100	
21	Desert Fire Protection, LLC - AN	Holding Company	100	
22	Desert Fire Protection, a Nevada Limited Partnership - AO	Construction Services	100	
23				
24	Desert Fire Protection, Inc. - AN	Construction Services	100	
25	Duro Electric Company - S	Construction Services	100	
26	E.S.I., Inc. - P	Construction Services	100	
27	Frebco, Inc. - AM	Construction Services	100	

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	Hamlin Electric Company - Q	Construction Services	100	
2	Harp Engineering, Inc. - F	Engineering Services	100	
3	Independent Fire Fabricators, LLC - AN	Construction Services	100	
4	International Line Builders, Inc. - F	Construction Services	100	
5	ILB Hawaii, Inc. - G	Construction Services	100	
6	LME&U Holdings, LLC - F	Holding Company	100	
7	Lone Mountain Excavation & Utilities, LLC - AF	Construction Services	100	
8	Loy Clark Pipeline Co. - F	Construction Services	100	
9	MDU Industrial Services, Inc. - F	Holding Company	100	
10	Midland Technical Crafts, Inc. - AM	Construction Services	100	
11	Nevada Valley Solar Solutions I, LLC - F	Alternative Energy	100	
12	On Electric Group, Inc. - F	Construction Services	100	
13	Pouk & Steinle, Inc. - F	Construction Services	100	
14	Rocky Mountain Contractors, Inc. - F	Construction Services	100	
15	USI Industrial Services, Inc. - AM	Construction Services	100	
16	Wagner Group, Inc., The - F	Holding Company	100	
17	Wagner Industrial Electric, Inc. - AM	Holding Company	100	
18	Wagner-Smith Company, The - P	Construction Services	100	
19	Wagner-Smith Equipment Co. - F	Construction Services	100	
20	Wagner-Smith Pumps & Systems, Inc. - P	Construction Services	100	
21	MAAK Holdings, Inc. - F	Holding Company	100	
22	WBI Holdings, Inc. - A	Holding Company	100	
23	Fidelity Exploration & Production Company - E	Oil & Natural Gas Production	100	
24	Fidelity Oil Co. - K	Oil & Natural Gas Production	100	
25	WBI Energy, Inc. (f/k/a WBI Pipeline & Storage	Holding Company	100	
26	Group, Inc.) - E			
27				

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	WBI Energy Transmission, Inc. (f/k/a Williston	Natural Gas Transmission	100	
2	Basin Interstate Pipeline Company) - L			
3	WBI Energy Wind Ridge Pipeline, LLC - L	Interstate Natural Gas Transp	100	
4	WBI Canadian Pipeline, Ltd. - L	Natural Gas Trans & Storage	100	
5	WBI Energy Midstream, LLC (f/k/a Bitter Creek	Natural Gas Gathering	100	
6	Pipelines, LLC) - L			
7	WBI Energy Services, Inc. - E	Holding Company	100	
8	Prairielands Energy Marketing, Inc. - J	Energy Marketing	100	
9	Centennial Holdings Capital LLC - A	Holding Company	100	
10	FutureSource Capital Corp. - R	Asset Management	100	
11	Nevada Solar Solutions, LLC - AL	Alternative Energy	100	
12	InterSource Insurance Company - R	Captive Insurance Company	100	
13	Centennial Energy Resources LLC - A	Holding Company	100	
14	Centennial Energy Resources	Holding Company	100	
15	International, Inc. - D			
16	MDU Resources International LLC - W	Holding Company	100	
17	MDU Resources Luxembourg I LLC S.a.r.l. - W	Holding Company	100	
18	MDU Resources Luxembourg II LLC S.a.r.l. - AC	Holding Company	100	
19	MDU Brasil Ltda. - X	Holding Company	100	
20	(1)-Direct subsidiary of MDU Resources			
21	Group, Inc.			
22	A-100% held by Centennial Energy Holdings, Inc			
23	B-100% held by Knife River Corporation			
24	C-100% held by KRC Holdings, Inc.			
25	D-100% held by Centennial Energy Resources LLC			
26	E-100% held by WBI Holdings, Inc.			
27				

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	F-100% held by MDU Construction Services			
2	Group, Inc.			
3	G-100% held by International Line Builders,			
4	Inc.			
5	H-100% held by Alaska Basic Industries, Inc.			
6	I-Partners include Knife River Hawaii, Inc.			
7	(50%) and Knife River Dakota, Inc. (50%)			
8	J-100% held by WBI Energy Services, Inc.			
9	K-100% held by Fidelity Exploration &			
10	Production Company			
11	L-100% held by WBI Energy, Inc.			
12	M-100% held by Baldwin Contracting			
13	Company, Inc.			
14	N-Reserved for future use			
15	O-78% held by Knife River Corporation -			
16	Northwest			
17	P-100% held by The Wagner Group, Inc.			
18	Q-100% held by Rocky Mountain			
19	Contractors, Inc.			
20	R-100% held by Centennial Holdings			
21	Capital LLC			
22	S-100% held by MDU United Construction			
23	Solutions, Inc.			
24	T-100% held by Knife River Corporation -			
25	North Central			
26	U-100% held by Prairie Intermountain			
27	Energy Holdings, LLC			

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	V-Equity interest held by Fidelity Exploration			
2	& Production Company - 75%			
3	W-100% held by Centennial Energy Resources			
4	International, Inc.			
5	X-99.9999% held by MDU Resources Luxembourg			
6	II LLC S.a.r.l. and .0001% held by			
7	Centennial Energy Resources International,			
8	Inc.			
9	Y-Entity was dissolved through merger with			
10	affiliate or dissolution			
11	Z-100% held by MDU Energy Capital, LLC			
12	AA-Reserved for future use			
13	AB-Reserved for future use			
14	AC-100% held by MDU Resources Luxembourg I			
15	LLC S.a.r.l.			
16	AD-100% held by Cascade Natural			
17	Gas Corporation			
18	AE-100% held by Prairielands Energy Marketing,			
19	Inc.			
20	AF-100% held by LME&U Holdings, LLC			
21	AG-100% held by BEH Electric Holdings, LLC			
22	AH-100% held by Prairie Cascade			
23	Energy Holdings, LLC			
24	AI-100% held by BMH Mechanical Holdings, LLC			
25	AJ-Reserved for future use			
26	AK-Reserved for future use			
27	AL-100% held by FutureSource Capital Corp.			

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	AM-100% held by MDU Industrial Services, Inc.			
2	AN-100% held by Desert Fire Holdings, Inc.			
3	AO-Partners include Desert Fire Protection,			
4	LLC (1%) and Desert Fire Holdings,			
5	Inc. (99%)			
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
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	755,000
3			
4	President and Chief Executive Officer of Cascade	Nicole A. Kivisto	320,000
5	Natural Gas Corporation, Great Plains Natural Gas		
6	Co., Intermountain Gas Company and Montana-		
7	Dakota Utilities Co.		
8			
9	Vice President - Administration	Cynthia J. Norland	230,000
10			
11	Vice President - Human Resources	Anne M. Jones	211,783
12			
13	Vice President, General Counsel and Secretary	Daniel S. Kuntz	270,961
14			
15	Vice President, Chief Accounting Officer	Jason L. Vollmer	190,192
16	and Treasurer		
17			
18	Vice President and Chief Financial Officer	Doran N. Schwartz	380,000
19			
20	Executive Vice President - Business Development	Dennis L. Haider	273,000
21			
22	Chief Information Officer	Margaret (Peggy) A. Link	199,587
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 9 Column: b

Cynthia J. Norland retired effective January 20, 2017.

Schedule Page: 104 Line No.: 11 Column: b

Anne M. Jones was named Vice President - Human Resources, MDU Resources Group, Inc., effective January 1, 2016, to replace Mark A. Del Vecchio who resigned.

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

Daniel S. Kuntz was named Vice President, General Counsel and Secretary, MDU Resources Group, Inc., effective January 9, 2016, to replace Paul K. Sandness who retired.

Schedule Page: 104 Line No.: 15 Column: b

Jason L. Vollmer was named Vice President, Chief Accounting Officer and Treasurer, effective March 19, 2016 to replace Nathan W. Ring who resigned.

Schedule Page: 104 Line No.: 22 Column: b

Margaret (Peggy) A. Link was named Chief Information Officer, MDU Resources Group, Inc. effective January 1, 2016, and was designated a company officer effective January 1, 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	Dickinson, North Dakota
12		
13	A. Bart Holaday	Denver, Colorado, and Grand Forks, North Dakota
14		
15	Patricia L. Moss	Bend, Oregon
16		
17	John K. Wilson	Omaha, Nebraska
18		
19	William E. McCracken	Warren, New Jersey
20		
21		
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		
48		

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

Does the respondent have formula rates? Yes
 No

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

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

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

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

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Midcontinent Independent System Operator, Inc. -	ER13-1169-001
2	FERC Electric Tariff	
3		
4	Midcontinent Independent System Operator, Inc. -	ER13-1547-000
5	FERC Electric Tariff	
6		
7	Midcontinent Independent System Operator, Inc. -	ER13-1827-000
8	FERC Electric Tariff	
9		
10	Midcontinent Independent System Operator, Inc. -	ER13-2379-000
11	FERC Electric Tariff	
12		
13	Midcontinent Independent System Operator, Inc. -	ER13-2379-003
14	FERC Electric Tariff	
15		
16	Midcontinent Independent System Operator, Inc. -	ER13-2379-004
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
---	--

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		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent
MDU Resources Group, Inc.

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

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

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	200	Summary of Utility Plant		c 3 & 21
3	201	Summary of Utility Plant		d 3
4	205	Electric Plant In Service		g 46
5	205 & 207	Electric Plant In Service		g 5 & 99
6	207	Electric Plant In Service		g 58
7	207	Electric Plant In Service		g 75
8	216	Construction Work In Progress - Electric		b 1
9	219	Accumulated Provision for Depreciation of		c 20-24
10		Electric Utility Plant		
11	219	Accumulated Provision for Depreciation of		c 25
12		Electric Utility Plant		
13	219	Accumulated Provision for Depreciation of		c 26
14		Electric Utility Plant		
15	219	Accumulated Provision for Depreciation of		c 28
16		Electric Utility Plant		
17	227	Materials & Supplies		c 8
18	234	Accumulated Deferred Income Taxes		c 8
19		(Account 190)		
20	263	Taxes Accrued. Prepaid and Charged During Year		i 18
21	263	Taxes Accrued. Prepaid and Charged During Year		i 24
22	263.1	Taxes Accrued. Prepaid and Charged During Year		i 4
23	263.1	Taxes Accrued. Prepaid and Charged During Year		i 12
24	263.1	Taxes Accrued. Prepaid and Charged During Year		i 17-22
25	263.1	Taxes Accrued. Prepaid and Charged During Year		i 25
26	263.1	Taxes Accrued. Prepaid and Charged During Year		i 26
27	267	Accumulated Deferred Investment Tax Credit		h 8
28	275	Accumulated Deferred Income Taxes - Other		k 2
29		Property (Account 282)		
30	277	Accumulated Deferred Income Taxes - Other		k 9
31		(Account 283)		
32	321	Electric Operation and Maintenance Expenses		b 96 & 112
33	323	Electric Operation and Maintenance Expenses		b 197
34	336	Depreciation and Amortization of Electric Plant		f 1
35	336	Depreciation and Amortization of Electric Plant		b 7
36	336	Depreciation and Amortization of Electric Plant		f 10
37	336	Depreciation and Amortization of Electric Plant		b 11
38	354	Distribution of Salaries & Wages		b 20,21,23,26
39	356	Common Utility Plant and Expenses		
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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 1062 Line No.: 1 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 2 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 3 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 4 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 5 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 6 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 7 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 8 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 9 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 11 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 13 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 15 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 17 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 18 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 20 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 21 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 22 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 23 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 24 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 25 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 26 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 27 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 28 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 30 Column: a
Include electric portion of FAS 109
Schedule Page: 1062 Line No.: 32 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 33 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO
Schedule Page: 1062 Line No.: 34 Column: a

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 35 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

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

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 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	------------------------------	--

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:	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) 12/31/2016	2016/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. The Respondent renewed franchises in 2016 in Crookston, Minnesota, Wolf Point, Montana, Piedmont, South Dakota, the following North Dakota cities: Alamo, Berthold, Des Lacs, Dunn Center, and the following Wyoming cities: Dayton, Sheridan, Ranchester. 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 \$111,000,000 at December 31, 2016. The issuance of commercial paper and other short-term debt is authorized pursuant to the following orders:

On September 11, 2015 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. ES15-38-000.

On August 4, 2015 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. D2015.7.56, Default Order No. 7427.

7. None.

8. Wage increases to nonunion employees averaged 3.17% in 2016. Wage increases to union employees averaged 3.21% effective 5/1/16. The estimated impact of the increases amounted to approximately \$2,728,000.

9. See Note 14 in Notes To Financial Statements beginning on page 122.

10. None.

11. None.

12. None.

13. Anne M. Jones was named Vice President - Human Resources, MDU Resources Group, Inc., effective January 1, 2016, to replace Mark A. Del Vecchio who resigned.

Daniel S. Kuntz was named Vice President General Counsel and Secretary, MDU Resources Group, Inc., effective January 9, 2016, to replace Paul K. Sandness who retired.

Jason L. Vollmer was named Vice President, Chief Accounting Officer and Treasurer, effective March 19, 2016 to replace Nathan W. Ring who resigned.

William R. Connors has accepted an executive position with a subsidiary of the company and resigned as Vice President - Renewable Resources, effective January 7, 2016.

Margaret (Peggy) A. Link was named Chief Information Officer, MDU Resources Group, Inc. effective January 1, 2016, and was designated a company officer effective January 1, 2017.

Cynthia J. Norland, Vice President of Administration of MDU Resources Group, Inc., retired effective January 20, 2017.

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) 12/31/2016	Year/Period of Report 2016/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

14. Not applicable.

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) 12/31/2016	Year/Period of Report End of 2016/Q4
---	---	--	---

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	2,418,364,465	2,313,925,710
3	Construction Work in Progress (107)	200-201	67,808,467	49,427,086
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,486,172,932	2,363,352,796
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	878,703,820	835,120,944
6	Net Utility Plant (Enter Total of line 4 less 5)		1,607,469,112	1,528,231,852
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)		1,607,469,112	1,528,231,852
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,692,161	2,372,868
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		16,090,676	15,640,751
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,352,234	3,678,472
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,603,873,802	1,722,350,774
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)		70,369,897	66,784,202
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)		1,685,982,141	1,801,097,255
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,946,952	2,770,168
36	Special Deposits (132-134)		2,279,900	14,275
37	Working Fund (135)		212,131	150,750
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		24,806,476	20,902,043
41	Other Accounts Receivable (143)		3,663,520	3,953,301
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		481,777	448,073
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		34,423,691	33,128,824
45	Fuel Stock (151)	227	4,528,869	5,373,602
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	17,336,690	19,057,339
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)		12,822,648	11,509,418
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,936,055	5,671,080
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		47,631,992	39,280,240
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)		157,107,147	141,362,967
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,276,700	2,533,923
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,406,606	2,993,931
72	Other Regulatory Assets (182.3)	232	217,540,263	203,700,877
73	Prelim. Survey and Investigation Charges (Electric) (183)		948,016	619,177
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		12,888	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-35,372	985
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	26,117,491	21,453,443
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)		5,297,814	5,968,060
82	Accumulated Deferred Income Taxes (190)	234	87,892,895	69,928,510
83	Unrecovered Purchased Gas Costs (191)		1,874,756	-3,670,064
84	Total Deferred Debits (lines 69 through 83)		345,332,057	303,528,842
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,798,582,618	3,776,593,784

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) 12/31/2016	Year/Period of Report end of 2016/Q4
---	---	--	---

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	195,804,665
3	Preferred Stock Issued (204)	250-251	15,000,000	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)		1,239,047,477	1,236,677,978
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	6,558,718
11	Retained Earnings (215, 215.1, 216)	118-119	595,204,310	570,240,768
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	317,077,496	426,114,449
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)	-35,732,744	-37,148,174
16	Total Proprietary Capital (lines 2 through 15)		2,316,244,326	2,396,505,155
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	681,754,986	625,264,519
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)		681,754,986	625,264,519
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)		122,938	1,073,542
29	Accumulated Provision for Pensions and Benefits (228.3)		46,541,513	53,421,814
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		1,343,280	916,543
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)		119,521,302	103,736,547
35	Total Other Noncurrent Liabilities (lines 26 through 34)		167,529,033	159,148,446
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		36,758,884	53,267,087
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		5,591,989	6,621,950
41	Customer Deposits (235)		1,425,667	1,479,642
42	Taxes Accrued (236)	262-263	14,992,270	10,994,840
43	Interest Accrued (237)		7,531,734	8,195,895
44	Dividends Declared (238)		37,767,342	36,783,577
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)		937,989	1,008,226
48	Miscellaneous Current and Accrued Liabilities (242)		30,518,735	21,606,234
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)		135,524,610	139,957,451
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		23,481,419	22,189,157
57	Accumulated Deferred Investment Tax Credits (255)	266-267	1,640,385	1,752,301
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	91,493,076	94,382,563
60	Other Regulatory Liabilities (254)	278	22,896,238	12,397,095
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	499,023	0
63	Accum. Deferred Income Taxes-Other Property (282)		297,349,295	270,793,872
64	Accum. Deferred Income Taxes-Other (283)		60,170,227	54,203,225
65	Total Deferred Credits (lines 56 through 64)		497,529,663	455,718,213
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,798,582,618	3,776,593,784

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	552,791,714	545,779,755		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	346,893,487	367,926,546		
5	Maintenance Expenses (402)	320-323	27,549,761	26,982,873		
6	Depreciation Expense (403)	336-337	65,925,578	51,170,337		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,095,801	3,654,921		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	2,820	2,819		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-552,023	414,089		
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	21,813,906	19,539,225		
15	Income Taxes - Federal (409.1)	262-263	-5,061,445	12,436,427		
16	- Other (409.1)	262-263	-896,217	1,572,336		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	68,117,857	55,547,983		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	55,003,060	53,490,940		
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)		472,886,465	485,756,616		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		79,905,249	60,023,139		

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)	
						1
321,162,370	278,225,388	231,629,344	267,554,367			2
						3
168,442,439	150,467,420	178,451,048	217,459,126			4
22,320,344	21,919,993	5,229,417	5,062,880			5
48,934,860	35,373,732	16,990,718	15,796,605			6
						7
1,620,991	1,584,507	2,474,810	2,070,414			8
		2,820	2,819			9
-552,023	414,089					10
						11
						12
						13
12,747,568	10,925,054	9,066,338	8,614,171			14
-12,175,706	2,487,287	7,114,261	9,949,140			15
-1,575,121	344,596	678,904	1,227,740			16
51,253,120	40,666,080	16,864,737	14,881,903			17
34,830,630	31,754,041	20,172,430	21,736,899			18
						19
						20
						21
						22
						23
						24
256,185,842	232,428,717	216,700,623	253,327,899			25
64,976,528	45,796,671	14,928,721	14,226,468			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)		79,905,249	60,023,139		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		100,033	366,478		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		71,515	205,444		
33	Revenues From Nonutility Operations (417)		6,686,433	9,071,275		
34	(Less) Expenses of Nonutility Operations (417.1)		3,546,711	5,802,800		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,611,755	-669,222,881		
37	Interest and Dividend Income (419)		2,679,301	1,849,087		
38	Allowance for Other Funds Used During Construction (419.1)		-3,391	7,275,431		
39	Miscellaneous Nonoperating Income (421)		503,222	126,077		
40	Gain on Disposition of Property (421.1)		6,613			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		14,965,740	-656,542,777		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		177,706	60,713		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		174,287	742,304		
46	Life Insurance (426.2)		-1,052,133	955,469		
47	Penalties (426.3)		2,209			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		117,353	80,799		
49	Other Deductions (426.5)		1,352	379,992		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-579,226	2,219,277		
51	Taxes Applicable to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	300,545	278,094		
53	Income Taxes-Federal (409.2)	262-263	-712,193	-234,908		
54	Income Taxes-Other (409.2)	262-263	-760,954	306,896		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,639,201	4,920,370		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	856,545	4,904,795		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		111,917	659,434		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-501,863	-293,777		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		16,046,829	-658,468,277		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		30,559,947	26,151,839		
63	Amort. of Debt Disc. and Expense (428)		337,723	300,570		
64	Amortization of Loss on Reaquired Debt (428.1)		670,246	719,510		
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)		308,257	726,403		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		356,915	3,908,865		
70	Net Interest Charges (Total of lines 62 thru 69)		31,519,258	23,989,457		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		64,432,820	-622,434,595		
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)		64,432,820	-622,434,595		

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		570,240,768	555,934,822
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Dividend equivalents on stock based compensation		-232,375	(82,896)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-232,375	(82,896)
16	Balance Transferred from Income (Account 433 less Account 418.1)		55,821,065	46,788,286
17	Appropriations of Retained Earnings (Acct. 436)			
18	4.50%			
19	4.70%			
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.50%		-450,003	(450,003)
25	4.70%		-235,000	(235,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-685,003	(685,003)
30	Dividends Declared-Common Stock (Account 438)			
31			-147,454,825	(143,326,441)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-147,454,825	(143,326,441)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		117,514,680	111,612,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		595,204,310	570,240,768
	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)		595,204,310	570,240,768
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		426,114,449	1,206,892,280
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,611,755	(669,222,881)
51	(Less) Dividends Received (Debit)		117,514,680	111,612,000
52			-134,028	57,050
53	Balance-End of Year (Total lines 49 thru 52)		317,077,496	426,114,449

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

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

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

Dividend equivalents on stock based compensation - CEHI	(\$ 68,992)
Dividend equivalents on stock based compensation - MDU EC	\$ 11,942

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)	64,432,820	-622,434,595
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	69,472,176	55,242,166
5	Amortization of		
6	Loss on Reaquired Debt, Bond Discount and Debt Exp	1,007,968	1,020,081
7			
8	Deferred Income Taxes (Net)	13,897,453	1,164,400
9	Investment Tax Credit Adjustment (Net)	-111,916	-659,434
10	Net (Increase) Decrease in Receivables	-4,875,815	13,592,715
11	Net (Increase) Decrease in Inventory	932,859	-2,188,910
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	13,130,347	10,749,305
14	Net (Increase) Decrease in Other Regulatory Assets	-16,088,758	-441,467
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,050,586	7,293,648
16	(Less) Allowance for Other Funds Used During Construction	-3,391	7,275,431
17	(Less) Undistributed Earnings from Subsidiary Companies	-108,902,925	-780,834,881
18	Other (provide details in footnote):		
19	Unrecovered Purchased Gas Costs	-5,544,820	14,321,208
20	Net Change in Other Current & Accrued Assets	-10,882,352	8,544,884
21	Other Noncurrent Changes	7,576,883	-2,129,505
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	240,802,575	257,633,946
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-154,154,491	-346,272,649
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-5,828,349	-10,020,498
29	Gross Additions to Nonutility Plant	-449,925	-210,563
30	(Less) Allowance for Other Funds Used During Construction	3,391	-7,275,431
31	Other (provide details in footnote):		
32			
33	Customer Advances for Construction	1,292,262	-434,342
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-159,143,894	-349,662,621
35			
36	Acquisition of Other Noncurrent Assets (d)	-128,825	5,085
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-5,000,000	-7,000,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	15,000,000	100,000,000
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.
 (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)
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 Non Utility Plant	680,706	584,605
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-148,592,013	-256,072,931
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	106,419,500	224,185,317
62	Preferred Stock		
63	Common Stock		21,897,956
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69	Tax Withholding on Stock-Based Compensation	-226,301	
70	Cash Provided by Outside Sources (Total 61 thru 69)	106,193,199	246,083,273
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-50,009,533	-108,008,987
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-685,003	-685,003
81	Dividends on Common Stock	-146,471,060	-142,149,807
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-90,972,397	-4,760,524
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,238,165	-3,199,509
87			
88	Cash and Cash Equivalents at Beginning of Period	2,920,918	6,120,427
89			
90	Cash and Cash Equivalents at End of period	4,159,083	2,920,918

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) 12/31/2016	Year/Period of Report 2016/Q4
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.

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 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	------------------------------	--

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 Reacquired Debt, and 257, Unamortized Gain on Reacquired 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) 12/31/2016	Year/Period of Report 2016/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
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
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
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 294,000 natural gas residential, commercial, industrial and municipal customers in 278 communities and adjacent rural areas as of December 31, 2016.

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 \$761.0 million; current and accrued assets would increase by \$820.4 million; deferred debits would increase by \$904.5 million; long-term debt would increase by \$1.1 billion; other noncurrent liabilities and current and accrued liabilities would increase by \$366.6 million; and deferred credits would increase by \$1.1 billion as of December 31, 2016. Furthermore, operating revenues would increase by \$3.6 billion and operating expenses, excluding income taxes, would increase by \$3.3 billion for the twelve months ended December 31, 2016. In addition, net cash provided by operating activities would increase by \$221.4 million; net cash used in investing activities would increase by \$156.5 million; net cash used in financing activities would increase by \$103.9 million; the effect of exchange rate changes on cash would increase by \$4,000; and the net change in cash and cash equivalents would be a decrease of \$39.0 million for the twelve months ended December 31, 2016. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2016, up to the date of issuance of these financial statements.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of 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 \$856,000 and \$963,000 at December 31, 2016 and 2015, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2016 and 2015 was \$482,000 and \$448,000, respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage, were stated at the lower of average cost or market value. Natural gas in storage is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2016	2015
	(In thousands)	
Plant materials and operating supplies	\$ 17,337	\$ 19,057
Gas stored underground-current	12,822	11,509
Fuel stock	4,529	5,374
Total	\$ 34,688	\$ 35,940

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was \$2.7 million and \$2.4 million at December 31, 2016 and 2015, 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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

service. The amount of AFUDC capitalized for the years ended December 31 was as follows:

	2016	2015
	(In thousands)	
AFUDC - borrowed	\$ 357	\$ 3,909
AFUDC - equity	\$ (3)	\$ 7,275

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:

	2016	2015	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Electric:			
Generation	\$ 1,036,373	\$ 1,003,173	39
Distribution	398,382	375,612	44
Transmission	284,048	255,842	57
Construction in progress	62,110	42,435	-
Other	103,107	104,650	14
Natural gas distribution:			
Distribution	481,727	459,603	43
Construction in progress	5,698	6,992	-
Other	114,728	115,046	12
Less accumulated depreciation, depletion and amortization	878,704	835,121	
Net utility plant	\$ 1,607,469	\$ 1,528,232	
Nonutility property	\$ 16,091	\$ 15,641	
Less accumulated depreciation, depletion and amortization	4,352	3,678	
Net nonutility property	\$ 11,739	\$ 11,963	

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 2016 and 2015. 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.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2016 and 2015, there were no impairment losses recorded. At December 31, 2016, 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 3.3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2016. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued utility revenues represent revenues recognized in excess of amounts billed. Accrued utility revenues were \$47.6 million and \$39.3 million at December 31, 2016 and 2015, 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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 or refundable, as applicable, through rate adjustments were \$1.9 million and \$(3.7) million at December 31, 2016 and 2015, respectively, which is included in unrecovered purchased gas costs.

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

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

New accounting standards

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

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

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

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

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the statement of financial position for leases with terms of more than 12 months. This guidance also requires additional disclosures. This guidance will be effective for the Company on

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

January 1, 2019, and should be applied using a modified retrospective approach with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

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

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

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

disclosures.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from postretirement liability adjustments and other comprehensive income (loss) recorded by its subsidiaries.

The postretirement liability adjustment in other comprehensive income was \$1.7 million and \$(2.0) million, net of tax of \$(1.0) million and \$1.2 million, for the years ended December 31, 2016 and 2015, respectively.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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)

Twelve Months Ended December 31, 2015	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
(In thousands)			
Balance at December 31, 2014	\$ (3,994)	\$ (38,109)	\$ (42,103)
Other comprehensive income (loss) before reclassifications	249	(680)	(431)
Amounts reclassified from accumulated other comprehensive loss	103	3,028	3,131
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	(2,310)	4,565	2,255
Net current-period other comprehensive income (loss)	(1,958)	6,913	4,955
Balance at December 31, 2015	\$ (5,952)	\$ (31,196)	\$ (37,148)

Reclassifications out of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31,	2016	2015	Location on Statement of Income
(In thousands)			
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	\$ (2,182)	\$ (165)	(a)
	827	62	Income taxes
	(1,355)	(103)	
Subsidiary reclassifications out of accumulated other comprehensive loss	(1,661)	(3,028)	Equity in earnings of Subsidiary Companies
Total reclassifications	\$ (3,016)	\$ (3,131)	

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2016 and 2015. 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*	2016	2015
(In thousands)			
Regulatory assets:			
Pension and postretirement benefits (a)	(h)	\$ 101,611	\$ 107,595
Taxes recoverable from customers (a)	Over plant lives	15,989	16,714
Asset retirement obligations (a) (b)	---	9,437	8,000
Unamortized loss on required debt	Up to 10 years	5,298	5,968
Costs related to identifying generation development (c)	Up to 10 years	3,407	3,808
Unrecovered purchased gas costs	Up to 1 year	1,875	(3,670)
Other (a) (d) (e)	Largely within 1 year	18,754	2,740
Total regulatory assets		156,371	141,155
Regulatory liabilities:			
Plant removal and decommissioning costs (b) (f)		57,363	56,735
Pension and postretirement benefits (f)		9,099	3,591
Taxes refundable to customers (f)		6,177	7,045
Accumulated provision for rate refunds		1,343	917
Other (f) (g)		2,992	3,158
Total regulatory liabilities		76,974	71,446
Net regulatory position		\$ 79,397	\$ 69,709

* 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, 2016 and 2015, approximately \$121.2 million and \$122.2 million respectively, of regulatory assets were not earning a rate of return.

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 \$47.9 million and \$45.2 million as of December 31, 2016 and 2015, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized gains on these investments for the years ended December 31, 2016 and 2015, were \$2.3 million and \$1.1 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, 2016 and 2015, there were no transfers between Levels 1 and 2.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	Fair Value Measurements at December 31, 2016, Using				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.

	Fair Value Measurements at December 31, 2015, Using				Balance at December 31, 2015
	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	\$ —	\$ 410	\$ —	\$ —	\$ 410
Insurance contract*	—	45,192	—	—	45,192
Total assets measured at fair value	\$ —	\$ 45,602	\$ —	\$ —	\$ 45,602

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

The Company'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:

	2016		2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(In thousands)				
Long-term debt	\$ 681,755	\$ 717,599	\$ 625,265	\$ 652,415

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2016	Amount Outstanding at December 31, 2015	Letters of Credit at December 31, 2016	Expiration Date
(Dollars in millions)						
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a) \$ 175.0	\$ 111.0	(b) \$ 44.5	(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 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.

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	2016	2015
	(In thousands)	
Senior Notes at a weighted average rate of 5.02%, due on dates ranging from September 16, 2018 to November 21, 2046	\$ 570,000	\$ 580,000
Commercial paper at an interest rate of 1.07%, supported by revolving credit agreement	111,000	44,500
Credit agreements at a weighted average rate of 5.63%, due on dates ranging from January 1, 2020 to November 30, 2038	755	765
Total long-term debt	\$ 681,755	\$ 625,265

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

	2017	2018	2019	2020	2021	Thereafter
	(In thousands)					
Long-term debt maturities	\$110	\$100,111	\$111,111	\$21	\$13	\$470,389

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:

	2016	2015
	(In thousands)	
Balance at beginning of year	\$ 103,737	\$ 6,510
Liabilities incurred	10,834	---
Liabilities settled	(995)	---
Accretion expense	5,976	939
Revisions in estimates	(31)	96,288
Balance at end of year	\$ 119,521	\$ 103,737

The 2015 revisions in estimates consist principally of updated natural gas distribution mains and lines asset retirement obligation costs.

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.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Note 7 - Preferred Stocks

Preferred stocks at December 31 were as follows:

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

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

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

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

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

Note 8 - Common Stock

For the years 2016 and 2015, dividends declared on common stock were \$.7550 and \$.7350 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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

invest in the Company's common stock. From January 2014 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, purchased shares of authorized but unissued common stock from the Company. From September 2015 through December 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2016, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From September 2015 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan have been de-registered.

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

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

Note 9 - Stock-Based Compensation

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

Total stock-based compensation expense (after tax), excluding the amount recognized by the Company's subsidiaries, was \$808,000 and \$721,000 in 2016 and 2015, respectively.

As of December 31, 2016, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company's subsidiaries, related to stock-based compensation was approximately \$1.4 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

37,218 shares with a fair value of \$1.1 million and 58,181 shares with a fair value of \$1.1 million issued under this plan during the years ended December 31, 2016 and 2015, 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, 2016, were as follows:

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

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

	2016		2015	
Weighted average grant-date fair value		\$ 14.60		\$ 18.98
Blended volatility range	29.25 %	- 32.51 %	22.86 %	- 24.61 %
Risk-free interest rate range	.47 %	- .92 %	.05 %	- 1.07 %
Weighted average discounted dividends per share		\$ 1.56		\$ 1.57

The fair value of the performance shares that vested during the year ended December 31, 2016 was \$953,000. There were no performance shares that vested in 2015.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

Note 10 - Income Taxes

Income before income taxes for the years ended December 31, 2016 and 2015, respectively was \$62,176 and \$62,282.

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

	2016	2015
	(In thousands)	
Current:		
Federal	\$ (5,774)	\$ 12,202
State	(1,657)	1,879
	(7,431)	14,081
Deferred:		
Income taxes:		
Federal	11,595	1,566
State	2,303	506
Investment tax credit - net	(112)	(659)
	13,786	1,413
Total income tax expense	\$ 6,355	\$ 15,494

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	2016	2015
	(In thousands)	
Deferred tax assets:		
Postretirement	\$ 41,319	\$ 43,312
Production Tax Credits	16,944	3,400
Compensation-related	13,049	9,406
Customer advances	8,852	8,375
Other	7,729	5,435
Total deferred tax assets	87,893	69,928
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	297,848	277,128
Postretirement	41,039	40,922
Regulatory matters	5,937	6,195
Cost recovery mechanisms	4,635	392
Other	8,560	360
Total deferred tax liabilities	358,019	324,997
Net deferred income tax liability	\$ (270,126)	\$ (255,069)

As of December 31, 2016 and 2015, the Company had a federal income tax credit carryforward of \$16.9 million and \$3.4 million respectively. The federal income tax credit carryforwards will expire in 2036 and 2037 if not utilized. As of December 31, 2016 and 2015, 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, 2015, to December 31, 2016, to deferred income tax expense:

	2016
	(In thousands)
Change in net deferred income tax liability from the preceding table	\$ 15,057
Deferred taxes associated with other comprehensive income	(1,016)
Other	(255)
Deferred income tax expense for the period	\$ 13,786

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Years ended December 31,	2016		2015	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	\$ 21,762	35.0	\$ 21,799	35.0
Increases (reductions) resulting from:				
Production tax credit	(13,544)	(21.8)	(3,400)	(5.5)
Deductible K-Plan dividends	(1,180)	(1.9)	(1,109)	(1.8)
Nonqualified benefit plan	(1,085)	(1.7)	(590)	(0.9)
Amortization and deferral of investment tax credit	(73)	(0.1)	231	0.4
AFUDC equity	1	0.0	(2,546)	(4.1)
State income taxes, net of federal income tax	1,183	1.9	1,068	1.7
Tax compliance and uncertain tax positions	---	---	136	0.2
Other	(709)	(1.2)	(95)	(0.1)
Total income tax expense	\$ 6,355	10.2	\$ 15,494	24.9

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 2012. With few exceptions, as of December 31, 2016, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2011.

For the year ended December 31, 2015, the Company recognized approximately \$428,000 in interest expense, and \$192,000 in interest income, related to income taxes. The Company had accrued assets of approximately \$18,000 at both December 31, 2016 and 2015, 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:

	2016	2015
	(In thousands)	
Interest, net of amount capitalized and AFUDC – borrowed of \$357 and \$3,909 in 2016 and 2015, respectively	\$ 30,867	\$ 21,479
Income taxes refunded, net	\$ (8,641)	\$ (37,361)

Noncash investing transactions at December 31 were as follows:

	2016	2015
	(In thousands)	
Property, plant and equipment additions in accounts payable	\$ 9,495	\$ 28,359

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) 12/31/2016	Year/Period of Report 2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Note 12 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

Prior to 2015, all of the Company's defined pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits.

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

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.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
(In thousands)				
Change in benefit obligation:				
Benefit obligation at beginning of year	\$ 251,676	\$ 269,583	\$ 46,752	\$ 53,003
Service cost	—	—	716	914
Interest cost	9,679	9,678	1,749	1,835
Plan participants' contributions	—	—	825	806
Actuarial gain	(99)	(13,276)	(6,444)	(6,049)
Benefits paid	(15,398)	(14,309)	(3,331)	(3,757)
Benefit obligation at end of year	245,858	251,676	40,267	46,752
Change in net plan assets:				
Fair value of plan assets at beginning of year	183,045	201,078	47,449	50,124
Actual gain (loss) on plan assets	14,566	(5,906)	2,274	240
Employer contribution	—	2,182	36	36
Plan participants' contributions	—	—	825	806
Benefits paid	(15,398)	(14,309)	(3,331)	(3,757)
Fair value of net plan assets at end of year	182,213	183,045	47,253	47,449
Funded status – over (under)	\$ (63,645)	\$ (68,631)	\$ 6,986	\$ 697
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	\$ (63,645)	\$ (68,631)	\$ 6,986	\$ 697
Net amount recognized	\$ (63,645)	\$ (68,631)	\$ 6,986	\$ 697
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	\$ 108,983	\$ 115,715	\$ 3,416	\$ 10,046
Prior service credit	—	—	(9,204)	(10,181)
Total	\$ 108,983	\$ 115,715	\$ (5,788)	\$ (135)

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:

	2016	2015
(In thousands)		
Projected benefit obligation	\$ 245,858	\$ 251,676
Accumulated benefit obligation	\$ 245,858	\$ 251,676
Fair value of plan assets	\$ 182,213	\$ 183,045

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
(In thousands)				
Components of net periodic benefit cost (credit):				
Service cost	\$ —	\$ —	\$ 716	\$ 914
Interest cost	9,679	9,678	1,749	1,835
Expected return on assets	(11,467)	(12,295)	(2,591)	(2,681)
Amortization of prior service credit	—	—	(976)	(976)
Recognized net actuarial loss	3,535	4,016	502	985
Net periodic benefit cost (credit)	1,747	1,399	(600)	77
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities):				
Net (gain) loss	(3,198)	4,926	(6,127)	(3,608)
Amortization of actuarial loss	(3,535)	(4,016)	(502)	(985)
Amortization of prior service credit	—	—	976	976
Total recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities)	(6,733)	910	(5,653)	(3,617)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss/regulatory assets (liabilities)	\$ (4,986)	\$ 2,309	\$ (6,253)	\$ (3,540)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss or regulatory asset (liability), as applicable, into net periodic benefit cost in 2017 is \$3.6 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss or regulatory asset (liability), as applicable, into net periodic benefit cost in 2017 are \$62,000 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	
	2016	2015	2016	2015
Discount rate	3.81 %	3.97 %	3.83 %	4.04 %
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	
	2016	2015	2016	2015
Discount rate	3.98 %	3.69 %	4.04 %	3.73 %
Expected return on plan assets	6.75 %	7.00 %	5.75 %	6.00 %

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2016, the expected

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

	2016	2015
Health care trend rate assumed for next year	10.7%	4.0%
Health care cost trend rate - ultimate	4.5%	6.0%
Year in which ultimate trend rate achieved	2024	1999

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

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

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	\$ 30	\$ (26)
Effect on postretirement benefit obligation	\$ 1,692	\$ (1,453)

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

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

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

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

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	Fair Value Measurements at December 31, 2016, Using			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.

	Fair Value Measurements at December 31, 2015, Using			Balance at December 31, 2015
	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	\$ —	\$ 4,610	\$ —	\$ 4,610
Equity securities:				
U.S. companies	8,328	—	—	8,328
International companies	1,283	—	—	1,283
Collective and mutual funds *	84,957	34,977	—	119,934
Corporate bonds	—	34,194	—	34,194
Municipal bonds	—	6,427	—	6,427
U.S. Government securities	2,909	3,755	—	6,664
Total assets measured at fair value	\$ 97,477	\$ 83,963	\$ —	\$ 181,440

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

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

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

	Fair Value Measurements at December 31, 2016, Using			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.

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	Fair Value Measurements at December 31, 2015, Using			Balance at December 31, 2015
	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	\$ —	\$ 1,856	\$ —	\$ 1,856
Equity securities:				
U.S. companies	940	—	—	940
Insurance contract*	—	44,653	—	44,653
Total assets measured at fair value	\$ 940	\$ 46,509	\$ —	\$ 47,449

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

The Company expects to contribute approximately \$1.1 million to its defined benefit pension plans in 2017. The Company does not expect to contribute to its postretirement benefit plans in 2017.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
(In thousands)			
2017	\$ 14,593	\$ 2,785	\$ 133
2018	14,702	2,822	130
2019	14,759	2,769	126
2020	14,891	2,661	121
2021	15,011	2,642	115
2022 – 2026	75,508	12,905	445

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was \$509,000 and \$3.8 million in 2016 and 2015, 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 \$59.1 million and \$64.1 million at December 31, 2016 and 2015, respectively. The accumulated benefit obligation for these plans was \$59.1 million and \$60.0 million at December 31, 2016 and 2015, respectively. A discount rate of 3.54 percent and 3.76 percent at December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2015, were used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2016, due to the plans being froze. A discount rate of 3.76 percent and 3.50 percent for the years ended December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

for the years ended December 31, 2016 and 2015, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate \$3.8 million in 2017; \$4.0 million in 2018; \$4.2 million in 2019; \$4.5 million in 2020, \$4.5 million in 2021 and \$21.6 million for the years 2022 through 2026.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2016 and 2015 were \$33,000 and \$30,000, respectively.

The Company had investments of \$68.2 million and \$64.6 million at December 31, 2016 and 2015, respectively, consisting of equity securities of \$42.2 million and \$34.2 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of \$20.4 million and \$19.7 million, respectively, and other investments of \$5.6 million and \$10.7 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees, and costs incurred under these plans were \$10.7 million in 2016 and \$10.4 million in 2015.

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:

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

Note 14 - Regulatory Matters and Revenues Subject to Refund

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately \$1.6 million

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.		12/31/2016	2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

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

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

On March 1, 2017, Montana-Dakota filed its annual updates to its Infrastructure Rider and Transmission Cost Recovery Rider with the SDPUC. No change in rates was proposed for the Infrastructure Rider with a change of approximately \$127,000 proposed over current rates to be recovered through the Transmission Cost Recovery Rider. The matters are pending before the SDPUC.

On April 1, 2017, Phase 2 of the revenue increase, approved by the MTPSC as part of the application for an electric rate increase filed on June 25, 2015, was implemented. This resulted in an additional increase of \$4.7 million effective with service rendered on and after April 1, 2017.

Note 15 - Commitments and Contingencies
Claims and Litigation

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

\$1.7 million and \$1.1 million for contingencies related to litigation as of December 31, 2016 and 2015, respectively.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2016, were \$2.1 million in 2017, \$1.8 million in 2018, \$1.8 million in 2019, \$1.7 million in 2020, \$1.6 million in 2021 and \$27.0 million thereafter. Rent expense was \$2.0 million and \$3.6 million for the years ended December 31, 2016 and 2015, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 27 years. The commitments under these contracts as of December 31, 2016, were \$144.2 million in 2017, \$71.2 million in 2018, \$66.3 million in 2019, \$49.3 million in 2020, \$44.1 million in 2021 and \$137.8 million thereafter. These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2016 and 2015, were \$228.1 million and \$417.1 million, respectively.

Note 16 - Subsequent Event

On March 1, 2017, the Company provided notice of its intent to redeem all outstanding shares of preferred stock. Effective April 1, 2017, all outstanding preferred shares were redeemed.

**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)	1,955,065,752	1,300,936,832
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	452,813,804	440,416,305
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,407,879,556	1,741,353,137
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	67,808,467	59,471,192
12	Acquisition Adjustments	10,484,909	10,387,643
13	Total Utility Plant (8 thru 12)	2,486,172,932	1,811,211,972
14	Accum Prov for Depr, Amort, & Depl	878,703,820	582,483,079
15	Net Utility Plant (13 less 14)	1,607,469,112	1,228,728,893
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	839,553,772	570,038,828
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	28,695,916	2,056,608
22	Total In Service (18 thru 21)	868,249,688	572,095,436
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	10,454,132	10,387,643
33	Total Accum Prov (equals 14) (22,26,30,31,32)	878,703,820	582,483,079

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
528,808,631				125,320,289	3
					4
					5
11,784,780				612,719	6
					7
540,593,411				125,933,008	8
					9
					10
3,881,032				4,456,243	11
97,266					12
544,571,709				130,389,251	13
245,331,446				50,889,295	14
299,240,263				79,499,956	15
					16
					17
243,338,976				26,175,968	18
					19
					20
1,925,981				24,713,327	21
245,264,957				50,889,295	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
66,489					32
245,331,446				50,889,295	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	3,648,522	86,083
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	3,648,522	86,083
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,018,687	
9	(311) Structures and Improvements	73,555,519	2,865,053
10	(312) Boiler Plant Equipment	322,778,352	27,043,143
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	85,095,309	1,555,744
13	(315) Accessory Electric Equipment	19,560,325	948,947
14	(316) Misc. Power Plant Equipment	18,512,618	1,961,066
15	(317) Asset Retirement Costs for Steam Production	5,186,357	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	525,707,167	34,373,953
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	6,854,115	80,619
39	(342) Fuel Holders, Products, and Accessories	3,108,228	183,292
40	(343) Prime Movers		
41	(344) Generators	435,510,579	-4,552,162
42	(345) Accessory Electric Equipment	15,647,190	492,951
43	(346) Misc. Power Plant Equipment	1,255,382	-131,052
44	(347) Asset Retirement Costs for Other Production	4,663,120	7,394,225
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	467,077,147	3,467,873
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	992,784,314	37,841,826

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
			3,734,605		4
			3,734,605		5
					6
					7
3,625			1,015,062		8
308,470			76,112,102		9
2,314,442			347,507,053		10
					11
804,114			85,846,939		12
6,823			20,502,449		13
880,565		123,723	19,716,842		14
			5,186,357		15
4,318,039		123,723	555,886,804		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			38,533		37
2,934			6,931,800		38
63,182			3,228,338		39
					40
451,552		9,284	430,516,149		41
43,989			16,096,152		42
		106,345	1,230,675		43
			12,057,345		44
561,657		115,629	470,098,992		45
4,879,696		239,352	1,025,985,796		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	4,373,336	332,991
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	123,675,156	17,361,424
51	(354) Towers and Fixtures	4,992,886	
52	(355) Poles and Fixtures	74,357,092	413,102
53	(356) Overhead Conductors and Devices	43,394,790	10,657,451
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)	255,842,286	28,764,968
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,766,231	226,926
61	(361) Structures and Improvements		
62	(362) Station Equipment	63,969,356	7,477,674
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	39,878,914	2,228,175
65	(365) Overhead Conductors and Devices	30,964,325	2,381,207
66	(366) Underground Conduit	223,988	
67	(367) Underground Conductors and Devices	105,239,104	7,967,424
68	(368) Line Transformers	68,315,087	2,454,797
69	(369) Services	35,018,561	1,387,318
70	(370) Meters	17,913,978	462,165
71	(371) Installations on Customer Premises	2,798,292	156,963
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	7,484,880	336,449
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	375,612,464	25,079,098
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	1,552,609	15,312
88	(391) Office Furniture and Equipment	664,097	36,526
89	(392) Transportation Equipment	8,612,802	828,140
90	(393) Stores Equipment	14,774	
91	(394) Tools, Shop and Garage Equipment	3,667,227	188,291
92	(395) Laboratory Equipment	539,358	218,094
93	(396) Power Operated Equipment	14,542,636	1,897,958
94	(397) Communication Equipment	495,451	150,415
95	(398) Miscellaneous Equipment	58,769	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	30,186,573	3,334,736
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	30,186,573	3,334,736
100	TOTAL (Accounts 101 and 106)	1,658,074,159	95,106,711
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)	1,658,074,159	95,106,711

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
			4,706,327	48
			1,789	49
230,765			140,805,815	50
			4,992,886	51
246,410		-340	74,523,444	52
81,854			53,970,387	53
			1,944,583	54
			3,101,857	55
				56
			797	57
559,029		-340	284,047,885	58
				59
			3,993,157	60
				61
137,237			71,309,793	62
				63
300,543		340	41,806,886	64
182,074			33,163,458	65
			223,988	66
590,839			112,615,689	67
583,233	-43		70,186,608	68
181,376			36,224,503	69
75,875			18,300,268	70
99,027			2,856,228	71
				72
159,324			7,662,005	73
			39,748	74
2,309,528	-43	340	398,382,331	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			38,850	86
165,689			1,402,232	87
231,613			469,010	88
1,221,765		274,922	8,494,099	89
			14,774	90
25,043		32,044	3,862,519	91
27,398			730,054	92
3,032,460		113,930	13,522,064	93
36,135		418	610,149	94
			58,769	95
4,740,103		421,314	29,202,520	96
				97
				98
4,740,103		421,314	29,202,520	99
12,488,356	-43	660,666	1,741,353,137	100
				101
				102
				103
12,488,356	-43	660,666	1,741,353,137	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	48,364,401
2	Construct 230/34.5 kV substation in Watford City, ND	2,162,706
3	Construct 115/69kV bay in substation near Stanley, ND	1,197,412
4	Construct 115/12.5kV S. 9th Street substation in Bismarck, ND	1,171,662
5	Construct 230kV substation for Foxtail Wind near Ellendale, ND	-5,994,141
6		
7	Minor projects less than \$1,000,000:	
8	Steam Production	1,924,528
9	Other Production	437,148
10	Transmission	6,012,554
11	Distribution	1,955,937
12	General	599,305
13	Intangible	1,639,680
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	59,471,192

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	540,299,158	540,299,158		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	48,934,860	48,934,860		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,165,869	1,165,869		
7	Other Clearing Accounts	-140,378	-140,378		
8	Other Accounts (Specify, details in footnote):	-1,614,325	-1,614,325		
9		571,898	571,898		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	48,917,924	48,917,924		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	12,488,356	12,488,356		
13	Cost of Removal	1,932,049	1,932,049		
14	Salvage (Credit)	1,903,730	1,903,730		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	12,516,675	12,516,675		
16	Other Debit or Cr. Items (Describe, details in footnote):	-6,661,579	-6,661,579		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	570,038,828	570,038,828		

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

20	Steam Production	243,975,327	243,975,327		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	69,445,344	69,445,344		
25	Transmission	102,052,730	102,052,730		
26	Distribution	144,645,599	144,645,599		
27	Regional Transmission and Market Operation				
28	General	9,919,828	9,919,828		
29	TOTAL (Enter Total of lines 20 thru 28)	570,038,828	570,038,828		

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			849,293,487
4				
5	Equity in undistributed subsidiary earnings since acquisition			395,220,819
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			446,942,839
10				
11	Equity in undistributed subsidiary earnings since acquisition			30,893,629
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	1,722,350,774

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
		821,876,154		3
				4
-5,576,010	98,014,680	291,525,852		5
				6
				7
				8
		464,920,152		9
				10
14,187,765	19,500,000	25,551,644		11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
8,611,755	117,514,680	1,603,873,802		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)	5,373,602	4,528,869	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)	15,221,043	13,266,709	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,627,737	2,874,413	Electric
8	Transmission Plant (Estimated)	335,632	91,892	Electric
9	Distribution Plant (Estimated)	1,124,380	1,318,107	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-251,453	-214,431	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	19,057,339	17,336,690	
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)	24,430,941	21,865,559	

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) 12/31/2016	Year/Period of Report 2016/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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	52,100.00		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	5,078.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Transfer-Lewis & Clark				
23	Station to Wygen III	20.00			
24	Transfer-Heskett Station				
25	to Wygen III	20.00			
26					
27					
28	Total	40.00			
29	Balance-End of Year	46,982.00		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	167.00		168.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year	167.00		168.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
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.

2018		2019		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		353,882.00		1
								2
								3
				11,607.00		11,607.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						5,078.00		18
								19
								20
								21
								22
						20.00		23
								24
						20.00		25
								26
								27
						40.00		28
11,607.00		11,607.00		278,568.00		360,371.00		29
								30
								31
								32
								33
								34
								35
168.00		242.00		6,512.00		7,257.00		36
								37
								38
				67.00		67.00		39
168.00		242.00		6,445.00		7,190.00		40
								41
								42
								43
				67.00	3	67.00		3 44
				67.00	3	67.00		3 45
								46

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/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	171,860	773,372
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			189,106	1,859,593
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	814,359	407	40,718	773,641
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	814,359		401,684	3,406,606

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

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

407	\$242,228
419	<u>(53,122)</u>
	\$189,106

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) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

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 AFUDC on portion of Coyote I Station	110,212		403	110,212	
2	that had been disallowed in rate base by Montana;					
3	amortization of 12/83 balance over 388 months end-					
4	ing 10/16 and amortization of 6/84 balance over					
5	356 months					
6						
7	Deferred depreciation on portion of Coyote I	25,657		403	25,657	
8	Station that had been disallowed in rate base by					
9	Montana; amortization of 12/83 balance over 388					
10	months ending 10/16 and amortization of 6/84					
11	balance over 356 months					
12						
13	Interest deferred on portion of Coyote I Station	4,508		403	4,508	
14	AFUDC which had been disallowed in rate base by					
15	Montana; amortization of interest on 6/84 AFUDC					
16	balance over 356 months					
17						
18	Unamortized Regulatory Commission Expense:	600,575	694,458		559,676	735,357
19	Montana gas amortization over 36 months					
20	ending 1/17; South Dakota gas amortization					
21	over 36 months ending 6/19; North Dakota					
22	gas amortization over 36 months ending 1/18;					
23	Wyoming gas amortization over 60 months ending 5/20					
24	Montana electric amortization over 36 months ending					
25	3/19; South Dakota electric amortization over					
26	60 months ending 6/21					
27						
28	Accumulated costs associated with gas rate	370,107	1,364,457	182.3	694,458	1,040,106
29	cases in Wyoming and Minnesota, and electric					
30	rate cases in North Dakota, Montana,					
31	South Dakota, and Wyoming					
32						
33	Asset Retirement Obligations	79,069,572	7,123,348	230	985,115	85,207,805
34						
35	Deferred Fuel and Purchased Power Costs -					
36	North Dakota - Electric	(2,287,720)			481,448	-2,769,168
37	Wyoming - Electric	249,992			2,052	247,940
38	Montana - Electric	(1,596,707)	834,522			-762,185
39	South Dakota - Electric				78,715	-78,715
40						
41	Deferred Pension	107,544,416		253	6,086,023	101,458,393
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) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter /Year Account Charged (d)	Written off During the Period Amount (e)	
1	Manufactured Gas Plant Site - Bismarck, ND	181,533		928	90,780	90,753
2	amortization over 120 months ending 12/17					
3	Regulatory Matters -Deferred Tax Related	16,713,768	1,340,326		2,064,858	15,989,236
4						
5	Electric Generation Development Costs	814,359		182.2	814,359	
6						
7	ND Transmission Cost Recovery Adjustment -	441,081	8,615,265	400	4,125,305	4,931,041
8	[PU-11-672]					
9						
10	Montana Public Service Commission/Montana	515,476	59,654	408.1	200,621	374,509
11	Consumer Counsel tax deferral [Docket No.					
12	D2014.8.72, D2015.9.67, D2015.9.68 and					
13	D2015.6.51]					
14						
15	ND Environmental Cost Recovery Rider	596,102	2,674,551	400	94,454	3,176,199
16	[Case No. PU-13-85]					
17						
18	WY Renewable Energy Rider	(136)	45	142	106	-197
19	[Docket No. 20004-108-ET-14]					
20						
21	Manufactured Gas Plant Site - Billings, MT	297,214	84,131			381,345
22	[Docket No. D2014.11.95]					
23						
24	Deferred Pension Expense - ND Gas	50,868	101,276			152,144
25	[Case No. PU-15-90]					
26						
27	ND Generation Resource Recovery Rider		2,462,590	400	2,003	2,460,587
28	[Case No. PU-15-704]					
29						
30	ND Renewable Resource Cost Adjustment		2,575,294	400	1,129,072	1,446,222
31	[Case No. PU-15-703]					
32						
33	Loss on Buildings - North Dakota		2,829,847			2,829,847
34						
35	SD Transmission Rider		105,866	400	27,830	78,036
36	[Docket No. EL15-024]					
37						
38	SD Infrastructure Rider		204,726	400	19,954	184,772
39	[Docket No. EL15-024]					
40						
41	MN Revenue Decoupling		366,236			366,236
42	[Docket No. G004/GR-15-879]					
43						
44	TOTAL :	203,700,877	31,436,592		17,597,206	217,540,263

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) 12/31/2016	2016/Q4
FOOTNOTE DATA			

Schedule Page: 232	Line No.: 18	Column: d
---------------------------	---------------------	------------------

928(Electric)	(88,038)
184	(150,421)
928(Gas)	(321,217)
	<u>(559,676)</u>

Schedule Page: 232	Line No.: 36	Column: d
---------------------------	---------------------	------------------

555(Deferral)	(904,402)
555(Amortization)	431,011
431	(8,019)
419	(15)
229	(23)
	<u>(481,448)</u>

Schedule Page: 232	Line No.: 37	Column: d
---------------------------	---------------------	------------------

555(Deferral)	197,992
555(Amortization)	(199,971)
431	(73)
	<u>(2,052)</u>

Schedule Page: 232	Line No.: 38	Column: c
---------------------------	---------------------	------------------

555(Deferral)	(302,292)
447(Deferral)	(8,067)
555(Amortization)	1,205,968
431	(61,087)
	<u>834,522</u>

Schedule Page: 232	Line No.: 39	Column: d
---------------------------	---------------------	------------------

555(Deferral)	(78,793)
431	(29)
419	107
	<u>(78,715)</u>

Schedule Page: 232.1	Line No.: 3	Column: d
-----------------------------	--------------------	------------------

282	(1,282,272)
283	(782,586)
	<u>(2,064,858)</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		91,479		91,479	
2						
3	Conservation programs	-993,260	2,947,924		2,195,760	-241,096
4						
5	Advance to FutureSource Capital Corp. for land	784,342	344,766			1,129,108
6						
7						
8	Goodwill - Great Plains Natural Gas Co.	4,812,244				4,812,244
9						
10						
11	Subsidiary post-retirement trust assets	16,153,081			2,721,771	13,431,310
12						
13						
14	Post-retirement Benefit Costs	697,036	6,413,033	131	124,144	6,985,925
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	21,453,443				26,117,491

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

181	\$	80,499
214		10,980
	\$	<u>91,479</u>

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

142	\$2,185,986
143	9,143
419	587
488	29
131	15
	<u>\$2,195,760</u>

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

228.3	\$1,725,735
253	646,691
186	349,345
	<u>\$2,721,771</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	9,685,010	8,801,848
3	Compensation-related	5,151,810	7,390,427
4	Customer Advances	1,839,697	1,904,888
5	Postretirement Benefit Costs	579,223	1,458,716
6	Production Tax Credit Carryforward	3,399,955	16,943,932
7	Other	2,139,994	4,632,089
8	TOTAL Electric (Enter Total of lines 2 thru 7)	22,795,689	41,131,900
9	Gas		
10	Pension Expense	12,944,508	11,764,197
11	Customer Advances	6,535,716	6,947,238
12	Compensation-related	4,254,187	5,658,436
13	Postretirement Benefit Costs	781,882	1,989,828
14	Uniform Capitalization	385,134	410,603
15	Other	1,115,666	747,259
16	TOTAL Gas (Enter Total of lines 10 thru 15)	26,017,093	27,517,561
17	Other (Specify) *	21,115,728	19,243,434
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	69,928,510	87,892,895

Notes

	Balance at Beginning of Year	Balance at End of Year
*Non-Utility		
Uniform Capitalization	7,114	-
C.I.A.C.'s	646,909	938,822
Charitable Contributions	281,335	329,615
Contingency Reserve	75,801	-
ITC-State	692,231	648,020
SISP Expense	19,321,366	17,304,339
MISO MVP Reserve	51,139	-
AMT Carryforward	17,464	-
State Credit Carryforward	22,584	22,584
Bad Debts Expense	(215)	54
Total Non-Utility	21,115,728	19,243,434

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			105.00
8	4.70% Cumulative			102.00
9				
10	Total Account 204	500,000		
11				
12	Preferred Stock A - Cumulative	1,000,000		
13				
14	Preference Stock - Cumulative	500,000		
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
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
100,000	10,000,000					7
50,000	5,000,000					8
						9
150,000	15,000,000					10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

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) 12/31/2016	Year/Period of Report 2016/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: d

Plus accrued dividends

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

Plus accrued dividends

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/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

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 254 Line No.: 2 Column: b

The 2016 Capital Stock Expense balance increased \$10,979 in connection with prior year issuance of common stock.

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	6.66%	25,000,000	68,308
9	6.61%	25,000,000	68,308
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	66,042
18			
19	SUBTOTAL	620,000,000	3,078,911
20			
21	5.1% Preferred Stock, Cumulative, subject to redemption	5,000,000	
22	Commercial Paper - 0.823% average for 2016		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	625,509,197	3,719,988

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	091618	091608	091618	100,000,000	6,040,000	7
100109	093016	100109	093016		1,244,125	8
090109	093016	090109	093016		1,234,785	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	184,444	17
						18
				570,000,000	29,617,254	19
						20
052361				308,600	15,739	21
				111,000,000	899,851	22
092308	113038			446,386	27,103	23
				111,754,986	942,693	24
						25
						26
						27
						28
						29
						30
						31
						32
				681,754,986	30,559,947	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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

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

The Respondent intends to make annual sinking fund contributions to retire 1,000 shares of 5.1% Series preferred stock at par. The redemption price is \$102 plus accrued dividends.

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)	64,432,820
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Dividends Received from Subsidiary Companies	117,514,680
6	See Footnote	7,347,748
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	70,152,883
11	AFUDC Equity	3,391
12	Unamortized Loss on Reacquired Debt	670,246
13	See Footnote	26,476,283
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	8,611,755
16		
17		
18	See Footnote	11,737,030
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	148,998,902
21	Dividends Received From Subsidiaries	117,514,680
22	Regulatory Commission Expense	804,781
23	Supplemental Income Security Plan	5,740,496
24	Prepaid Demand Charges	447,020
25	Unrecovered Purchased Gas Cost	1,376,343
26	See Footnote	10,692,527
27	Federal Tax Net Income	-19,325,483
28	Show Computation of Tax:	
29	Federal Tax @ 35% of line 27	-6,763,919
30	Other Credits and Adjustments	-28,245
31	Wind Production Credit	
32	Closing/Filing True-Up & Out of Period Adjustments	1,018,524
33		
34	Total	-5,773,638
35		
36	Response to Instruction #2 - See Footnote	
37		
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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

Taxable Income Not Reported on Books:

Reserved Revenues	\$ 426,737
MISO MVP Reserve	383,560
Contributions in Aid of Construction	5,252,530
Customer Advances	1,256,676
Fuel Tax Credit	28,245
Total Carried to page 261, line 6	<u>\$ 7,347,748</u>

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

Deductions Recorded on Books Not Deducted for Return:

Bad Debts	\$ 33,704
Federal Income Tax Provision	5,820,765
State Income Tax Provision	533,962
State Income Tax Deduction	1,216,830
Disallowed Meals and Entertainment Expense - 50	194,906
Preferred Stock Expense	15,739
Regulatory Assets Awaiting Recovery	814,359
Capitalized Overheads	66,319
Bonus Accrual & 401k Profit Sharing	9,361,760
Deferred Compensation - Directors	1,155,732
Vacation Accrual	252,800
Management Incentive	71,802
Pension Expense	530,457
Montana Decommissioning	5,965,841
Montana PSC/MCC Tax Deferral	140,967
Charitable Contributions	174,287
Lobbying Expenses	117,353
Manufactured Gas Plant	6,648
F&PP Deferral	2,052
Total Carried to page 261, line 13	<u>\$26,476,283</u>

Schedule Page: 261 Line No.: 18 Column: b

Income Recorded on Books Not Included in Return:

Cost Recovery Mechanisms	\$11,239,673
Mor-Gran-Sou Capacity Revenue	81,806
WAPA Fiber Demand Revenue	49,315
Minnesota Decoupling	366,236
Total Carried to page 261 line 18	<u>\$11,737,030</u>

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

Deductions on Return Not Charged Against Book Income:

Dividend Paid Deduction	\$ 180,001
401(k) Dividend Deduction	3,370,426
Board of Directors - Retirement Benefits	42,188
Performance Share Program	1,197,899
Post Retirement Benefits	431,960
Contingency Reserve	732,357
Deferred Medicare Part D	264,203
Abandoned Power Plant Cost Recovery	412,675
Retired Power Plant	51,884
Loss on Buildings	2,847,412
Prepaid Expenses	1,085,229
Miscellaneous	76,293
Total Carried to page 261, line 24	<u>\$10,692,527</u>

Schedule Page: 261 Line No.: 36 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

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

(Earnings and Profits). The 2016 federal tax provisions were:

Centennial Energy Holdings, Inc.	\$82,250,960
MDU Energy Capital	<u>5,510,972</u>
Total	\$87,761,932

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	1,338,758		-5,773,639	-1,725,366	1,220,718
3	State	-880,062		-1,657,170	-6,916,436	118,910
4	SUBTOTAL	458,696		-7,430,809	-8,641,802	1,339,628
5						
6	UNEMPLOYMENT					
7	Federal	29,893		59,302	57,287	
8	Arizona	40		-40		
9	Idaho	17,395		78,117	79,027	
10	Minnesota	1,031		6,768	7,270	
11	Montana	3,998		17,476	19,431	
12	Nevada					
13	North Dakota	11,681		85,316	76,955	
14	Oregon					
15	South Dakota	1,661		5,226	5,301	
16	Washington	3,758		10,695	13,296	
17	Wyoming	669		3,182	3,090	
18	SUBTOTAL	70,126		266,042	261,657	
19						
20	GROSS REVENUE					
21	Montana	81,775		371,806	319,769	
22	South Dakota			83,750	83,750	
23	Wyoming	59,843		91,221	105,454	
24	SUBTOTAL	141,618		546,777	508,973	
25						
26	USE					
27	Minnesota	306		11,987	11,983	
28	North Dakota	-1,267		273,942	237,774	
29	South Dakota	8,096		34,229	39,900	
30	Washington			918		
31	Wyoming	1,260		70,489	67,419	
32	Idaho	504		5,629	4,394	
33	Iowa					
34	Nebraska					
35	SUBTOTAL	8,899		397,194	361,470	
36						
37	PROPERTY					
38	Minnesota (GPNG)	595,000		696,465	602,465	
39	Montana	3,922,141		9,496,357	8,672,494	
40	North Dakota	3,704,844		3,497,062	3,708,754	
41	TOTAL	10,994,840		18,113,799	15,455,997	1,339,628

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-1,488,797		-12,175,706			6,402,067	2
4,498,114		-1,575,121			-82,049	3
3,009,317		-13,750,827			6,320,018	4
						5
						6
31,908		16,297			43,005	7
					-40	8
16,485		10,921			67,196	9
529		107			6,661	10
2,043		9,174			8,302	11
						12
20,042		31,970			53,346	13
						14
1,586		1,028			4,198	15
1,157		288			10,407	16
761		1,171			2,011	17
74,511		70,956			195,086	18
						19
						20
133,812		243,435			128,371	21
		18,343			65,407	22
45,610		55,469			35,752	23
179,422		317,247			229,530	24
						25
						26
310					11,987	27
34,901					273,942	28
2,425					34,229	29
918					918	30
4,330					70,489	31
1,739					5,629	32
						33
						34
44,623					397,194	35
						36
						37
689,000					696,465	38
4,746,004		5,159,114			4,337,243	39
3,493,152		2,336,013			1,161,049	40
14,992,270		-1,003,259			19,117,058	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)	30,640		32,397	30,640	
2	South Dakota	1,207,103		1,014,516	1,207,745	
3	Wyoming	136,601		261,777	267,489	
4	SUBTOTAL	9,596,329		14,998,574	14,489,587	
5						
6						
7	FRANCHISE					
8	Delaware	36,050		180,050	180,050	
9	Wyoming	107,213		258,904	242,815	
10	Hettinger, ND	1,041		6,204	6,085	
11						
12	SUBTOTAL	144,304		445,158	428,950	
13						
14						
15						
16	MISCELLANEOUS					
17	Federal-FICA	487,360		7,469,156	6,914,933	
18	Federal-Highway Use			6,730	6,730	
19	Montana WET Tax	30,175		120,985	122,779	
20	Montana-Electric License	11,606		76,017	67,465	
21	ND-Coal Conversion	36,061		918,382	917,850	
22	ND-Generation Tax			274,337		
23						
24	Secretaries of State					
25	(annual filing fees)			2,568	2,568	
26	Fort Peck Tribal	4,483		12,000	4,483	
27	Crow Agency Tribal	4,843		10,356	10,021	
28	Federal CNG Tax	9			3	
29	Montana CNG Tax	435		328	326	
30	North Dakota CNG Tax	-104		4	4	
31	South Dakota CNG Tax					
32	SUBTOTAL	574,868		8,890,863	8,047,162	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	10,994,840		18,113,799	15,455,997	1,339,628

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)	
32,397					32,397	1
1,013,874		494,704			519,812	2
130,889		196,692			65,085	3
10,105,316		8,186,523			6,812,051	4
						5
						6
						7
36,050		106,770			73,280	8
123,302		169,129			89,775	9
1,160					6,204	10
						11
160,512		275,899			169,259	12
						13
						14
						15
						16
1,041,583		2,488,591			4,980,565	17
		5,108			1,622	18
28,381		120,985				19
20,158		76,017				20
36,593		918,382				21
274,337		274,337				22
						23
						24
		1,523			1,045	25
12,000		12,000				26
5,178					10,356	27
6						28
437					328	29
-104					4	30
						31
1,418,569		3,896,943			4,993,920	32
						33
						34
						35
						36
						37
						38
						39
						40
14,992,270		-1,003,259			19,117,058	41

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) 12/31/2016	2016/Q4
FOOTNOTE DATA			

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

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

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

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

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

Allocated on a gross revenue ratio by state.

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

Charged directly to various inventory and construction accounts.

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

Allocated based on specific identification.

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

Allocated on a corporate overhead ratio basis.

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

Allocated based on specific identification.

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

Allocated based on specific identification.

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

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

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

Allocated on a corporate overhead ratio basis.

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

Allocated on a corporate overhead ratio basis.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		1,752,301			420	111,916	
8	TOTAL	1,752,301				111,916	
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
1,640,385			7
1,640,385			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	68,631,374		6,732,714	1,746,833	63,645,493
2						
3	Accrued and deferred benefit					
4	compensation plans	6,950,382		720,259	2,023,367	8,253,490
5						
6	Intercompany portion of					
7	Supplemental Income					
8	Security Program trust assets	16,200,949	131	41,545	592,701	16,752,105
9						
10	Gas affordability tracker	15,080	131	10,309		4,771
11						
12	Capacity rights contracts	2,284,027	454	131,121		2,152,906
13						
14						
15						
16	MISO MVP Reserve	300,751	456	254,943	638,503	684,311
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	94,382,563		7,890,891	5,001,404	91,493,076

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

182	\$5,828,228
186	904,486
	<u>\$6,732,714</u>

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

131	\$ 122,692
216	11,552
242	586,015
	<u>\$ 720,259</u>

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

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities		566,031	22,400
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)		566,031	22,400
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)		566,031	22,400
18	Classification of TOTAL			
19	Federal Income Tax		502,031	
20	State Income Tax		64,000	22,400
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)

12/31/2016

Year/Period of Report

End of 2016/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	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)	(k)	
							1
							2
							3
		282	46,446	282	1,838	499,023	4
							5
							6
							7
			46,446		1,838	499,023	8
							9
							10
							11
							12
							13
							14
							15
							16
			46,446		1,838	499,023	17
							18
			41,194			460,837	19
			5,252		1,838	38,186	20
							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	205,365,446	39,392,341	10,113,788
3	Gas	57,638,135	1,514,015	4,465,531
4	Utility	3,378,718		
5	TOTAL (Enter Total of lines 2 thru 4)	266,382,299	40,906,356	14,579,319
6	Non-Utility	4,411,573		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	270,793,872	40,906,356	14,579,319
10	Classification of TOTAL			
11	Federal Income Tax	249,644,290	35,660,009	11,620,100
12	State Income Tax	21,149,582	5,246,347	2,959,219
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	1,632,966	282	1,741,713	234,752,746	2
			929,117		864,978	54,622,480	3
			2,492,452		2,741,377	3,627,643	4
			5,054,535		5,348,068	293,002,869	5
54,052	119,199					4,346,426	6
							7
							8
54,052	119,199		5,054,535		5,348,068	297,349,295	9
							10
39,821	92,634		3,516,321		4,071,093	274,186,158	11
14,231	26,565		1,538,214		1,276,975	23,163,137	12
							13

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) 12/31/2016	2016/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 3 Column: g

282	\$ 927,279
281	1,838
	<u>\$ 929,117</u>

Schedule Page: 274 Line No.: 3 Column: i

282	\$ 818,532
281	46,446
	<u>\$ 864,978</u>

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

Utility definition includes Regulatory Matters.

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

Regulatory Matters - 254	\$(7,000,493)
Regulatory Matters - 182.3	10,379,211
	<u>\$ 3,378,718</u>

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

Regulatory Matters - 254	\$ 1,210,180
Regulatory Matters - 182.3	1,282,272
	<u>\$ 2,492,452</u>

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

Regulatory Matters - 254	\$ 1,909,038
Regulatory Matters - 182.3	832,339
	<u>\$ 2,741,377</u>

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

Regulatory Matters - 254	\$(6,301,635)
Regulatory Matters - 182.3	9,929,278
	<u>\$ 3,627,643</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	87,497	138,450	139,168
4	Def. Pension Exp - Reg Asset	17,488,260	204,116	1,194,139
5	Unamort Loss on Required Debt	1,721,394	143,121	267,672
6	Reg Assets Awaiting Recovery	285,026		285,026
7	Unrecovered Plant Costs	1,160,356	289,283	157,164
8	Other - Electric	1,000,141	9,221,087	2,881,281
9	TOTAL Electric (Total of lines 3 thru 8)	21,742,674	9,996,057	4,924,450
10	Gas			
11	Unrecovered Purch. Gas Costs	223,520	1,471,956	946,307
12	Regulatory Commission Expense	272,166	315,568	251,595
13	Unamort Loss on Required Debt	546,173	7,770	138,166
14	Def. Pension Exp - Reg Asset	23,371,848	200,550	1,523,460
15	Reg Assets Awaiting Recovery	70,650	39,709	110,347
16	Other - Gas	1,713,417	4,897,822	2,790,106
17	TOTAL Gas (Total of lines 11 thru 16)	26,197,774	6,933,375	5,759,981
18	Other	6,262,777		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	54,203,225	16,929,432	10,684,431
20	Classification of TOTAL			
21	Federal Income Tax	49,786,107	14,732,722	8,956,615
22	State Income Tax	4,417,118	2,196,710	1,727,816
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)		
						86,779	3
						16,498,237	4
						1,596,843	5
							6
						1,292,475	7
						7,339,947	8
						26,814,281	9
							10
						749,169	11
						336,139	12
						415,777	13
						22,048,938	14
						12	15
		190	1,259,502	190	1,243,317	3,804,948	16
			1,259,502		1,243,317	27,354,983	17
2,527	6,212		2,848,167		2,590,038	6,000,963	18
2,527	6,212		4,107,669		3,833,355	60,170,227	19
							20
2,241	6,112		1,946,368		1,695,906	55,307,881	21
286	100		2,161,301		2,137,449	4,862,346	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

UTILITY: Other - Electric	
Contingency Reserve	\$ 2,637
Regulatory Commission Expense	94,840
MT PSC/MCC Tax Deferral	171,147
ND Environmental Cost Recovery Rider	225,731
Postretirement Benefit Costs	78,593
Property Insurance	260,458
Transmission Cost Adj	166,735
	\$ 1,000,141

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

UTILITY: Other - Electric	
Regulatory Commission Expense	\$ 354,630
MT PSC/MCC Tax Deferral	7,726
ND Environmental Cost Recovery Rider	1,052,721
Postretirement Benefit Costs	1,003,170
Property Insurance	194,259
Transmission Cost Adj	3,448,288
Loss on Buildings	803,493
ND Generation Resource Recovery Rider	967,941
ND Renewable Resource Recovery Rider	1,028,554
Prepaid Expenses	253,953
SD Infrastructure Rider	71,135
SD Transmission Cost Recovery Rider	35,217
	\$ 9,221,087

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

UTILITY: Other - Electric	
Regulatory Commission Expense	\$ 108,967
MT PSC/MCC Tax Deferral	31,118
ND Environmental Cost Recovery Rider	77,468
Postretirement Benefit Costs	39,699
Property Insurance	298,098
Transmission Cost Adj	1,751,016
Loss on Buildings	30,834
ND Generation Resource Recovery Rider	37,802
ND Renewable Resource Recovery Rider	481,860
Prepaid Expenses	10,050
SD Infrastructure Rider	6,465
SD Transmission Cost Recovery Rider	7,904
	\$ 2,881,281

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

UTILITY: Other - Gas	
Contingency Reserve	\$ 162,953
MT PSC/MCC Tax Deferral	31,886
Postretirement Benefit Costs	105,035
Prepaid Demand	1,175,960
Property Insurance	101,289
Def Pension Exp - ND Gas - Reg Asset	19,229
Manufactured Gas Plant Site - Billings	117,065
	\$ 1,713,417

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

UTILITY: Other - Gas	
MT PSC/MCC Tax Deferral	\$ 12,285
Postretirement Benefit Costs	1,340,686
Prepaid Demand	2,686,485
Property Insurance	55,539
Def Pension Exp - ND Gas - Reg Asset	39,812
Manufactured Gas Plant Site - Billings	42,992
Loss on Buildings	308,920
Manufactured Gas Plant Site - Bismarck	72,730
MN Revenue Decoupling	164,074
Prepaid Expenses	174,299
	\$ 4,897,822

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

UTILITY: Other - Gas	
MT PSC/MCC Tax Deferral	\$ 44,416
Postretirement Benefit Costs	53,056
Prepaid Demand	2,504,378
Property Insurance	107,134
Def Pension Exp - ND Gas - Reg Asset	1,528
Manufactured Gas Plant Site - Billings	9,855
Loss on Buildings	11,855
Manufactured Gas Plant Site - Bismarck	38,424
MN Revenue Decoupling	12,562
Prepaid Expenses	6,898
	\$ 2,790,106

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

UTILITY: Other - Gas	
Prepaid Demand	\$ 1,259,502

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

UTILITY: Other - Gas	
Prepaid Demand	\$ 1,243,317

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

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

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 5,800,730
Regulatory Matters - 182.3 - Gas	533,827
Regulatory Matters - 254 - Electric	(54,136)
Regulatory Matters - 254 - Gas	(85,576)
Total Utility Other	<u>\$ 6,194,845</u>

NON UTILITY: Other	
AMT Carryforward Federal	\$ 6,112
Partnership Ordinary Gain/(Loss)	61,820
Total Non-Utility	<u>\$ 67,932</u>

TOTAL OTHER \$ 6,262,777

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

NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	\$ 2,527

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

NON UTILITY: Other	
AMT Carryforward Federal	\$ 6,112
Partnership Ordinary Gain/(Loss)	100
Total Non-Utility	<u>\$ 6,212</u>

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 693,041
Regulatory Matters - 182.3 - Gas	89,545
Regulatory Matters - 254 - Electric	733,933
Regulatory Matters - 254 - Gas	1,331,648
Total Utility Other	<u>\$ 2,848,167</u>

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	\$ 458,107
Regulatory Matters - 182.3 - Gas	49,880
Regulatory Matters - 254 - Electric	777,495
Regulatory Matters - 254 - Gas	1,304,556
Total Utility Other	<u>\$ 2,590,038</u>

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

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

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	7,044,514		5,556,950	4,689,032	6,176,596
2						
3	Retired Power Plant - amortizations over	355,035	405	58,532	6,648	303,151
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	3,570,896			5,421,844	8,992,740
10						
11	Grain Drying Margin Sharing - North Dakota	114,723	496	117,695	94,579	91,607
12	Gas [Case No. PU-13-803]					
13						
14	Grain Drying Margin Sharing - South Dakota	93,642	496	102,144	88,344	79,842
15	Gas [Docket No. NG-12-008]					
16						
17	Gain on Building Sale - North Dakota	872,362				872,362
18	Electric					
19						
20	Gain on Building Sale; North Dakota -Gas	325,425	405	17,564		307,861
21	Amortization over 240 months ending 6/34					
22	[Case No. PU-13-803]					
23						
24	Deferred Post-Retirement Expense;	20,498	920	362	86,102	106,238
25	North Dakota - Gas [Case No. PU-15-90]					
26						
27	Decommissioning cost amortization - Montana		407	1,006,829	6,972,670	5,965,841
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	12,397,095		6,860,076	17,359,219	22,896,238

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

190	1,810,838
282	1,909,038
283	<u>1,837,074</u>
	5,556,950

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	117,014,058	107,766,549
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	135,389,644	121,462,557
5	Large (or Ind.) (See Instr. 4)	31,913,313	32,786,482
6	(444) Public Street and Highway Lighting	2,749,398	2,481,405
7	(445) Other Sales to Public Authorities	4,209,854	3,724,162
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	620,578	585,968
10	TOTAL Sales to Ultimate Consumers	291,896,845	268,807,123
11	(447) Sales for Resale	1,026,988	-661
12	TOTAL Sales of Electricity	292,923,833	268,806,462
13	(Less) (449.1) Provision for Rate Refunds	1,619,235	337,960
14	TOTAL Revenues Net of Prov. for Refunds	291,304,598	268,468,502
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	152,566	157,863
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,138,819	5,608,546
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	20,013,693	2,060,817
22	(456.1) Revenues from Transmission of Electricity of Others	5,552,694	1,929,660
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	29,857,772	9,756,886
27	TOTAL Electric Operating Revenues	321,162,370	278,225,388

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
1,132,571	1,173,860	118,483	116,665	2
				3
1,491,763	1,499,620	22,693	22,278	4
544,207	550,348	244	241	5
31,143	31,379	565	516	6
52,840	54,470	762	786	7
				8
6,013	6,340	201	204	9
3,258,537	3,316,017	142,948	140,690	10
45,018	41			11
3,303,555	3,316,058	142,948	140,690	12
				13
3,303,555	3,316,058	142,948	140,690	14

Line 12, column (b) includes \$ 1,744,398 of unbilled revenues.

Line 12, column (d) includes -144 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) 12/31/2016	Year/Period of Report 2016/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

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	180,666	15,750,302	20,309	8,896	0.0872
4	20-Small General Electric Service	2,889	238,452	273	10,582	0.0825
5	52-Outdoor Lighting Service	741	84,447	897	826	0.1140
6	North Dakota					
7	10-Residential Electric Service	729,632	72,286,802	78,515	9,293	0.0991
8	13-Optional Residential Thermal E	117	8,178	4	29,250	0.0699
9	16-Optional Time-of-Day Service	113	9,981	8	14,125	0.0883
10	20-Small General Electric Service	4,916	595,763	657	7,482	0.1212
11	25-Irrigation Power Service	1	286	1	1,000	0.2860
12	30-General Electric Service	8,645	811,367	95	91,000	0.0939
13	32-General Electric Space Heating	1,762	134,817	25	70,480	0.0765
14	52-Outdoor Lighting Service	1,188	120,453	1,187	1,001	0.1014
15	South Dakota					
16	10-Residential Electric Service	61,214	6,935,126	6,570	9,317	0.1133
17	20-Small General Electric Service	481	51,528	37	13,000	0.1071
18	24-Private Lighting Service	191	17,515	263	726	0.0917
19	32-General Electric Space Heating	14	1,221	2	7,000	0.0872
20	53-Special Residential Dual Fuel	5,315	339,202	370	14,365	0.0638
21	54-Special General Electric Dual	85	4,711	2	42,500	0.0554
22	Wyoming					
23	10-Residential Electric Service	124,910	13,220,940	13,146	9,502	0.1058
24	11-Special Residential Controlled	8,026	409,410	710	11,304	0.0510
25	20-Small General Electric Service	976	116,675	175	5,577	0.1195
26	24-Outdoor Lighting Service	479	24,148	621	771	0.0504
27	Unbilled-Net	209	5,852,733			28.0035
28	Adjustment for Duplicate Customer			-5,491		
29	Subtotal Residential	1,132,570	117,014,057	118,376	9,568	0.1033
30	Small Commercial-442					
31	Montana					
32	20-Small General Electric Service	104,346	8,380,646	5,336	19,555	0.0803
33	25-Irrigation Power Service	5,631	345,184	130	43,315	0.0613
34	30-General Electric Service	28	4,091	12	2,333	0.1461
35	32-General Electric Space Heating	1,403	87,291	14	100,214	0.0622
36	52-Outdoor Lighting Service	1,925	220,245	804	2,394	0.1144
37	North Dakota					
38	20-Small General Electric Service	92,533	10,214,119	9,199	10,059	0.1104
39	25-Irrigation Power Service	1,005	71,977	38	26,447	0.0716
40	26-Optional Time-of-Day Small Gen	1,013	135,731	195	5,195	0.1340
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	30-General Electric Service	425,845	39,841,135	2,918	145,937	0.0936
2	32-General Electric Space Heating	40,884	3,123,494	482	84,822	0.0764
3	40-Small Municipal Electric Servi	3	326	1	3,000	0.1087
4	52-Outdoor Lighting Service	5,278	535,503	1,270	4,156	0.1015
5	South Dakota					
6	20-Small General Electric Service	30,486	3,333,425	1,927	15,820	0.1093
7	24-Private Lighting Service	432	39,608	254	1,701	0.0917
8	25-Irrigation Power Service	221	15,367	5	44,200	0.0695
9	26-Optional Time-of-Day General E	91	10,534	15	6,067	0.1158
10	32-General Electric Space Heating	1,383	100,680	84	16,464	0.0728
11	50-General Electric Water Heating	-143	-13,154	1	-143,000	0.0920
12	54-Special General Electric Dual	2,928	158,812	44	66,545	0.0542
13	56-General Electric Space Heating	316	27,719	12	26,333	0.0877
14	Wyoming					
15	20-Small General Electric Service	48,503	4,369,751	2,432	19,944	0.0901
16	22-Special General Controlled Ele	222	11,437	19	11,684	0.0515
17	24-Outdoor Lighting Service	999	50,296	315	3,171	0.0503
18	25-Irrigation Power Service	3,434	297,100	79	43,468	0.0865
19	26-Irrigation Power Service Optio	99	12,439	7	14,143	0.1256
20	Unbilled-Net	-1,096	3,459,061			-3.1561
21	Adjustment for Duplicate Customer			-4,371		
22	Subtotal Small Commercial	767,769	74,832,817	21,222	36,178	0.0975
23						
24	Large Commercial-442					
25	Montana					
26	25-Irrigation Power Service	601	37,718	10	60,100	0.0628
27	30-Large General Electric Service	155,232	10,820,916	274	566,540	0.0697
28	31-Optional Time-of-Day Large Gen	659	59,113	1	659,000	0.0897
29	52-Outdoor Lighting Service	488	55,862	78	6,256	0.1145
30	North Dakota					
31	20-Small General Electric Service	128	12,417	7	18,286	0.0970
32	25-Irrigation Power Service	38	2,995	2	19,000	0.0788
33	30-General Electric Service	384,951	33,751,773	1,063	362,136	0.0877
34	31-Optional Time-of-Day General S	27,030	2,073,585	54	500,556	0.0767
35	32-General Electric Space Heating	10,998	805,744	44	249,955	0.0733
36	38-Interruptible Large Power Dema	28,378	1,978,544	3	9,459,333	0.0697
37	52-Outdoor Lighting Service	399	40,466	109	3,661	0.1014
38	South Dakota					
39	24-Private Lighting Service	139	12,720	30	4,633	0.0915
40	30-Large General Electric Service	27,906	2,479,418	106	263,264	0.0888
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	24-Outdoor Lighting Service	61	3,077	16	3,813	0.0504
3	26-Optional Time-of-Day Irrigatio	3	332			0.1107
4	39-Large General Electric Service	85,632	5,780,453	148	578,595	0.0675
5	Unbilled-Net	1,351	2,641,694			1.9554
6	Adjustment for Duplicate Customer			-439		
7	Subtotal Large Commercial	723,994	60,556,827	1,506	480,740	0.0836
8						
9	Small Industrial-442					
10	Montana					
11	20-Small General Electric Service	4,646	356,412	79	58,810	0.0767
12	31-Optional Time-of-Day Large Gen	13,708	861,205	4	3,427,000	0.0628
13	52-Outdoor Lighting Service	3	322	3	1,000	0.1073
14	North Dakota					
15	20-Small General Electric Service	226	24,712	21	10,762	0.1093
16	30-General Electric Service	32,236	2,369,932	39	826,564	0.0735
17	32-General Electric Space Heating	639	47,016	4	159,750	0.0736
18	52-Outdoor Lighting Service	32	3,290	9	3,556	0.1028
19	South Dakota					
20	20-Small General Electric Service	57	6,803	3	19,000	0.1194
21	24-Private Lighting Service	10	923	3	3,333	0.0923
22	27-Feed Grinding Service	2	501	1	2,000	0.2505
23	32-General Electric Space Heating	2	231			0.1155
24	54-Special Gen Electric Dual Fuel	13	709			0.0545
25	Wyoming					
26	20-Small General Electric Service	282	26,102	11	25,636	0.0926
27	24-Outdoor Lighting Service	2	83	2	1,000	0.0415
28	Unbilled-Net	286	221,223			0.7735
29	Adjustment for Duplicate Customer			-28		
30	Subtotal Small Industrial	52,144	3,919,464	151	345,325	0.0752
31						
32	Large Industrial-442					
33	Montana					
34	30-Large General Electric Service	84,895	5,156,097	27	3,144,259	0.0607
35	31-Optional Time-of-Day Large Gen	3,838	318,165	4	959,500	0.0829
36	35-Contract Service	228,783	10,748,843	12	19,065,250	0.0470
37	52-Outdoor Lighting Service	1	171	3	333	0.1710
38	North Dakota					
39	30-General Electic Service	158,308	10,101,525	45	3,517,956	0.0638
40	31-Optional Time-of-Day General E	3,985	364,652	9	442,778	0.0915
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	32-General Electric Space Heating	31	2,974	1	31,000	0.0959
2	38-Interruptible Large Power Dema	3,678	181,719	1	3,678,000	0.0494
3	52-Outdoor Lighting Service	9	899	3	3,000	0.0999
4	South Dakota					
5	24-Private Lighting Service	12	1,062	2	6,000	0.0885
6	30-Large General Electric Service	7,818	592,603	6	1,303,000	0.0758
7	Wyoming					
8	39-Large General Electric Service	1,498	155,234	5	299,600	0.1036
9	Unbilled-Net	-794	369,904			-0.4659
10	Adjustment for Duplicate Customer			-27		
11	Subtotal Large Industrial	492,062	27,993,848	91	5,407,275	0.0569
12						
13	Public Street and Highway - 444					
14	Montana					
15	20-Small General Electric Service	88	7,109	5	17,600	0.0808
16	41-Municipal Lighting Service	6,889	538,677	97	71,021	0.0782
17	52-Outdoor Lighting Service	126	14,509	16	7,875	0.1152
18	North Dakota					
19	20-Small General Electric Service	136	25,167	48	2,833	0.1851
20	40-Small Municipal Electric Servi	27	2,128	1	27,000	0.0788
21	41-Municipal Lighting Service	19,861	1,653,573	598	33,212	0.0833
22	52-Outdoor Lighting Service	363	36,901	41	8,854	0.1017
23	South Dakota					
24	24-Private Lighting Service	10	951	7	1,429	0.0951
25	41-Municipal Lighting Service	2,507	247,306	52	48,212	0.0986
26	Wyoming					
27	20-Small General Electric Service	12	2,261	5	2,400	0.1884
28	24-Outdoor Lighting Service	7	361	2	3,500	0.0516
29	41-Municipal Lighting Service	1,117	87,293	5	223,400	0.0781
30	Unbilled-Net	1	133,161			133.1610
31	Adjustment for Duplicate Customer			-322		
32	Subtotal Public Street and Highwa	31,144	2,749,397	555	56,115	0.0883
33						
34	Other Sales to Public Authorities					
35	Montana					
36	48-Municipal Pumping Service	7,020	467,422	110	63,818	0.0666
37	North Dakota					
38	20-Small General Electric Service	407	49,710	56	7,268	0.1221
39	30-General Electric Service	1,503	142,016	8	187,875	0.0945
40	32-General Electric Space Heating	234	16,786	6	39,000	0.0717
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	3,878	357,595	293	13,235	0.0922
2	48-Municipal Pumping Service	38,409	2,799,955	322	119,283	0.0729
3	South Dakota					
4	48-Municipal Pumping Service	1,486	123,734	52	28,577	0.0833
5	Unbilled-Net	-97	252,636			-2.6045
6	Adjustment for Duplicate Customer			-79		
7	Subtotal Other Sales	52,840	4,209,854	768	68,802	0.0797
8						
9	Interdepartmental-448					
10	Montana					
11	Billed	497	52,265	94	5,287	0.1052
12	North Dakota					
13	Billed	5,128	486,347	157	32,662	0.0948
14	South Dakota					
15	Billed	218	29,291	10	21,800	0.1344
16	Wyoming					
17	Billed	174	22,642	28	6,214	0.1301
18	Unbilled-Net	-5	30,035			-6.0070
19	Adjustment for Duplicate Customer			-13		
20	Subtotal Interdepartmental Sales	6,012	620,580	276	21,783	0.1032
21						
22	Total	3,258,535	291,896,844	142,945	22,796	0.0896
23						
24	Fuel Clause Adjustment					
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: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 304 Line No.: 27 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.1 Line No.: 20 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.2 Line No.: 5 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.2 Line No.: 28 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.3 Line No.: 9 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.3 Line No.: 30 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.4 Line No.: 5 Column: f

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

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

Revenue per KWh sold for unbilled-net reflects implementation of new tracker revenue effective in 2016.

Schedule Page: 304.4 Line No.: 24 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 4,131,047

20-Small General Electric Service 67,554

52-Outdoor Lighting Service 16,912

North Dakota

10-Residential Electric Service 16,163,561

13-Optional Residential Thermal Energy Storage 2,721

16-Optional Time-of-Day Residential Electric Service 2,585

20-Small General Electric Service 110,608

25-Irrigation Power Service 12

30-General Electric Service 194,635

32-General Electric Space Heating Service 41,984

52-Outdoor Lighting Service 25,997

South Dakota

10-Residential Electric Service 706,953

20-Small General Electric Service 5,334

24-Private Lighting Service 2,224

32-General Electric Space Heating Service 160

53-Special Residential Electric Dual Fuel Space Heating Service 54,921

54-Special General Electric Dual Fuel Space Heating Service 628

Wyoming

10-Residential Electric Service 749,919

11-Special Residential Controlled Electric Service 47,978

20-Small General Electric Service 5,841

24-Outdoor Lighting Service 2,887

Unbilled-net (23,979)

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Subtotal Residential	22,310,482
Small Commercial-442	
Montana	
20-Small General Electric Service	2,385,769
25-Irrigation Power Service	115,577
30-General Electric Service	676
32-General Electric Space Heating Service	33,687
52-Outdoor Lighting Service	44,014
North Dakota	
20-Small General Electric Service	2,062,585
25-Irrigation Power Service	19,217
26-Optional Time-of-Day Small General Electric Service	21,259
30-General Electric Service	9,263,883
32-General Electric Space Heating Service	950,512
40-Small Municipal Electric Service	58
52-Outdoor Lighting Service	117,182
South Dakota	
20-Small General Electric Service	355,732
24-Private Lighting Service	5,025
25-Irrigation Power Service	3,219
26-Optional Time-of-Day Small General Electric Service	1,265
32-General Electric Space Heating Service	26,268
50-General Electric Water Heating Service	(1,222)
54-Special General Electric Dual Fuel Space Heating Service	21,422
56-General Electric Space Heating Service	2,329
Wyoming	
20-Small General Electric Service	291,235
22-Special General Controlled Electric Service	1,320
24-Outdoor Lighting Service	6,003
25-Irrigation Power Service	20,772
26-Irrigation Power Service Optional Time-of-Day	602
Unbilled-net	(59,019)
Subtotal Small Commercial	15,689,370
Large Commercial-442	
Montana	
25-Irrigation Power Service	12,237
30-Large General Electric Service	3,518,212
31-Optional Time-of-Day Large General Electric Service	15,752
52-Outdoor Lighting Service	11,130
North Dakota	
20-Small General Electric Service	2,827
25-Irrigation Power Service	705
30-General Electric Service	8,321,440
31-Optional Time-of-Day General Electric Service	577,850
32-General Electric Space Heating Service	252,628
38-Interruptible Large Power Demand Response	584,657
52-Outdoor Lighting Service	8,742
South Dakota	
24-Private Lighting Service	1,598
30-Large General Electric Service	339,175
Wyoming	
24-Outdoor Lighting Service	368

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.		12/31/2016	2016/Q4
FOOTNOTE DATA			

26-Optional Time-of-Day Irrigation Service	21
39-Large General Electric Service	459,278
Unbilled-net	10,474
Subtotal Large Commercial	14,117,094

Small Industrial-442

Montana

20-Small General Electric Service	106,419
31-Optional Time-of-Day Large General Electric Service	304,527
52-Outdoor Lighting Service	64

North Dakota

20-Small General Electric Service	5,091
30-General Electric Service	679,121
32-General Electric Space Heating Service	14,573
52-Outdoor Lighting Service	712

South Dakota

20-Small General Electric Service	560
24-Private Lighting Service	114
27-Feed Grinding Service	16
32-General Electric Space Heating Service	34
54-Special General Electric Dual Fuel Space Heating Service	95

Wyoming

20-Small General Electric Service	1,700
24-Outdoor Lighting Service	10
Unbilled-net	3,709
Subtotal Small Industrial	1,116,745

Large Industrial-442

Montana

30-General Electric Service	1,939,410
31-Optional Time-of-Day Large General Electric Service	85,654
35-Contract Service	4,335,662
52-Outdoor Lighting Service	34

North Dakota

30-General Electric Service	3,318,853
31-Optional Time-of-Day General Electric Service	86,757
32-General Electric Space Heating Service	663
39-Large General Electric Service	78,476
52-Outdoor Lighting Service	194

South Dakota

24-Private Lighting Service	132
30-Large General Electric Service	88,066

Wyoming

39-Large General Service	9,005
Unbilled-net	(29,867)
Subtotal Large Industrial	9,913,039

Public Street and Highway Lighting-444

Montana

20-Small General Service	1,988
41-Municipal Lighting Service	157,234
52-Outdoor Lighting Service	2,991

North Dakota

20-Small General Service	3,126
--------------------------	-------

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

40-Small Municipal Electric Service	604
41-Municipal Lighting Service	437,808
52-Outdoor Lighting Service	7,936
South Dakota	
24-Private Lighting Service	122
41-Street Lighting Service	29,277
Wyoming	
20-Small General Electric Service	71
24-Outdoor Lighting Service	43
41-Municipal Lighting Service	6,714
Unbilled-net	(169)
Subtotal Public Street and Highway Lighting	647,745
Other Sales to Public Authorities-445	
Montana	
48-Municipal Pumping Service	158,476
North Dakota	
20-Small General Electric Service	9,067
30-General Electric Service	33,350
32-General Electric Space Heating Service	5,761
40-Small Municipal Electric Service	85,677
48-Municipal Pumping Service	811,969
South Dakota	
48-Municipal Pumping Service	16,613
Unbilled-net	(5,769)
Subtotal Other Sales	1,115,144
Interdepartmental Sales-448	
Montana	11,416
North Dakota	112,082
South Dakota	2,109
Wyoming	1,045
Unbilled-net	(393)
Subtotal Interdepartmental	126,259
Total Fuel Clause Adjustment	65,035,878

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	Sales for Resale Fuel Cost					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts.

Footnote any demand not stated on a megawatt basis and explain.

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
45,018		1,026,988		1,026,988	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
45,018	0	1,026,988	0	1,026,988	
45,018	0	1,026,988	0	1,026,988	

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) 12/31/2016	Year/Period of Report 2016/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	2,618,096	2,536,452
5	(501) Fuel	46,240,749	37,448,796
6	(502) Steam Expenses	6,947,055	5,200,654
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,951,390	1,824,045
10	(506) Miscellaneous Steam Power Expenses	4,126,322	3,993,607
11	(507) Rents	713,336	765,806
12	(509) Allowances		58
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	62,596,948	51,769,418
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,142,004	994,586
16	(511) Maintenance of Structures	750,942	989,075
17	(512) Maintenance of Boiler Plant	7,285,766	6,886,084
18	(513) Maintenance of Electric Plant	1,528,588	1,853,728
19	(514) Maintenance of Miscellaneous Steam Plant	1,909,230	1,598,106
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,616,530	12,321,579
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	75,213,478	64,090,997
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	220,454	48,856
63	(547) Fuel	3,996,875	3,456,939
64	(548) Generation Expenses	2,038,164	526,996
65	(549) Miscellaneous Other Power Generation Expenses	403,682	346,677
66	(550) Rents	604,408	141,383
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,263,583	4,520,851
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	74,571	72,358
70	(552) Maintenance of Structures	6,396	29,874
71	(553) Maintenance of Generating and Electric Plant	685,251	616,291
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	8,788	12,516
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	775,006	731,039
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	8,038,589	5,251,890
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	25,274,022	45,330,680
77	(556) System Control and Load Dispatching	2,034,033	1,591,720
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	27,308,055	46,922,400
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	110,560,122	116,265,287
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,935,353	1,745,692
84			
85	(561.1) Load Dispatch-Reliability	482,245	533,679
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	966,483	1,000,691
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	525,385	531,296
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	38,272	38,703
93	(562) Station Expenses	695,575	698,769
94	(563) Overhead Lines Expenses	315,799	293,343
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	25,069,506	4,687,579
97	(566) Miscellaneous Transmission Expenses	43,107	46,234
98	(567) Rents	94,729	2,005,700
99	TOTAL Operation (Enter Total of lines 83 thru 98)	32,166,454	11,581,686
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	31,596	34,241
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	826,487	871,496
108	(571) Maintenance of Overhead Lines	992,769	981,685
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,850,852	1,887,422
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	34,017,306	13,469,108

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	433,705	386,315
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	433,705	386,315
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)	433,705	386,315
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,467,425	1,462,678
135	(581) Load Dispatching		
136	(582) Station Expenses	615,486	721,793
137	(583) Overhead Line Expenses	668,727	681,848
138	(584) Underground Line Expenses	1,562,352	1,554,399
139	(585) Street Lighting and Signal System Expenses	113,309	179,613
140	(586) Meter Expenses	1,074,010	798,665
141	(587) Customer Installations Expenses	170,320	216,796
142	(588) Miscellaneous Expenses	3,275,619	3,447,743
143	(589) Rents	196,213	304,143
144	TOTAL Operation (Enter Total of lines 134 thru 143)	9,143,461	9,367,678
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	499,277	499,630
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	217,128	329,934
149	(593) Maintenance of Overhead Lines	3,423,623	3,443,523
150	(594) Maintenance of Underground Lines	917,863	926,151
151	(595) Maintenance of Line Transformers	198,463	164,639
152	(596) Maintenance of Street Lighting and Signal Systems	170,329	159,652
153	(597) Maintenance of Meters	11,678	17,919
154	(598) Maintenance of Miscellaneous Distribution Plant	1,037,100	837,546
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,475,461	6,378,994
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,618,922	15,746,672
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	136,392	100,414
160	(902) Meter Reading Expenses	480,206	445,397
161	(903) Customer Records and Collection Expenses	3,127,062	2,543,075
162	(904) Uncollectible Accounts	1,018,726	919,708
163	(905) Miscellaneous Customer Accounts Expenses	135,074	138,393
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	4,897,460	4,146,987

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	45,841	40,015
168	(908) Customer Assistance Expenses	61,222	65,101
169	(909) Informational and Instructional Expenses	148,001	146,867
170	(910) Miscellaneous Customer Service and Informational Expenses	453	1,031
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	255,517	253,014
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	345	12,289
175	(912) Demonstrating and Selling Expenses	81,070	118,475
176	(913) Advertising Expenses	17,759	15,201
177	(916) Miscellaneous Sales Expenses	7,345	8,388
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	106,519	154,353
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	6,917,097	5,593,556
182	(921) Office Supplies and Expenses	3,696,945	3,605,321
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	659,030	610,597
185	(924) Property Insurance	1,074,272	930,772
186	(925) Injuries and Damages	1,672,344	1,634,162
187	(926) Employee Pensions and Benefits	7,554,178	7,294,384
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	720,658	449,066
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	81,269	81,313
192	(930.2) Miscellaneous General Expenses	859,084	521,540
193	(931) Rents	1,035,860	644,007
194	TOTAL Operation (Enter Total of lines 181 thru 193)	24,270,737	21,364,718
195	Maintenance		
196	(935) Maintenance of General Plant	602,495	600,959
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	24,873,232	21,965,677
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	190,762,783	172,387,413

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		30	30	30
3	Western Area Power Admin - Ft. Peck	LF	19			
4	Western Area Power Administration	EX	19			
5	Midcontinent Independent	EX	MISO			
6	System Operator (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)	
93,061			4,476,190	2,054,868		6,531,058	1
			126,000			126,000	2
14,347				477,037		477,037	3
	-45,491	262			91,725	91,725	4
792,130			6,595	17,493,257		17,499,852	5
							6
			342,333			342,333	7
					-337,596	-337,596	8
			543,613			543,613	9
							10
							11
							12
							13
							14
899,538	-45,491	262	5,494,731	20,025,162	-245,871	25,274,022	

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

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	Powder River Energy Corp	Powder River Energy Corp	Powder River Energy Corp	OLF
2	Midcontinent Independent			
3	System Operator (MISO)	MISO participants	MISO participants	OS
4	MISO	Western Area Power Administration	Western Area Power Administration	OLF
5	MISO	Western Area Power Administration	Western Area Power Administration	OS
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	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)	
5	Sheridan	Various		9,076	9,076	1
						2
MISO	Various	Various				3
MISO	Various	Various		1,320,528	1,269,739	4
MISO	Dickinson	Dickinson		3,332	3,204	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	1,332,936	1,282,019	

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.
	6,807		6,807	1
				2
		729,401	729,401	3
	4,791,554		4,791,554	4
	24,932		24,932	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	4,823,293	729,401	5,552,694	

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: c

Sheridan-Johnson REA contract is perpetual

Schedule Page: 328 Line No.: 3 Column: m

MISO Schedule 24 charges

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			
			Megawatt-hours Received (c)	Megawatt-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	Western Area Power Admn	FNS				21,102		21,102
5	Mor Gran Sou Elec Coop	LFP	1,482	1,602				
6	Grand Elec Coop	LFP	596	646		3,179		3,179
7	Midcontinent							
8	Independent							
9	System Operator (MISO)	OS					6,673,590	6,673,590
10	Southwest Power Pool	FNS				18,371,635		18,371,635
11								
12								
13								
14								
15								
16								
	TOTAL		2,078	2,248		18,395,916	6,673,590	25,069,506

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 9 Column: g

MISO Schedule 26-RECB charges.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	344,135
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	514,949
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	859,084

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			322,079		322,079
2	Steam Production Plant	13,894,321				13,894,321
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,251,064			-51,884	17,199,180
7	Transmission Plant	5,061,568				5,061,568
8	Distribution Plant	10,669,535				10,669,535
9	Regional Transmission and Market Operation					
10	General Plant	444,047				444,047
11	Common Plant-Electric	1,614,325		1,350,796		2,965,121
12	TOTAL	48,934,860		1,672,875	-51,884	50,555,851

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	76,112	63.00		2.86	R2.5	16.60
15	312	347,507	45.00		2.42	R0.5	17.80
16	314	85,847	45.00		2.63	R0.5	21.20
17	315	20,503	50.00		1.56	R2.5	21.80
18	316	19,717	30.00		4.33	R0.5	12.20
19	317.0	5,186					
20	Subtotal	554,872					
21							
22	OTHER PRODUCTION						
23							
24	341	6,932	70.00		4.77	R1	12.60
25	342	3,228	43.00		3.13	R5	21.40
26	344	430,516	55.00		3.70	R3	19.00
27	345	16,096	28.00		4.73	L2	12.40
28	346	1,231	28.00		3.08	S1	21.40
29	347.0	12,057					
30	Subtotal	470,060					
31							
32	TRANSMISSION PLANT						
33							
34	350.2	3,176	50.00		1.36	R3	25.60
35	352	2	45.00		1.10	R2.5	4.70
36	353	140,806	60.00	-10.00	1.81	R3	45.20
37	354	4,993	55.00	-5.00	1.65	R5	24.90
38	355	74,523	50.00	-35.00	2.41	R3	36.00
39	356	53,970	65.00	-15.00	1.34	R3	45.20
40	357	1,945	50.00		2.01	R3	43.60
41	358	3,102	50.00		2.01	R3	43.60
42	359.1	1					
43	Subtotal	282,518					
44							
45	DISTRIBUTION PLANT						
46							
47	360.2	957	50.00		1.35	R2	25.60
48	362	71,310	50.00	-5.00	1.78	R2.5	37.60
49	364	41,807	50.00	-70.00	3.99	R1	37.60
50	365	33,163	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	224	50.00		1.86	R3	29.60
13	367	112,615	40.00	-15.00	2.96	R2	32.00
14	368	70,187	55.00	-10.00	2.22	R3	40.80
15	369	36,225	45.00	-27.00	1.97	R3	31.40
16	370	18,300	20.00	-5.00	4.23	L3	14.90
17	371	2,856	22.00	-15.00	5.11	R0.5	15.60
18	373	7,662	43.00	-40.00	3.46	R1	28.00
19	374.0	40					
20	Subtotal	395,346					
21							
22	GENERAL PLANT						
23							
24	303	3,735			8.72	NA	11.50
25	390	1,402	29.00	25.00	3.12	L2	18.20
26	391	469			19.44	NA	
27	392	8,494	11.00	20.00	4.53	L3	6.19
28	393	15	30.00		3.33	NA	
29	394	3,863	20.00		4.94	NA	
30	395	730	20.00		4.86	NA	
31	396	13,522	9.00	20.00	5.55	L0	8.77
32	397	609			12.30	NA	
33	398	59	25.00		4.00	NA	
34	Subtotal	32,898					
35							
36	Total	1,735,694					
37	FOOTNOTE						
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

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) 12/31/2016	2016/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.: 37 Column: a

Column (b) - 12/31/16 depreciable sub-plant account balances

Other depreciation provisions include:

Provision for deferred AFUDC, interest and depreciation of Coyote I Station which had been disallowed in Montana rate base: \$140,378 in 2016.

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				109,121
6					
7	Gas				189,908
8					
9					
10	NORTH DAKOTA				
11	Electric				80,393
12					
13	Gas				282,237
14					
15					
16	SOUTH DAKOTA				
17	Electric				38,272
18					
19	Gas				108,383
20					
21					
22					
23					
24					
25					
26	WYOMING				
27	Electric				21,676
28					
29	Gas				85,800
30					
31					
32	MINNESOTA				
33	Gas				54,892
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				970,682

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	147,639	174,317	928	70,576	212,862	5
							6
Gas	928	18,871		928	184,746	5,162	7
							8
							9
							10
Electric	928	381,882	361,286			441,679	11
							12
Gas	928	4,731	-150,421	928	64,500	67,316	13
							14
							15
							16
Electric	928	39,351	150,750	928	17,462	171,560	17
							18
Gas	928	-81,060	183,506	928	56,862	235,027	19
							20
							21
							22
							23
							24
							25
							26
Electric	928	63,748	62,044			83,720	27
							28
Gas	928	24,821		928	15,108	70,692	29
							30
							31
							32
Gas	928	90,848	432,553			487,445	33
							34
							35
							36
Gas	928	92					37
							38
							39
							40
							41
							42
							43
							44
							45
		690,923	1,214,035		409,254	1,775,463	46

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,721,513		
49	Administrative and General	233,776		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,955,824		
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)	614,787		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)	535		
57	Distribution (Lines 36 and 48)	14,279,099		
58	Customer Accounts (Line 37)	4,352,207		
59	Customer Service and Informational (Line 38)	418,563		
60	Sales (Line 39)	148,744		
61	Administrative and General (Lines 40 and 49)	4,552,503		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	24,366,438	2,798,961	27,165,399
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	55,619,789	6,389,019	62,008,808
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	9,741,176	1,118,964	10,860,140
69	Gas Plant	7,653,780	879,186	8,532,966
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	17,394,956	1,998,150	19,393,106
72	Plant Removal (By Utility Departments)			
73	Electric Plant	527,973	60,648	588,621
74	Gas Plant	414,836	47,652	462,488
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	942,809	108,300	1,051,109
77	Other Accounts (Specify, provide details in footnote):			
78	183 - Preliminary Survey & Investigation	79,072		79,072
79	184 - Clearing Accounts	157,001		157,001
80	416 - Cost/Expense of Mech Job & Constr.	35,818		35,818
81	417 - Expense for Non-Utility Operations	554,880		554,880
82	426 - Misc Non Operating Exp.	21,566		21,566
83	121 - Non Utility	45,364		45,364
84	146 - Accounts Receivable from Associated Companies	5,506,554		5,506,554
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,400,255		6,400,255
96	TOTAL SALARIES AND WAGES	80,357,809	8,495,469	88,853,278

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) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
---	---	--	--

COMMON UTILITY PLANT AND EXPENSES

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

Account No.	Utility Plant	Accumulated Depreciation	Depreciation Expense
PLANT IN SERVICE			
303 Misc. Intangible Plant	55,919,203	24,713,327	3,236,076
389 Land and Land Rights	2,248,339	0	0
390 Structures and Improvements	43,452,780	15,118,366	973,058
391 Office Furniture & Equipment	7,154,854	3,961,481	1,101,674
392 Transportation Equipment	11,509,350	4,729,611	488,815
393 Stores Equipment	78,127	30,575	(1,978)
394 Miscellaneous Tools	707,810	269,924	28,413
396 Power Operated Equipment	0	0	0
397 Communication Equipment	3,657,973	1,286,082	284,418
398 Miscellaneous Equipment	1,204,572	498,694	60,814
399.1 Asset Retirement Obligations	0	0	0
	125,933,008	50,608,060	6,171,290
WORK IN PROGRESS			
	4,456,243	281,235	0
	130,389,251	50,889,295	6,171,290
Allocation of Common Utility Plant			
Electric Department	72,808,359	29,339,186	2,965,121
Natural Gas Department	57,580,892	21,550,109	2,890,707
Clearing Accounts			315,462
	130,389,251	50,889,295	6,171,290

Basis of Allocation

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

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: INTEGRATED

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	727	11	1900	515	212				
2	February	661	12	1000	468	193				
3	March	631	1	1000	449	182				
4	Total for Quarter 1				1,432	587				
5	April	559	18	1200	424	135				
6	May	554	5	1800	428	126				
7	June	689	9	1800	529	160				
8	Total for Quarter 2				1,381	421				
9	July	774	20	1700	597	177				
10	August	737	3	1600	565	172				
11	September	661	1	1700	506	155				
12	Total for Quarter 3				1,668	504				
13	October	524	19	1100	389	135				
14	November	642	29	1900	471	171				
15	December	796	17	2000	565	231				
16	Total for Quarter 4				1,425	537				
17	Total Year to Date/Year				5,906	2,049				

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	50	17	2000	49	1				
2	February	48	1	2000	46	2				
3	March	42	18	1200	41	1				
4	Total for Quarter 1				136	4				
5	April	40	18	2100	38	2				
6	May	37	11	1100	37					
7	June	59	21	1800	57	2				
8	Total for Quarter 2				132	4				
9	July	63	25	1900	61	2				
10	August	62	2	1700	61	1				
11	September	55	2	1700	53	2				
12	Total for Quarter 3				175	5				
13	October	42	11	2000	41	1				
14	November	47	29	1900	46	1				
15	December	60	16	1900	58	2				
16	Total for Quarter 4				145	4				
17	Total Year to Date/Year				588	17				

Name of Respondent
MDU Resources Group, Inc.

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

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	3,258,537
3	Steam	1,976,727	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	45,018
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	650,036	27	Total Energy Losses	227,910
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,531,465
9	Net Generation (Enter Total of lines 3 through 8)	2,626,763			
10	Purchases	899,538			
11	Power Exchanges:				
12	Received	-45,491			
13	Delivered	262			
14	Net Exchanges (Line 12 minus line 13)	-45,753			
15	Transmission For Other (Wheeling)				
16	Received	1,332,936			
17	Delivered	1,282,019			
18	Net Transmission for Other (Line 16 minus line 17)	50,917			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,531,465			

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	323,919	1,412	515	11	1900
30	February	269,354	5,643	468	12	1000
31	March	265,748	594	449	1	1000
32	April	243,763		424	18	1200
33	May	229,577	414	428	5	1800
34	June	253,596	7,790	529	9	1800
35	July	286,173	6,123	597	20	1700
36	August	284,765	6,032	565	3	1600
37	September	236,621	9,620	506	1	1700
38	October	244,724	2,360	389	19	1100
39	November	260,706	3,938	471	29	1900
40	December	339,143	1,092	565	17	2000
41	TOTAL	3,238,089	45,018			

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) 12/31/2016	Year/Period of Report 2016/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	28,417	50	17	2000
30	Feb	23,851	48	1	2000
31	Mar	23,602	42	18	1200
32	Apr	21,288	40	18	2100
33	May	20,791	37	11	1100
34	Jun	24,584	59	21	1800
35	Jul	27,762	63	25	1900
36	Aug	25,367	62	2	1700
37	Sep	20,524	55	2	1700
38	Oct	21,904	42	11	2000
39	Nov	23,055	47	29	1900
40	Dec	32,231	60	16	1900
41	Total	293,376	605		

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>Lewis & Clark</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler				
3	Year Originally Constructed	1954	1958				
4	Year Last Unit was Installed	1963	1958				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	86.00	44.00				
6	Net Peak Demand on Plant - MW (60 minutes)	103	52				
7	Plant Hours Connected to Load	7687	7503				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	100	52				
10	When Limited by Condenser Water	92	52				
11	Average Number of Employees	51	32				
12	Net Generation, Exclusive of Plant Use - KWh	458787700	261058453				
13	Cost of Plant: Land and Land Rights	242583	80862				
14	Structures and Improvements	24443995	11284823				
15	Equipment Costs	96114751	61956669				
16	Asset Retirement Costs	1181551	3605749				
17	Total Cost	121982880	76928103				
18	Cost per KW of Installed Capacity (line 17/5) Including	1418.4056	1748.3660				
19	Production Expenses: Oper, Supv, & Engr	983203	281556				
20	Fuel	14296067	6081604				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	2344370	1835738				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	830156	197087				
26	Misc Steam (or Nuclear) Power Expenses	1514199	1168437				
27	Rents	0	9000				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	339868	161522				
30	Maintenance of Structures	163753	68970				
31	Maintenance of Boiler (or reactor) Plant	1674611	1378235				
32	Maintenance of Electric Plant	264301	398078				
33	Maintenance of Misc Steam (or Nuclear) Plant	777212	550654				
34	Total Production Expenses	23187740	12130881				
35	Expenses per Net KWh	0.0505	0.0465				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal-Lignite	Coal-Sub Bit	Tires	Coal-Lignite	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Tons	Tons	Tons	Mcf	
38	Quantity (Units) of Fuel Burned	438787	3	2522	255565	10059	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	7020	8735	15000	6779	1815	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	31.162	0.000	81.999	22.524	5.254	0.000
41	Average Cost of Fuel per Unit Burned	32.101	28.427	81.997	23.590	5.254	0.000
42	Average Cost of Fuel Burned per Million BTU	2.286	1.627	2.733	1.740	2.895	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.023	0.000	0.000
44	Average BTU per KWh Net Generation	13658.469	0.000	0.000	12760.118	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			109			27			6
76			7822			8081			7
0			0			0			8
22			108			27			9
22			100			27			10
0			19			6			11
712080			440834079			200317000			12
609			150559			0			13
223817			9495364			3556732			14
3182089			140092352			62543192			15
0			279185			0			16
3406515			150017460			66099924			17
147.1497			1594.0650			2360.7116			18
11014			291087			550934			19
71299			10913147			2510582			20
0			0			0			21
24478			903105			411092			22
0			0			0			23
0			0			0			24
58004			376495			146931			25
0			712794			189598			26
0			0			701106			27
0			0			0			28
10834			152611			247428			29
401			247799			96437			30
65415			1149283			524039			31
0			231823			86747			32
0			150331			5648			33
241445			15128475			5470542			34
0.3391			0.0343			0.0273			35
Gas	Fuel Oil		Coal-Sub Bit	Fuel Oil		Coal-Sub Bit			36
Mcf	Bbl		Tons	Bbl		Tons			37
13931	0	0	289977	689	0	142988	0	0	38
1084	140000	0	8266	140000	0	8030	0	0	39
5.118	0.000	0.000	37.321	51.265	0.000	17.558	0.000	0.000	40
5.118	0.000	0.000	37.474	67.414	0.000	17.558	0.000	0.000	41
4.722	0.000	0.000	2.267	11.469	0.000	1.093	0.000	0.000	42
0.100	0.000	0.000	0.025	0.000	0.000	0.013	0.000	0.000	43
21206.869	0.000	0.000	10883.576	0.000	0.000	11463.766	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)				
		Glendive	Coyote				
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)	73	108				
7	Plant Hours Connected to Load	318	6689				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	75	107				
10	When Limited by Condenser Water	73	81				
11	Average Number of Employees	3	21				
12	Net Generation, Exclusive of Plant Use - KWh	6276780	615729630				
13	Cost of Plant: Land and Land Rights	37924	519148				
14	Structures and Improvements	306033	27331187				
15	Equipment Costs	27774795	112866318				
16	Asset Retirement Costs	0	119872				
17	Total Cost	28118752	140836525				
18	Cost per KW of Installed Capacity (line 17/5) Including	372.3352	1358.7701				
19	Production Expenses: Oper, Supv, & Engr	29731	511316				
20	Fuel	416329	12439349				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	42454	1452750				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	116330	400721				
26	Misc Steam (or Nuclear) Power Expenses	0	541294				
27	Rents	0	3230				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	31175	240575				
30	Maintenance of Structures	2758	173983				
31	Maintenance of Boiler (or reactor) Plant	151012	2559598				
32	Maintenance of Electric Plant	561	547639				
33	Maintenance of Misc Steam (or Nuclear) Plant	0	425385				
34	Total Production Expenses	790350	19295840				
35	Expenses per Net KWh	0.1259	0.0313				
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	81207	726	0	505651	4629	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1108	140000	0	6901	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.445	76.299	0.000	23.881	52.309	0.000
41	Average Cost of Fuel per Unit Burned	4.445	76.299	0.000	24.101	54.567	0.000
42	Average Cost of Fuel Burned per Million BTU	4.011	12.982	0.000	1.746	9.280	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.066	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	15014.656	0.000	0.000	11378.717	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>R.M. Heskett</i> (f)			Line No.
Gas Turbine			Gas Turbine						1
Conventional			Conventional						2
2014			2015						3
2014			2015						4
89.00			18.70			0.00			5
94			19			0			6
133			1078			0			7
0			0			0			8
75			19			0			9
57			14			0			10
0			0			0			11
2867855			11917644			0			12
0			0			0			13
0			0			0			14
53413818			45570328			0			15
0			0			0			16
53413818			45570328			0			17
600.1553			2436.9159			0			18
32606			2041			0			19
2887657			330998			0			20
0			0			0			21
57589			19222			0			22
0			0			0			23
0			0			0			24
8053			17818			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
2980			0			0			30
77168			26739			0			31
2298			0			0			32
0			0			0			33
3068351			396818			0			34
1.0699			0.0333			0.0000			35
Gas			Gas			Gas			36
Mcf			Mcf			Mcf			37
55596	0	0	56930	0	0	6546	0	0	38
1	0	0	0	0	0	1114	0	0	39
3.205	0.000	0.000	5.058	0.000	0.000	0.590	0.000	0.000	40
3.205	0.000	0.000	5.058	0.000	0.000	0.590	0.000	0.000	41
2.877	0.000	0.000	0.000	0.000	0.000	0.530	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	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

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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	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

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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/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: 402 Line No.: 5 Column: c

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: 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, including Lewis & Clark II.

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: 44 Column: c1

Average Btu per net kWh generated for all fuels including Lewis & Clark II.

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: f1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 44 Column: b1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: c1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: d1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: f1

Average Btu per net kWh generated for all fuels.

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	OIL					
2	Portable Generators	2012	5.50	6.0	9,391	2,259,046
3						
4	WIND					
5	Diamond Willow	2007	30.00	30.4	100,119,000	64,124,969
6	Cedar Hills	2010	19.50	20.1	60,790,000	47,611,196
7	Thunder Spirit	2015	107.50	107.0	427,959,570	209,930,790
8	WASTE HEAT					
9	Ormat Facility	2009	7.50	6.4	39,383,550	15,630,093
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

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
	25,000	2,416	21,275	Oil		2
						3
						4
	281,011		183,005	Wind		5
	196,713		143,771	Wind		6
	2,113,439		17,320	Wind		7
						8
	231,205	288,176	38,294	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
						38
						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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 2 Column: c

Maximum Turbine Name Plate Rating

Schedule Page: 410 Line No.: 5 Column: b

7 turbines added in 2010

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								
13	Lines Below 132 Kilovolts		115.00	115.00	2	616.90	4.12	
14			69.00	69.00	Various	95.06	1.33	1
15			41.60	69.00	2	86.44	17.19	1
16			57.00	69.00	2	3.34		1
17			57.00	60.00	Various	899.38	0.89	1
18			33.00	60.00	1	18.38		1
19			57.00	57.00	1	2.61		2
20			41.60		Various	1,044.83	23.29	
21			33.00	35.00	1	28.99		1
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,143.13	46.82	19

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
								12
Various								13
Various								14
4/0 ACSR								15
4/0 ACSR								16
Various								17
4/0 ACSR								18
4/0 ACSR								19
Various								20
Various								21
								22
	3,232,160	138,382,919	141,615,079	6,306,644	1,024,365	94,729	7,425,738	23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	3,232,160	138,382,919	141,615,079	6,306,644	1,024,365	94,729	7,425,738	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) 12/31/2016	Year/Period of Report 2016/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.: 13 Column: h

Various

Schedule Page: 422 Line No.: 20 Column: d

Various

Schedule Page: 422 Line No.: 20 Column: h

Various

Schedule Page: 422 Line No.: 23 Column: j

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

Schedule Page: 422 Line No.: 23 Column: k

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

Schedule Page: 422 Line No.: 23 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	Enbridge Stanley Tap		2.65	SP	17.00	1	1
2	Correction from 2012		-1.97	Retired			
3							
4	Medora	Dickinson	0.56	SP	20.00	1	1
5			-0.72	Retired			
6							
7	Dickinson 46kV West Tap Line		0.35	SP	20.00	1	1
8			-0.15	Retired			
9							
10	Oasis Tap Line		0.05	SP	20.00	1	1
11							
12	Williston Waste Water Plant		0.06	SP	16.00	1	1
13	Correction to 2014 WO		0.07	SP	20.00	1	1
14							
15	Emerald Ridge Sub		0.60	SP	18.00	1	1
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.50		131.00	7	7

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)	
397.5	MCMACSR	TP-115	69						1
			115						2
									3
477	MCMACSR	T-46-HA	42		337,590	208,689		546,279	4
							41,033	41,033	5
									6
477	MCMACSR	T-46-HA	42		193,036	96,518		289,554	7
							20,043	20,043	8
									9
4/0	ACSR	T-60-E	57		56,228		5,415	61,643	10
									11
4/0	ACSR	T-60-HA	57		92,274	58,600	12,743	163,617	12
4/0	ACSR	T-60-HA	57						13
									14
336.4	MCMACSR	TP-60-HA1	33		308,819	46,790	23,169	378,778	15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					987,947	410,597	102,403	1,500,947	44

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) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 424	Line No.: 1	Column: a	Correction from 2012
Schedule Page: 424	Line No.: 1	Column: j	8' x 8' x 13' Vertical
Schedule Page: 424	Line No.: 4	Column: j	7' x 7' x 10' Vertical
Schedule Page: 424	Line No.: 4	Column: k	46 KV Design
Schedule Page: 424	Line No.: 7	Column: j	7' x 7' x 10' Vertical
Schedule Page: 424	Line No.: 7	Column: k	46 KV Design
Schedule Page: 424	Line No.: 10	Column: j	7' x 7' Vertical
Schedule Page: 424	Line No.: 10	Column: k	60 KV Design
Schedule Page: 424	Line No.: 12	Column: j	7' x 7' x 10' Vertical
Schedule Page: 424	Line No.: 12	Column: k	60 KV Design
Schedule Page: 424	Line No.: 13	Column: j	7' x 7' x 10' Vertical
Schedule Page: 424	Line No.: 13	Column: k	60 KV Design
Schedule Page: 424	Line No.: 15	Column: j	6' x 6' x 8' Vertical
Schedule Page: 424	Line No.: 15	Column: k	60 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	60.00	
10	Glendive, MT (Turbine)	Trans at Plant	115.00	13.20	
11	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
12	Heskett Station, ND	Trans at Plant	230.00	115.00	13.80
13	Heskett Station, ND	Trans at Plant	116.00	13.20	
14	Heskett Station, ND	Trans at Plant	115.00	13.20	
15	Heskett Station, ND	Trans at Plant	115.00	41.60	
16	Heskett Station, ND	Trans at Plant	115.00	69.00	
17	Lewis & Clark Station, MT	Trans at Plant	115.00	13.80	
18	Lewis & Clark Station, MT	Trans at Plant	57.00	13.80	
19	Lewis & Clark Station, MT	Trans at Plant	115.00	60.00	
20	Miles City, MT (Turbine)	Trans at Plant	57.00	13.80	
21	Substations under 10,000 KVA (0)				
22	SUBTOTAL		2802.00	860.67	41.40
23					
24	Baker, MT	Trans Unattended	115.00	57.00	
25	Baker, MT	Trans Unattended	230.00	115.00	14.10
26	Baker, MT Cabin Creek Jct	Trans Unattended	115.00	57.20	
27	Beulah Jct., ND	Trans Unattended	115.00	41.60	
28	Bismarck Jct., ND (E. Bismarck)	Trans Unattended	115.00	41.60	
29	Bismarck, ND NW	Trans Unattended	115.00	41.60	
30	Bismarck, ND Sweet Ave.	Trans Unattended	115.00	41.60	
31	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
32	Dickinson, ND	Trans Unattended	115.00	41.60	
33	Dickinson, ND	Trans Unattended	115.00	41.60	
34	Dunning, ND	Trans Unattended	115.00	57.00	
35	Ellendale Jct., ND	Trans Unattended	230.00	115.00	13.80
36	Ellendale Jct., ND	Trans Unattended	115.00	41.60	
37	Elgin, ND	Trans Unattended	69.00	41.60	
38	Gascoyne Jct., ND	Trans Unattended	115.00	41.60	
39	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
40	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
104	1					1
52	1					2
28	2					3
120	1					4
21	1					5
168	1					6
28	2					7
11	1					8
50	1					9
40	1					10
37	1					11
112	1					12
94	1	1				13
28	1					14
34	1					15
45	1			1		4 16
53	1					17
20	1					18
47	1					19
31	1					20
						21
1123	22	1		1		4 22
						23
40	1			1		4 24
112	1					25
83	1					26
45	1					27
80	2			2		8 28
47	1			1		4 29
56	1					30
20	1			1		2 31
75	1					32
93	1					33
20	1			1		2 34
100	1					35
37	1					36
15	1					37
11	1			1		1 38
30	1			1		3 39
56	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	Halliday, ND	Trans Unattended	115.00	41.60	
2	Hettinger Jct., ND	Trans Unattended	115.00	41.60	
3	Hettinger Jct., ND	Trans Unattended	230.00	115.00	14.10
4	Kenmare Jct., ND	Trans Unattended	115.00	57.00	
5	Linton Jct., ND	Trans Unattended	115.00	41.60	
6	Mandan, ND 230	Trans Unattended	230.00	115.00	13.80
7	Mandan, ND Collins	Trans Unattended	115.00	41.60	
8	McIntosh Jct., SD	Trans Unattended	115.00	41.60	
9	Miles City, MT	Trans Unattended	230.00	115.00	13.80
10	Miles City, MT	Trans Unattended	115.00	57.00	13.80
11	New England, ND	Trans Unattended	115.00	41.60	
12	Plentywood Jct., MT	Trans Unattended	115.00	57.00	
13	Poplar Jct., MT	Trans Unattended	115.00	57.00	
14	Ray, ND Jct.	Trans Unattended	115.00	57.00	
15	Rosebud Creek, MT	Trans Unattended	230.00	60.00	13.80
16	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
17	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
18	Stanley Jct., ND	Trans Unattended	115.00	69.00	12.47
19	Tioga, ND	Trans Unattended	230.00	115.00	
20	Tioga Jct., ND	Trans Unattended	115.00	57.00	
21	Wishek Jct., ND	Trans Unattended	115.00	41.60	
22	Wishek Jct., ND	Trans Unattended	230.00	115.00	13.80
23	Substations under 10,000 KVA (7)				
24	SUBTOTAL		5819.00	2467.60	206.67
25					
26	Substations under 10,000 KVA Distrib at Plant (2)				
27	SUBTOTAL				
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)	
20	1			1	2	1
25	1			1	2	2
112	1					3
30	1			1	3	4
15	1			1	2	5
224	1					6
30	1					7
13	1			1	1	8
100	1					9
56	1					10
22	1			1	2	11
47	1					12
37	1					13
75	1					14
40	1					15
37	1					16
20	1					17
22	1			1	2	18
112	1					19
75	1					20
30	1			1	3	21
112	1					22
14	12	1		3		23
2188	52	1		19	41	24
						25
8	2			3	1	26
8	2			3	1	27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Beulah, ND Coyote Creek	Distrib Unattended	115.00	22.90	
2	Beulah, ND W. M. Port 1	Distrib Unattended	115.00	6.90	
3	Beulah, ND W. M. Port 2	Distrib Unattended	115.00	6.90	
4	Baker, MT Lookout Butte	Distrib Unattended	57.20	12.47	
5	Baker, MT Pine Unit #1	Distrib Unattended	57.00	12.47	
6	Bismarck, ND Kirkwood	Distrib Unattended	115.00	12.47	
7	Bismarck, ND SE Expressway	Distrib Unattended	115.00	12.47	
8	Bismarck, ND NW (Century)	Distrib Unattended	115.00	12.47	
9	Bismarck, ND NE	Distrib Unattended	115.00	12.47	
10	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
11	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
12	Bismarck, ND Turnpike	Distrib Unattended	115.00	12.47	
13	Bismarck, ND South 9th St.	Distrib Unattended	41.60	12.47	
14	Bismarck, ND Sunrise	Distrib Unattended	115.00	12.47	
15	Bismarck, ND 26th & D	Distrib Unattended	41.60	12.47	
16	Bismarck, ND 26th & D	Distrib Unattended	115.00	12.47	
17	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
18	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
19	Dickinson, ND NE	Distrib Unattended	41.60	12.47	
20	Dickinson, ND Refinery	Distrib Unattended	41.60	12.47	
21	Dickinson, ND 21st	Distrib Unattended	41.60	12.47	
22	Dickinson, ND West	Distrib Unattended	41.60	12.47	
23	Glendive, MT	Distrib Unattended	57.00	12.47	
24	Glendive, MT West	Distrib Unattended	57.00	12.47	
25	Glendive, MT	Distrib Unattended	57.00	12.47	
26	Lignite, ND	Distrib Unattended	57.00	2.40	
27	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
28	Mandan, ND Collins Ave	Distrib Unattended	115.00	12.47	
29	Mandan, ND Midway (New)	Distrib Unattended	41.60	12.47	
30	Mandan, ND Tesoro	Distrib Unattended	41.60	4.16	
31	Mandan, ND	Distrib Unattended	115.00	12.47	
32	Miles City, MT Greenstar	Distrib Unattended	57.00	12.47	
33	Miles City, MT 8th St	Distrib Unattended	57.00	12.47	
34	Miles City, MT South	Distrib Unattended	57.00	12.47	
35	Mobridge, SD	Distrib Unattended	115.00	12.47	
36	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
37	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
38	Sheridan, WY SW	Distrib Unattended	230.00	41.60	
39	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
40	Sheridan, WY Soldier Creek	Distrib Unattended	41.60	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
11	1					4
11	1			3	1	5
28	1			6	2	6
53	2			9	4	7
22	1			3	2	8
28	1			6	2	9
47	1			15	3	10
47	1			12	4	11
56	2			9	3	12
11	1			3	1	13
28	1			6	2	14
14	1			3	1	15
28	1			6	2	16
14	1			3	1	17
14	1			3	1	18
14	1			3	1	19
14	1					20
11	1			3	1	21
14	1			6	2	22
14	1			3	1	23
10	1			3	1	24
10	1			3	1	25
12	4			3	1	26
14	1			3	1	27
28	1					28
28	1			6	2	29
11	1					30
50	2			9	3	31
10	1			3	2	32
11	1			3	1	33
10	1			6	2	34
22	1			9	2	35
11	1			3	2	36
13	1			3	2	37
75	1					38
11	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	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
2	Sheridan, WY West	Distrib Unattended	41.60	12.47	
3	Sidney, MT	Distrib Unattended	57.00	12.47	
4	Sidney, MT	Distrib Unattended	57.00	12.47	
5	Stanley, ND	Distrib Unattended	69.00	12.47	
6	Stanley, ND Enbridge	Distrib Unattended	69.00	12.47	
7	Watford City, ND South Park	Distrib Unattended	34.50	7.20	
8	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
9	Williston, ND NE	Distrib Unattended	57.00	12.47	
10	Williston, ND NW North	Distrib Unattended	57.00	12.47	
11	Williston, ND NW South	Distrib Unattended	57.00	12.47	
12	Williston, ND Sabin Metals	Distrib Unattended	57.00	13.80	
13	Williston, ND Oasis	Distrib Unattended	57.00	12.47	
14	Substations Under 10,000 KVA (244)				
15	SUBTOTAL		3803.90	667.01	
16					
17	GRAND TOTAL		12424.90	3995.28	248.07
18					
19					
20	FOOTNOTES				
21					
22					
23					
24					
25					
26					
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)	
11	1			3	2	1
11	1			3	2	2
11	1			3	1	3
14	1			3	1	4
14	1			3	1	5
14	1			3	1	6
11	1			3	1	7
11	1			3	1	8
10	1			3	1	9
14	1			3	1	10
14	1			3	1	11
10	1					12
11	1			3	1	13
638	399			474	60	14
1648	458			672	130	15
						16
4967	534	2		695	176	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 28 Column: a
See (A) and (B) of footnotes
Schedule Page: 426 Line No.: 29 Column: a
See (B) and (C) of footnotes
Schedule Page: 426 Line No.: 34 Column: a
See (J) and (K) of footnotes
Schedule Page: 426 Line No.: 37 Column: a
See (N) and (O) of footnotes
Schedule Page: 426.1 Line No.: 1 Column: a
See (H) and (I) of footnotes
Schedule Page: 426.1 Line No.: 9 Column: a
See (P) of footnotes
Schedule Page: 426.1 Line No.: 10 Column: a
See (L) and (M) of footnotes
Schedule Page: 426.1 Line No.: 15 Column: a
See (D) and (E) of footnotes
Schedule Page: 426.1 Line No.: 22 Column: a
See (F) and (G) of footnotes
Schedule Page: 426.3 Line No.: 20 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 cost and available capacity in the respective percentages of 63% and 37%. All maintenance and operating expenses are shared in the same percentage. The Respondent's 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. 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 allocated 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	3,865,430
3	Cost of Service	CHCC	401,165,184,228	2,021,969
4	Contract Services	CHCC	184	411,936
5	Contract Services	WBIH		598,139
6	Contract Services	MDU CSG	401,402,417,107	782,222
7				
8				
9	Total			7,679,696
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	717,768
22	Cost of Service for Facilities Used	MDU CSG	454,493	234,644
23	Cost of Service for Facilities Used	MDU EC	454,493	1,992,876
24	Cost of Service for Facilities Used	WBIH	454,493	158,427
25				
26	Total			3,103,715
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

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

Name of Respondent

MDU Resources Group, Inc.

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/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				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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) 12/31/2016	Year/Period of Report 2016/Q4
MDU Resources Group, Inc.			
FOOTNOTE DATA			

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

Company Abbreviations used in Column (b)

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

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

107,146,184,401,402,417