MONTANA-DAKOTA
UTILITIES CO.
A Subsidiary of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
701-222-7900

April 15, 2020

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Annual Reports

Montana-Dakota Utilities Co. (Montana-Dakota) herewith electronically submit its Electric and Gas Annual Reports for the year ended December 31, 2019 consisting of:

North Dakota Electric and Gas Annual Reports
North Dakota Electric and Gas Cost of Service Studies
Report of Independent Public Accountants

The gas report includes information for Montana-Dakota and its division Great Plains Natural Gas Co.

As requested, Montana-Dakota has also submitted electronically a copy of the 2019 FERC Form No. 1.

Montana-Dakota respectfully requests that this electronic filing be accepted as being in full compliance with the filing requirements of this Commission.

Sincerely,

/s/ Travis R. Jacobson

Travis R. Jacobson
Director of Regulatory Affairs

ANNUAL REPORT

STATE OF NORTH DAKOTA

GAS OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2019

MONTANA-DAKOTA UTILITIES CO.
A Subsidiary of MDU Resources Group, Inc.

GREAT PLAINS NATURAL GAS CO.
A Division of Montana-Dakota Utilities Co.

INDEX

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

		(A)	(B)	(C)	(D)	(E)
		2019	2019		2018 1/	
Line		Total	North	ND %	North	Variance
#	Description	Company	Dakota	(B / A)	Dakota	(B-D / D)
	Operating Revenues:					
1	Residential	$159,049,250	61,227,555	38.50%	$60,883,062	0.57%
2	Firm General	111,227,184	48,125,656	43.27%	45,874,278	4.91%
3	Small Interruptible	9,761,766	6,218,508	63.70%	5,681,488	9.45%
4	Large Interruptible	5,579,527	1,930,536	34.60%	1,734,196	11.32%
5	Transportation	7,066,654	3,609,805	51.08%	2,997,453	20.43%
6	Other Operating Revenues	6,130,815	3,856,346	62.90%	3,937,023	-2.05%
7	Unbilled Revenue	(3,714,483)	(1,311,938)	35.32%	329,144	-498.59%
8	Reserve for Refunds	(378,716)	(93,490)	24.69%	(712,503)	-86.88%
9	Total Operating Revenues	$294,721,997	$123,562,978	41.93%	$120,724,141	2.35%
	Operating Expenses:					
10	Cost of Purchased Gas	$182,122,901	$77,820,649	42.73%	$75,245,400	3.42%
11	Production	770,043	334,283	43.41%	294,870	13.37%
12	Transmission	41,284	10,215	24.74%	6,696	52.55%
13	Distribution Expense	26,423,078	10,261,368	38.83%	9,878,192	3.88%
14	Customer Accounts Expense	7,110,300	2,584,081	36.34%	2,618,418	-1.31%
15	Customer Service & Info. Exp.	1,372,942	260,400	18.97%	224,919	15.78%
16	Sales Expense	443,383	180,699	40.75%	185,029	-2.34%
17	Administration & General Exp.	24,068,053	9,107,793	37.84%	8,397,054	8.46%
18	Depreciation Expense	23,975,718	10,272,599	42.85%	8,715,741	17.86%
19	Taxes Other than Income	11,875,589	2,562,018	21.57%	2,275,877	12.57%
20	Total Operating Expenses	$278,203,291	$113,394,105	40.76%	$107,842,196	5.15%
21	Net Operating Income					
22	before Income Taxes	$16,518,706	$10,168,873	61.56%	$12,881,945	-21.06%
	Income Tax Expense:					
23	Investment Tax Credits					
24	Deferred Income Taxes	$3,463,240	$2,237,516	64.61%	($207,891)	-1176.29%
25	Income Taxes	(3,138,360)	(1,243,057)	39.61%	2,443,679	-150.87%
26	Total Income Tax Expense	$324,880	$994,459	306.10%	$2,235,788	-55.52%
27	**Net Regulated Earnings**	$16,193,826	$9,174,414	56.65%	$10,646,157	-13.82%

I. INTRASTATE RETURN ON EQUITY — GAS UTILITY

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Line #	Description	(A) 2019 Total Company	(B) 2019 North Dakota		(C) ND % (B / A)	(D) 2018 1/ North Dakota	(E) Variance (B-D / D)
	Rate Base:						
1	Plant in Service 2/	$670,233,416	$305,656,931		45.60%	$283,843,113	7.69%
2	Less: Accumulated Depreciation 2/	294,373,009	109,560,561		37.22%	102,553,621	6.83%
3	Net Plant in Service	$375,860,407	$196,096,370		52.17%	$181,289,492	8.17%
	Additions:						
4	Materials and Supplies 3/	$5,207,621	$2,391,229		45.92%	$1,880,884	27.13%
5	Prepayments 3/	705,050	290,727		41.23%	262,264	10.85%
6	Prepaid Demand/Commodity 3/	726,223	5,465	4/	0.75%	3,183	71.69%
7	Fuel Stocks 3/	37,861	37,861		100.00%	56,706	-33.23%
8	Gas in Underground Storage 3/	2,471,045	26,511	4/	1.07%	24,517	8.13%
9	Unamort. Redemption Cost of Pref. Stock 2/	108,192	55,363		51.17%	28,676	93.06%
10	Unamortized Loss on Debt 2/	781,902	410,423		52.49%	463,183	-11.39%
11	Gain/Loss on Property 2/	512,853	512,853		100.00%	116,889	338.75%
12	Other 2/	23,727	0		0.00%	0	0.00%
13	Total Additions	$10,574,474	$3,730,432		35.28%	$2,836,302	31.52%
	Deductions:						
14	Accum. Deferred Income Taxes 2/	$53,623,565	$23,357,955		43.56%	$22,278,376	4.85%
15	Cust. Advances for Construct. 3/	15,080,990	11,063,109		73.36%	12,726,229	-13.07%
16	Total Deductions	$68,704,555	$34,421,064		50.10%	$35,004,605	-1.67%
17	**Average Rate Base**	$317,730,326	$165,405,738		52.06%	$149,121,189	10.92%
18	Rate of Return on Avg. Rate Base	5.097%	5.547%			7.139%	
19	Less: Weighted Cost of Debt	2.346%	2.346%			2.419%	
20	Weighted Cost of Pref. Stock	0.000%	0.000%			0.000%	
21	Weighted Return on Equity	2.751%	3.201%			4.720%	
22	% of Equity to Capital Structure	50.082%	50.082%			50.025%	
23	**Return on Equity**	5.493%	6.392%			9.435%	

1/ Beginning with the report for calendar year 2018, the reported information includes Montana-Dakota Utilities Co. and its division Great Plains Natural Gas Co.
2/ Beginning and ending year average.
3/ Thirteen month average.
4/ Reflects thirteen month average balance for Great Plains Natural Gas-North Dakota only.

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

		(A)	(B)	(C)	(D)
Line #	Description	2018 Average (000's)	Ratio	Cost	Weighted Cost
1	Long-Term Debt 1/	$730,420	46.457%	4.820%	2.239%
2	Short-Term Debt 2/	54,409	3.461%	3.095%	0.107%
3	Common Equity	787,435	50.082%	3/	3/
4	Total	$1,572,264	100.000%		3/

1/ Includes additional other long-term debt and excludes $9.1 million economic development loan for a North Dakota project.
2/ Reflects monthly average short-term debt.
3/ Return on equity is calculated in Section I, page 2 of 2.

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2019

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
Unsecured Long-Term Debt									
5.98% - Senior Note	12/15/03	12/15/33	5.980%	$30,000,000	$30,000,000	624,465	2.082%	0	0.000%
6.33% - Senior Note	08/24/06	08/24/26	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
5.18% - Senior Note	04/15/14	04/15/44	5.180%	50,000,000	50,000,000	239,178	0.478%	0	0.000%
4.24% - Senior Note	07/15/14	07/15/24	4.240%	60,000,000	60,000,000	291,263	0.485%	0	0.000%
4.34% - Senior Note	07/15/14	07/15/26	4.340%	40,000,000	40,000,000	197,042	0.493%	0	0.000%
3.78% - Senior Note	10/29/15	10/30/25	3.780%	87,000,000	87,000,000	471,997	0.543%	0	0.000%
4.87% - Senior Note	10/29/15	10/30/45	4.870%	11,000,000	11,000,000	59,461	0.541%	0	0.000%
4.03% - Senior Note	12/10/15	12/10/30	4.030%	52,000,000	52,000,000	286,355	0.551%	0	0.000%
4.15% - Senior Note	11/21/16	11/21/46	4.150%	40,000,000	40,000,000	226,084	0.565%	0	0.000%
3.73% - Senior Note	03/21/17	03/31/37	3.730%	40,000,000	40,000,000	173,637	0.434%	0	0.000%
3.36% - Senior Note	03/21/17	03/31/32	3.360%	20,000,000	20,000,000	86,071	0.430%	0	0.000%
2.00% - Senior Note	9/5/2017	9/3/2032	2.000%	9,100,000	9,100,000	6,029	0.062%	0	0.000%
3.66% - Senior Note	10/17/19	10/17/39	3.660%	50,000,000	50,000,000	234,202	0.468%	0	0.000%
3.98% - Senior Note	10/17/19	10/17/49	3.980%	50,000,000	50,000,000	234,202	0.468%	0	0.000%
4.08% - Senior Note	11/18/19	11/18/59	4.080%	100,000,000	100,000,000	435,969	0.436%	0	0.000%
Total Long-Term Debt Capital				$739,100,000	$739,100,000	$3,910,016		$10,532,009	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
Unsecured Long-Term Debt						
5.98% - Senior Note	$29,375,535	97.918%	6.210%	$30,000,000	1,863,000	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
5.18% - Senior Note	49,760,822	99.522%	5.280%	50,000,000	2,640,000	
4.24% - Senior Note	59,708,737	99.515%	4.346%	60,000,000	2,607,600	
4.34% - Senior Note	39,802,958	99.507%	4.442%	40,000,000	1,776,800	
3.78% - Senior Note	86,528,003	99.457%	3.883%	87,000,000	3,378,210	
4.87% - Senior Note	10,940,539	99.459%	4.964%	11,000,000	546,040	
4.03% - Senior Note	51,713,645	99.449%	4.122%	52,000,000	2,143,440	
4.15% - Senior Note	39,773,916	99.435%	4.228%	40,000,000	1,691,200	
3.73% - Senior Note	39,826,363	99.566%	3.797%	40,000,000	1,518,800	
3.36% - Senior Note	19,913,929	99.570%	3.425%	20,000,000	685,000	
2.00% - Senior Note	9,100,000	100.000%	2.000%	9,100,000	182,000	
3.66% - Senior Note	49,765,798	99.532%	3.728%	50,000,000	1,864,000	
3.98% - Senior Note	49,765,798	99.532%	4.046%	50,000,000	2,023,000	
4.08% - Senior Note	99,564,031	99.564%	4.144%	100,000,000	4,144,000	
Total Long-Term Debt Capital	$724,664,004			$739,100,000	$34,577,090	4.678%

1/ Yield to maturity based upon the life, net proceeds, and semiannual compounding of stated interest rate.

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION
MAJOR TRANSACTIONS 2019

Line #	Affiliate's Name	General Description of Service Rendered and/or Supplied	Revenue or (Expense) Total Company	Revenue or (Expense) Allocated to North Dakota
1	Knife River Corporation	Electric Sales	$152,483	$152,483
2		Natural Gas Sales	114,700	69,470
3	WBI Energy	Electric Sales	625,744	153,926
4		Natural Gas Pipeline Services	(57,635,241)	(26,295,733)
5		Natural Gas Sales	35,754	5,338
6	FutureSource	Electric Sales	182,927	182,927
7		Natural Gas Sales	14,357	14,357
8	JTL Group	Natural Gas Sales	11,450	0
9	Total Corrosion Solution	Natural Gas Sales	2,607	0
10	Rocky Mountain Contractor	Natural Gas Sales	4,952	0
	Total		($56,490,267)	($25,717,232)

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION
Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. Combined

Line #	Description		2019	2018	2017	2016	2015
	Customer Related						
1	Year End Customers	- Residential	97,163	96,464	95,959	95,525	95,078
2		- Firm General	15,855	15,659	15,483	15,244	14,870
3		- Small Interruptible	143	140	144	135	184
4		- Large Interruptible	2	2	2	2	1
5		- Other - Transportation 1/	76	77	78	97	87
6		- Total	113,239	112,342	111,666	111,003	110,220
7	Dk Sold	- Residential	9,483,387	9,312,803	8,184,807	7,401,182	7,888,589
8		- Firm General	8,898,696	8,424,902	7,562,295	6,625,698	7,022,228
9		- Small Interruptible	1,615,405	1,460,247	1,542,463	1,418,219	1,663,003
10		- Large Interruptible	481,593	442,814	404,073	367,952	47,386
11		- Other - Transportation	7,018,159	6,950,990	6,743,178	6,469,831	6,778,537
12		- Total	27,497,240	26,591,756	24,436,816	22,282,882	23,399,743

1/ Years 2015-2016 may include duplication of customers also receiving sales service.

MONTANA-DAKOTA UTILITIES CO. AND GREAT PLAINS NATURAL GAS CO.

NORTH DAKOTA COST OF SERVICE STUDY GAS OPERATIONS

2019

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
INCOME STATEMENT
GAS UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2019

	Total Company	North Dakota	Others
Operating Revenues			
Sales Revenues			
Residential	$159,049,250	$61,227,555	$97,821,695
Firm General	111,227,184	48,125,656	63,101,528
Small Interruptible	9,761,766	6,218,508	3,543,258
Large Interruptible	5,579,527	1,930,536	3,648,991
Unbilled Revenue	(3,726,674)	(1,132,825)	(2,593,849)
Reserve for Refunds	(378,716)	(93,490)	(285,226)
Total Sales Revenues	281,512,337	116,275,940	165,236,397
Transportation Revenues			
Small Interruptible	2,239,654	1,251,855	987,799
Large Interruptible	4,827,000	2,357,950	2,469,050
Unbilled Revenue	12,191	(179,113)	191,304
Total Transportation Revenues	7,078,845	3,430,692	3,648,153
Other Operating Revenues	6,130,815	3,856,346	2,274,469
Total Operating Revenues	$294,721,997	$123,562,978	$171,159,019
Operating Expenses			
Operation and Maintenance			
Cost of Purchased Gas	$182,122,901	$77,820,649	$104,302,252
Production	770,043	334,283	435,760
Transmission	41,284	10,215	31,069
Distribution	26,423,078	10,261,368	16,161,710
Customer Accounts	7,110,300	2,584,081	4,526,219
Customer Service & Information	1,372,942	260,400	1,112,542
Sales	443,383	180,699	262,684
Administrative & General	24,068,053	9,107,793	14,960,260
Total O&M Expenses	242,351,984	100,559,488	141,792,496
Depreciation			
Transmission	140,892	40,323	100,569
Distribution	19,297,863	8,379,363	10,918,500
General	969,632	241,138	728,494
Common	737,216	343,332	393,884
Amort. of Intangible Plant - General	659,475	358,652	300,823
Amort. of Intangible Plant - Common	2,170,640	909,791	1,260,849
Total Depreciation Expense	23,975,718	10,272,599	13,703,119

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
INCOME STATEMENT
GAS UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2019

	Total Company	North Dakota	Others
Operating Expenses Con't.			
Taxes Other Than Income Taxes			
Ad Valorem Taxes			
Transmission	53,089	13,483	39,606
Distribution	7,972,098	1,356,291	6,615,807
General	626,762	79,246	547,516
Common	207,359	50,732	156,627
Intangible	169,807	101,126	68,681
Total Ad Valorem Taxes	9,029,115	1,600,878	7,428,237
Other Taxes	2,846,474	961,140	1,885,334
Total Taxes Other Than Income Taxes	11,875,589	2,562,018	9,313,571
Current Income Taxes	(3,138,360)	(1,243,057)	(1,895,303)
Deferred Income Taxes	3,463,240	2,237,516	1,225,724
Total Operating Expenses	$278,528,171	$114,388,564	$164,139,607
Operating Income	$16,193,826	$9,174,414	$7,019,412
Year End Rate Base	$332,338,469	$170,764,252	$161,574,217
Rate of Return	4.87%	5.37%	4.34%

MONTANA-DAKOTA UTILITIES CO.
GREAT PLAINS NATURAL GAS CO.
YEAR END RATE BASE
GAS UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2019

Plant in Service	Total Company	North Dakota	Others
Gas Plant in Service			
Transmission	$7,197,267	$2,000,051	$5,197,216
Distribution	550,823,374	255,344,183	295,479,191
General	54,795,436	15,722,066	39,073,370
Intangible Plant - General	13,416,925	8,957,806	4,459,119
Common	29,373,265	16,487,347	12,885,918
Intangible Plant - Common	35,764,449	15,171,417	20,593,032
Acquisition Adjustment	97,266	97,266	0
Total Gas Plant in Service	691,467,982	313,780,136	377,687,846
Accumulated Reserve for Depreciation			
Transmission	1,937,484	531,161	1,406,323
Distribution	254,672,728	94,817,585	159,855,143
General	13,137,211	2,786,396	10,350,815
Intangible Plant - General	3,671,933	1,997,449	1,674,484
Common	10,537,664	5,405,473	5,132,191
Intangible Plant - Common	18,112,655	7,878,175	10,234,480
Acquisition Adjustment	74,951	74,951	0
Total Accum. Reserve for Depreciation	302,144,626	113,491,190	188,653,436
Net Gas Plant in Service	389,323,356	200,288,946	189,034,410
Additions			
Materials and Supplies	5,192,697	2,462,611	2,730,086
Fuel Stocks	40,656	40,656	0
Prepayments	130,302	52,770	77,532
Prepaid Demand/Commodity	1,369,266	8,814	1,360,452
Gas in Underground Storage	3,402,475	38,256	3,364,219
Unamort. Redemption Cost of Pref Stock	104,305	53,373	50,932
Unamortized Loss on Debt	722,421	382,846	339,575
Gain/Loss on Property	501,631	501,631	0
Total Additions	11,463,753	3,540,957	7,922,796
Total Before Deductions	$400,787,109	$203,829,903	$196,957,206
Deductions			
Accumulated Deferred Income Taxes	55,618,163	24,136,121	31,482,042
Customer Advances	12,830,477	8,929,530	3,900,947
Total Deductions	68,448,640	33,065,651	35,382,989
Year End Rate Base	$332,338,469	$170,764,252	$161,574,217

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

2019

Deloitte.

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INDEPENDENT ACCOUNTANTS' REPORT

To the Managing Committee of
Montana-Dakota Utilities Co.:

We have examined the accompanying schedules of the Cost of Gas per dk and Fuel and Purchased Power Cost per kWh (collectively, "the Schedules") of Montana-Dakota Utilities Co. (the "Company"), a wholly-owned subsidiary of MDU Resources Group Inc., for the period from January 1, 2019 to December 31, 2019. The Company's management is responsible for the calculation of the cost of gas per dk and fuel and purchased power cost per kWh in the Schedules in accordance with the criteria established by the North Dakota Public Service Commission (the "Commission") and based upon Chapters 69-09-01-30 and 69-09-02-39 of the North Dakota Administrative Code (the "Code") and Cost of Gas Rate 88 and Fuel and Purchased Power Adjustment Rate 58 (the "Tariffs") filed by the Company with the Commission. Our responsibility is to express an opinion on these Schedules based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether the Schedules are in accordance with the criteria, in all material respects. An examination involves performing procedures to obtain evidence about the Schedules. The nature, timing, and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of the Schedules, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

In our opinion, the Schedules of the Cost of Gas per dk and Fuel and Purchased Power Cost per kWh of Montana-Dakota Utilities Co. for the period from January 1, 2019 to December 31, 2019, present the cost of gas per dk and the fuel and purchased power cost per kWh in accordance with Chapters 69-09-01-30 and 69-09-02-39 of the North Dakota Administrative Code and Cost of Gas Rate 88 and Fuel Clause Rate 58, in all material respects.

This report is intended solely for the information and use of the Managing Committee of the Company and the Commission, and is not intended to be, and should not be, used by anyone other than these specified parties.

Deloitte & Touche LLP

April 3, 2020

MONTANA-DAKOTA UTILITIES CO.

SCHEDULE OF 2019 COST OF GAS PER DK

Effective for the Month of:	Residential and General Service ($)	Small and Large Interruptible ($)	Air Force Interruptible ($)
January	4.258	3.102	3.077
February	3.971	2.789	2.765
March	3.971	2.789	2.765
April	3.650	2.485	2.463
May	3.650	2.485	2.463
June	3.990	2.575	2.552
July	3.681	2.450	2.428
August	3.681	2.450	2.428
September	3.681	2.450	2.428
October	3.571	2.595	2.398
November	3.571	2.595	2.398
December	3.571	2.595	2.398

MONTANA-DAKOTA UTILITIES CO.

SCHEDULE OF 2019 FUEL AND PURCHASED POWER COST PER kWh

Rate Effective Date	Primary ($)	Secondary ($)
January 1, 2019	0.02706	0.02814
February 1, 2019	0.02680	0.02782
March 1, 2019	0.02700	0.02786
April 1, 2019	0.02910	0.02983
May 1, 2019	0.02681	0.02745
June 1, 2019	0.02566	0.02632
July 1, 2019	0.02470	0.02543
August 1,2019	0.02125	0.02211
September 1, 2019	0.02311	0.02416
October 1, 2019	0.02430	0.02540
November 1, 2019	0.02466	0.02584
December 1, 2019	0.02381	0.02489

Deloitte.

Deloitte & Touche LLP
50 South 6th Street
Suite 2800
Minneapolis, MN 55402-1538
USA

Tel: +1 612 397 4000
Fax: +1 612 397 4450
www.deloitte.com

INDEPENDENT ACCOUNTANTS' REPORT

To the Managing Committee of
Great Plains Natural Gas Co.:

We have examined the accompanying schedule of Cost of Gas per dk (the "Schedule") of Great Plains Natural Gas Co. (the "Company"), a wholly-owned subsidiary of MDU Resources Group Inc., for the period from January 1, 2019 to December 31, 2019. The Company's management is responsible for the calculation of the cost of gas per dk in the Schedule in accordance with the criteria established by the North Dakota Public Service Commission (the "Commission") and based upon Chapter 69-09-01-30 of the North Dakota Administrative Code (the "Code") and the Cost of Gas Rate 88 (the "Tariff") filed by the Company with the Commission. Our responsibility is to express an opinion on the Schedule based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether the Schedule is in accordance with the criteria, in all material respects. An examination involves performing procedures to obtain evidence about the Schedule. The nature, timing, and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of the Schedule, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

In our opinion, the Schedule of the Cost of Gas per dk of Great Plains Natural Gas Co. for the period from January 1, 2019 to December 31, 2019, presents the cost of gas in accordance with Chapter 69-09-01-30 of the North Dakota Administrative Code (the "Code"), and the Cost of Gas Rates (the "Tariffs") filed by the Company with the Commission, in all material respects.

This report is intended solely for the information and use of the Managing Committee of the Company and the Commission, and is not intended to be, and should not be, used by anyone other than these specified parties.

Deloitte & Touche LLP

April 3, 2020

GREAT PLAINS NATURAL GAS CO.

SCHEDULE OF 2019 COST OF GAS PER DK

Effective for the Month of	Cost of Gas Factor	
	Firm ($)	Interruptible ($)
January	5.9838	4.1457
February	5.9838*	4.1457*
March	5.2964	3.8036
April	4.7578	3.2650
May	4.4407	2.9567
June	2.6451	2.9057
July	2.2554	2.5160
August	2.9375	2.5196
September	2.9375	2.5196
October	2.9375	2.5196
November	3.2307	2.7913
December	3.6078	3.1545

*In accordance with Chapter 69-09-01-30 of the North Dakota Administrative Code and Gas Rate Schedule 88, Great Plains shall file to reflect changes in its average cost of gas supply only when the amount of such change is at least $0.25 per dk. The change in cost of gas per dk for interruptible rates from January to February was above the threshold of $0.25 per dk; however, the Company did not file for the change in cost of gas per dk. Had the Company filed for the change in cost of gas per dk, the firm and interruptible rates would have been $6.0173 and $4.5245, respectively.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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)	Year/Period of Report
Montana-Dakota Utilities Co.	End of 2019/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Montana-Dakota Utilities Co.	End of 2019/Q4

03 Previous Name and Date of Change *(if name changed during year)*
MDU Resources Group, Inc. 01/01/2019

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	06 Title of Contact Person
Tammy Nygard	Controller

07 Address of Contact Person *(Street, City, State, Zip Code)*
400 North Fourth Street, Bismarck, ND 58501

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(701) 222-7646	(1) ☒ An Original (2) ☐ A Resubmission	12/31/2019

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Tammy Nygard		
02 Title		
Controller	Tammy Nygard	04/14/2020

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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".

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

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.

Tammy Nygard - Controller
400 North Fourth Street
Bismarck, North Dakota 58501-4092

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

Delaware - March 14, 1924

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

None

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Montana-Dakota Utilities Co., the respondent, is a direct wholly owned subsidiary of MDU Energy Capital, LLC. MDU Energy Capital, LLC, is a direct wholly owned subsidiary of MDU Resources Group, Inc.

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	Director, Chair of the Board	David L. Goodin	860,000
3			
4	Director, President and Chief Executive Officer	Nicole A. Kivisto	455,000
5			
6	Vice President - Human Resources	Anne M. Jones	265,000
7			
8	Director, General Counsel and Secretary	Daniel S. Kuntz	360,000
9			
10	Director, Treasurer	Jason L. Vollmer	400,000
11			
12	Chief Information Officer	Margaret (Peggy) A. Link	265,000
13			
14	Vice President - Customer Service	Mark A. Chiles	210,000
15			
16	Vice President - Engineering and Operations	Patrick C. Darras	235,900
17	Services		
18			
19	Vice President - Safety, Process Improvement and	Hart Gilcrhist	223,800
20	Operations Systems		
21			
22	Assistant Secretary	Kristi B. Hourigan	166,480
23			
24	Assistant Secretary	Karl A. Liepitz	181,040
25			
26	Executive Vice President - Business Development	Scott W. Madison	271,400
27	and Gas Supply		
28			
29	Vice President - Field Operations	Eric P. Martuscelli	233,700
30			
31	Controller	Tammy J. Nygard	190,000
32			
33	Executive Vice President - Regulatroy Affairs,	Garret Senger	281,300
34	Customter Service and Administration		
35			
36	Vice President - Electric Supply	Jay Skabo	257,500
37			
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44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	David L. Goodin, Chair of the Board	Bismarck, North Dakota
2		
3	Nicole A. Kivisto, President and Chief Executive Officer	Bismarck, North Dakota
4		
5	Daniel S. Kuntz, Gerenal Counsel and Secretary	Bismarck, North Dakota
6		
7	Jason L. Vollmer, Treasurer	Bismarck, North Dakota
8		
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Schedule Page: 105 Line No.: 1 Column: a

All Directors joined the Board of Directors on January 1, 2019 following the Holding Company Reorganization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] No

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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	
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10	Midcontinent Independent System Operator, Inc -	ER14-421-001
11	FERC Electric Tariff	
12		
13	Midcontinent Independent System Operator, Inc -	ER14-649-000
14	FERC Electric Tariff	
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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	
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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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Does the respondent have formula rates?	[ ] Yes [X] 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	
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16	Midcontinent Independent System Operator, Inc -	ER16-18-000
17	FERC Electric Tariff	
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19	Midcontinent Independent System Operator, Inc -	ER16-2417-000
20	FERC Electric Tariff	
21		
22	Midcontinent Independent System Operator, Inc -	ER16-314-000
23	FERC Electric Tariff	
24		
25	Midcontinent Independent System Operator, Inc -	ER16-392-000
26	FERC Electric Tariff	
27		
28	Midcontinent Independent System Operator, Inc -	ER16-197-000
29	FERC Electric Tariff	
30		
31	Midcontinent Independent System Operator, Inc -	ER16-888-000
32	FERC Electric Tariff	
33		
34	Midcontinent Independent System Operator, Inc -	ER19-249-000
35	FERC Electric Tariff	
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Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/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 [X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201603115138	03/11/2016	ER16-1140-000	Annual Informational	Montana-Dakota Utilities Co.
2				Attachment O filing	MISO Attachments O, GG, and MM
3					
4	201703135373	03/12/2017	ER17-1181-000	Annual Informational	Montana-Dakota Utilities Co.
5				Attachment O filing	MISO Attachments O, GG, and MM
6					
7	201803155115	03/15/2018	ER18-1115-000	Annual Informational	Montana-Dakota Utilities Co.
8				Attachment O filing	MISO Attachments O, GG, and MM
9					
10	20180322-5264	03/21/2018	ER18-1115-000	Supplemental (update	Montana-Dakota Utilities Co.
11				to March 15 2018)	MISO Attachments O, GG, and MM
12				Annual Informational	
13				Attachment O filing	
14					
15	20190314-5164	03/14/2019	ER19-1307-000	Annual Informational	Montana-Dakota Utilities Co.
16				Attachment O filing	MISO Attachments O, GG, and MM
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INFORMATION ON FORMULA RATES
Formula Rate Variances

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

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

Schedule Page: 1062 Line No.: 1 Column: a
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Schedule Page: 1062 Line No.: 43 Column: a

Exclude Wyoming jurisdiction not interconnected with MISO

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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.

1. The Respondent renewed franchises in 2019 in Cowley, Wyoming, and and the folling North Dakota cities: Beach, Bismarck, Center, Dickinson, Flaxton, Glen Ullin, Hettinger, Jamestown, Langdon, Lincoln, Marmarth, Milnor, Mohall, Portal, and Richardton. No consideration was given for the renewal of the franchises other than the agreement to pay franchise fees to the extent applicable.

2. Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Respondent prior to the closing of the Holding Company Reorganization, is now a wholly owned subsidiary of MDU Energy Capital, LLC as of January 1, 2019. This authorization was granted in Docket No. EC18-51-000 on June 19, 2018.For additional information see Note 1 in Notes to Financial Statements on page 122.

3. On February 7, 2019, in Docket No. EC18-79-000, the Commission authorized the acquisition of 48 megawatts of wind generation capacity associated with an expansion of the Thunder Spirit Wind Project.

4. None.

5. The natural gas utiltiy extended service into new service areas in Ransom and Sargent counties in North Dakota in September of 2018 with a 23-mile extension from a tap off the Alliance Pipeline near Milnore, North Dakota. The North Dakota Public Service Commission granted a Certificate of Public Convenience and Necessity to provide natural gas service in this area on June 16, 2017 with service provided to customers located directly off the line starting in September 2018. In 2019, Montana-Dakota extended service off this line to the communities of Gwinner and Milnor, North Dakota. The Gwinner distribution was placed into service on October 18,2019 and the Milnor distribution system was placed into service on September 13,2019. As of December 31,2019, service was provided to 179 customers off this extension of the system.

6. The Respondent's short-term indebtedness totaled $118,600,000 at December 31, 2019.The issuance of commercial paper and other short-term debt is authorized pursuant to the following orders:

On September 12, 2019, 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. ES19-37-000.

On August 20, 2019, 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. D2019.7.41, Default Order No. 7688.

7. None.

8. Wage increases to nonunion employees averaged 3.63% in 2019. Wage increases to union employees averaged 2.61% effective 4/29/19. The estimated impact of the increases amounted to appoximately $3,000,000.

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

10. None.

11. None.

12. None.

13. The Montana-Dakota Utilities Co. Management Structure is as follows:

David L. Goodin - Director, Chair of the Board
Nicole A. Kivisto - Director, President and Chief Executive Officer
Daniel S. Kuntz - Director, General Counsel and Secretary
Jason L. Vollmer - Director, Treasurer
Mark A. Chiles - Vice President - Customer Service
Patrick C. Darras - Vice President - Engineering and Operations Services
Hart Gilchrist - Vice President - Safety, Process Improvement and Operations Systems
Kirsti B. Hourigan - Assistant Secretary
Anne M. Jones - Vice President - Human Resources
Karl A. Liepitz - Assistant Secretary
Margaret (Peggy) A. Link - Chief Information Officer
Scott W. Madison - Executive Vice President - Business Development and Gas Supply
Eric P. Martuscelli - Vice President - Field Operations
Tammy J. Nygard - Controller
Garret Senger - Executive Vice President - Regulatory Affairs, Customer Service and Administration
Jay Skabo - Vice President - Electric Supply

14. Not Applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2019/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	2,884,982,013	2,663,919,506
3	Construction Work in Progress (107)	200-201	73,597,988	165,864,516
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,958,580,001	2,829,784,022
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,051,780,047	967,632,867
6	Net Utility Plant (Enter Total of line 4 less 5)		1,906,799,954	1,862,151,155
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)		1,906,799,954	1,862,151,155
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		1,584,292	1,718,566
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		17,183,717	16,931,362
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,014,058	6,199,490
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	1,790,885,738
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)		35,472,517	76,201,921
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)		45,642,176	1,877,819,531
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,101,977	-273,799
36	Special Deposits (132-134)		8,351	617,411
37	Working Fund (135)		404,400	312,522
38	Temporary Cash Investments (136)		0	1,178,164
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		25,441,438	27,283,245
41	Other Accounts Receivable (143)		4,742,209	14,756,480
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		607,757	779,796
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,082,412	36,014,729
45	Fuel Stock (151)	227	4,557,811	4,784,694
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	23,683,940	21,026,434
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)		10,136,688	8,508,246
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		6,316,901	5,480,655
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)		43,690,970	47,151,553
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)		125,559,340	166,060,538
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,366,323	2,581,364
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,051,519	2,508,004
72	Other Regulatory Assets (182.3)	232	248,309,102	214,409,347
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,025,691	1,112,510
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		466,818	11,624
75	Other Preliminary Survey and Investigation Charges (183.2)		175,485	57,531
76	Clearing Accounts (184)		-51,596	-31,304
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	30,927,165	28,836,015
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)		3,582,671	4,154,385
82	Accumulated Deferred Income Taxes (190)	234	34,336,206	51,529,326
83	Unrecovered Purchased Gas Costs (191)		-7,260,615	-2,576,502
84	Total Deferred Debits (lines 69 through 83)		317,928,769	302,592,300
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,397,514,531	4,210,342,090

Schedule Page: 110   Line No.: 85   Column: c

Current Year End of Quarter/Year Balance, column (c), reflect the Balance Sheet balances on Montana-Dakota Utilities Co. following the Holding Company Reorganization discussed on page 109.1, #2.

Schedule Page: 110   Line No.: 85   Column: d

Prior Year End Balance, column (d), reflect the Balance Sheet balances of MDU Resources Group, Inc. prior to the Holding Company Reorganization discussed on page 109.1, #2.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) ☐ An Original (2) ☐ A Resubmission	/ /	end of 2019/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	1,000	196,564,907
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		138,653,236	1,255,155,546
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	0	6,579,697
11	Retained Earnings (215, 215.1, 216)	118-119	666,173,397	642,942,878
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	520,659,042
13	(Less) Reaquired Capital Stock (217)	250-251	0	3,625,813
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-5,845,725	-38,342,046
16	Total Proprietary Capital (lines 2 through 15)		798,981,908	2,566,774,817
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	858,114,076	788,725,495
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)		858,114,076	788,725,495
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)		919,830	190,410
29	Accumulated Provision for Pensions and Benefits (228.3)		15,956,506	41,383,945
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		1,003,000	15,514,270
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)		157,784,448	142,922,575
35	Total Other Noncurrent Liabilities (lines 26 through 34)		175,663,784	200,011,200
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		42,766,713	48,869,177
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		7,440,437	12,438,043
41	Customer Deposits (235)		1,981,246	1,443,059
42	Taxes Accrued (236)	262-263	12,804,780	24,703,900
43	Interest Accrued (237)		7,768,377	6,739,759
44	Dividends Declared (238)		9,970,000	39,695,262
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) ☐ An Original (2) ☐ A Resubmission	/ /	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,049,033	1,181,720
48	Miscellaneous Current and Accrued Liabilities (242)		27,235,388	31,208,839
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)		111,015,974	166,279,759
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		17,699,064	20,525,735
57	Accumulated Deferred Investment Tax Credits (255)	266-267	4,060,897	3,377,889
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	44,742,469	83,378,564
60	Other Regulatory Liabilities (254)	278	155,076,682	164,617,567
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	884,588	854,528
63	Accum. Deferred Income Taxes-Other Property (282)		189,360,966	182,374,129
64	Accum. Deferred Income Taxes-Other (283)		41,914,123	33,422,407
65	Total Deferred Credits (lines 56 through 64)		453,738,789	488,550,819
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,397,514,531	4,210,342,090

Schedule Page: 112 Line No.: 66 Column: c

Current Year End of Quarter/Year Balance, column (c), reflect the Balance Sheet balances on Montana-Dakota Utilities Co. following the Holding Company Reorganization discussed on page 109.1, #2.

Schedule Page: 112 Line No.: 66 Column: d

Prior Year End Balance, column (d), reflect the Balance Sheet balances of MDU Resources Group, Inc. prior to the Holding Company Reorganization discussed on page 109.1, #2.

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 columnin 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	645,374,811	621,198,166		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	422,920,524	407,117,069		
5	Maintenance Expenses (402)	320-323	30,415,373	30,161,633		
6	Depreciation Expense (403)	336-337	75,275,701	68,005,660		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,252,373	5,016,468		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	6,856	5,683		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		495,524	495,524		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,334,742	131,812		
13	(Less) Regulatory Credits (407.4)		894,959	1,342,439		
14	Taxes Other Than Income Taxes (408.1)	262-263	28,529,542	25,882,003		
15	Income Taxes - Federal (409.1)	262-263	-26,666,009	-15,347,311		
16	- Other (409.1)	262-263	-1,988,693	1,606,831		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	71,610,094	88,606,884		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	54,330,232	79,041,212		
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)		552,960,836	531,298,605		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		92,413,975	89,899,561		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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		
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)	Line No.
						1
350,587,922	333,761,110	294,786,889	287,437,056			2
						3
187,548,433	178,939,882	235,372,091	228,177,187			4
23,435,480	23,690,520	6,979,893	6,471,113			5
54,163,135	49,101,906	21,112,566	18,903,754			6
						7
2,439,823	2,373,537	2,812,550	2,642,931			8
4,035	2,862	2,821	2,821			9
495,524	495,524					10
						11
2,286,961	123,943	47,781	7,869			12
894,959	1,342,439					13
16,653,953	15,176,117	11,875,589	10,705,886			14
-24,273,767	-18,730,535	-2,392,242	3,383,224			15
-1,257,985	1,008,001	-730,708	598,830			16
51,030,628	53,380,868	20,579,466	35,226,016			17
37,214,006	41,814,205	17,116,226	37,227,007			18
						19
						20
						21
						22
						23
						24
274,417,255	262,405,981	278,543,581	268,892,624			25
76,170,667	71,355,129	16,243,308	18,544,432			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		92,413,975	89,899,561		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		5,885	36,795		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		21,079	17,990		
33	Revenues From Nonutility Operations (417)		4,834,950	6,541,586		
34	(Less) Expenses of Nonutility Operations (417.1)		2,790,768	3,310,802		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119		211,109,757		
37	Interest and Dividend Income (419)		1,834,040	1,331,795		
38	Allowance for Other Funds Used During Construction (419.1)		669,240	1,026,572		
39	Miscellaneous Nonoperating Income (421)		11,838	42,767		
40	Gain on Disposition of Property (421.1)		217,354	42,872		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,761,460	216,803,352		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		5,636	42,128		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		668,189	129,536		
46	Life Insurance (426.2)		-4,568,068	1,328,943		
47	Penalties (426.3)		1,148	1,516		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		185,115	156,315		
49	Other Deductions (426.5)		2,000,000			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-1,707,980	1,658,438		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	50,525	49,487		
53	Income Taxes-Federal (409.2)	262-263	-273,929	124,697		
54	Income Taxes-Other (409.2)	262-263	-1,053,024	-1,901,830		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	5,815,543	1,521,095		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	6,353,445	1,374,916		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		-683,008	-1,546,913		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,131,322	-34,554		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		7,600,762	215,179,468		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		32,946,514	32,672,609		
63	Amort. of Debt Disc. and Expense (428)		353,931	350,328		
64	Amortization of Loss on Reaquired Debt (428.1)		571,714	571,714		
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)		723,763	448,838		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,703,307	1,282,817		
70	Net Interest Charges (Total of lines 62 thru 69)		32,892,615	32,760,672		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		67,122,122	272,318,357		
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)		67,122,122	272,318,357		

Schedule Page: 114 Line No.: 78 Column: c

Total Current Year, column (c), reflect the Income Statement balances of Montana-Dakota Utilities Co. following the Holding Company Reorganization discussed on page 109.1, #2.

Schedule Page: 114 Line No.: 78 Column: d

Total Previous Year, column (d), reflect the Income Statement balances of MDU Resources Group, Inc. prior to the Holding Company Reorganization discussed on page 109.1, #2.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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		642,942,878	620,946,628
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	OCI Stranded Taxes Adjustment	219		1,044,813
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			1,044,813
10	Dividends Equivalents on Stock Based Compensation	253	18,397	(461,628)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		18,397	(461,628)
16	Balance Transferred from Income (Account 433 less Account 418.1)		67,122,122	61,208,600
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-43,910,000	(155,695,135)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-43,910,000	(155,695,135)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			115,899,600
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		666,173,397	642,942,878
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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)		666,173,397	642,942,878
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		520,659,042	419,801,251
50	Equity in Earnings for Year (Credit) (Account 418.1)			211,109,757
51	(Less) Dividends Received (Debit)			115,899,600
52	MDUR Corporate Reorgranization Equity Transfer		-520,659,042	5,647,634
53	Balance-End of Year (Total lines 49 thru 52)			520,659,042

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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)	67,122,122	272,318,357
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	82,470,237	72,312,708
5	Amortization of		
6	Loss on Reacquired Debt, Bond Discount and Debt Exp	-213,245	343,465
7			
8	Deferred Income Taxes (Net)	16,741,960	9,711,851
9	Investment Tax Credit Adjustment (Net)	683,008	1,546,913
10	Net (Increase) Decrease in Receivables	-7,626,137	-14,436,634
11	Net (Increase) Decrease in Inventory	-3,924,791	-2,820,729
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,052,024	23,281,803
14	Net (Increase) Decrease in Other Regulatory Assets	14,479,768	8,688,521
15	Net Increase (Decrease) in Other Regulatory Liabilities	-4,964,556	563
16	(Less) Allowance for Other Funds Used During Construction	669,240	1,026,572
17	(Less) Undistributed Earnings from Subsidiary Companies		95,210,157
18	Other (provide details in footnote):		
19	Unrecovered Purchased Gas Costs	4,684,113	4,751,514
20	Net Change in Other Current & Accrued Assets	3,233,397	7,310,350
21	Other Noncurrent Changes	-21,331,690	10,716,358
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	132,632,922	297,488,311
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-137,700,197	-233,006,571
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-15,269,561	-7,516,547
29	Gross Additions to Nonutility Plant	-260,672	-495,927
30	(Less) Allowance for Other Funds Used During Construction	-669,240	-1,026,572
31	Other (provide details in footnote):		
32			
33	Customer Advances for Construction	-2,826,671	-3,148,980
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-155,387,861	-243,141,453
35			
36	Acquisition of Other Noncurrent Assets (d)	-536,349	-527,466
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		-10,000,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		40,000,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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 Nonutility Plant	817,074	811,995
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-155,107,136	-212,856,924
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	270,100,000	200,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Stock Expense		-10,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	270,100,000	199,990,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-200,711,418	-125,960,755
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Repurchase of Common Stock		-1,920,095
77	Tax Withholding on Performance Shares	-574,376	-1,720,999
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-44,050,502	-154,572,486
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	24,763,704	-84,184,335
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,289,490	447,052
87			
88	Cash and Cash Equivalents at Beginning of Period	1,216,887	769,835
89			
90	Cash and Cash Equivalents at End of period	3,506,377	1,216,887

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.: 73 Column: c

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

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	(81,585)	(35,164,333)		(154,950)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(143,727)	4,440,688		(61,062)
3	Preceding Quarter/Year to Date Changes in Fair Value	113,929	(5,346,123)		216,012
4	Total (lines 2 and 3)	(29,798)	(905,435)		154,950
5	Balance of Account 219 at End of Preceding Quarter/Year	(111,383)	(36,069,768)		
6	Balance of Account 219 at Beginning of Current Year	(111,383)	(36,069,768)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	111,383	30,224,043		
9	Total (lines 7 and 8)	111,383	30,224,043		
10	Balance of Account 219 at End of Current Quarter/Year		(5,845,725)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(1,932,850)		(37,333,718)	[redacted]	[redacted]
2			4,235,899	[redacted]	[redacted]
3	(228,045)		(5,244,227)	[redacted]	[redacted]
4	(228,045)		(1,008,328)		(1,008,328)
5	(2,160,895)		(38,342,046)	[redacted]	[redacted]
6	(2,160,895)		(38,342,046)	[redacted]	[redacted]
7				[redacted]	[redacted]
8	2,160,895		32,496,321	[redacted]	[redacted]
9	2,160,895		32,496,321		32,496,321
10			(5,845,725)	[redacted]	[redacted]

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 Cormmission 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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of MDU Resources
Company	Montana-Dakota Utilities Co., a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019 (formerly a public utility division of MDU Resources prior to the closing of the Holding Company Reorganization)
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal fired electric generating facility near Beulah, North Dakota (25 percent ownership)
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 as of January 1, 2019 (formerly a public utility division of MDU Resources prior to the closing of the Holding Company Reorganization)
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among the Company, MDU Resources and MDUR Newco Sub, which resulted in MDU Resources becoming a holding company and indirectly owning all of the outstanding capital stock of the Company
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of MDU Resources
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as MDU Resources

MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into the Company in the Holding Company Reorganization
MDU Resources	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc., prior to January 1, 2019, and the new holding company of the same name after January 1, 2019.
MISO	Midcontinent Independent System Operator, Inc.
Montana-Dakota	Montana-Dakota Utilities Co., a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019, (formerly a public utility division of MDU Resources prior to the closing of the Holding Company Reorganization), now known as the Company
MNPUC	Minnesota Public Utilities Commission
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
SDPUC	South Dakota Public Utilities Commission
TCJA	Tax Cuts and Jobs Act
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies
Basis of presentation
The Company is incorporated under the laws of the state of Delaware and is a wholly owned subsidiary of MDU Energy Capital. The Company is made up of Montana-Dakota and Great Plains, a public utility division of Montana-Dakota.

On January 2, 2019, MDU Resources announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota becoming a subsidiary of MDU Resources. The purpose of the reorganization was to make the public utility division into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. Authorization for the reorganization was granted by the FERC in Docket No. EC18-51-000. The Company has also received approval for the reorganization by the various state jurisdictions in which it operates.

As approved by the FERC, the amounts presented in the accompanying notes to the financial statements prior to January 1, 2019, relate to the corporate structure prior to the Holding Company Reorganization.

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 302,000 natural gas residential, commercial, industrial and municipal customers in 288 communities and adjacent rural areas as of December 31, 2019.

Montana-Dakota and Great Plains are regulated businesses which account for certain income and expense items under the provisions of regulatory accounting, which requires them to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

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 has 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, operating leases, and current unrecovered purchased gas costs. If GAAP were followed, utility plant, other property and investments would increase by $144.1 million; current and accrued assets would decrease by $9.8 million; deferred debits would decrease by $73.5 million; long-term debt would decrease by $3.4 million; current and accrued liabilities would increase by $27.6 million; and deferred credits and other noncurrent liabilities would increase by $36.7 million as of December 31, 2019. Furthermore, operating revenues would increase by $5.6 million and operating expenses, excluding income taxes, would increase by $4.4 million for the twelve months ended December 31, 2019. In addition, net cash provided by operating activities would increase by $4.6 million; net cash used in investing activities would increase by $4.5 million; net cash provided by financing activities would decrease by $1.1 million; and the net change in cash and cash equivalents would be a decrease of $1.1 million for the twelve months ended December 31, 2019.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Management has also evaluated the impact of events occurring after December 31, 2019, up to the date of issuance of these financial statements. For more information on the Company’s subsequent events, see Note 17.

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 $515,000 and $640,000 at December 31, 2019 and 2018, 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, 2019 and 2018 was $608,000 and $780,000, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue was $43.7 million and $47.2 million at December 31, 2019 and 2018, respectively.

Inventories and natural gas in storage
Natural gas in storage is valued at cost using the last-in, first-out method. All other inventories are valued at lower of cost or net realizable value using the average cost method. The portion of the cost of natural gas in storage expected to be used within 12 months was included in inventories. Inventories at December 31 consisted of:

	2019	2018
	(In thousands)	
Plant materials and operating supplies	**$ 23,684**	$ 21,026
Gas stored underground-current	**10,136**	8,508
Fuel stock	**4,558**	4,785
Total	**$ 38,378**	$ 34,319

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was $1.6 million and $1.7 million at December 31, 2019 and 2018, respectively.

Investments
The Company's investments include 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 5 and 12.

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

	2019	2018
	(In thousands)	
AFUDC - borrowed	$ 1,703	$ 1,283
AFUDC - equity	$ 669	$ 1,027

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, and amortization.

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

	2019	2018	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Electric:			
Generation	$ 1,139,059	$ 1,131,484	48
Distribution	443,780	430,750	46
Transmission	445,485	302,315	65
Construction in progress	66,664	161,742	-
Other	126,759	117,133	15
Natural gas distribution:			
Distribution	589,079	547,788	47
Construction in progress	7,190	4,122	-
Other	140,564	134,450	17
Less accumulated depreciation, and amortization	1,051,780	967,633	
Net utility plant	$ 1,906,800	$ 1,862,151	
Nonutility property	$ 17,184	$ 16,931	
Less accumulated depreciation, and amortization	7,014	6,199	
Net nonutility property	$ 10,170	$ 10,732	

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 2019 and 2018. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Regulatory assets and liabilities
The Company accounts 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. The Company records regulatory assets or liabilities at the time the Company determines the amounts to be recoverable in current or future rates.

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 the Company completes in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

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. Goodwill impairment, if any, is measured by 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 goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2019 and 2018, there were no impairment losses recorded. At December 31, 2019, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, risk adjusted capital cost, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted capital cost at each reporting unit. A risk adjusted capital cost of 4.0 percent was utilized in the goodwill impairment test performed in the fourth quarter of 2019. The goodwill impairment test also utilized a long-term growth rate projection of 1.7 percent in the goodwill impairment test performed in the fourth quarter of 2019. Under the market approach, the Company estimates fair value using various multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

Revenue recognition
Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

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

The Company recognizes all other revenues when services are rendered or goods are delivered.

Asset retirement obligations
The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a regulatory asset or liability.

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 within a period of 12 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $7.3 million and $2.6 million at December 31, 2019 and 2018, respectively, and included in unrecovered purchased gas costs.

Income taxes
MDU Resources and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by MDU Resources, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. MDU Resources makes a similar allocation for state income taxes paid in connection with combined state filings. MDU Resources provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Taxes recoverable from customers have been recorded as regulatory assets. Taxes refundable to customers and excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as regulatory liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

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

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in interest and penalties, respectively.

Use of estimates
The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as long-lived assets and goodwill; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; regulatory assets expected to be recovered in rates charged to customers; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the valuation of stock-based compensation. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

New accounting standards
Recently adopted accounting standards
ASU 2016-02 - Leases In February 2016, the FASB issued this ASU guidance relating to ASC 842 - *Leases*. The guidance required lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remained largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also required additional disclosures, both quantitative and qualitative, related to operating and financing leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company adopted the standard for its GAAP financial statements on January 1, 2019.

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

ASU 2017-04 - Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The Company early adopted the guidance on a prospective basis beginning with the preparation of its 2019 goodwill impairment test in the fourth quarter of 2019. The adoption of the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures.

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

Recently issued accounting standards not yet adopted

ASU 2016-13 - Measurement of Credit Losses on Financial Instruments In June 2016, the FASB issued guidance on the measurement of credit losses on certain financial instruments. The guidance introduces a new impairment model known as the current expected credit loss model that will replace the incurred loss impairment methodology currently included under GAAP. This guidance requires entities to present certain investments in debt securities, trade accounts receivable and other financial assets at their net carrying value of the amount expected to be collected on the financial statements. The Company adopted the guidance on January 1, 2020.

The Company formed an implementation team to review and assess existing financial assets to identify and evaluate the financial assets subject to the new current expected credit loss model. The Company assessed the impact of the guidance on its processes and internal controls and has identified and updated existing internal controls and processes to ensure compliance with the new guidance, such modifications were deemed insignificant. During the assessment phase, the Company completed checklists to identify the complete portfolio of assets subject to the current expected credit loss model. The Company determined the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures and did not record a material cumulative effect adjustment upon adoption.

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

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

ASU 2019-12 - Simplifying the Accounting for Income Taxes In December 2019, the FASB issued guidance on simplifying the accounting for income taxes by removing certain exceptions in ASC 740 and providing simplification amendments. The guidance removes exceptions on intraperiod tax allocations and reporting and provides simplification on accounting for franchise taxes, tax basis goodwill and tax law changes. The guidance will be effective for the Company on January 1, 2021, with early adoption permitted. Transition requirements vary among the exceptions and amendments which include retrospective, modified retrospective and prospective application. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

Accumulated other comprehensive income (loss)
The Company's accumulated other comprehensive income (loss) is comprised of postretirement liability adjustments.

The postretirement liability adjustment in other comprehensive loss was $5.8 million, net of tax of $1.9 million, for the year ended December 31, 2019.

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

Twelve Months Ended December 31, 2019	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2018	$ (4,846)	$ (33,496)	$ (38,342)
Adjustment for Holding Company Reorganization	---	33,496	33,496
Other comprehensive income before reclassifications	(1,230)	---	(1,230)
Amounts reclassified from accumulated other comprehensive loss	230	---	230
Net current-period other comprehensive income	(1,000)	---	(1,000)
Balance at December 31, 2019	**$ (5,846)**	**$ ---**	**$ (5,846)**

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

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Statement of Income. The reclassifications were as follows:

Twelve Months Ended December 31,		2019		2018	Location on Statement of Income
		(In thousands)			
Amortization of postretirement liability losses included in net periodic benefit cost	$	**(304)**	$	(131)	(a)
		74		32	Income taxes
		(230)		(99)	
Subsidiary reclassifications out of accumulated other comprehensive loss		**---**		(2,616)	Equity in earnings of Subsidiary Companies
Total reclassifications	**$**	**(230)**	$	(2,715)	

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

Note 2 - Revenue from contracts with customer

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

As part of the adoption of ASC 606 - *Revenue from Contracts with Customers*, the Company elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is 12 months or less.

Disaggregation

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

Year Ended December 31, 2019	Electric	Natural Gas Distribution	Total
		(In thousands)	
Residential utility sales	$ 125,369	$ 162,461	$ 287,830
Commercial utility sales	141,596	113,569	255,165
Industrial utility sales	37,765	6,503	44,268
Other utility sales	7,408	---	7,408
Natural gas transportation	---	6,988	6,988
Other	35,574	6,516	42,090
Revenues from contracts with customers	347,712	296,037	643,749
Revenues out of scope	4,013	2,454	6,467
Total external operating revenues	$ 351,725	$ 298,491	$ 650,216

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

Note 3 - 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, 2019 and 2018. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 4 - Regulatory Assets and Liabilities
The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period*	2019	2018
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(h)	**$ 94,630**	$ 96,595
Plant to be retired (a)	---	**32,932**	---
Asset retirement obligations (a) (b)	Over plant lives	**17,317**	13,763
Taxes recoverable from customers (a)	Over plant lives	**8,027**	8,179
Unamortized loss on required debt	Up to 7 years	**3,583**	4,154
Costs related to identifying generation development (c)	Up to 7 years	**2,051**	2,508
Unrecovered purchased gas costs	Up to 1 year	**(7,261)**	(2,577)
Other (a) (d) (e)	Up to 19 years	**8,748**	13,832
Total regulatory assets		**160,027**	136,454
Regulatory liabilities:			
Taxes refundable to customers (f)		**138,393**	148,015
Plant removal and decommissioning costs (b) (f)		**55,539**	56,095
Pension and postretirement benefits (f)		**13,832**	10,309
Accumulated provision for rate refunds		**1,003**	15,514
Other (f) (g)		**7,007**	6,209
Total regulatory liabilities		**215,774**	236,142
Net regulatory position		**$ (55,747)**	$ (99,688)

* 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, and amortization 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, 2019 and 2018, approximately $126.9 million and $119.4 million respectively, of regulatory assets were not earning a rate of return.

In February 2019, the Company announced that it intends to retire three aging coal-fired electric generating units in early 2021 and early 2022. The Company has accelerated the depreciation related to these facilities in property, plant and equipment and has recorded the difference between the accelerated depreciation, in accordance with GAAP, and the depreciation approved for rate-making purposes as regulatory assets. The Company expects to recover the regulatory assets related to the plants to be retired in future rates.

If, for any reason, the Company's regulated business ceases to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 5 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified defined 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 $22.7 million and $49.2 million at December 31, 2019 and 2018, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized gain on these investments for the year ended December 31, 2019, was $3.4 million. The net unrealized loss on these investments for the year ended December 31, 2018, was $2.4 million. The change in fair value, which is considered part of the cost of the plan, is classified in Other Income and Deductions as Life Insurance on the Statement of Income.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's 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, 2019 and 2018, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2019, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2019
		(In thousands)		
Assets:				
Money market funds	$ —	$ 1,107	$ —	$ 1,107
Insurance contract*	—	22,669	—	22,669
Total assets measured at fair value	$ —	$ 23,776	$ —	$ 23,776

*The insurance contract invests approximately 51 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 12 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 1 percent in cash equivalents.

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

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

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

In the second quarter of 2019, the Company reviewed a non-utility investment for impairment. This was a cost-method investment and was written down to zero using the income approach to determine its fair value, requiring the Company to record a write-down of $2.0 million, before tax. The fair value of this investment was categorized as Level 3 in the fair value hierarchy. The reduction is reflected in Other Investments on the Company's Comparative Balance Sheet, as well as within Other Income and Deductions as Other Deductions on the Statement of Income.

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 categorized as Level 2 in the fair value hierarchy and 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:

	2019	2018
	(In thousands)	
Carrying Amount	**$ 858,114**	$ 788,725
Fair Value	**$ 934,279**	$ 795,113

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

Note 6 - Debt

Certain debt instruments of the Company contain restrictive and financial covenants and cross default provisions. In order to borrow under the debt agreements, the Company must be in compliance with the applicable covenants and certain other conditions all of which the Company was in compliance with at December 31, 2019. 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, 2019	Amount Outstanding at December 31, 2018	Letters of Credit at December 31, 2018	Expiration Date
			(Dollars in millions)			
Montana-Dakota Utilities Co.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 118.6 (b)	$ 48.5 (b)	$ ---	12/19/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the revolving credit agreement at December 31, 2019, and $48.5 million was outstanding at December 31, 2018.

(b) Amount outstanding included in other long-term debt on the Comparative Balance Sheet.

The 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

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

		2019		2018
		(In thousands)		
Senior notes at a weighted average rate of 4.47%, due on dates ranging from July 15, 2024 to November 18, 2059	**$**	**730,000**	$	530,000
Commercial paper at an interest rate of 2.03%, supported by revolving credit agreement		**118,600**		48,500
Term loan agreements at an interest rate of 2.00%, due on September 3, 2032		**9,100**		209,800
Other note at a rate of 6.0%, due on November 30, 2038		**414**		425
Total long-term debt	**$**	**858,114**	$	788,725

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

On December 19, 2019, the Company amended and restated its revolving credit agreement extending the maturity date to December 19, 2024. 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, the ratio of funded debt to total capitalization (determined on a consolidated basis) 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.

On July 24, 2019, the Company entered into a $200.0 million note purchase agreement with maturity dates ranging from October 17, 2039 to November 18, 2059, at a weighted average interest rate of 3.95 percent. The agreement contains customary covenants and provisions, including a covenant of the Company not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent.

The Company's ratio of total debt to total capitalization at December 31, 2019, was 52 percent.

Schedule of Debt Maturities Long-term debt maturities for the five years and thereafter following December 31, 2019, were as follows:

	2020	2021	2022	2023	2024	Thereafter
				(In thousands)		
Long-term debt maturities	$700	$700	$700	$700	$179,300	$676,014

Note 7 - 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:

		2019		2018
		(In thousands)		
Balance at beginning of year	$	**142,923**	$	127,809
Liabilities incurred		**7,100**		6,293
Liabilities settled		**(2,349)**		(1,006)
Accretion expense *		**7,289**		6,690
Revisions in estimates		**2,821**		3,137
Balance at end of year	$	**157,784**	$	142,923

* Includes $7.3 million and $6.7 million in 2019 and 2018, respectively, related to regulatory assets.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets. For more information on the Company's regulatory assets and liabilities, see Note 4.

Note 8 - Common Stock

Prior to the Holding Company Reorganization, the Company held common stock. For the year ended December 31, 2018, the dividend declared on common stock was $.7950 per common share. Dividends on common stock were paid quarterly to the stockholders of record less than 30 days prior to the distribution date. For the year ended December 31, 2018, the dividends declared to common stockholders were $155.7 million.

Note 9 - Stock-Based Compensation

Total stock-based compensation expense (after tax) was $1.7 million and $1.2 million in 2019 and 2018, respectively.

As of December 31, 2019, total remaining unrecognized compensation expense related to stock-based compensation was approximately $2.6 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock awards

Non-employee directors received shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan in 2018. There were 38,605 shares with a fair value of $1.0 million issued to non-employee directors during the year ended December 31, 2018.

Restricted stock awards

In February 2018, the Company granted restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. The restricted stock awards became the obligation of the holding company after the reorganization.

Performance share awards
Due to the Holding Company Reorganization, the Company had no target grants of performance shares outstanding at December 31, 2019.

Note 10 - Income Taxes
Income before income taxes for the years ended December 31, 2019 and 2018, respectively was $54.6 million and $57.0 million.

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

	2019	2018
		(In thousands)
Current:		
Federal	$ (26,940)	$ (15,223)
State	(3,042)	(295)
	(29,982)	(15,518)
Deferred:		
Income taxes:		
Federal	13,512	8,835
State	3,230	877
Investment tax credit - net	683	1,547
	17,425	11,259
Total income tax expense	$ (12,557)	$ (4,259)

The changes included in the TCJA were broad and complex. The SEC issued, and the FASB adopted, rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company has reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

The Company has recorded regulatory liabilities in FERC account 254 for excess deferred income taxes, including gross ups, to reflect the future revenue reduction required to return previously collected income taxes to customers. The balance of the excess deferred income tax regulatory liability, including gross ups, was $138.3 million and $148.1 million as of December 31, 2019 and 2018, respectively.

Total plant-related excess deferred taxes, those originating in FERC accounts 281 or 282, were $138.1 million and $148.1 million, as of December 31, 2019 and 2018, respectively, and were largely considered protected. The Company has proposed in all of its state jurisdictions to amortize both protected and non-protected plant-related excess deferred taxes on an ARAM basis which is based on plant lives. See Note 1 for more information on the Company’s weighted average depreciable lives. All state jurisdictions have approved this treatment.

Non-plant-related excess deferred taxes originating in FERC account 190 were ($2.2) million and ($3.2) million, as of December 31, 2019 and 2018, respectively.
Non-plant-related excess deferred taxes originating in FERC account 283 were $2.3 million and $3.2 million, as of December 31, 2019 and 2018, respectively. These excess deferred taxes are being amortized on a straight-line basis over periods ranging from 1-10 years as

approved by the respective state jurisdictions.

Amortization of the excess deferred taxes are being recorded to FERC Accounts 410.1 and 411.1 as appropriate. For the year ended December 31, 2019, the amortization of excess deferred taxes, including gross ups, has reduced the related regulatory liabilities by $9.8 million.

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

	2019	2018
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 17,805**	$ 23,695
Production Tax Credits	**5,343**	8,015
Compensation-related	**4,593**	7,903
Customer advances	**4,155**	4,988
Other	**2,440**	6,928
Total deferred tax assets	**34,336**	51,529
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**190,246**	183,229
Postretirement	**26,953**	26,206
Plants to be retired	**8,610**	620
Cost recovery mechanisms	**1,569**	1,688
Other	**4,782**	4,908
Total deferred tax liabilities	**232,160**	216,651
Net deferred income tax liability	**$ (197,824)**	$ (165,122)

As of December 31, 2019 and 2018, the Company had a federal income tax credit carryforward of $5.3 million and $8.0 million respectively. The federal income tax credit carryforwards will expire in 2040 if not utilized. As of December 31, 2019 and 2018, 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, 2018, to December 31, 2019, to deferred income tax expense:

	2019
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 32,702**
Deferred taxes associated with TCJA enactment for regulated activities	**(7,449)**
Deferred taxes associated with corporate reorganization	**(6,811)**
Deferred taxes associated with other comprehensive income (loss)	**323**
Other	**(1,340)**
Deferred income tax expense for the period	**$ 17,425**

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,	2019		2018	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	$ **11,459**	**21.0**	$ 11,959	21.0
Increases (reductions) resulting from:				
Production tax credit	**(15,843)**	**(29.0)**	(11,759)	(20.6)
Excess deferred income tax amortization	**(7,449)**	**(13.7)**	(5,364)	(9.4)
Amortization and deferral of investment tax credit	**683**	**1.3**	(120)	(0.2)
R&D tax credit	**(245)**	**(0.4)**	(669)	(1.2)
Deductible K-Plan dividends	**(568)**	**(1.0)**	(644)	(1.1)
AFUDC equity	**219**	**0.4**	(215)	(0.4)
State income taxes, net of federal income tax	**179**	**0.3**	2,163	3.8
Nonqualified benefit plan	**(1,234)**	**(2.3)**	182	0.3
Other	**242**	**0.4**	208	0.3
Total income tax expense	$ **(12,557)**	**(23.0)**	$ (4,259)	(7.5)

MDU Resources and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The Company is no longer subject to U.S. federal income tax examinations by tax authorities for years ending prior to 2015. With few exceptions, as of December 31, 2019, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2015.

For the years ended December 31, 2019 and 2018, total reserves for uncertain tax positions were not material. The Company recognizes interest related to uncertain tax positions in interest expense and penalties related to income taxes in income tax expense.

Note 11 - Cash Flow Information

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

	2019	2018
	(In thousands)	
Interest, net of AFUDC – borrowed of $1,703 and $1,283 in 2019 and 2018, respectively	$ **30,215**	$ 32,841
Income taxes refunded, net	$ **(14,869)**	$ (36,926)

Noncash investing and financing transactions at December 31 were as follows:

	2019	2018
	(In thousands)	
Property, plant and equipment additions in accounts payable	$ **15,832**	$ 12,907
Issuance of common stock in connection with acquisition by a subsidiary	$ **---**	$ 18,186

Note 12 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Prior to 2013, all of the Company’s defined benefit pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits to an annuity company. The transfer of the benefit payments for these participants reduced the Company’s liability and future premiums.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified. Employees who had attained age 55 with 10 years of continuous service by December 31, 2010, were provided the option to choose between a pre-65 comprehensive medical plan coupled with a Medicare supplement or a specified company funded Retiree Reimbursement Account, regardless of when they retire. All other eligible employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire to 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.

Changes in benefit obligation and plan assets for the years ended December 31, 2019 and 2018, and amounts recognized in the Comparative Balance Sheet at December 31, 2019 and 2018, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 192,341**	$ 250,889	**$ 31,688**	$ 40,128
Service cost	**---**	---	**373**	621
Interest cost	**7,468**	8,183	**1,176**	1,257
Plan participants' contributions	**---**	---	**459**	731
Actuarial (gain) loss	**19,782**	(17,944)	**1,365**	(4,389)
Benefits paid	**(12,861)**	(21,159)	**(2,418)**	(2,749)
Benefit obligation at end of year	**206,730**	219,969	**32,643**	35,599
Change in net plan assets:				
Fair value of plan assets at beginning of year	**146,292**	192,712	**41,865**	50,531
Actual gain (loss) on plan assets	**27,664**	(11,422)	**8,150**	(1,551)
Employer contribution	**15,453**	7,200	**6**	70
Plan participants' contributions	**---**	---	**459**	731
Benefits paid	**(12,861)**	(21,159)	**(2,417)**	(2,749)
Fair value of net plan assets at end of year	**176,548**	167,331	**48,063**	47,032
Funded status – over (under)	**$ (30,182)**	$ (52,638)	**$ 15,420**	$ 11,433
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	**$ (30,182)**	$ (52,638)	**$ 15,420**	$ 11,433
Net amount recognized	**$ (30,182)**	$ (52,638)	**$ 15,420**	$ 11,433
Amounts recognized in regulatory assets or liabilities:				
Actuarial (gain) loss	**$ 94,491**	$ 103,455	**$ (3,940)**	$ 599
Prior service credit	**---**	---	**(5,691)**	(7,253)
Total	**$ 94,491**	$ 103,455	**$ (9,631)**	$ (6,654)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. The table above includes amounts related to regulated operations, which are recorded as regulatory assets or liabilities and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets and liabilities, see Note 4.

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

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

	2019	2018
	(In thousands)	
Projected benefit obligation	**$ 206,730**	$ 219,969
Accumulated benefit obligation	**$ 206,730**	$ 219,969
Fair value of plan assets	**$ 176,548**	$ 167,331

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	
	2019	2018	**2019**	2018
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 373**	$ 621
Interest cost	**7,468**	8,183	**1,176**	1,257
Expected return on assets	**(8,751)**	(11,352)	**(2,476)**	(2,754)
Amortization of prior service credit	**---**	---	**(932)**	(976)
Recognized net actuarial loss	**2,662**	3,890	**---**	---
Net periodic benefit cost (credit), including amount capitalized	**1,379**	721	**(1,859)**	(1,852)
Less amount capitalized	**---**	---	**87**	119
Net periodic benefit cost (credit)	**1,379**	721	**(1,946)**	(1,971)
Other changes in plan assets and benefit obligations recognized in regulatory assets or liabilities:				
Net (gain) loss	**906**	4,831	**(4,515)**	(84)
Amortization of actuarial loss	**(2,871)**	(3,890)	**---**	---
Amortization of prior service credit	**---**	---	**946**	976
Total recognized in regulatory assets or liabilities	**(1,965)**	941	**(3,569)**	892
Total recognized in net periodic benefit cost (credit) and regulatory assets or liabilities	**$ (586)**	$ 1,662	**$ (5,515)**	$ (1,079)

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets or liabilities into net periodic benefit cost in 2020 is $3.5 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets or liabilities into net periodic benefit credit in 2020 are $0 and $864,000, respectively. Prior service credit is amortized 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	
	2019	2018	**2019**	2018
Discount rate	**2.96%**	4.02%	**2.97%**	4.03%
Expected return on plan assets	**6.25%**	6.75%	**5.75%**	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
Discount rate	**4.02 %**	3.38%	**4.03%**	3.38%
Expected return on plan assets	**6.25 %**	6.75%	**5.75%**	5.75%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2019, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation of 30 percent equity securities and 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:

	2019	2018
Health care trend rate assumed for next year	**7.4%**	8.0 %
Health care cost trend rate - ultimate	**4.5%**	4.5 %
Year in which ultimate trend rate achieved	**2024**	2024

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The Company contributes a flat dollar amount to the monthly premiums, which is updated annually on January 1.

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, 2019:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 43	$ (37)
Effect on postretirement benefit obligation	$ 610	$ (539)

In 2019, the Company contributed an additional $12.4 million to its defined benefit pension plans, which increased the funded status and decreased future expenses for the plans. The Company does not expect to contribute to its defined benefit pension and postretirement benefit plans in 2020.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2019, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2020	$ 12,205	$ 2,214	$ 64
2021	12,275	2,175	59
2022	12,359	2,135	55
2023	12,413	2,095	50
2024	12,419	2,056	45
2025– 2029	60,152	9,594	152

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

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's pension plans’ assets are determined using the market approach.

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

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded. The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data. The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2019 and 2018, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2019, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2019
		(In thousands)		
Assets:				
Cash equivalents	$ ---	$ **12,647**	$ ---	$ **12,647**
Equity securities:				
U.S. companies	**6,987**	---	---	**6,987**
International companies	---	**453**	---	**453**
Collective and mutual funds *	**77,773**	**28,466**	---	**106,239**
Corporate bonds	---	**39,039**	---	**39,039**
Municipal bonds	---	**5,717**	---	**5,717**
U.S. Government securities	**3,526**	**1,007**	---	**4,533**
Total assets measured at fair value	$ **88,286**	$ **87,329**	$ ---	$ **175,615**

*Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in common stock of large-cap U.S. companies, 18 percent in U.S. Government securities, 9 percent in corporate bonds, 6 percent in cash equivalents and 17 percent in other investments.

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

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2019 and 2018, 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, 2019, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2019
	(In thousands)			
Assets:				
Cash equivalents	$ ---	$ 2,041	$ ---	$ 2,041
Equity securities:				
U.S. companies	1,054	---	---	1,054
Insurance contract*	5	44,963	---	44,968
Total assets measured at fair value	$ 1,059	$ 47,004	$ ---	$ 48,063

*The insurance contract invests approximately 50 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 11 percent in other investments.

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

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

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified defined benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

The projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2019	2018
	(In thousands)	
Projected benefit obligation	**$ 17,059**	$ 47,176
Accumulated benefit obligation	**$ 17,059**	$ 47,176

Components of net periodic benefit cost for these plans for the years ended December 31 were as follows:

		2019	2018
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	**$**	**109** $	185
Interest cost		**606**	1,586
Recognized net actuarial loss		**59**	290
Net periodic benefit cost	**$**	**774** $	2,061

Weighted average assumptions used at December 31 were as follows:

	2019	2018
Benefit obligation discount rate	**2.71%**	3.85%
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.85%**	3.18%
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified defined benefit plans at December 31, 2019, are expected to aggregate as follows:

		2020	2021	2022	2023	2024	2025-2029
				(In thousands)			
Nonqualified benefits	$	1,640 $	1,616 $	1,619 $	1,664 $	1,594 $	5,386

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2019 and 2018 were $227,000 and $96,000, respectively.

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

	2019	2018
	(In thousands)	
Investments		
Insurance contract*	**$ 22,669**	$ 49,213
Life insurance**	**10,996**	19,122
Other	**1,108**	5,054
Total investments	**$ 34,773**	$ 73,389

* For more information on the insurance contract, see Note 5.
**Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees, and the costs incurred under these plans were $9.1 million in 2019 and $10.6 million in 2018.

Note 13 - Jointly Owned Facilities
The financial statements include the Company's ownership interests in three coal-fired electric generating facilities (Big Stone Station, Coyote Station and Wygen III) and one major transmission line (BSSE). Each owner of the jointly owned facilities is responsible for financing its investment.

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

At December 31, the Company's share of the cost of utility plant in service, construction work in progress and related accumulated depreciation for the jointly owned facilities was as follows:

	Ownership Percentage		2019		2018
			(In thousands)		
Big Stone Station:	22.7%				
Utility plant in service		$	**152,836**	$	156,534
Construction work in progress			**518**		92
Less accumulated depreciation			**46,266**		49,345
		$	**107,088**	$	107,281
BSSE:	50.0%				
Utility plant in service		$	**105,767**	$	---
Construction work in progress			**---**		105,846
Less accumulated depreciation			**1,232**		---
		$	**104,535**	$	105,846
Coyote Station:	25.0%				
Utility plant in service		$	**160,235**	$	155,236
Construction work in progress			**21**		1,920
Less accumulated depreciation			**107,638**		105,565
		$	**52,618**	$	51,591
Wygen III:	25.0%				
Utility plant in service		$	**67,869**	$	65,382
Construction work in progress			**112**		220
Less accumulated depreciation			**10,482**		9,174
		$	**57,499**	$	56,428

Note 14 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. As indicated below, certain regulatory proceedings and cases may also contain recurring mechanisms that can have an annual true-up. Examples of these recurring mechanisms include infrastructure riders, transmission trackers, renewable resource cost adjustment riders, as well as weather normalization and decoupling mechanisms. The following paragraphs summarizes the Company’s significant regulatory proceedings and cases by jurisdiction including the status of each open request. The Company is unable to predict the ultimate outcome of these matters, the timing of final decisions of the various regulators and courts, or the effect on the Company’s results of operations, financial position or cash flows.

MNPUC

On September 27, 2019, Great Plains filed an application with the MNPUC for a natural gas rate increase of approximately $2.9 million annually or approximately 12.0 percent above current rates. The requested increase was primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. On November 22, 2019, Great Plains received approval to implement an interim rate increase of approximately $2.6 million or approximately 11.0 percent, subject to refund, effective January 1, 2020. This matter is pending before the MNPUC.

MTPSC

On November 1, 2019, Montana-Dakota submitted an application with the MTPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. This matter is pending before the MTPSC.

NDPSC

Montana-Dakota has a transmission cost adjustment rider that allows annual updates to rates for actual costs for transmission-related projects and services. On July 19, 2019, Montana-Dakota filed a change to its transmission cost adjustment rates to reflect projected charges for July 2019 through June 2020 assessed to Montana-Dakota for transmission-related services provided by MISO and Southwest Power Pool, along with the projected transmission service revenues or credits received for the same time period. Montana-Dakota also requested recovery of six transmission capital projects. Total revenues of approximately $9.2 million, which reflects a true-up of the prior period adjustment, were requested resulting in an increase of approximately $600,000 or approximately 7.2 percent over current rates, which includes approximately $1.5 million related to transmission capital projects. On October 22, 2019, the NDPSC approved the rates as requested. The rates were effective October 28, 2019.

Montana-Dakota has a renewable resource cost adjustment rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On November 1, 2019, Montana-Dakota filed an annual update to its renewable resource cost adjustment requesting to recover a revised revenue requirement of approximately $14.7 million annually, not including the prior period true-up adjustment. The update reflects a decrease of approximately $800,000 from the revenues currently included in rates. On February 19, 2020, the NDPSC approved the increase with rates effective on March 1, 2020.

On August 28, 2019, Montana-Dakota filed an application with the NDPSC for an advanced determination of prudence and a certificate of public convenience and necessity to construct, own and operate Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota. A settlement agreement with the NDPSC Advocacy Staff was filed on April 2, 2020. A public hearing is scheduled for April 30, 2020.

On September 16, 2019, Montana-Dakota submitted an application with the NDPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. A settlement agreement with the NDPSC Advocacy Staff was filed on April 2, 2020. A public hearing is scheduled for April 30, 2020.

SDPUC

On November 8, 2019, Montana-Dakota submitted an application with the SDPUC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. The SDPUC approved the use of deferred accounting treatment as requested on January 7, 2020.

Montana-Dakota has a transmission cost recovery rider that allows annual updates to rates for actual costs for transmission-related projects and services. On February 28, 2020, Montana-Dakota filed a change to its transmission cost recovery rates to reflect projected charges for 2020 assessed to Montana-Dakota for transmission-related services provided by MISO and Southwest Power Pool, along with the projected transmission service revenues or credits received for the same time period. Montana-Dakota also requested recovery of two transmission capital projects. Total revenues of approximately $764,000, which reflects a true-up of the prior period adjustment, were requested resulting in a decrease of approximately $15,000 or approximately 1.9 percent under current rates, which includes approximately $87,000 related to transmission capital projects. This matter is pending before the SDPUC.

Montana-Dakota has an infrastructure rider rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On February 28, 2020, Montana-Dakota filed an annual update to its infrastructure rider requesting to recover a revenue requirement of approximately $1.3 million annually, including the prior period true-up adjustment, an increase of approximately $300,000 from revenues currently included in rates. This matter is pending before the SDPUC.

WYPSC

On May 23, 2019, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase of approximately $1.1 million annually or approximately 7.0 percent above current rates. The requested increase was to recover increased operating expenses and investments in distribution facilities to improve system safety and reliability. On December 17, 2019, Montana-Dakota filed a settlement agreement with the WYPSC. On January 15, 2020, the WYPSC approved the settlement, as adjusted to reflect an annual increase in revenues of approximately $828,000 or approximately 5.5 percent, with rates effective March 1, 2020.

FERC

On December 9, 2019, MISO accepted Montana-Dakota's annual revenue requirement update to its transmission formula rates under the MISO tariff for its multi-value project for approximately $13.1 million, which was effective January 1, 2020. The update effective January 1, 2020, reflects the reduced return on equity order issued by the FERC on November 21, 2019.

Note 15 - Commitments and Contingencies

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

At December 31, 2019 and 2018, the Company accrued liabilities, which have not been discounted, of $920,000 and $190,000, respectively. The accruals are for contingencies, including litigation and environmental matters. This includes amounts that have been accrued for matters discussed in Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company’s financial position, results of operations or cash flows. Legal costs are expensed as they are incurred.

Environmental matters

Manufactured Gas Plant Sites A claim has been made against Montana-Dakota for cleanup of environmental contamination at a manufactured gas plant site operated by Montana-Dakota and its predecessors. Any accruals related to this claim are reflected in regulatory assets. For more information see Note 4.

Demand has been made of Montana-Dakota to participate in investigation and remediation of environmental contamination at a site in Missoula, Montana. The site operated as a former manufactured gas plant from approximately 1907 to 1938 when it was converted to a butane-air plant that operated until 1956. Montana-Dakota or its predecessors owned or controlled the site for a period of the time it operated as a manufactured gas plant and Montana-Dakota operated the butane-air plant from 1940 to 1951, at which time it sold the plant. There are no documented wastes or by-products resulting from the mixing or distribution of butane-air gas. Preliminary assessment of a portion of the site provided a recommended remedial alternative for that portion of approximately $560,000. However, the recommended remediation would not address any potential contamination to adjacent parcels that may be impacted by contamination from the manufactured gas plant. Montana-Dakota and another party agreed to voluntarily investigate and remediate the site and that Montana-Dakota will pay two-thirds of the costs for further investigation and remediation of the site. Montana-Dakota received notice from a prior insurance carrier that it will participate in payment of defense costs incurred in relation to the claim. Montana-Dakota has accrued $375,000 for the remediation of this site.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements.

The future operating lease undiscounted cash flows as of December 31, 2019, were:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Operating leases	$1,662	$1,589	$1,394	$1,346	$1,340	$26,111

Total lease costs were $2.1 million for the year ended December 31, 2019.

Purchase commitments

The Company has entered into various commitments, largely consisting of contracts for natural gas and coal supply, purchased power, natural gas transportation and storage contracts, employee service; and information technology. Certain of these contracts are subject to variability in volume and price. The commitment terms vary in length up to 21 years. The commitments under these contracts as of December 31, 2019, were:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Purchase commitments	$173,184	$74,193	$39,013	$31,441	$11,035	$60,105

These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2019 and 2018, were $314.5 million and $292.6 million, respectively.

Guarantees

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Comparative Balance Sheets and is recovered from customers as a component of electric fuel and purchased power.

The coal supply agreement transfers all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations, as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. The authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing.

At December 31, 2019, the Company's exposure to loss as a result of the agreement, based on the Company's ownership percentage, was $36.0 million.

Note 16 – Related-Party Transactions

The Company provides and receives certain services to/from associated companies. The amount charged for services provided to the Company was $82.2 million and $63.5 million for the years ended December 31, 2019 and 2018, respectively, largely transportation, storage and gathering services provided by subsidiaries of WBI Holdings related to the Company's natural gas distribution operations. Certain support services are also provided to the Company, which includes costs for payroll, pension and other post retirement benefits. The Company records its allocated share of the MDU Resources pension and other post retirement benefit plans, which are included in miscellaneous deferred debits and other deferred credits. The amount charged for services received from the Company was $33.7 million and $112.0 million for the years ended December 31, 2019 and 2018, respectively.

The following details the amounts included in the Comparative Balance Sheet related to associated companies at December 31:

	2019	2018
	(In thousands)	
Accounts receivable from associated companies	**$ 4,082**	$ 36,015
Accounts payable to associated companies	**7,440**	12,438
Dividend declared	**9,970**	---
Miscellaneous deferred debits	**12,313**	14,033
Other deferred credits	**10,970**	18,770

Note 17 – Subsequent Event

In March 2020, the World Health Organization declared the outbreak of COVID-19 a pandemic. Measures put in place by governmental leaders to help limit the spread may have a significant impact on economic activity in the near term. The Company is monitoring the related impacts however, it will take time before the Company can fully determine the impact of COVID-19 on the Company’s results of operations, financial position and cash flows.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,558,624,028	1,761,947,720
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	315,792,379	301,370,525
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,874,416,407	2,063,318,245
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	73,597,988	60,581,510
12	Acquisition Adjustments	10,565,606	10,468,340
13	Total Utility Plant (8 thru 12)	2,958,580,001	2,134,368,095
14	Accum Prov for Depr, Amort, & Depl	1,051,780,047	703,678,491
15	Net Utility Plant (13 less 14)	1,906,799,954	1,430,689,604
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	998,016,828	689,415,181
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	43,284,699	3,859,741
22	Total In Service (18 thru 21)	1,041,301,527	693,274,922
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	10,478,520	10,403,569
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,051,780,047	703,678,491

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
651,791,776				144,884,532	3
					4
					5
12,616,583				1,805,271	6
					7
664,408,359				146,689,803	8
					9
					10
2,202,056				10,814,422	11
97,266					12
666,707,681				157,504,225	13
284,475,179				63,626,377	14
382,232,502				93,877,848	15
					16
					17
280,728,295				27,873,352	18
					19
					20
3,671,933				35,753,025	21
284,400,228				63,626,377	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
74,951					32
284,475,179				63,626,377	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	7,576,290	4,468,253
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	7,576,290	4,468,253
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,015,062	
9	(311) Structures and Improvements	104,362,199	6,228,686
10	(312) Boiler Plant Equipment	313,990,744	6,439,368
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	86,210,990	2,235,239
13	(315) Accessory Electric Equipment	24,883,048	598,440
14	(316) Misc. Power Plant Equipment	21,988,951	1,912,449
15	(317) Asset Retirement Costs for Steam Production	7,316,279	13,071,351
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	559,767,273	30,485,533
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	36,653,115	7,119,406
39	(342) Fuel Holders, Products, and Accessories	1,978,388	1,101,187
40	(343) Prime Movers		
41	(344) Generators	448,960,805	-14,630,041
42	(345) Accessory Electric Equipment	53,873,458	6,998,314
43	(346) Misc. Power Plant Equipment	1,818,427	349,922
44	(347) Asset Retirement Costs for Other Production	18,006,254	1,134,935
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	561,328,980	2,073,723
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,121,096,253	32,559,256

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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
			12,044,543		4
			12,044,543		5
					6
					7
			1,015,062		8
44,376		-23,249	110,523,260		9
5,175,525			315,254,587		10
					11
343,266		39,247	88,142,210		12
226,192		-39,247	25,216,049		13
1,131,145		13,789	22,784,044		14
10,879,823			9,507,807		15
17,800,327		-9,460	572,443,019		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
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					34
					35
					36
			38,533		37
			43,772,521		38
			3,079,575		39
					40
3,024,809			431,305,955		41
4,034,417			56,837,355		42
107,271		-7,813	2,053,265		43
			19,141,189		44
7,166,497		-7,813	556,228,393		45
24,966,824		-17,273	1,128,671,412		46

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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	4,870,020	247,629
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	149,466,553	30,267,811
51	(354) Towers and Fixtures	4,992,886	
52	(355) Poles and Fixtures	77,877,510	5,466,145
53	(356) Overhead Conductors and Devices	59,977,770	107,420,562
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)	302,233,765	143,402,147
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,111,478	149,279
61	(361) Structures and Improvements		
62	(362) Station Equipment	78,775,207	3,711,297
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	45,075,199	873,831
65	(365) Overhead Conductors and Devices	34,273,859	729,483
66	(366) Underground Conduit	235,918	-1,387
67	(367) Underground Conductors and Devices	123,801,452	5,183,803
68	(368) Line Transformers	75,958,052	3,031,582
69	(369) Services	38,076,248	973,153
70	(370) Meters	18,728,502	318,049
71	(371) Installations on Customer Premises	3,029,794	743,536
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	8,644,712	2,481,609
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	430,750,169	18,194,235
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	1,532,133	186,133
88	(391) Office Furniture and Equipment	246,273	23,669
89	(392) Transportation Equipment	8,464,184	1,107,966
90	(393) Stores Equipment	14,774	
91	(394) Tools, Shop and Garage Equipment	4,907,303	536,766
92	(395) Laboratory Equipment	660,345	
93	(396) Power Operated Equipment	13,751,778	1,717,238
94	(397) Communication Equipment	1,853,179	62,920
95	(398) Miscellaneous Equipment	58,769	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	31,527,588	3,634,692
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		545,071
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	31,527,588	4,179,763
100	TOTAL (Accounts 101 and 106)	1,893,184,065	202,803,654
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)	1,893,184,065	202,803,654

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
		2,066	5,119,715		48
			1,789		49
144,012			179,590,352		50
			4,992,886		51
43,623		-517	83,299,515		52
43,842		-1,549	167,352,941		53
			1,944,583		54
			3,101,857		55
					56
			797		57
231,477			445,404,435		58
					59
			4,260,757		60
					61
597,704			81,888,800		62
					63
202,208			45,746,822		64
71,279			34,932,063		65
			234,531		66
503,891			128,481,364		67
384,353			78,605,281		68
148,900			38,900,501		69
107,075			18,939,476		70
1,091,979			2,681,351		71
					72
2,056,723			9,069,598		73
			39,748		74
5,164,112			443,780,292		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			38,850		86
			1,718,266		87
18,574			251,368		88
655,299		22,528	8,939,379		89
			14,774		90
101,856			5,342,213		91
31,276			629,069		92
1,692,079		238,789	14,015,726		93
52,319		4,050	1,867,830		94
3,752			55,017		95
2,555,155		265,367	32,872,492		96
					97
			545,071		98
2,555,155		265,367	33,417,563		99
32,917,568		248,094	2,063,318,245		100
					101
					102
					103
32,917,568		248,094	2,063,318,245		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	Install 115kV Line Ellendale to Leola-SD Portion	7,916,786
2	Construct 230/34.5kV Watford City Substation	6,558,355
3	Construct Linton NW Transmission Sub	6,466,629
4	Install 34.5kV Line Around Watford City	4,803,057
5	Install 115kV Loop TL 174-1 in Dickinson	4,517,692
6	Install Capacitor & Reactor Switcher Ellendale Sub	4,143,136
7	Install 115kV Line Ellendale to Leola-ND Portion	3,213,774
8	Construct New Leola Sub- 115kV portion	2,550,580
9	Rebuild Transmission Line Glendive-Baker	2,470,416
10	Install 115kV Loop Dickinson Junction Sub	2,060,747
11	GIS Field Verification Pilot Project	2,026,932
12	Purchase Mobile Sub Bismarck Spare	1,229,344
13	Construction Video Board	1,016,724
14		
15		
16		
17		
18		
19	Minor projects less than $1,000,000:	
20	Steam Production	318,344
21		
22	Other Production	64,932
23		
24	Transmission	3,631,223
25		
26	Distribution	6,406,429
27		
28	General	101,810
29		
30	Intangible	1,084,600
31		
32		
33		
34		
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36		
37		
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39		
40		
41		
42		
43	TOTAL	60,581,510

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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	623,443,481	623,443,481		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	54,163,135	54,163,135		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,231,564	1,231,564		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	38,162,600	38,162,600		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	93,557,299	93,557,299		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	27,428,996	27,428,996		
13	Cost of Removal	5,988,597	5,988,597		
14	Salvage (Credit)	1,095,778	1,095,778		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	32,321,815	32,321,815		
16	Other Debit or Cr. Items (Describe, details in footnote):	4,736,216	4,736,216		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	689,415,181	689,415,181		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	298,076,547	298,076,547		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	115,438,342	115,438,342		
25	Transmission	114,695,033	114,695,033		
26	Distribution	151,053,951	151,053,951		
27	Regional Transmission and Market Operation				
28	General	10,151,308	10,151,308		
29	TOTAL (Enter Total of lines 20 thru 28)	689,415,181	689,415,181		

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

Common plant depreciation expense charged to electric operations	$ (1,145,780)
SFAS 143 ARO depreciation expense reclassed to a regulatory asset	6,002,465
Accelerated Depreciation reclassified to Regulatory Asset	33,305,915
	$ 38,162,600

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

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	CENTENNIAL ENERGY HOLDINGS, INC. (100% OWNED)	12/88		
3	Capital investment in subsidiaries			732,282,521
4				
5	Equity in undistributed subsidiary earnings since acquisition			482,931,230
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			543,895,644
10				
11	Equity in undistributed subsidiary earnings since acquisition			31,776,343
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	1,790,885,738

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
-732,282,521				3
				4
-482,931,230				5
				6
				7
				8
-543,895,644				9
				10
-31,776,343				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
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				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-1,790,885,738				42

Schedule Page: 224 Line No.: 2 Column: a

Current Year End of Year Balance, column (g), reflect the Balance Sheet balances on Montana-Dakota Utilities Co. following the Holding Company Reorganization discussed on page 109.1, #2.

Schedule Page: 224 Line No.: 8 Column: a

Current Year End of Year Balance, column (g), reflect the Balance Sheet balances on Montana-Dakota Utilities Co. following the Holding Company Reorganization discussed on page 109.1, #2.

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,784,694	4,557,811	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)	16,965,194	19,272,368	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,967,108	3,132,141	Electric
8	Transmission Plant (Estimated)	109,400	57,317	Electric
9	Distribution Plant (Estimated)	1,780,372	1,484,378	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-795,640	-262,264	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	21,026,434	23,683,940	
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)	25,811,128	28,241,751	

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	59,818.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	11,607.00		11,607.00	
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	3,845.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Lewis&Clark to Wygen III	28.00			
23	RM Hesket to Wygen III	28.00			
24					
25					
26					
27					
28	Total	56.00			
29	Balance-End of Year	67,524.00		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				
37	Add: Withheld by EPA	168.00		168.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	168.00			
40	Balance-End of Year			168.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	168.00	11		
45	Gains	168.00	11		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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/transferors 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.

2021 No. (f)	2021 Amt. (g)	2022 No. (h)	2022 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
						59,818.00		1
								2
								3
11,607.00		11,607.00		278,568.00		324,996.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						3,845.00		18
								19
								20
								21
						28.00		22
						28.00		23
								24
								25
								26
								27
						56.00		28
11,607.00		11,607.00		278,568.00		380,913.00		29
								30
								31
								32
								33
								34
								35
								36
168.00		168.00		5,660.00		6,332.00		37
								38
				168.00		336.00		39
168.00		168.00		5,492.00		5,996.00		40
								41
								42
								43
				168.00	2	336.00	13	44
				168.00	2	336.00	13	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
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9						
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11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Electric Generation Development	1,718,605		407	171,860	257,790
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			203,189	1,264,395
30	Costs: MT Public Service					
31	Commission authorization granted					
32	8/2/11 due to cancellation of					
33	construction; Montana electric					
34	amortization over 180 months					
35						
36	Electric Generation Development	814,359		407	81,436	529,334
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			456,485	2,051,519

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

407	$242,228
419	(39,039)
	$203,189

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unamortized Regulatory Commission Expense:	1,399,640	322,582		673,780	1,048,442
2	Montana gas amortization over 36 months					
3	ending 6/21; Wyoming gas amortization over 60					
4	months ending 5/20; Minnesota gas amortization					
5	over 48 months ending 9/20; North Dakota gas					
6	amortization over 36 months ending 11/21;					
7	Montana electric amortization over 36 months					
8	ending 2/22; North Dakota electric amortization					
9	over 36 months ending 8/20; South Dakota electric					
10	amortization over 60 months ending 6/21; Wyoming					
11	electric amortization over 60 months ending 2/22					
12						
13	Asset Retirement Obligations, recovered over	98,227,564	26,227,067	230	16,863,830	107,590,801
14	plant lives					
15						
16	Deferred Fuel and Purchased Power Costs -					
17	North Dakota - Electric [Case No. PU-16-666]	279,778	2,778,952		7,457,008	-4,398,278
18	Wyoming - Electric [Docket No. 20004-128-EA-18]	(914,860)	865,828		140,948	-189,980
19	Montana - Electric [Docket No. D2018.9.60]	(65,552)	1,046,220		1,914,702	-934,034
20	South Dakota - Electric [Docket No. EL15-024]	49,348	169,952		520,934	-301,634
21						
22	Deferred Pension, recovered as expense is	96,384,002		253	1,893,370	94,490,632
23	incurred					
24						
25	Regulatory Matters -Deferred Tax Related,	8,178,849	288,555		654,243	7,813,161
26	recovered over plant lives					
27						
28	ND Transmission Cost Recovery Adjustment -	940,715	614,964		1,684,095	-128,416
29	[Case No. PU-18-379]					
30						
31	Montana Public Service Commission/Montana	140,067	114,689	408.1	160,614	94,142
32	Consumer Counsel tax deferral [Docket No.					
33	D2014.8.72, D2015.9.67, D2015.9.68 and					
34	D2015.6.51]					
35						
36	WY Renewable Energy Rider	(342)	410	142	389	-321
37	[Docket No. 20004-128-EA-18]					
38						
39	Manufactured Gas Plant Site - Missoula, MT, not		427,621	143	29,699	397,922
40	yet being amortized					
41						
42	Manufactured Gas Plant Site - Billings MT, not yet	564,311	111,564			675,875
43	being amortized [Docket No. D2014.11.95]					

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 Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Pension Expense - ND Gas,	210,685		920	72,235	138,450
2	amortization over 3 years ending 11/21					
3	[Case No. PU-17-295]					
4						
5	ND Generation Resource Recovery Rider		257,917		321,054	-63,137
6	[Case No. PU-18-380]					
7						
8	ND Renewable Resource Cost Adjustment	2,178,193	3,335,813	400	1,821,525	3,692,481
9	[Case No. PU-18-82]					
10						
11	Loss on Buildings - North Dakota, amortization	2,763,121		407.3	145,720	2,617,401
12	over 20 years ending 11/38 [Case No. PU-16					
13	-666 and Case No. PU-17-295]					
14						
15	SD Transmission Rider	(34,169)	41,534		197,464	-190,099
16	[Docket No. EL15-024]					
17						
18	SD Infrastructure Rider	93,555	300,336	400	143,958	249,933
19	[Docket No. EL19-010]					
20						
21	Preferred Stock Premium, amortization over 15	576,667		407.3	40,000	536,667
22	years ending 5/33 [Docket No. D2017.9.79]					
23						
24	MT Ad Valeorem Tax Tracker	2,569,017	44,557	400	1,622,557	991,017
25	[Docket No. 2016.12.96]					
26						
27	MN Gas Utility Infrastructure Cost Adjustment	695,333	436,145		42,862	1,088,616
28	[Docket No. G-004/M-18-282]					
29						
30	MT Gas Conservation Program Tracking Mechanism	173,425	32,622	495	48,448	157,599
31	[Docket No. D2017.3.27]					
32						
33	Plant to be Retired, not yet being amortized		35,207,538		2,275,676	32,931,862
34						
35	Unless otherwise noted, amortization period					
36	for regulatory assets above are over a 12					
37	month period					
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	214,409,347	72,624,866		38,725,111	248,309,102

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

928 (Electric)	280,303
928 (Gas)	393,477
	673,780

Schedule Page: 232 Line No.: 17 Column: d

182.3	12,713
555	7,430,807
419	(3,566)
431	13,586
229	3,468
	7,457,008

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

182.3	364
555	129,317
431	9,954
229	1,313
	140,948

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

182.3	24,042
555	1,886,622
419	801
431	2,776
229	461
	1,914,702

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

182.3	(49,574)
555	571,424
431	(916)
	520,934

Schedule Page: 232 Line No.: 25 Column: d

282	494,655
283	159,588
	654,243

Schedule Page: 232 Line No.: 28 Column: d

400	1,677,935
431	6,160
	1,684,095

Schedule Page: 232.1 Line No.: 5 Column: d

400	318,087
431	2,967
	321,054

Schedule Page: 232.1 Line No.: 15 Column: d

400	184,904
431	12,560
	197,464

Schedule Page: 232.1 Line No.: 27 Column: d

400	41,165
489	1,697
	42,862

Schedule Page: 232.1 Line No.: 33 Column: d

253	126,654
407.3	2,149,022
	2,275,676

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred capital stock expense		20,000	181	20,000	
2						
3	Conservation programs	-1,441,971	1,595,707	142	1,772,157	-1,618,421
4						
5	Advance to FutureSource Capital	1,301,491	4,309			1,305,800
6	Corp. for land					
7						
8	Goodwill - Great Plains Natural	4,812,244				4,812,244
9	Gas Co.					
10						
11	Subsidiary post-retirement	12,731,660	12,142,585		13,866,838	11,007,407
12	trust assets					
13						
14	Post-retirement Benefit Costs	11,432,591	6,326,185		2,338,641	15,420,135
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	28,836,015				30,927,165

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

131	$ 281,670
124	19,113
186	241,608
123.1	13,324,447
	$13,866,838

Schedule Page: 233 Line No.: 14 Column: d

131	$ 68,157
186	242,153
219	350,634
234	409,553
254	1,268,144
	$ 2,338,641

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pension Expense	4,862,793	3,564,861
3	Compensation-related	4,647,677	2,482,925
4	Customer Advances	1,038,304	1,193,592
5	Postretirement Benefit Costs	1,063,284	1,427,570
6	Production Tax Credit Carryforward	8,015,316	5,343,149
7	Other	4,888,160	1,255,966
8	TOTAL Electric (Enter Total of lines 2 thru 7)	24,515,534	15,268,063
9	Gas		
10	Pension Expense	6,089,486	4,744,838
11	Customer Advances	3,949,955	2,961,416
12	Compensation-related	3,255,137	2,110,224
13	Postretirement Benefit Costs	1,451,409	1,946,337
14	Uniform Capitalization	228,000	227,647
15	Other	383,359	64,320
16	TOTAL Gas (Enter Total of lines 10 thru 15	15,357,346	12,054,782
17	Other (Specify) *	11,656,446	7,013,361
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	51,529,326	34,336,206

Notes

	Balance at Beginning of Year	Balance at End of Year
*Non-Utility		
C.I.A.C.'s	719,406	4,152
ITC - State	686,105	865,168
SISP Expense	10,228,351	6,121,446
Other	22,584	22,595
Total Non-Utility	11,656,446	7,013,361

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	1,000	1.00	
3	Total Account 201	1,000		
4				
5	Account 204(none)			
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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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
1,000	1,000					2
1,000	1,000					3
						4
						5
						6
						7
						8
						9
						10
						11
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						42

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	3.36%	20,000,000	86,071
8	3.73%	40,000,000	173,637
9	5.98%	30,000,000	624,465
10	5.18%	50,000,000	239,178
11	4.24%	60,000,000	291,263
12	4.34%	40,000,000	197,042
13	3.78%	87,000,000	471,997
14	4.03%	52,000,000	286,355
15	4.87%	11,000,000	59,461
16	4.15%	40,000,000	226,084
17	2.00%	10,500,000	6,029
18	3.66%	50,000,000	234,202
19	3.98%	50,000,000	234,202
20	4.08%	100,000,000	435,969
21	SUBTOTAL	740,500,000	3,910,016
22			
23	Term Loan	70,000,000	
24	Commercial Paper - 2.041% average		674,981
25	Minot Air Force Base Note Payable	509,197	
26	LIBOR Floating Rate Note	100,000,000	22,192
27	LIBOR Floating Rate Note	100,000,000	10,800
28	SUBTOTAL	270,509,197	707,973
29			
30			
31			
32			
33	TOTAL	1,011,009,197	4,617,989

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 Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
082406	082426	082406	082426	100,000,000	6,330,000	6
032117	032132	032117	032132	20,000,000	672,000	7
032117	032137	032117	032137	40,000,000	1,492,000	8
121503	121533	121503	121533	30,000,000	1,794,000	9
041514	041544	041514	041544	50,000,000	2,590,000	10
071514	071524	071514	071524	60,000,000	2,544,000	11
071514	071526	071514	071526	40,000,000	1,736,000	12
102915	103025	102915	103025	87,000,000	3,288,600	13
121015	121030	121015	121030	52,000,000	2,095,600	14
102915	103045	102915	103045	11,000,000	535,700	15
112116	112146	112116	112146	40,000,000	1,660,000	16
090517	090332	090517	090332	9,100,000	193,161	17
101719	101739	101719	101739	50,000,000	376,167	18
101719	101749	101719	101749	50,000,000	409,056	19
111819	111859	111819	111859	100,000,000	487,333	20
				739,100,000	26,203,617	21
						22
122018	060823				-17,646	23
				118,600,000	1,689,195	24
092308	113038			414,076	25,218	25
091718	101719	091718	101719		2,408,750	26
101818	111819	101818	111819		2,637,380	27
				119,014,076	6,742,897	28
						29
						30
						31
						32
				858,114,076	32,946,514	33

Schedule Page: 256 Line No.: 24 Column: i

This amount includes a commitment fee of $221,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 field, 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)	67,122,122
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	9,036,529
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote	98,820,008
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote	19,131,893
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote	185,766,760
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-29,919,994
28	Show Computation of Tax:	
29	Federal Tax @ 21% of line 30	-6,283,199
30	Other Credits and Adjustments	27,166
31	Research & Development Tax Credit	-225,000
32	Wind Production Tax Credit	-25,741,080
33	Closing/Filing True-Up & Out of Period Adjustments	5,282,174
34		
35		
36	Total 2019 Federal Income Tax	-26,939,938
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Reported on Books:	
Contributions in Aid of Construction	$ 8,459,204
Cost Recovery Mechanisms	414,765
Contract Demand Deferral	144,726
Fuel Tax Credit	17,834
Total	$ 9,036,529

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted for Return:	
Book Depreciation and Amortization	$83,287,310
Unamortized Loss on Reacquired Debt	571,714
State Income Tax Deduction	3,009,152
State Income Tax Provision	871,477
Regulatory Commission Expense	351,198
Unrecovered Purchased Gas Cost	1,171,363
Disallowed Meals and Entertainment Expense	270,660
Qualified Transportation Fringe - Parking	166,399
Lobbying Expenses	185,115
Bonus Accrual & 401k Profit Sharing	6,983,482
Contingency Reserve	104,419
Vacation Accrual	487,820
F&PP Deferral	329,125
Montana PSC/MCC Tax Deferral	53,821
Preferred Stock Redemption Amortization	40,000
Abandoned Power Plant Cost Recovery	456,485
Loss on Buildings	84,537
Partnership Ordinary Income/Loss	387,638
Accrued Tax Interest	8,293
Total	$98,820,008

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return:	
Reserved Revenues	$14,511,270
Customer Advances	3,405,712
Mor-Gran-Sou Capacity Revenue	81,806
WAPA Fiber Demand Revenue	49,315
MISO MVP Reserve	414,550
AFUDC Equity	669,240
Total	$19,131,893

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income:	
Tax Depreciation and Amortization	$109,953,565
Federal Income Tax Provision	13,428,163
Supplemental Income Security Plan	5,022,365
401(k) Dividend Deduction	2,706,567
Bad Debts	172,039
Performance Share Program	1,090,997
Prepaid Demand Charges	1,415,982
Prepaid Expenses	63,500
Sundry Reserves	595,482
Pension Expense	14,001,024
Post Retirement Benefits	1,912,404
Management Incentive	163,127
Manufactored Gas Plant	134,486
Deferred Medicare Part D	161,646
Retired Power Plant	60,853
Montana Decommissioning	3,280,963

Plant Closure	31,534,493
Dividend Received Deduction	45,819
PCB Related Income	23,285
Total	$185,766,760

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Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 know, 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 Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	CORPORATE INCOME					
2	Federal	9,119,374		-26,939,938	-14,390,166	8,294
3	State	1,868,654		-3,041,717	-1,554,617	-426
4	SUBTOTAL	10,988,028		-29,981,655	-15,944,783	7,868
5						
6	UNEMPLOYMENT					
7	Federal	30,426		53,335	49,361	
8	Arizona					
9	Idaho	8,063		37,266	37,244	
10	Minnesota	492		3,015	3,094	
11	Montana	4,667		23,393	21,582	
12	Texas	25		42	49	
13	North Dakota	28,656		139,954	159,233	
14	Oregon	346		2,635	2,724	
15	South Dakota	1,206		2,972	3,635	
16	Washington	1,337		19,397	16,399	
17	Wyoming	309		1,501	1,599	
18	SUBTOTAL	75,527		283,510	294,920	
19						
20	GROSS REVENUE					
21	Montana	67,226		426,135	293,683	
22	South Dakota			103,480	103,480	
23	Wyoming	47,716		128,013	111,722	
24	SUBTOTAL	114,942		657,628	508,885	
25						
26	USE					
27	Minnesota	53		7,118	7,134	
28	North Dakota	130,747		431,851	519,705	
29	South Dakota	7,072		48,506	50,411	
30	Washington	3,768		887	3,768	
31	Wyoming	205		15,425	15,559	
32	Idaho	142		1,807	1,679	
33	Iowa					
34	Nebraska					
35	SUBTOTAL	141,987		505,594	598,256	
36						
37	PROPERTY					
38	Minnesota (GPNG)	846,000		915,195	877,195	
39	Montana	5,264,459		12,846,850	11,714,459	
40	North Dakota	4,318,269		4,752,159	4,326,444	
41	TOTAL	24,703,900		1,166,438	13,073,426	7,868

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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)	
						1
-3,422,104		-24,273,767			-2,666,171	2
381,128		-1,257,985			-1,783,732	3
-3,040,976		-25,531,752			-4,449,903	4
						5
						6
34,400		16,158			37,177	7
						8
8,085		4,450			32,816	9
413		40			2,975	10
6,478		10,901			12,492	11
18		2			40	12
9,377		72,035			67,919	13
257					2,635	14
543		672			2,300	15
4,335		265			19,132	16
211		522			979	17
64,117		105,045			178,465	18
						19
						20
199,678		257,933			168,202	21
		24,498			78,982	22
64,007		82,483			45,530	23
263,685		364,914			292,714	24
						25
						26
37					7,118	27
42,893					431,851	28
5,167					48,506	29
887					887	30
71					15,425	31
270					1,807	32
						33
						34
49,325					505,594	35
						36
						37
884,000					915,195	38
6,396,850		7,113,507			5,733,343	39
4,743,984		3,086,528			1,665,631	40
12,804,780		-8,877,799			10,044,237	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 know, 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 Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	North Dakota (GPNG)	36,967		39,982	36,967	
2	South Dakota	1,455,254		1,642,815	1,456,854	
3	Wyoming	145,413		306,987	298,907	
4	SUBTOTAL	12,066,362		20,503,988	18,710,826	
5						
6						
7	FRANCHISE					
8	Delaware			85,002	85,002	
9	Wyoming	145,688		283,842	282,755	
10	Hettinger, ND	1,619		12,878	12,942	
11						
12	SUBTOTAL	147,307		381,722	380,699	
13						
14						
15						
16	MISCELLANEOUS					
17	Federal-FICA	1,027,753		7,099,727	6,813,004	
18	Federal-Highway Use			7,814	7,814	
19	Montana WET Tax	29,478		117,821	118,940	
20	Montana-Electric License	21,380		72,303	78,371	
21	ND-Coal Conversion-Heskett	36,863		403,492	404,377	
22	ND-Generation Tax			591,579	591,579	
23	ND-Coal Conversion-Coyote			479,446	479,446	
24	Secretaries of State					
25	(annual filing fees)			2,504	2,504	
26	Fort Peck Tribal	30,273		28,965	28,588	
27	Crow Agency Tribal	24,000		12,000		
28	Federal CNG Tax					
29	Montana CNG Tax					
30	North Dakota CNG Tax					
31	South Dakota CNG Tax					
32	SUBTOTAL	1,169,747		8,815,651	8,524,623	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	24,703,900		1,166,438	13,073,426	7,868

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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)	
39,982					39,982	1
1,641,215		1,006,821			635,994	2
153,493		230,683			76,304	3
13,859,524		11,437,539			9,066,449	4
						5
						6
						7
		50,321			34,681	8
146,775		168,831			115,011	9
1,555					12,878	10
						11
148,330		219,152			162,570	12
						13
						14
						15
						16
1,314,476		2,826,348			4,273,379	17
		5,867			1,947	18
28,359		117,821				19
15,312		72,303				20
35,978		403,492				21
		591,579				22
		479,446				23
						24
		1,482			1,022	25
30,650		28,965				26
36,000					12,000	27
						28
						29
						30
						31
1,460,775		4,527,303			4,288,348	32
						33
						34
						35
						36
						37
						38
						39
						40
12,804,780		-8,877,799			10,044,237	41

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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		3,377,889	420	998,462	420	315,454	
8	TOTAL	3,377,889		998,462		315,454	
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							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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
4,060,897	25 Years		7
4,060,897			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
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			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

OTHER DEFFERED 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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued pension expense	52,637,718		23,834,854	1,379,116	30,181,980
2						
3	Accrued and deferred benefit					
4	compensation plans	9,639,626		9,416,705	204,403	427,324
5						
6	Intercompany portion of					
7	Supplemental Income					
8	Security Program trust assets	18,770,040		19,314,565	11,514,171	10,969,646
9						
10	Gas affordability tracker	25,966	131	60,742	41,382	6,606
11						
12	Capacity rights contracts	1,890,664		485,774	1,752,023	3,156,913
13						
14						
15						
16	MISO MVP Reserve	414,550	229	414,550		
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	83,378,564		53,527,190	14,891,095	44,742,469

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

131	15,452,375
182	1,793,758
186	6,588,721
	23,834,854

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

242	4,751,282
216	93,294
234	4,572,129
	9,416,705

Schedule Page: 269 Line No.: 8 Column: c

124	18,770,040
254	444,913
182	99,612
	19,314,565

Schedule Page: 269 Line No.: 12 Column: c

151	228,000
182	126,653
E-454	131,121
	485,774

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	854,528	730,436	691,812
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	854,528	730,436	691,812
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)	854,528	730,436	691,812
18	Classification of TOTAL			
19	Federal Income Tax	735,673	588,241	553,852
20	State Income Tax	118,855	142,195	137,960
21	Local Income Tax			

NOTES

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	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
		254	13,581	254	5,017	884,588	4
							5
							6
							7
			13,581		5,017	884,588	8
							9
							10
							11
							12
							13
							14
							15
							16
			13,581		5,017	884,588	17
							18
			12,665		4,155	761,552	19
			916		862	123,036	20
							21

NOTES (Continued)

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	264,865,253	18,928,668	20,775,314
3	Gas	56,537,077	2,798,643	2,874,067
4	Utility	-141,483,571		
5	TOTAL (Enter Total of lines 2 thru 4)	179,918,759	21,727,311	23,649,381
6	Non-Utility	2,455,370		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	182,374,129	21,727,311	23,649,381
10	Classification of TOTAL			
11	Federal Income Tax	156,780,004	16,979,084	19,942,987
12	State Income Tax	25,594,125	4,748,227	3,706,394
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
		282	414,405	282	440,986	263,045,188	2
		282	401,949	282	375,368	56,435,072	3
			2,747,279		12,489,960	-131,740,890	4
			3,563,633		13,306,314	187,739,370	5
2,779,104	3,612,878					1,621,596	6
							7
							8
2,779,104	3,612,878		3,563,633		13,306,314	189,360,966	9
							10
2,249,556	2,923,597		1,675,592		11,338,730	162,805,198	11
529,548	689,281		1,888,041		1,967,584	26,555,768	12
							13

NOTES (Continued)

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

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

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

Regulatory Matters - 254	$(147,667,371)
Regulatory Matters - 182.3	6,183,800
	$(141,483,571)

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

Regulatory Matters - 254	$ 2,252,624
Regulatory Matters - 182.3	494,655
	$ 2,747,279

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

Regulatory Matters - 254	$ 12,271,791
Regulatory Matters - 182.3	218,169
	$ 12,489,960

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

Regulatory Matters - 254	$(137,648,203)
Regulatory Matters - 182.3	5,907,314
	$(131,740,889)

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

ACCUMULATED DEFFERED 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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Fuel & Purch. Power Deferral	78,642	212,733	291,375
4	Def. Pension Exp - Reg Asset	10,227,168	399,495	597,626
5	Unamort Loss on Reaquired Debt	808,133	4,117	115,453
6				
7	Unrecovered Plant Costs	620,051	8,422,695	432,523
8	Other - Electric	3,712,483	1,664,627	1,087,790
9	TOTAL Electric (Total of lines 3 thru 8)	15,446,477	10,703,667	2,524,767
10	Gas			
11	Unrecovered Purch. Gas Costs	330,708	49,260	379,901
12	Regulatory Commission Expense	212,571	21,385	98,815
13	Unamort Loss on Reaquired Debt	205,236	160,421	188,541
14	Def. Pension Exp - Reg Asset	13,283,563	476,350	740,064
15				
16	Other - Gas	5,275,783	5,147,474	3,954,561
17	TOTAL Gas (Total of lines 11 thru 16)	19,307,861	5,854,890	5,361,882
18	Other	-1,331,931		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	33,422,407	16,558,557	7,886,649
20	Classification of TOTAL			
21	Federal Income Tax	28,697,542	13,477,456	6,089,151
22	State Income Tax	4,724,865	3,081,101	1,797,498
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
		283	10,990,003	283	10,848,938	9,887,972	4
		283	4,242	283	5,140	697,695	5
							6
						8,610,223	7
		283	114,329	283	31,641	4,206,632	8
			11,108,574		10,885,719	23,402,522	9
							10
						67	11
						135,141	12
		283	4,242	283	3,344	176,218	13
		283	14,616,341	283	14,757,406	13,160,914	14
							15
			925,414		73,184	5,616,466	16
			15,545,997		14,833,934	19,088,806	17
			3,155,447		3,910,173	-577,205	18
			29,810,018		29,629,826	41,914,123	19
							20
			22,277,787		22,205,275	36,013,335	21
			7,532,231		7,424,551	5,900,788	22
							23

NOTES (Continued)

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

UTILITY: Other - Electric

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

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

UTILITY: Other - Electric

Loss on Buildings	$ 957
MT Ad Valorem Tax Tracker	5,592
MT PSC/MCC Tax Deferral	3,724
ND Renewable Resource Recovery Rider	738,649
ND Transmission Tracker	8,514
Postretirement Benefit Costs	664,295
Preferred Stock Redemption Amort	289
Prepaid Expense	87,578
Property Insurance Recovery	47,484
Regulatory Commission Expense	56,711
SD Infrastructure Rider	50,834
	$ 1,664,627

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

UTILITY: Other - Electric

Excess Deferred Income Taxes	$ 59,859
Loss on Buildings	26,756
MT Ad Valorem Tax Tracker	109,460
MT PSC/MCC Tax Deferral	17,897
ND Renewable Resource Recovery Rider	369,089
ND Transmission Tracker	238,095
Postretirement Benefit Costs	95,570
Preferred Stock Redemption Amort	8,142
Prepaid Expense	78,408
Property Insurance Recovery	1,693
Regulatory Commission Expense	64,826
SD Infrastructure Rider	17,995
	$ 1,087,790

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

UTILITY: Other - Electric

Contingency Reserve	$ 1,678
Excess Deferred Income Taxes	478,888
Loss on Buildings	454,078
MT Ad Valorem Tax Tracker	249,227
MT PSC/MCC Tax Deferral	45,729
ND Renewable Resource Recovery Rider	901,146
Postretirement Benefit Costs	1,660,198
Preferred Stock Redemption Amort	105,373
Prepaid Expense	81,863
Property Insurance Recovery	45,791

Regulatory Commission Expense	130,175
SD Infrastructure Rider	52,486
	$ 4,206,632

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

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

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

UTILITY: Other - Gas	
Def Pension Exp - ND Gas - Reg Asset	$ 654
Grain Drying Margin Sharing	6,524
Loss on Buildings	362
Manufactured Gas Plant Site - Billings	30,959
Manufactured Gas Plant Site - Missoula	110,423
MN Infrastructure Rider	135,214
MT Ad Valorem Tax Tracker	29,776
MT Conservation Tracking Adjustment	22,238
Postretirement Benefit Costs	1,536,269
Preferred Stock Redemption Amort	71
Prepaid Demand	3,182,340
Prepaid Expenses	76,891
Property Insurance Recovery	15,753
	$ 5,147,474

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

UTILITY: Other - Gas	
Def Pension Exp - ND Gas - Reg Asset	$ 18,283
Excess Deferred Income Taxes	650,609
Grain Drying Margin Sharing	8,871
Loss on Buildings	10,126
Manufactured Gas Plant Site - Billings	1,582
Manufactured Gas Plant Site - Missoula	5,641
MN Infrastructure Rider	22,177
MT Ad Valorem Tax Tracker	341,431
MT Conservation Tracking Adjustment	11,705
Postretirement Benefit Costs	779,296
Preferred Stock Redemption Amort	1,970
Prepaid Demand	2,031,737
Prepaid Expenses	70,571
Property Insurance Recovery	562
	$ 3,954,561

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

283	$ 86,291
190	839,123
	$ 925,414

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

283	$ 45,762

190	27,422
	$ 73,184

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

UTILITY: Other - Gas	
Contingency Reserve	$ 97,772
Def Pension Exp - ND Gas - Reg Asset	33,789
Excess Deferred Income Taxes	1,259,246
Loss on Buildings	184,696
Manufactured Gas Plant Site - Billings	177,973
Manufactured Gas Plant Site - Missoula	104,782
MN Infrastructure Rider	312,890
MT Ad Valorem Tax Tracker	11,733
MT Conservation Tracking Adjustment	41,499
Postretirement Benefit Costs	2,209,727
Preferred Stock Redemption Amort	25,486
Prepaid Demand	1,085,263
Prepaid Expenses	56,419
Property Insurance Recovery	15,191
	$ 5,616,466

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	$ 1,838,048
Regulatory Matters - 182.3 - Gas	157,001
Regulatory Matters - 254 - Electric	(755,162)
Regulatory Matters - 254 - Gas	(2,654,696)
Total Utility Other	$(1,414,809)
NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	$ 82,878
Total Non-Utility	$ 82,878
TOTAL OTHER	$(1,331,931)

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	$ 142,218
Regulatory Matters - 182.3 - Gas	17,370
Regulatory Matters - 254 - Electric	1,172,140
Regulatory Matters - 254 - Gas	1,737,777
Total Utility Other	$ 3,069,505
NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	$ 85,942
Total Non-Utility	$ 85,942
TOTAL OTHER	$ 3,155,447

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	$ 61,910
Regulatory Matters - 182.3 - Gas	8,475
Regulatory Matters - 254 - Electric	1,171,116
Regulatory Matters - 254 - Gas	2,665,608
Total Utility Other	$ 3,907,109
NON UTILITY: Other	
Partnership Ordinary Gain/(Loss)	$ 3,064
Total Non-Utility	$ 3,064

TOTAL OTHER	$ 3,910,173

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

UTILITY: Other	
Regulatory Matters - 182.3 - Electric	$ 1,757,740
Regulatory Matters - 182.3 - Gas	148,106
Regulatory Matters - 254 - Electric	(756,186)
Regulatory Matters - 254 - Gas	(1,726,865)
Total Utility Other	$ (577,205)

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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Regulatory matters - Deferred Tax Related	148,015,300		17,738,527	7,901,580	138,178,353
2						
3	Retired Power Plant - amortizations over	181,444	405	60,853		120,591
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. El 15-024]					
8						
9	Deferred Other Postretirement	10,020,714			3,621,309	13,642,023
10						
11	Grain Drying Margin Sharing - North Dakota,	215,795	496	356,158	382,877	242,514
12	South Dakota Gas [Case No. PU-13-803] &					
13	[Docket No. NG12-008]					
14						
15	Gain on Building Sale - North Dakota	811,273	405	43,618		767,655
16	Electric [Case No. PU-16-666]					
17						
18	Gain on Building Sale; North Dakota	272,732	405	17,565		255,167
19	Gas - Amortization over 240 months ending					
20	6/34 [Case No. PU-13-803]					
21						
22	Deferred Post-Retirement Expense;	288,505	920	98,916		189,589
23	North Dakota - Gas [Case No. PU-15-90]					
24						
25	Decommissioning cost amortization - Montana	3,280,963		3,280,963		
26	[Docket No. D2018.9.60]					
27						
28	SD Conservation Program Tracking Mechanism	76,160		57,887	103,770	122,043
29	[Docket No. NG18-002]					
30						
31	MN Conservation Improvement Program	830,804	495	242,004	126,987	715,787
32	[Docket No. G004/GR-15-879]					
33						
34	MN Revenue Decoupling	623,877		467,621	541,978	698,234
35	[Docket No. G-004/GR-15-879]					
36						
37	Contract Demand Deferral				144,726	144,726
38	North Dakota - Gas [Case No. PU-17-346]					
39						
40						
41	TOTAL	164,617,567		22,364,112	12,823,227	155,076,682

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

190	$	1,732,244
282		12,276,809
283		3,729,474
	$	17,738,527

Schedule Page: 278 Line No.: 25 Column: c

407.4	$	894,959
108		2,386,004
	$	3,280,963

Schedule Page: 278 Line No.: 28 Column: c

421	$	12,878
431		26
495		44,983
	$	57,887

Schedule Page: 278 Line No.: 34 Column: c

400	$	438,724
489.3		28,897
	$	467,621

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Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	125,614,395	126,172,875
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	142,061,388	141,961,125
5	Large (or Ind.) (See Instr. 4)	37,790,082	36,081,553
6	(444) Public Street and Highway Lighting	2,058,659	2,400,148
7	(445) Other Sales to Public Authorities	4,769,823	4,847,694
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	625,259	633,925
10	TOTAL Sales to Ultimate Consumers	312,919,606	312,097,320
11	(447) Sales for Resale	1,379,957	1,039,756
12	TOTAL Sales of Electricity	314,299,563	313,137,076
13	(Less) (449.1) Provision for Rate Refunds	837,710	15,345,655
14	TOTAL Revenues Net of Prov. for Refunds	313,461,853	297,791,421
15	Other Operating Revenues		
16	(450) Forfeited Discounts	358,412	401,237
17	(451) Miscellaneous Service Revenues	163,129	226,874
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,421,193	4,345,855
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,555,985	2,368,373
22	(456.1) Revenues from Transmission of Electricity of Others	28,627,350	28,627,350
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	37,126,069	35,969,689
27	TOTAL Electric Operating Revenues	350,587,922	333,761,110

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
1,177,889	1,196,619	118,449	118,426	2
				3
1,499,958	1,513,911	22,978	22,756	4
549,403	551,000	234	236	5
22,653	26,899	589	587	6
58,350	59,883	750	748	7
				8
6,052	6,089	268	269	9
3,314,305	3,354,401	143,268	143,022	10
85,599	45,974			11
3,399,904	3,400,375	143,268	143,022	12
				13
3,399,904	3,400,375	143,268	143,022	14

Line 12, column (b) includes $ -811,927 of unbilled revenues.

Line 12, column (d) includes -11,408 MWH relating to unbilled revenues

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

Basis of classification - Commercial Customers

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

Basis of classification - Commercial Customers

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

Basis of classification - Industrial Customers

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

Basis of classification - Industrial Customers

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

Unbilled revenue includes over/under related to trackers.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Montana					
3	10-Residential Electric Service	182,130	19,516,830	20,064	9,077	0.1072
4	20-Small General Electric Service	2,528	269,276	249	10,153	0.1065
5	25-Irrigation Power Service	1	570	1	1,000	0.5700
6	52-Outdoor Lighting Service	661	96,889	911	726	0.1466
7	North Dakota					
8	10-Residential Electric Service	769,612	81,339,943	78,439	9,812	0.1057
9	13-Optional Residential Thermal E	160	12,115	4	40,000	0.0757
10	16-Optional Time-of-Day Service	74	6,974	5	14,800	0.0942
11	20-Small General Electric Service	5,011	671,151	698	7,179	0.1339
12	25-Irrigation Power Service		590	1		
13	30-General Electric Service	6,486	659,328	86	75,419	0.1017
14	32-General Electric Space Heating	2,391	186,694	26	91,962	0.0781
15	52-Outdoor Lighting Service	1,075	112,024	1,151	934	0.1042
16	South Dakota					
17	10-Residential Electric Service	64,080	7,454,554	6,513	9,839	0.1163
18	20-Small General Electric Service	530	58,203	37	14,324	0.1098
19	24-Outdoor Lighting Service	171	16,889	257	665	0.0988
20	53-Special Residential Dual Fuel	5,991	425,097	316	18,959	0.0710
21	Wyoming					
22	10-Residential Electric Service	131,259	14,464,206	13,539	9,695	0.1102
23	11-Special Residential Controlled	9,966	585,544	714	13,958	0.0588
24	20-Small General Electric Service	944	116,616	162	5,827	0.1235
25	24-Outdoor Lighting Service	418	24,189	584	716	0.0579
26	Unbilled-Net	-5,599	-403,287			0.0720
27	Adjustment for Duplicate Customer			-5,308		
28	Subtotal Residential	1,177,889	125,614,395	118,449	9,944	0.1066
29						
30	Small Commercial-442					
31	Montana					
32	20-Small General Electric Service	105,190	10,830,202	5,360	19,625	0.1030
33	25-Irrigation Power Service	3,838	363,642	157	24,446	0.0947
34	32-General Electric Space Heating	2,850	194,927	15	190,000	0.0684
35	52-Outdoor Lighting Service	1,472	225,944	797	1,847	0.1535
36	North Dakota					
37	20-Small General Electric Service	83,897	10,283,608	8,907	9,419	0.1226
38	25-Irrigation Power Service	686	69,396	37	18,541	0.1012
39	26-Optional Time-of-Day Small Gen	1,392	191,593	251	5,546	0.1376
40	30-General Electric Service	427,562	42,227,683	3,095	138,146	0.0988
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	32-General Electric Space Heating	47,334	3,671,944	495	95,624	0.0776
2	40-Small Municipal Electric Servi	1	198			0.1980
3	52-Outdoor Lighting Service	4,418	460,592	1,233	3,583	0.1043
4	South Dakota					
5	20-Small General Electric Service	31,029	3,509,341	1,944	15,961	0.1131
6	24-Outdoor Lighting Service	384	37,784	265	1,449	0.0984
7	25-Irrigation Power Service	92	9,540	7	13,143	0.1037
8	26-Optional Time-of-Day General E	143	17,801	24	5,958	0.1245
9	32-General Electric Space Heating	7,044	475,722	154	45,740	0.0675
10	Wyoming					
11	20-Small General Electric Service	48,932	4,536,160	2,501	19,565	0.0927
12	22-Special General Controlled Ele	250	14,869	18	13,889	0.0595
13	24-Outdoor Lighting Service	883	51,207	308	2,867	0.0580
14	25-Irrigation Power Service	2,068	224,718	73	28,329	0.1087
15	26-Irrigation Power Service Optio	51	9,501	6	8,500	0.1863
16	Unbilled-Net	-1,313	-152,396			0.1161
17	Adjustment for Duplicate Customer			-4,309		
18	Subtotal Small Commercial	768,203	77,253,976	21,338	36,002	0.1006
19						
20	Large Commercial-442					
21	Montana					
22	25-Irrigation Power Service	525	46,321	11	47,727	0.0882
23	30-Large General Electric Service	153,457	13,924,936	258	594,795	0.0907
24	31-Optional Time-of-Day Large Gen	189	26,996			0.1428
25	52-Outdoor Lighting Service	378	56,125	74	5,108	0.1485
26	North Dakota					
27	20-Small General Electric Service	207	22,701	15	13,800	0.1097
28	25-Irrigation Power Service	32	2,858	2	16,000	0.0893
29	30-General Electric Service	399,481	36,594,826	1,221	327,175	0.0916
30	31-Optional Time-of-Day General S	23,109	2,091,326	64	361,078	0.0905
31	32-General Electric Space Heating	13,214	1,012,074	46	287,261	0.0766
32	34-Firm Service Economic Developm	757	67,528	1	757,000	0.0892
33	38-Interruptible Large Power Dema	29,199	2,124,363	3	9,733,000	0.0728
34	52-Outdoor Lighting Service	305	31,843	98	3,112	0.1044
35	South Dakota					
36	24-Outdoor Lighting Service	135	13,290	32	4,219	0.0984
37	30-Large General Electric Service	28,296	2,721,407	110	257,236	0.0962
38	Wyoming					
39	24-Outdoor Lighting Service	53	3,071	15	3,533	0.0579
40	39-Large General Electric Service	86,736	6,251,325	155	559,587	0.0721
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 Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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.

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1	Unbilled-Net	-4,316	-183,578			0.0425
2	Adjustment for Duplicate Customer			-465		
3	Subtotal Large Commercial	731,757	64,807,412	1,640	446,193	0.0886
4						
5	Small Industrial-442					
6	Montana					
7	20-Small General Electric Service	3,600	347,217	80	45,000	0.0964
8	31-Optional Time-of-Day Large Gen	10,715	872,732	4	2,678,750	0.0814
9	35-Contract Service	6,284	378,156	1	6,284,000	0.0602
10	52-Outdoor Lighting Service	2	312	2	1,000	0.1560
11	North Dakota					
12	20-Small General Electric Service	186	22,085	18	10,333	0.1187
13	30-General Electric Service	7,561	668,891	36	210,028	0.0885
14	32-General Electric Space Heating	887	69,369	3	295,667	0.0782
15	52-Outdoor Lighting Service	31	3,217	8	3,875	0.1038
16	South Dakota					
17	20-Small General Electric Service	38	4,411	4	9,500	0.1161
18	24-Outdoor Lighting Service	9	870	3	3,000	0.0967
19	Wyoming					
20	20-Small General Electric Service	314	28,708	9	34,889	0.0914
21	24-Outdoor Lighting Service	2	93	2	1,000	0.0465
22	Unbilled-Net	1,039	40,427			0.0389
23	Adjustment for Duplicate Customer			-26		
24	Subtotal Small Industrial	30,668	2,436,488	144	212,972	0.0794
25						
26	Large Industrial-442					
27	Montana					
28	30-Large General Electric Service	89,040	7,016,951	25	3,561,600	0.0788
29	31-Optional Time-of-Day Large Gen	722	87,808	4	180,500	0.1216
30	35-Contract Service	211,648	12,806,614	12	17,637,333	0.0605
31	52-Outdoor Lighting Service	1	220	3	333	0.2200
32	North Dakota					
33	30-General Electic Service	201,404	14,160,492	44	4,577,364	0.0703
34	31-Optional Time-of-Day General E	4,041	407,937	8	505,125	0.1009
35	32-General Electric Space Heating	49	4,147	1	49,000	0.0846
36	38-Interruptible Large Power Dema	3,773	193,855	1	3,773,000	0.0514
37	52-Outdoor Lighting Service	8	814	3	2,667	0.1018
38	South Dakota					
39	24-Outdoor Lighting Service	7	689	2	3,500	0.0984
40	30-Large General Electric Service	7,557	634,981	6	1,259,500	0.0840
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 Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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1	Wyoming					
2	37-Large Power Standby Service	26	3,561	1	26,000	0.1370
3	39-Large General Electric Service	1,313	131,163	5	262,600	0.0999
4	Ubilled-Net	-854	-95,639			0.1120
5	Adjustment for Duplicate Customer			-25		
6	Subtotal Large Industrial	518,735	35,353,593	90	5,763,722	0.0682
7						
8	Public Street and Highway - 444					
9	Montana					
10	20-Small General Electric Service	141	13,845	4	35,250	0.0982
11	41-Municipal Lighting Service	2,854	280,169	88	32,432	0.0982
12	52-Outdoor Lighting Service	54	8,114	3	18,000	0.1503
13	North Dakota					
14	20-Small General Electric Service	380	52,808	57	6,667	0.1390
15	40-Small Municipal Electric Servi	28	2,230	1	28,000	0.0796
16	41-Municipal Lighting Service	16,224	1,391,803	643	25,232	0.0858
17	52-Outdoor Lighting Service	101	10,485	25	4,040	0.1038
18	South Dakota					
19	24-Outdoor Lighting Service	12	1,166	3	4,000	0.0972
20	41-Street Lighting Service	2,385	249,887	55	43,364	0.1048
21	Wyoming					
22	20-Small General Electric Service	9	1,914	4	2,250	0.2127
23	24-Outdoor Lighting Service		19	1		
24	41-Municipal Lighting Service	772	68,824	4	193,000	0.0892
25	Unbilled-Net	-308	-22,605			0.0734
26	Adjustment for Duplicate Customer			-299		
27	Subtotal Public Street and Highwa	22,652	2,058,659	589	38,458	0.0909
28						
29	Other Sales to Public Authorities					
30	Montana					
31	48-Municipal Pumping Service	5,604	508,448	109	51,413	0.0907
32	North Dakota					
33	20-Small General Electric Service	368	50,064	53	6,943	0.1360
34	30-General Electric Service	1,673	169,183	11	152,091	0.1011
35	32-General Electric Space Heating	298	21,808	6	49,667	0.0732
36	40-Small Municipal Electric Servi	3,728	373,431	282	13,220	0.1002
37	48-Municipal Pumping Service	45,208	3,508,460	319	141,718	0.0776
38	South Dakota					
39	48-Municipal Pumping Service	1,508	131,778	49	30,776	0.0874
40	Unbilled-Net	-37	6,653			-0.1798
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	Adjustment for Duplicate Customer			-79		
2	Subtotal Other Sales	58,350	4,769,825	750	77,800	0.0817
3						
4	Interdepartmental-448					
5	Montana					
6	Billed	567	70,631	97	5,845	0.1246
7	North Dakota					
8	Billed	4,985	492,379	142	35,106	0.0988
9	South Dakota					
10	Billed	343	39,690	10	34,300	0.1157
11	Wyoming					
12	Billed	177	24,061	31	5,710	0.1359
13	Unbilled-Net	-19	-1,501			0.0790
14	Adjustment for Duplicate Customer			-12		
15	Subtotal Interdepartmental Sales	6,053	625,260	268	22,586	0.1033
16						
17	Total	3,314,307	312,919,608	143,268	23,134	0.0944
18						
19	Fuel Clause Adjustment					
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Schedule Page: 304.4 Line No.: 19 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	4,806,174
20-Small General Electric Service	67,253
25-Irrigation Power Service	34
52-Outdoor Lighting Service	17,417
North Dakota	
10-Residential Electric Service	20,354,374
13-Optional Residential Thermal Energy Storage	4,274
16-Optional Time-of-Day Residential Electric Service	1,997
20-Small General Electric Service	133,000
25-Irrigation Power Service	12
30-General Electric Service	171,930
32-General Electric Space Heating Service	64,635
52-Outdoor Lighting Service	28,352
South Dakota	
10-Residential Electric Service	1,631,435
20-Small General Electric Service	13,554
24-Outdoor Lighting Service	4,337
53-Special Residential Electric Dual Fuel Space Heating Service	156,647
Wyoming	
10-Residential Electric Service	4,194,702
11-Special Residential Controlled Electric Service	324,336
20-Small General Electric Service	30,254
24-Outdoor Lighting Service	13,314
Unbilled-net	(288,935)
Subtotal Residential	31,729,096
Small Commercial-442	
Montana	
20-Small General Electric Service	2,776,320
25-Irrigation Power Service	94,174
32-General Electric Space Heating Service	77,033
52-Outdoor Lighting Service	39,475
North Dakota	
20-Small General Electric Service	2,220,569
25-Irrigation Power Service	17,267
26-Optional Time-of-Day Small General Electric Service	36,657
30-General Electric Service	11,204,464
32-General Electric Space Heating Service	1,270,039
40-Small Municipal Electric Service	35
52-Outdoor Lighting Service	116,965
South Dakota	
20-Small General Electric Service	786,682
24-Outdoor Lighting Service	9,742
25-Irrigation Power Service	2,147
26-Optional Time-of-Day Small General Electric Service	3,599
32-General Electric Space Heating Service	185,038
Wyoming	
20-Small General Electric Service	1,560,273
22-Special General Controlled Electric Service	8,201

24-Outdoor Lighting Service	28,271
25-Irrigation Power Service	62,749
26-Irrigation Power Service Optional Time-of-Day	1,559
Unbilled-net	(115,972)
Subtotal Small Commercial	20,385,287
Large Commercial-442	
Montana	
25-Irrigation Power Service	12,698
30-Large General Electric Service	4,028,548
31-Optional Time-of-Day Large General Electric Service	5,278
52-Outdoor Lighting Service	9,984
North Dakota	
20-Small General Electric Service	5,502
25-Irrigation Power Service	775
30-General Electric Service	10,437,017
31-Optional Time-of-Day General Electric Service	611,827
32-General Electric Space Heating Service	353,953
34-Firm Service Economic Development Rate	19,755
38-Interruptible Large Power Demand Response	740,302
52-Outdoor Lighting Service	8,117
South Dakota	
24-Outdoor Lighting Service	3,419
30-Large General Electric Service	714,654
Wyoming	
24-Outdoor Lighting Service	1,689
39-Large General Electric Service	2,716,912
Unbilled-net	(192,524)
Subtotal Large Commercial	19,477,906
Small Industrial-442	
Montana	
20-Small General Electric Service	95,508
31-Optional Time-of-Day Large General Electric Service	278,456
35-Contract Service Rate	138,726
52-Outdoor Lighting Service	56
North Dakota	
20-Small General Electric Service	4,941
30-General Electric Service	184,347
32-General Electric Space Heating Service	23,374
52-Outdoor Lighting Service	818
South Dakota	
20-Small General Electric Service	978
24-Outdoor Lighting Service	226
Wyoming	
20-Small General Electric Service	10,005
24-Outdoor Lighting Service	51
Unbilled-net	25,211
Subtotal Small Industrial	762,697
Large Industrial-442	
Montana	
30-General Electric Service	2,334,720
31-Optional Time-of-Day Large General Electric Service	19,163

35-Contract Service	4,672,339
52-Outdoor Lighting Service	39
North Dakota	
30-General Electric Service	5,129,056
31-Optional Time-of-Day General Electric Service	106,433
32-General Electric Space Heating Service	1,309
38-Interruptible Large Power Demand Response	96,673
52-Outdoor Lighting Service	207
South Dakota	
24-Outdoor Lighting Service	178
30-Large General Electric Service	191,303
Wyoming	
37-Large Power Standby Service	865
39-Large General Service	41,769
Unbilled-net	(43,871)
Subtotal Large Industrial	12,550,183
Public Street and Highway Lighting-444	
Montana	
20-Small General Service	3,734
41-Municipal Lighting Service	75,045
52-Outdoor Lighting Service	1,395
North Dakota	
20-Small General Service	10,024
40-Small Municipal Electric Service	737
41-Municipal Lighting Service	428,528
52-Outdoor Lighting Service	2,632
South Dakota	
24-Outdoor Lighting Service	304
41-Street Lighting Service	60,450
Wyoming	
20-Small General Electric Service	292
24-Outdoor Lighting Service	10
41-Municipal Lighting Service	24,856
Unbilled-net	(10,649)
Subtotal Public Street and Highway Lighting	597,358
Other Sales to Public Authorities-446	
Montana	
48-Municipal Pumping Service	146,570
North Dakota	
20-Small General Electric Service	9,740
30-General Electric Service	44,254
32-General Electric Space Heating Service	8,153
40-Small Municipal Electric Service	98,786
48-Municipal Pumping Service	1,167,213
South Dakota	
48-Municipal Pumping Service	38,169
Unbilled-net	(5,761)
Subtotal Other Sales	1,507,124
Interdepartmental Sales-448	
Montana	14,970
North Dakota	131,398

South Dakota	8,934
Wyoming	5,715
Unbilled-Net	(1,100)
Subtotal Interdepartmental	159,917
Total Fuel Clause Adjustment	87,169,568

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 note 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 tong-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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Midwest Independent Transmission					
2	System Operator (MISO)	OS	MISO	N/A	N/A	N/A
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
85,599		1,379,957		1,379,957	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
85,599	0	1,379,957	0	1,379,957	
85,599	**0**	**1,379,957**	**0**	**1,379,957**	

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	2,725,641	2,385,247
5	(501) Fuel	53,816,556	54,995,192
6	(502) Steam Expenses	7,799,898	7,928,936
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,238,985	2,060,269
10	(506) Miscellaneous Steam Power Expenses	3,238,594	4,174,418
11	(507) Rents	753,405	854,259
12	(509) Allowances	10	84
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	70,573,089	72,398,405
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,379,715	1,395,980
16	(511) Maintenance of Structures	813,042	790,065
17	(512) Maintenance of Boiler Plant	7,053,622	7,331,912
18	(513) Maintenance of Electric Plant	1,821,764	2,150,943
19	(514) Maintenance of Miscellaneous Steam Plant	1,935,537	1,833,788
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	13,003,680	13,502,688
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	83,576,769	85,901,093
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) Mainentance 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	358,741	293,990
63	(547) Fuel	3,468,532	3,732,798
64	(548) Generation Expenses	3,357,189	3,459,514
65	(549) Miscellaneous Other Power Generation Expenses	1,015,749	846,164
66	(550) Rents	858,275	635,529
67	TOTAL Operation (Enter Total of lines 62 thru 66)	9,058,486	8,967,995
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	167,316	126,295
70	(552) Maintenance of Structures	38,412	20,448
71	(553) Maintenance of Generating and Electric Plant	679,480	622,541
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	98,113	76,567
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	983,321	845,851
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	10,041,807	9,813,846
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	29,271,398	21,984,234
77	(556) System Control and Load Dispatching	1,955,027	1,961,434
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	31,226,425	23,945,668
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	124,845,001	119,660,607
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,032,960	3,682,170
84			
85	(561.1) Load Dispatch-Reliability	498,780	465,367
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,007,571	1,005,314
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	579,062	563,644
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	42,182	41,709
93	(562) Station Expenses	523,513	590,513
94	(563) Overhead Lines Expenses	297,079	284,218
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	25,098,052	24,809,164
97	(566) Miscellaneous Transmission Expenses	140,100	109,580
98	(567) Rents	127,617	112,419
99	TOTAL Operation (Enter Total of lines 83 thru 98)	32,346,916	31,664,098
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	183,847	117,651
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,019,166	891,366
108	(571) Maintenance of Overhead Lines	1,308,997	1,073,888
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,512,010	2,082,905
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	34,858,926	33,747,003

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	515,325	544,865
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	515,325	544,865
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)	515,325	544,865
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,179,470	1,938,901
135	(581) Load Dispatching		
136	(582) Station Expenses	663,017	589,271
137	(583) Overhead Line Expenses	625,493	748,462
138	(584) Underground Line Expenses	1,307,125	1,313,221
139	(585) Street Lighting and Signal System Expenses	14,112	46,680
140	(586) Meter Expenses	1,170,290	1,234,272
141	(587) Customer Installations Expenses	316,801	290,187
142	(588) Miscellaneous Expenses	3,679,492	3,269,976
143	(589) Rents	136,882	154,124
144	TOTAL Operation (Enter Total of lines 134 thru 143)	10,092,682	9,585,094
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	949,593	786,138
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	232,549	288,724
149	(593) Maintenance of Overhead Lines	3,105,014	3,542,223
150	(594) Maintenance of Underground Lines	886,811	792,466
151	(595) Maintenance of Line Transformers	109,575	181,157
152	(596) Maintenance of Street Lighting and Signal Systems	97,077	149,033
153	(597) Maintenance of Meters	57,871	61,235
154	(598) Maintenance of Miscellaneous Distribution Plant	967,150	913,164
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,405,640	6,714,140
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	16,498,322	16,299,234
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	168,111	137,761
160	(902) Meter Reading Expenses	534,729	500,074
161	(903) Customer Records and Collection Expenses	2,340,987	2,431,281
162	(904) Uncollectible Accounts	780,690	1,427,226
163	(905) Miscellaneous Customer Accounts Expenses	195,615	185,940
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	4,020,132	4,682,282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	72,353	29,723
168	(908) Customer Assistance Expenses	93,003	61,090
169	(909) Informational and Instructional Expenses	126,822	118,787
170	(910) Miscellaneous Customer Service and Informational Expenses	8,209	9,801
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	300,387	219,401
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,004	-1,347
175	(912) Demonstrating and Selling Expenses	104,075	70,984
176	(913) Advertising Expenses	9,257	23,845
177	(916) Miscellaneous Sales Expenses	8,336	7,662
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	122,672	101,144
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	9,392,160	8,473,516
182	(921) Office Supplies and Expenses	3,993,818	4,893,624
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	471,899	715,234
185	(924) Property Insurance	1,225,956	1,064,394
186	(925) Injuries and Damages	2,607,091	2,181,229
187	(926) Employee Pensions and Benefits	7,791,014	7,014,333
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,054,024	631,080
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	94,371	87,661
192	(930.2) Miscellaneous General Expenses	977,056	906,594
193	(931) Rents	1,684,930	863,265
194	TOTAL Operation (Enter Total of lines 181 thru 193)	29,292,319	26,830,930
195	Maintenance		
196	(935) Maintenance of General Plant	530,829	544,936
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	29,823,148	27,375,866
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	210,983,913	202,630,402

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Black Hills Power & Light Co.	RQ	BHPL #42	49	49	49
2	Beckton Hydro-Energy	LU				
3	Western Area Power Admin - Ft. Peck	LF	19			
4	Midcontinent Independent					
5	System Operator (MISO)	EX	MISO			
6	Customer Owned Generation	OS				
7	Deferral per tariff					
8	Enerwise Global Technologies, Inc.	OS				
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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)	
109,387			3,709,899	3,263,054	53,830	7,026,783	1
			11,650	10,815		22,465	2
14,301				343,229		343,229	3
							4
767,851			-32,393	15,054,422		15,022,029	5
			419,333			419,333	6
					5,157,091	5,157,091	7
			1,280,468			1,280,468	8
							9
							10
							11
							12
							13
							14
891,539			5,388,957	18,671,520	5,210,921	29,271,398	

FOOTNOTE DATA

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 Classifi-cation (d)
1	Midcontinent Independent			
2	System Operator (MISO)	MISO participants	MISO participants	OS
3				
4	MISO	MISO participants	MISO participants	NF
5				
6	MISO	MISO participants	MISO participants	OS
7				
8	Southwest Power Pool	Southwest Power Pool	Southwest Power Pool	OS
9				
10	MISO	MISO participants	MISO participants	OS
11				
12	MISO	MISO participants	MISO participants	OS
13				
14	MISO	MISO participants	MISO participants	OS
15				
16	MISO	MISO participants	MISO participants	OS
17				
18	MISO	MISO participants	MISO participants	OS
19				
20	Basin Electric Co-Op	Basin Electric Co-Op	Basin Electric Co-Op	OS
21				
22	Southwest Water Authority	Western Area Power Administration	Southwest Water Authority	OS
23				
24	Powder River Energy Corp	Powder River Energy Corp	Powder River Energy Corp	OLF
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered 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 (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
7	Various	Various				2
						3
8	Various	Various				4
						5
9	Various	Various	1,417			6
						7
9	Various	Various				8
						9
24	Various	Various		1,143,215	1,120,799	10
						11
26	Various	Various				12
						13
26A	Various	Various				14
						15
37	Various	Various				16
						17
38	Various	Various				18
						19
Facility Sharing	Various	Various				20
						21
	Dickinson	Dickinson		3,679	3,607	22
						23
5	Sheridan	Various		9,996	9,996	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,417	**1,156,890**	**1,134,402**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
		1,052,580	1,052,580	2
				3
		25,951	25,951	4
				5
3,170,005			3,170,005	6
				7
		10,319,958	10,319,958	8
				9
		778,372	778,372	10
				11
		1,130,245	1,130,245	12
				13
		13,865,137	13,865,137	14
				15
		11,550	11,550	16
				17
		13,615	13,615	18
				19
		244,000	244,000	20
				21
	27,462		27,462	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
3,170,005	**27,462**	**27,441,408**	**30,638,875**	

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	DELIVERED POWER TO AND							
2	RECEIVED POWER FROM							
3	WHEELER							
4	Mor Gran Sou Elec Coop	LFP	1,550	1,674				
5	Grand Elec Coop	LFP	584	632		3,331		3,331
6	Midcontinent							
7	Independent							
8	System Operator (MISO)	OS					8,368,376	8,368,376
9	Southwest Power Pool	FNS				16,726,345		16,726,345
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,134	2,306		16,729,676	8,368,376	25,098,052

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	358,170
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	618,886
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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43		
44		
45		
46	TOTAL	977,056

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)

(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			773,281		773,281
2	Steam Production Plant	14,814,842				14,814,842
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	20,811,653			-104,472	20,707,181
7	Transmission Plant	6,527,698				6,527,698
8	Distribution Plant	10,343,806				10,343,806
9	Regional Transmission and Market Operation					
10	General Plant	519,356				519,356
11	Common Plant-Electric	1,145,780		1,771,014		2,916,794
12	TOTAL	54,163,135		2,544,295	-104,472	56,602,958

B. Basis for Amortization Charges

Range from five year, 20% to ten year, 10% Straight Line Amortization from 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	110,523					
15	312	315,255					
16	314	88,142					
17	315	25,216					
18	316	22,784					
19	317.0	9,508					
20	Subtotal	571,428					
21							
22	OTHER PRODUCTION						
23							
24	341	43,773					
25	342	3,080					
26	344	431,306					
27	345	56,837					
28	346	2,053					
29	347.0	19,141					
30	Subtotal	556,190					
31							
32	TRANSMISSION PLANT						
33							
34	350.2	3,442					
35	352	2					
36	353	179,590					
37	354	4,993					
38	355	83,299					
39	356	167,353					
40	357	1,944					
41	358	3,102					
42	359.1	1					
43	Subtotal	443,726					
44							
45	DISTRIBUTION PLANT						
46							
47	360.2	961					
48	362	81,889					
49	364	45,747					
50	365	34,932					

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	235					
13	367	128,481					
14	368	78,605					
15	369	38,901					
16	370	18,939					
17	371	2,681					
18	373	9,070					
19	374.0	40					
20	Subtotal	440,481					
21							
22	GENERAL PLANT						
23							
24	303	12,045					
25	390	1,718					
26	391	251					
27	392	8,939					
28	393	15					
29	394	5,342					
30	395	629					
31	396	14,016					
32	397	1,868					
33	398	55					
34	399	545					
35	Subtotal	45,423					
36							
37							
38							
39	Total	2,057,248					
40	FOOTNOTE						
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Montana-Dakota Utilities Co.	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2019	2019/Q4

FOOTNOTE DATA

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

SFAS 143 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

SFAS 143 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

SFAS 143 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

SFAS 143 Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 40 Column: a

Column (b) - 12/31/19 depreciable sub-plant account balances.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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				205,229
6					
7	Gas				178,182
8					
9					
10	NORTH DAKOTA				
11	Electric				199,999
12					
13	Gas				339,913
14					
15					
16	SOUTH DAKOTA				
17	Electric				101,709
18					
19	Gas				47,453
20					
21					
22					
23					
24					
25					
26	WYOMING				
27	Electric				66,839
28					
29	Gas				21,403
30					
31					
32	MINNESOTA				
33	Gas				228,913
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				10,000
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				1,399,640

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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
Electric	928	102,521	228,984	928	99,228	334,985	5
							6
Gas	928	11,750	-948	928	72,177	105,057	7
							8
							9
							10
Electric	928	599,018		928	125,042	74,957	11
							12
Gas	928	426		928	116,542	223,371	13
							14
							15
							16
Electric	928	31,206		928	34,925	66,784	17
							18
Gas	928	-762		928	47,453		19
							20
							21
							22
							23
							24
							25
							26
Electric	928	40,977		928	21,107	45,732	27
							28
Gas	928	47,576	43,043	928	15,108	49,338	29
							30
							31
							32
Gas	928	184,748	50,555	928	131,250	148,218	33
							34
							35
							36
Gas	928	-122	-10,000	928			37
							38
							39
							40
							41
							42
							43
							44
							45
		1,017,338	311,634		662,832	1,048,442	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,407,645		
4	Transmission	3,241,061		
5	Regional Market			
6	Distribution	6,421,427		
7	Customer Accounts	2,034,345		
8	Customer Service and Informational	146,459		
9	Sales	88,433		
10	Administrative and General	6,703,568		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	27,042,938		
12	Maintenance			
13	Production	2,700,504		
14	Transmission	971,162		
15	Regional Market			
16	Distribution	3,502,391		
17	Administrative and General	175,580		
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,349,637		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,108,149		
21	Transmission (Enter Total of lines 4 and 14)	4,212,223		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	9,923,818		
24	Customer Accounts (Transcribe from line 7)	2,034,345		
25	Customer Service and Informational (Transcribe from line 8)	146,459		
26	Sales (Transcribe from line 9)	88,433		
27	Administrative and General (Enter Total of lines 10 and 17)	6,879,148		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	34,392,575	3,931,309	38,323,884
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	599,290		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	12,451,172		
37	Customer Accounts	3,795,102		
38	Customer Service and Informational	443,684		
39	Sales	258,290		
40	Administrative and General	5,187,068		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	22,734,606		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	4,471,330		
49	Administrative and General	222,631		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,693,961		
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)	599,290		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	16,922,502		
58	Customer Accounts (Line 37)	3,795,102		
59	Customer Service and Informational (Line 38)	443,684		
60	Sales (Line 39)	258,290		
61	Administrative and General (Lines 40 and 49)	5,409,699		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,428,567	3,135,274	30,563,841
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	61,821,142	7,066,583	68,887,725
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,605,541	1,212,287	11,817,828
69	Gas Plant	8,458,070	966,816	9,424,886
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	19,063,611	2,179,103	21,242,714
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,058,654	121,011	1,179,665
74	Gas Plant	844,291	96,508	940,799
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,902,945	217,519	2,120,464
77	Other Accounts (Specify, provide details in footnote):			
78	183 - Preliminary Survey & Investigation Charges	135,949		135,949
79	184 - Clearing Accounts	156,833		156,833
80	416 - Cost/Expense of Merchandising, Jobbing and Contract Wor	4,222		4,222
81	417 - Revenues from Nonutility Operations	377,189		377,189
82	121 - Nonutility Property	39,246		39,246
83	146 - Accounts Receivable from Associated Companies	7,266,406		7,266,406
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,979,845		7,979,845
96	TOTAL SALARIES AND WAGES	90,767,543	9,463,205	100,230,748

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	66,579,694	35,753,025	3,941,653
389	Land and Land Rights	3,097,435	0	0
390	Structures and Improvements	50,491,136	16,887,623	471,066
391	Office Furniture & Equipment	6,448,936	2,711,256	824,894
392	Transportation Equipment	13,681,783	5,288,567	676,530
393	Stores Equipment	125,604	40,774	3,950
394	Miscellaneous Tools	808,259	502,542	43,779
396	Power Operated Equipment	0	0	0
397	Communication Equipment	4,076,531	1,797,305	288,146
398	Miscellaneous Equipment	1,380,425	660,746	64,555
3991	Asset Retirement Obligations	0	0	0
		146,689,803	63,641,838	6,314,573
	WORK IN PROGRESS	10,814,422	(15,461)	0
		157,504,225	63,626,377	6,314,573
Allocation of Common Utility Plant				
	Electric Department	87,384,118	34,976,058	2,916,793
	Natural Gas Department	70,120,107	28,650,319	2,925,421
	Clearing Accounts			472,359
		157,504,225	63,626,377	6,314,573

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	764	29	1900	555	209				
2	February	765	8	1000	564	201				
3	March	743	4	900	538	205				
4	Total for Quarter 1				1,657	615				
5	April	560	10	1200	419	141				
6	May	530	30	1700	418	112				
7	June	623	27	1700	494	129				
8	Total for Quarter 2				1,331	382				
9	July	676	31	1800	532	144				
10	August	676	6	1600	537	139				
11	September	640	6	1800	495	145				
12	Total for Quarter 3				1,564	428				
13	October	618	29	1200	461	157				
14	November	675	11	1900	495	180				
15	December	715	10	900	520	195				
16	Total for Quarter 4				1,476	532				
17	Total Year to Date/Year				6,028	1,957				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	53	1	1900	51	2				
2	February	59	6	2000	58	1				
3	March	58	4	900	56	2				
4	Total for Quarter 1				165	5				
5	April	41	11	900	39	2				
6	May	40	1	900	38	2				
7	June	49	27	1800	48	1				
8	Total for Quarter 2				125	5				
9	July	59	31	1700	57	2				
10	August	58	1	1800	57	1				
11	September	57	4	1900	55	2				
12	Total for Quarter 3				169	5				
13	October	52	30	900	50	2				
14	November	50	11	1900	49	1				
15	December	49	8	1900	47	2				
16	Total for Quarter 4				146	5				
17	Total Year to Date/Year				605	20				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	3,314,305
3	Steam	2,046,614	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	85,599
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	746,156	27	Total Energy Losses	306,893
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,706,797
9	Net Generation (Enter Total of lines 3 through 8)	2,792,770			
10	Purchases	891,539			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,156,890			
17	Delivered	1,134,402			
18	Net Transmission for Other (Line 16 minus line 17)	22,488			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,706,797			

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	333,244	5,557	555	29	1900
30	February	315,703	270	564	8	1000
31	March	317,378	7,894	538	4	900
32	April	247,015	783	419	10	1200
33	May	237,142	1,828	418	30	1700
34	June	252,889	1,837	494	27	1700
35	July	282,190	7,300	532	31	1800
36	August	274,618	14,479	537	6	1600
37	September	261,712	22,695	495	6	1800
38	October	264,509	6,186	461	29	1200
39	November	299,896	14,587	495	11	1900
40	December	322,860	2,183	520	10	900
41	TOTAL	3,409,156	85,599			

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	28,328	51	1	1900
30	Feb	29,333	58	6	2000
31	Mar	26,948	56	4	900
32	Apr	21,490	39	11	900
33	May	21,487	38	1	900
34	Jun	20,506	48	27	1800
35	Jul	25,243	57	31	1700
36	Aug	25,252	57	1	1800
37	Sep	20,723	55	4	1900
38	Oct	24,011	50	30	900
39	Nov	26,036	49	11	1900
40	Dec	28,284	47	8	1900
41	Total	297,641			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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: *R.M. Heskett* (b)			Plant Name: *R.M. Heskett* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler					
3	Year Originally Constructed	1954					
4	Year Last Unit was Installed	1963					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	86.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	103			0		
7	Plant Hours Connected to Load	8579			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	100			0		
10	When Limited by Condenser Water	92			0		
11	Average Number of Employees	49			0		
12	Net Generation, Exclusive of Plant Use - KWh	438725800			0		
13	Cost of Plant: Land and Land Rights	242583			0		
14	Structures and Improvements	29687359			0		
15	Equipment Costs	94973739			0		
16	Asset Retirement Costs	3096372			0		
17	Total Cost	128000053			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1488.3727			0		
19	Production Expenses: Oper, Supv, & Engr	893559			0		
20	Fuel	16983994			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2945999			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1120839			0		
26	Misc Steam (or Nuclear) Power Expenses	996969			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	493534			0		
30	Maintenance of Structures	223985			0		
31	Maintenance of Boiler (or reactor) Plant	1138574			0		
32	Maintenance of Electric Plant	320461			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	888869			0		
34	Total Production Expenses	26006783			0		
35	Expenses per Net KWh	0.0593			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal-Lignite	Coal-Sub Bit	Tires	Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Tons	Tons	MCF		
38	Quantity (Units) of Fuel Burned	416904	167	3176	274	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6820	8735	16024	1168	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.520	0.000	82.026	5.165	0.000	0.000
41	Average Cost of Fuel per Unit Burned	40.097	34.740	81.959	5.165	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.940	1.989	2.557	4.422	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.039	0.026	0.034	0.058	0.000	0.000
44	Average BTU per KWh Net Generation	13200.927	0.000	0.000	0.000	0.000	0.000

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Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

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

Plant Name: *Miles City* (d)	Plant Name: *Big Stone* (e)	Plant Name: *WY Gen III* (f)	Line No.
Gas Turbine	Steam	Steam	1
Conventional	Conventional	Conventional	2
1972	1975	2010	3
1972	1975	2010	4
23.75	94.11	28.00	5
23	108	27	6
37	8011	7503	7
0	0	0	8
22	108	28	9
21	106	28	10
0	81	19	11
351878	656782830	188254000	12
609	150559	0	13
223817	33412630	3629973	14
4446309	111297655	64088557	15
0	478020	0	16
4670735	145338864	67718530	17
196.6625	1544.3509	2418.5189	18
30453	289451	627937	19
44103	12539742	2352063	20
0	0	0	21
0	1214247	578182	22
0	0	0	23
0	0	0	24
87943	368042	138930	25
0	885736	269100	26
0	0	741725	27
0	0	10	28
18295	160400	203953	29
12649	197165	157082	30
0	1020114	717548	31
23021	109702	131264	32
0	153838	7225	33
216464	16938437	5925019	34
0.6152	0.0258	0.0315	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Fuel Oil		Coal-Sub Bit	Fuel Oil		Coal-Sub Bit			36
Mcf	Bbl		Tons	Bbl		Tons			37
5917	0	0	417997	34129	0	132815	0	0	38
1089	140000	0	8224	140000	0	8106	0	0	39
7.468	0.000	0.000	29.453	83.936	0.000	16.392	0.000	0.000	40
7.468	0.000	0.000	29.811	96.736	0.000	17.709	0.000	0.000	41
6.857	0.000	0.000	1.812	16.460	0.000	1.092	0.000	0.000	42
0.126	0.000	0.000	0.019	0.172	0.000	0.012	0.000	0.000	43
18312.066	0.000	0.000	10475.293	0.000	0.000	11437.721	0.000	0.000	44

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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: *Glendive* (b)			Plant Name: *Coyote* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1979			1981		
4	Year Last Unit was Installed	2003			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	75.52			103.65		
6	Net Peak Demand on Plant - MW (60 minutes)	70			108		
7	Plant Hours Connected to Load	124			5878		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	71			107		
10	When Limited by Condenser Water	68			93		
11	Average Number of Employees	3			82		
12	Net Generation, Exclusive of Plant Use - KWh	2701645			501393864		
13	Cost of Plant: Land and Land Rights	37924			519148		
14	Structures and Improvements	1504563			29383569		
15	Equipment Costs	27259764			113726875		
16	Asset Retirement Costs	0			1313169		
17	Total Cost	28802251			144942761		
18	Cost per KW of Installed Capacity (line 17/5) Including	381.3857			1398.3865		
19	Production Expenses: Oper, Supv, & Engr	83130			550944		
20	Fuel	258286			14559178		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1325117		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	285589			503556		
26	Misc Steam (or Nuclear) Power Expenses	0			102988		
27	Rents	0			11680		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	46041			246491		
30	Maintenance of Structures	3093			159548		
31	Maintenance of Boiler (or reactor) Plant	0			2981953		
32	Maintenance of Electric Plant	99884			1069751		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			416235		
34	Total Production Expenses	776023			21927441		
35	Expenses per Net KWh	0.2872			0.0437		
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	26262	50042	0	415101	142286	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1151	140000	0	6977	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.796	86.101	0.000	34.133	84.143	0.000
41	Average Cost of Fuel per Unit Burned	5.796	89.018	0.000	34.371	86.164	0.000
42	Average Cost of Fuel Burned per Million BTU	5.036	15.133	0.000	2.463	14.655	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.069	0.209	0.000	0.029	0.170	0.000
44	Average BTU per KWh Net Generation	13781.766	0.000	0.000	11592.163	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: *Heskett III* (d)			Plant Name: *Lewis & Clark II* (e)			Plant Name: *Lewis & Clark* (f)			Line No.
Gas Turbine			Internal Combustion			Steam			1
Conventional			Conventional			Outdoor Boiler			2
2014			2015			1958			3
2014			2015			1958			4
89.00			18.70			44.00			5
100			19			52			6
112			298			7423			7
0			0			0			8
84			19			52			9
78			18			50			10
0			0			28			11
1900000			3673000			261457254			12
0			0			80862			13
7118825			0			14409729			14
45759691			44752564			67310065			15
0			0			4620247			16
52878516			44752564			86420903			17
594.1406			2393.1852			1964.1114			18
81225			33608			363750			19
2658432			184047			7381579			20
0			0			0			21
0			0			1736354			22
0			0			0			23
0			0			0			24
33940			355448			107618			25
0			0			983800			26
0			0			0			27
0			0			0			28
0			25454			275336			29
2265			15173			75262			30
0			0			1195433			31
95865			84776			190586			32
0			0			469370			33
2871727			698506			12779088			34
1.5114			0.1902			0.0489			35
Gas			Gas			Coal-Lignite	Coal-Sub Bit	Gas	36
Mcf			Mcf			Tons	Tons	Mcf	37
39844	0	0	27116	0	0	257076	3950	6496	38
1083	0	0	1202	0	0	6630	8152	1205	39
66.722	0.000	0.000	6.813	0.000	0.000	25.849	0.000	11.652	40
66.722	0.000	0.000	6.813	0.000	0.000	28.034	24.309	11.652	41
61.608	0.000	0.000	5.668	0.000	0.000	2.114	1.491	9.670	42
1.399	0.000	0.000	0.050	0.000	0.000	0.028	0.020	0.129	43
22710.909	0.000	0.000	8873.790	0.000	0.000	13314.054	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: d
Plant is designed for peak load service.

Schedule Page: 403 Line No.: -1 Column: e
Plant is 22.7% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 403 Line No.: -1 Column: f
Plant is 25.0% owned by Respondent. Statistics represent Respondent's share of plant cost, production expenses and other data.

Schedule Page: 402 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: d
Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: e
Statistics reflect 22.7% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 403 Line No.: 5 Column: f
Statistics reflect 25% of Maximum Turbine Name Plate Rating of 112

Schedule Page: 403 Line No.: 10 Column: d
Limited by ambient air temperature

Schedule Page: 402.1 Line No.: -1 Column: b
Plant is designed for peak load service.

Schedule Page: 402.1 Line No.: -1 Column: c
Plant is 25% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 402.1 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 5 Column: c
Statistics reflect 25% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 403.1 Line No.: 5 Column: d
Maximum Turbine Name Plate Rating

Schedule Page: 403.1 Line No.: 5 Column: e
Maximum Turbine Name Plate Rating

Schedule Page: 403.1 Line No.: 5 Column: f
Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 10 Column: b
Limited by ambient air temperature

Schedule Page: 403.1 Line No.: 10 Column: d
Limited by ambient air temperature

Schedule Page: 403.1 Line No.: 10 Column: e
Limited by fuel quality.

Schedule Page: 403.1 Line No.: 11 Column: d
Employees shared by and included in R. M. Heskett.

Schedule Page: 403.1 Line No.: 11 Column: e
Employees shared by and included in Lewis & Clark.

Schedule Page: 402 Line No.: 43 Column: b1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: d1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: f1
Average cost of all fuels burned per net kWh generated.

FOOTNOTE DATA

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

Average Btu per net kWh generated for all fuels.

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

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: d1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: e1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: f1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: c1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: d1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: e1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: f1

Average cost of all fuels burned per net kWh generated.

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

Average Btu per net kWh generated for all fuels.

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

Average Btu per net kWh generated for all fuels.

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

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: e1

Average Btu per net kWh generated for all fuels.

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

Average Btu per net kWh generated for all fuels.

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	OIL					
2	Portable Generators	2012	3.65	4.0	4,560	2,010,820
3						
4	WIND					
5	Diamond Willow	2007	30.00	30.2	95,224,380	64,232,462
6	Cedar Hills	2010	19.50	19.5	51,844,670	46,034,167
7	Thunder Spirit	2015	155.50	151.0	548,180,000	297,793,970
8	WASTE HEAT					
9	Ormat Facility	2009	7.50	6.5	42,276,230	15,019,424
10						
11						
12						
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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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
	32,522		25,875	Oil		2
						3
						4
	449,564		200,223	Wind		5
	331,487		171,214	Wind		6
	3,429,287		132,230	Wind		7
						8
	679,423		27,263	Waste Heat		9
						10
						11
						12
						13
						14
						15
						16
						17
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						19
						20
						21
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						43
						44
						45
						46

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

Maximum Turbine Name Plate Rating

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	AVS	Charlie Creek	345.00	345.00	3	26.57		1
2	Big Stone South	Ellendale	345.00	345.00	1	161.50		1
3	Coyote	Center	345.00	345.00	2	11.43		1
4	Coyote Switch Yard		345.00	345.00	2	1.04		1
5	Center	Jamestown	345.00	345.00	2	10.69		1
6	Big Stone Plant	Sisseton	230.00	230.00	2	47.55		1
7	Heskett Station	East Bismarck	230.00	230.00	2	10.49		1
8	Bismarck	Wishek	230.00	230.00	2	67.39		1
9	Wishek	Ellendale	230.00	230.00	2	54.82		1
10	Heskett Station	WAPA Tie	230.00	230.00	2	1.15		1
11	Montana Border	South Dakota Border	230.00	230.00	2	86.19		1
12	Merricourt Windfarm	Ellendale	230.00	230.00	2	29.71		1
13	Thunder Spirit Interconnect		230.00	230.00	2	0.55		1
14	Watford City	Watford City WAPA	230.00	230.00	1	0.25		1
15								
16	Lines Below 132 Kilovolts		115.00	115.00	2	627.02	4.12	
17			69.00	69.00	Various	96.21	1.33	1
18			41.60	69.00	2	86.44	17.19	1
19			57.00	69.00	2	3.34		1
20			57.00	60.00	Various	919.22	0.89	1
21			33.00	60.00	1	18.38		1
22			57.00	57.00	1	2.61		2
23			41.60		Various	1,042.39	26.71	
24			33.00	35.00	1	29.14		1
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,334.08	50.24	22

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
2-954 MCM								4
2-1272 MCM								5
954 MCM								6
795 MCM								7
795 MCM								8
795 MCM								9
954 MCM								10
954 MCM								11
954 MCM								12
795MCM								13
954 MCM								14
								15
Various								16
Various								17
4/0 ACSR								18
4/0 ACSR								19
Various								20
4/0 ACSR								21
4/0 ACSR								22
Various								23
Various								24
								25
	3,498,219	260,622,240	264,120,459	6,597,734	1,492,844	127,617	8,218,195	26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	3,498,219	260,622,240	264,120,459	6,597,734	1,492,844	127,617	8,218,195	36

Schedule Page: 422 Line No.: 5 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.: 16 Column: h

Various

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

Various

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

Various

Schedule Page: 422 Line No.: 26 Column: j

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

Schedule Page: 422 Line No.: 26 Column: k

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

Schedule Page: 422 Line No.: 26 Column: l

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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 competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Heskett	Jct. TL403-1 & TL405-1	-0.13	Retired			
2							
3	Sweet Ave	South 9th	0.02	H-Frame	19.00	1	1
4			-0.01	Retired			
5	Big Stone South	Ellendale TL 154-1	152.52	SP	5.00	1	1
6	Big Stone South	Ellendale TL 154-2	8.98	SP	5.00	1	1
7							
8	Rosebud	Forsyth Loop Line	11.80	SP	19.00	1	1
9							
10	Watford City	Watford City WAPA	0.25	SP	20.00	1	1
11							
12	Bismarck	Linton-Wishek	0.28	SP	14.00	1	1
13			-0.20	Retired			
14	Watford City N.	USBR Sub	0.15	H-Frame	20.00	1	1
15							
16	Bismarck	Wishek	0.12	3 Pole	9.00	1	1
17			-0.14	Retired			
18	Stanley Jct	Stanley	0.04	SP	23.00	1	1
19			-0.01	Retired			
20	Mobridge	Bowdle	0.15	SP	28.00	1	1
21			-0.05	Retired			
22	Glenham	Bowdle	0.13	H-Frame	15.00	1	1
23			-0.05	Retired			
24	Bowdle	1 Mile East	0.07	SP	28.00	1	1
25			-0.14	Retired			
26			-1.03	Retired			
27	Bowdle Jct	Bowdle	0.07	SP	28.00	1	1
28			0.06	U B on 34-1	53.00	1	1
29			-0.05	Retired			
30	Wishek	Ellendale	-0.06	Retired			
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		172.77		286.00	14	14

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)	
			42				3,679	3,679	1
									2
4/0	ACSR	T-46-MP	42		30,822	5,604		36,426	3
									4
477	MCMACSR	TTT06NUFH	345			105,769,636		105,769,636	5
477	MCMACSR	TTT06NUFH							6
									7
336	MCMACSR	T-60-B-1	60	247,636	2,431,434	511,561		3,190,631	8
									9
954	MCMACSR	TPBP-230	230		377,995	96,375		474,370	10
									11
4/0	ACSR	TL-115-PA-1	115		699,144	117,000		816,144	12
									13
336	MCMACSR	T-60-H-1	33		83,100	34,500		117,600	14
									15
954	MCMACSR	T-230-J	230		325,464			325,464	16
							25,434	25,434	17
4/0	ACSR	T-69-S3	69		53,409	113,035		166,444	18
							46	46	19
4/0	ACSR	T-46-AF	42		58,180			58,180	20
							273	273	21
336.4	MCMACSR	T-115-A	115		91,849	3,722		95,571	22
							251	251	23
4/0	ACSR	T-46-F	42		51,901			51,901	24
							2,892	2,892	25
									26
4/0	ACSR	T-46-F	42		96,041	1,001		97,042	27
4/0	ACSR	T-46-F	42						28
							801	801	29
			230				87,878	87,878	30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				247,636	4,299,339	106,652,434	121,254	111,320,663	44

Schedule Page: 424 Line No.: 1 Column: k
46 KV Design
Schedule Page: 424 Line No.: 3 Column: j
7' x 7' Horizontal
Schedule Page: 424 Line No.: 3 Column: k
46 KV Design
Schedule Page: 424 Line No.: 5 Column: j
25'6" x 25'6" Vertical
Schedule Page: 424 Line No.: 6 Column: j
25'6" x 25'6" Vertical
Schedule Page: 424 Line No.: 8 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 10 Column: j
12' x 12' Vertical
Schedule Page: 424 Line No.: 12 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 12 Column: o
Estimated Cost
Schedule Page: 424 Line No.: 14 Column: j
10' x 10' Horizontal
Schedule Page: 424 Line No.: 14 Column: o
Estimated Cost
Schedule Page: 424 Line No.: 16 Column: j
17'6" x 17'6" Horizontal
Schedule Page: 424 Line No.: 18 Column: j
10' x 10' Vertical
Schedule Page: 424 Line No.: 20 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 20 Column: k
46 KV Design
Schedule Page: 424 Line No.: 22 Column: j
14'6" x 14'6" Horizontal
Schedule Page: 424 Line No.: 24 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 24 Column: k
46 KV Design
Schedule Page: 424 Line No.: 27 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 27 Column: k
46 KV Design
Schedule Page: 424 Line No.: 28 Column: j
7' x 7' Vertical
Schedule Page: 424 Line No.: 28 Column: k
46 KV Design

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

SUBSTATIONS

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

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

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (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: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
104	1					1
52	1					2
28	2					3
120	1					4
21	1					5
168	1					6
28	2					7
11	1					8
40	1					9
87	2					10
125	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
						22
1248	23	1		1	4	23
						24
40	1			1	4	25
112	1					26
83	1					27
45	1					28
80	2			2	8	29
47	1			1	4	30
56	1					31
20	1			1	2	32
						33
						34
75	1					35
93	1					36
100	1					37
37	1					38
15	1					39
11	1			1	1	40

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Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

SUBSTATIONS

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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					
2	Beach, ND East	Distrib Unattended	57.00	4.16	
3	Beulah, ND Coyote Creek	Distrib Unattended	115.00	22.90	
4	Beulah, ND W. M. Port 1	Distrib Unattended	115.00	6.90	
5	Beulah, ND W. M. Port 2	Distrib Unattended	115.00	6.90	
6	Baker, Dist	Distrib Unattended	57.00	12.47	
7	Baker, MT Lookout Butte	Distrib Unattended	57.20	12.47	
8	Baker, MT Pine Unit #1	Distrib Unattended	57.00	12.47	
9	Bismarck, ND Kirkwood	Distrib Unattended	115.00	12.47	
10	Bismarck, ND SE Expressway	Distrib Unattended	115.00	12.47	
11	Bismarck, ND NW (Century)	Distrib Unattended	115.00	12.47	
12	Bismarck, ND NE	Distrib Unattended	115.00	12.47	
13	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
14	Bismarck, ND Turnpike	Distrib Unattended	115.00	12.47	
15	Bismarck, ND South 9th St.	Distrib Unattended	41.60	12.47	
16	Bismarck, ND Sunrise	Distrib Unattended	115.00	12.47	
17	Bismarck, ND 26th & D	Distrib Unattended	115.00	12.47	
18	Dayton, WY Smith Creek	Distrib Unattended			
19	Dayton, WY Tongue River	Distrib Unattended			
20	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
21	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
22	Dickinson, ND NE	Distrib Unattended	41.60	12.47	
23	Dickinson, ND Refinery	Distrib Unattended	41.60	12.47	
24	Dickinson, ND 21st	Distrib Unattended	41.60	12.47	
25	Dickinson, ND West	Distrib Unattended	41.60	12.47	
26	Fullerton, ND	Distrib Unattended	41.60	12.47	
27	Glendive, MT	Distrib Unattended	57.00	12.47	
28	Glendive, MT West	Distrib Unattended	57.00	12.47	
29	Glendive, MT	Distrib Unattended	57.00	12.47	
30	Hague, ND	Distrib Unattended			
31	Hazelton, ND	Distrib Unattended			
32	Kintyre, ND	Distrib Unattended			
33	Lignite, ND	Distrib Unattended	57.00	2.40	
34	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
35	Mandan, ND Collins Ave	Distrib Unattended	115.00	12.47	
36	Mandan, ND Midway	Distrib Unattended	41.60	12.47	
37	Mandan, ND	Distrib Unattended	115.00	12.47	
38	Miles City, MT Greenstar	Distrib Unattended	57.00	12.47	
39	Miles City, MT 8th St	Distrib Unattended	57.00	12.47	
40	Miles City, MT Leighton	Distrib Unattended	57.00	12.47	

Name of Respondent Montana-Dakota Utilities Co.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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	Miles City, MT South	Distrib Unattended	57.00	12.47	
2	Mobridge, SD	Distrib Unattended	115.00	12.47	
3	Monango, ND	Distrib Unattended	41.60	12.47	
4	Pollock, SD	Distrib Unattended			
5	Ranchester, WY Wolf Creek	Distrib Unattended			
6	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
7	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
8	Sheridan, WY Soldier Creek	Distrib Unattended	41.60	12.47	
9	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
10	Sheridan, WY West	Distrib Unattended	41.60	12.47	
11	Sidney, MT	Distrib Unattended	57.00	12.47	
12	Sidney, MT	Distrib Unattended	57.00	12.47	
13	Stanley, ND Dist	Distrib Unattended	69.00	12.47	
14	Stanley, ND	Distrib Unattended	69.00	12.47	
15	Stanley, ND Enbridge	Distrib Unattended	69.00	12.47	
16	Story, WY	Distrib Unattended			
17	Watford City, ND South Park	Distrib Unattended	34.50	7.20	
18	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
19	Williston, ND Harvest Hills	Distrib Unattended	57.00	12.47	
20	Williston, ND NE	Distrib Unattended	57.00	12.47	
21	Williston, ND NW North	Distrib Unattended	57.00	12.47	
22	Williston, ND NW South	Distrib Unattended	57.00	12.47	
23	Williston, ND Sabin Metals	Distrib Unattended	57.00	13.80	
24	Williston, ND Water Plant	Distrib Unattended	57.00	4.16	
25	Williston, ND Oasis	Distrib Unattended	57.00	12.47	
26	Wishek, ND	Distrib Unattended	41.60	4.16	
27	Zeeland, ND	Distrib Unattended			
28	Substations Under 10,000 KVA (228)				
29	SUBTOTAL		3812.90	671.14	
30					
31	GRAND TOTAL		13222.50	4199.78	248.07
32					
33					
34	FOOTNOTES				
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1			1	3	1
56	1					2
20	1			1	2	3
25	1			1	3	4
112	1					5
30	1			1	3	6
75	1					7
15	1			1	2	8
224	1					9
30	1					10
13	1			1	1	11
100	1					12
56	1					13
74	1			1	2	14
22	1			1	2	15
47	1					16
37	1					17
75	1					18
40	1					19
						20
57	2					21
75	1					22
22	1			1	2	23
112	1					24
75	1					25
						26
30	1			1	3	27
112	1					28
				3		29
30	14	1		3		30
2408	56	1		22	42	31
						32
8	2			3	1	33
8	2			3	1	34
						35
						36
						37
						38
						39
						40

SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
				3		2
14	1					3
10	1					4
11	1					5
13	1			3	1	6
11	1					7
11	1			3	1	8
28	1			6	2	9
53	2			9	4	10
22	1			3	2	11
28	1			6	2	12
94	2			27	8	13
56	2			9	3	14
30	1			9	3	15
28	1			6	2	16
42	2			9	3	17
				2		18
				1		19
14	1			3	1	20
14	1			3	1	21
14	1			3	1	22
14	1					23
11	1			3	1	24
14	1			6	2	25
				3		26
14	1			3	1	27
11	1			3	1	28
11	1			3	1	29
				3		30
				3		31
				3		32
12	4			3	1	33
14	1			3	1	34
28	1					35
28	1			6	2	36
50	2			9	3	37
10	1			3	1	38
11	1			3	1	39
11	1			3	1	40

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SUBSTATIONS (Continued)

5. Show in columns (I), (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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1			6	2	1
22	1			9	2	2
				3		3
				3		4
				1		5
24	2			6	3	6
11	1			3	2	7
14	1			3	2	8
11	1			3	2	9
11	1			3	2	10
11	1			3	1	11
14	1			3	1	12
				3	1	13
14	1			3	1	14
14	1			3	1	15
				3		16
11	1			3	1	17
11	1			3	1	18
22	2			6	2	19
10	1			3	1	20
14	1			3	1	21
14	1			3	1	22
10	1					23
				3	1	24
11	1			3	1	25
11	2			3	1	26
				3		27
672	367			458	58	28
1675	430			714	138	29
						30
5339	511	2		740	185	31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 426.1 Line No.: 3 Column: a

See (C) and (D) of footnotes

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

See (G) of footnotes

Schedule Page: 426.1 Line No.: 13 Column: a

See (E) and (F) of footnotes

Schedule Page: 426.1 Line No.: 19 Column: a

See (A) and (B) of footnotes

Schedule Page: 426.3 Line No.: 34 Column: a

FOOTNOTES:

(A) Mid-Yellowstone Electric Cooperative, Inc. has a 14,911 KVA capacity interest.

(B) Respondent and Mid-Yellowstone Electric Cooperative, Inc. shared the facilities construction expense and available capacity in the respective percentages of 63% and 37%. All maintenance and operating expenses are shared in the same percentage. Respondent expenses are reflected in accounts 570 and 562. Mid-Yellowstone Electric Cooperative, Inc. is not an associated company.

(C) Upper Missouri G&T Electric Cooperative, Inc. has a 15,300 KVA capacity interest.

(D) Upper Missouri G&T Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.

(E) Western Area Power Administration (WAPA) has a 9,500 KVA capacity interest.

(F) WAPA does routine maintenance at their expense and major repairs are divided 19% WAPA and 81% Respondent.

(G) WAPA has a 25,000 KVA capacity interest.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Montana-Dakota Utilities Co.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Insurance	CHCC	401,165,184, 227	4,342,085
3	Cost of Service	CHCC	401,165,184, 228	2,006,906
4	Other Goods or Services, less than $250,000	CHCC		129,974
5	Contract Services	KRC		176,205
6	Contract Services	MDU CSG	107, 401, 402, 417	2,146,800
7	Other Goods or Services, less than $250,000	MDU CSG	146, 402	7,484
8	Contract Services	MDU EC	401, 402, 107	2,065,402
9	Rent	MDU EC	401	456,132
10	Other Goods or Services, less than $250,000	MDU EC		450,169
11	Payroll	MDUR	146	1,658,136
12	Rent	MDUR	401	1,147,221
13	Office Expenses	MDUR	146, 401, 416	452,720
14	Other	MDUR		1,063,857
15	Gas Transportation, Storage and Gathering Services	WBIH	234	65,179,325
16	Contract Services	WBIH		670,936
17	Other Goods or Services, less than $250,000	WBIH		253,531
18	Total			82,206,883
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Other Goods or Services, less than $250,000	CEHI	146	54,716
22	Other Goods or Services, less than $250,000	CER	146	515
23	Other Goods or Services, less than $250,000	CHCC	146	157,817
24	Reimbursements	CHCC	146	-567,091
25	Cost of Service for Facilities Used	KRC	454, 493	710,252
26	Gas and Electric Utilities	KRC	400	278,633
27	Other Goods or Services, less than $250,000	KRC	146	124,721
28	Other Goods or Services, less than $250,000	MDU CSG	146, 400, 454, 493	331,657
29	Payroll and Employee Benefits	MDU EC	146	19,162,698
30	Contract Services	MDU EC	146	7,071,735
31	Computer/Software Support	MDU EC	146	2,080,137
32	Cost of Service for Facilities Used	MDU EC	454, 493	1,882,835
33	Travel	MDU EC	146	394,680
34	Communication Services	MDU EC	146	289,832
35	Rebates	MDU EC	146	-752,481
36	Other Goods or Services, less than $250,000	MDU EC	146, 147	1,638,017
37	Other Goods or Services, less than $250,000	MDUR	146, 147	142,000
38	Contract Services	WBIH	146	664,106
39	Gas and Electric Utilities	WBIH	400	330,680
40	Rebates	WBIH	146	-508,335
41	Other Goods or Services, less than $250,000	WBIH	146, 147, 454, 493	261,240
42	Total			33,748,364

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

Company Abbreviations used in Column (b)

CER	Centennial Energy Resources
CEHI	Centennial Energy Holdings Inc
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.
MDUR	MDU Resources Group Inc

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