YEAR ENDING 2020

ANNUAL REPORT

OF

NorthWestern Energy

GAS UTILITY

Docket 2021.01.011

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Gas Annual Report

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Sch. 1	IDENTIFICATION
Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Jeff B. Berzina
Telephone Number for Report Inquiries:	(406) 497-2759
Address for Correspondence Concerning Report:	11 East Park Street Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See NorthWestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1			
2	President & Chief Executive Officer	Executive	Robert Rowe
3			
4			
5	Chief Financial Officer	Tax, Internal Audit and Compliance,	Brian Bird
6		Financial Planning and Analysis	
7		Controller and Treasury Functions	
8		Investor Relations and Corporate Finance	
9		Business Technology	
10		Energy Risk Management	
11		Flight Services, Executive Compensation	
12			
13	Vice President,	Legal Services	Heather Grahame
14	General Counsel and Regulatory and	Corporate Secretary	
15	Federal Government Affairs	Risk Management	
16		Regulatory Affairs	
17		Federal Governmental Affairs	
18			
19	Vice President,	Distribution Operations - MT/SD/NE	Curt Pohl
20	Distribution	Construction, Asset Management	
21		Labor and Operational Performance	
22		Project Management	
23		Safety/Health/Environmental Services	
24		Business Development and Strategic Support	
25			
26	Vice President,	Transmission Planning, Engineering, Construction,	Michael Cashell
27	Transmission	and Operations	
28		Gas Transmission & Storage	
29		Substation Operations	
30		Transmission Policy, Services, and Operations	
31		Transmission Market Strategy	
32		Grid Real Time and Scada Operations	
33		FERC and NERC Compliance	
34		Support Services	
35			
36	Vice President,	Thermal and Wind Generation	John Hines
37	Supply and Montana Government Affairs	Hydro Operations	
38		Environmental and Lands Permitting & Compliance	
39		Long Term Resources	
40		Energy Supply Marketing Operations	
41		Montana Government Affairs	
42			
43		Brand, Advertising, and	Bobbi Schroeppel
44	Vice President,	Customer Communications	
45	Customer Care, Communications and	Customer Experience and Support	
46	Human Resources	Customer Interaction	
47		Community Connections	
48		Revenue Cycle Management	
49		Human Resources	
50			
51	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
52		Enterprise Risk and Business Continuity	
53			
54	Vice President & Controller	Financial Reporting	Crystal Lail
55		Accounting	
56		Accounts Payable/Payroll	
57		Compensation and Benefits	
58			
59			

Reflects active officers as of December 31, 2020.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 151,479**	**97.59%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		**$ 3,736**	**2.41%**
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
NorthWestern Energy Solutions, Inc.	Non-regulated customer services		
Total Corporation		**$ 155,215**	**100.00%**

Sch. 5	CORPORATE ALLOCATIONS				
Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$13,300,594	73.11%	$4,890,919
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Contributions, Print Services CC - Assoc & Dispatch Human Resources, and Regulatory Support Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	23,987,555	74.93%	8,023,900
Legal Department	Includes the following departments: Chief Legal, Contracts Administration, Regulatory Affairs MT, SD & NE Public and Regulartory Affairs and Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	14,437,991	74.77%	4,871,381
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Capital Related Exp, Data Center, Project Management & Asset Control, Record Mgmt Systems, and Security.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	23,537,312	79.03%	6,246,882
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,921,331	76.34%	1,215,434
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	899,261	78.00%	253,638
Distribution	Includes the following departments: Sioux Falls Facilities and Helena Building	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	21,105	78.00%	5,953
TOTAL			$80,105,150	75.85%	$25,508,107

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$263,125		
13						
14	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	3,022,609		
15		transmission, & compression	transmission & compression			
16			are at tariffed rates			
17	**Total Utility Subsidiaries Revenues**			$3,285,734		
18	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	500,400.00	14.9%	500,400.00
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,256,833.00	37.5%	$1,256,833
15						
16	**Total Utility Subsidiaries**			1,757,233.00		$1,757,233
17	**Total Utility Subsidiaries Expenses**			$3,379,623		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,757,233		$1,757,233

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)						
		Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1							
2	400	Operating Revenues	$ 249,458,929	$ 67,482,700	$ 181,976,229	$ 193,284,960	-5.85%
3							
4	**Total Operating Revenues**		249,458,929	67,482,700	181,976,229	193,284,960	-5.85%
5							
6		**Operating Expenses**					
7							
8	401	Operation Expense	134,748,153	49,150,160	85,597,993	85,888,772	-0.34%
9	402	Maintenance Expense	7,142,122	1,124,057	6,018,065	5,656,417	6.39%
10	403	Depreciation Expense	25,942,984	5,957,186	19,985,798	18,194,419	9.85%
11	404-405	Amort. & Depletion of Gas Plant	6,116,172	200,521	5,915,651	6,262,401	-5.54%
12	406	Amort. of Plant Acquisition Adj.	(846,505)	(846,505)	-	-	-
13	407.3	Regulatory Amortizations - Debit	2,165,328	2,081,286	84,042	(178,789)	147.01%
14	407.4	Regulatory Amortizations - Credit	(5,322,577)	(114,863)	(5,207,714)	(920,165)	>-300.00%
15	408.1	Taxes Other Than Income Taxes	41,069,685	2,086,412	38,983,273	37,422,608	4.17%
16	409.1	Income Taxes-Federal	4,279	-	4,279	33,747	-87.32%
17		-Other	3,423	-	3,423	26,997	-87.32%
18	410.1	Deferred Income Taxes-Dr.	33,216,112	4,652,398	28,563,714	34,626,497	-17.51%
19	411.1	Deferred Income Taxes-Cr.	(31,145,918)	(4,372,262)	(26,773,656)	(33,796,726)	20.78%
20	411.4	Investment Tax Credit Adj.	(89)	(89)	-	-	-
21							
22	**Total Operating Expenses**		213,093,169	59,918,301	153,174,868	153,216,178	-0.03%
23	**NET OPERATING INCOME**		$ 36,365,760	$ 7,564,399	$ 28,801,361	$ 40,068,782	-28.12%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, in accordance with FERC requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 141,848,463	$ 38,407,910	$ 103,440,553	$ 109,389,702	-5.44%
5	442.1 Commercial	73,728,032	22,382,037	51,345,995	55,667,878	-7.76%
6	442.2 Industrial Firm	840,088	-	840,088	995,758	-15.63%
7	445 Public Authorities	600,602	-	600,602	630,338	-4.72%
8	448 Interdepartmental Sales	322,825	-	322,825	381,244	-15.32%
9	491.2 CNG Station	-	-	-	-	-
10						
11	**Total Sales to Core DBUs**	217,340,010	60,789,947	156,550,063	167,064,920	-6.29%
12						
13	447 Sales for Resale	771,245	-	771,245	820,171	-5.97%
14						
15	**Total Sales of Natural Gas**	218,111,255	60,789,947	157,321,308	167,885,091	-6.29%
16						
17	496.1 Provision for Rate Refunds	-	-	-	-	-
18						
19	**Total Revenue Net of Rate Refunds**	218,111,255	60,789,947	157,321,308	167,885,091	-6.29%
20						
21	489.1 Gathering	771,372	-	771,372	584,899	
22	489.2 Transmission	29,230,460	6,426,305	22,804,155	23,353,867	-2.35%
23						
24	**Total Revenues From Transportation**	30,001,832	6,426,305	23,575,527	23,938,766	-1.52%
25						
26	Miscellaneous Revenues	1,345,842	266,448	1,079,394	1,461,103	-26.12%
27						
28	**Total Other Operating Revenue**	1,345,842	266,448	1,079,394	1,461,103	-26.12%
29	**TOTAL OPERATING REVENUE**	$ 249,458,929	$ 67,482,700	$ 181,976,229	$ 193,284,960	-5.85%
30						
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35						
36						

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	728 Liquefied Petroleum Gas	$ -	$ -	$ -	$ -	-
4	735 Miscellaneous Production Expenses	-	-	-	-	-
5	**Total Operation-Gas Raw Materials**	-	-	-	-	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements			-	-	-
9	**Total Maintenance-Gas Raw Materials**	-	-	-	-	-
10	**Total Gas Raw Materials**	-	-	-	-	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	188,700	-	188,700	309,751	-39.08%
15	751 Maps & Records	-	-	-	-	-
16	752 Gas Wells Expenses	724,747	-	724,747	1,347,069	-46.20%
17	753 Field Lines Expenses	8,588	-	8,588	5,377	59.72%
18	754 Field Compressor Station Expense	3,355,246	-	3,355,246	3,316,023	1.18%
19	755 Field Comp. Station Fuel & Power	(51,516)	-	(51,516)	(20,023)	-157.28%
20	756 Field Meas. & Reg. Station Expense	95,598	-	95,598	91,676	4.28%
21	757 Dehydration Expense	11,995	-	11,995	17,451	-31.26%
22	758 Gas Well Royalties	995,459	-	995,459	859,285	15.85%
23	759 Other Expenses	1,187,876	-	1,187,876	1,405,343	-15.47%
24	760 Rents	270,964	-	270,964	279,635	-3.10%
25	**Total Oper.-Production & Gathering**	6,787,657	-	6,787,657	7,611,587	-10.82%
26						
27	**Production Maintenance**					
28	762 Maint. of Gathering Structures	-	-	-	-	-
29	763 Maint. of Producing Gas Wells	-	-	-	56	-100.00%
30	764 Maint. of Field Lines	79,163	-	79,163	122,810	-35.54%
31	765 Maint. of Field Compressor Stations	204,326	-	204,326	243,583	-16.12%
32	766 Maint. of Field Meas. & Reg. Stations	885	-	885	546	62.09%
33	767 Maint. of Purification Equipment	100,453	-	100,453	65,225	54.01%
34	769 Maint. of Other Equipment	202	-	202	1,345	-84.98%
35	**Total Maintenance - Production**	385,029	-	385,029	433,565	-11.19%
36	**TOTAL Natural Gas Production & Gathering**	7,172,686	-	7,172,686	8,045,152	-10.84%
37						
38	**Other Gas Supply Expense-Operation**					
39	800 NG Wellhead Purchases	30,242,388	-	30,242,388	18,272,793	65.51%
40	803 NG Transmission Line Purchases	3,576,322	-	3,576,322	2,579,076	38.67%
41	805 Other Gas Purchases	34,687,590	34,557,569	130,021	(343,402)	137.86%
42	805 Purchased Gas Cost Adjustments	-	-	-	-	-
43	805 Incremental Gas Cost Adjustments	-	-	-	-	-
44	805 Deferred Gas Cost Adjustments	-	-	-	-	-
45	806 Exchange Gas	-	-	-	-	-
46	807 Well Expenses-Purchased Gas	486,494	3,287	483,207	768,402	-37.12%
47	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
48	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
49	807 Purch. Gas Calculations Expenses	-	-	-	-	-
50	808 Other Purchased Gas Expenses	-	-	-	-	-
51	808 Gas Withdrawn from Storage -Dr.	(5,386,063)	-	(5,386,063)	3,124,502	-272.38%
52	809 Gas Delivered to Storage -Cr.	-	-	-	-	-
53	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
54	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
55	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
56	813 Other Gas Supply Expenses	-	-	-	-	-
57	**Total Other Gas Supply Expenses**	63,606,731	34,560,856	29,045,875	24,401,371	19.03%
58	**Total Production Expenses**	70,779,417	34,560,856	36,218,561	32,446,523	11.63%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	19,859	-	19,859	169,449	-88.28%
5	815 Maps & Records	-	-	-	247	-100.00%
6	816 Wells	350,789	-	350,789	435,785	-19.50%
7	817 Lines	71,093	-	71,093	92,065	-22.78%
8	818 Compressor Station	460,896	-	460,896	450,838	2.23%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	23,532	-	23,532	37,091	-36.56%
11	821 Purification	133,088	-	133,088	88,985	49.56%
	823 Gas Losses	565,283	-	565,283	-	-
12	824 Other Expenses	129,956	-	129,956	124,487	4.39%
13	825 Storage Well Royalties	2,204	-	2,204	2,220	-0.72%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	1,756,700	-	1,756,700	1,468,238	19.65%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	8,850	-	8,850	19,171	-53.84%
19	831 Structures & Improvements	403,145	-	403,145	421,455	-4.34%
20	832 Reservoirs & Wells	20,602	-	20,602	6,347	224.59%
21	833 Lines	53,055	-	53,055	7,485	>300.00%
22	834 Compressor Station Equipment	82,074	-	82,074	327,750	-74.96%
23	835 Meas. & Reg. Station Equipment	64	-	64	694	-90.78%
24	836 Purification Equipment	46,529	-	46,529	55,606	-16.32%
25	837 Other Equipment	124	-	124	38	226.32%
26	**Total Maintenance-Underground Storage**	614,443	-	614,443	838,546	-26.73%
27	**Total Underground Storage Expenses**	2,371,143	-	2,371,143	2,239,713	5.87%
28	**Transmission Expenses**	(0)				
29	**Transmission-Operation**					
30	850 Supervision & Engineering	2,874,505	20,300	2,854,205	2,806,676	1.69%
31	851 System Control & Load Dispatching	806,000	-	806,000	874,047	-7.79%
32	853 Compressor Station Labor & Expense	561,062	-	561,062	565,581	-0.80%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
34	856 Mains	868,193	19,524	848,669	890,951	-4.75%
35	857 Measuring & Regulating Station	696,082	131	695,951	785,796	-11.43%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,999,005	1,027	1,997,978	1,883,038	6.10%
38	860 Rents	-	-	-	-	-
39	**Total Operation-Transmission**	7,804,847	40,982	7,763,865	7,806,089	-0.54%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	263,859	-	263,859	151,605	74.04%
42	862 Structures & Improvements	108,710	75	108,635	125,196	-13.23%
43	863 Mains	1,068,546	107	1,068,439	679,797	57.17%
44	864 Compressor Station Equipment	418,061	-	418,061	330,500	26.49%
45	865 Meas. & Reg. Station Equipment	167,286	252	167,034	194,704	-14.21%
46	867 Other Equipment	2,816	-	2,816	8,784	-67.94%
47	**Total Maintenance-Transmission**	2,029,278	434	2,028,844	1,490,586	36.11%
48	**Total Transmission Expenses**	9,834,125	41,416	9,792,709	9,296,675	5.34%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	This Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	2,175,325	812,714	1,362,611	1,634,995	-16.66%
4	871 Load Dispatching	164,892	164,892	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	5,402,970	2,507,834	2,895,136	2,706,180	6.98%
8	875 Meas. & Reg. Station-General	312,498	144,936	167,562	183,996	-8.93%
9	876 Meas. & Reg. Station-Industrial	-	-	-	-	-
10	877 Meas. & Reg. Station-City Gate	247,771	97,383	150,388	163,155	-7.83%
11	878 Meter & House Regulator	1,528,282	519,602	1,008,680	1,170,299	-13.81%
12	879 Customer Installations	1,461,091	227,578	1,233,513	1,544,007	-20.11%
13	880 Other Expenses	1,004,732	236,826	767,906	735,955	4.34%
14	881 Rents	4,021	-	4,021	3,894	3.26%
15	**Total Operation-Distribution**	12,301,582	4,711,765	7,589,817	8,142,481	-6.79%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	869,896	283,392	586,504	645,434	-9.13%
18	886 Structures & Improvements			-	-	-
19	887 Mains	536,291	257,096	279,195	349,719	-20.17%
20	889 Meas. & Reg. Station Exp.-General	136,577	82,253	54,324	55,482	-2.09%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	44,617	44,617	-	-	-
23	892 Services	447,749	144,580	303,169	258,424	17.31%
24	893 Meters & House Regulators	1,416,545	254,336	1,162,209	1,166,745	-0.39%
25	894 Other Equipment	-	-	-	-	-
26	**Total Maintenance-Distribution**	3,451,675	1,066,274	2,385,401	2,475,804	-3.65%
27	**Total Distribution Expenses**	15,753,257	5,778,039	9,975,218	10,618,285	-6.06%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	444,299	(146,301)	590,600	560,163	5.43%
32	903 Customer Records & Collection	2,941,764	772,513	2,169,251	2,183,041	-0.63%
33	904 Uncollectible Accounts	860,155	263,715	596,440	371,598	60.51%
34	905 Miscellaneous Customer Accounts	31,990	32,065	(75)	(508)	85.24%
35	**Total Customer Accounts Expenses**	4,278,208	921,992	3,356,216	3,114,294	7.77%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	1,576,290	741,677	834,613	842,381	-0.92%
41	909 Inform. & Instructional Advertising	502,016	91,500	410,516	380,459	7.90%
42	910 Misc. Customer Service & Inform.	-	-	-	-	-
43	**Total Customer Service & Information Exp.**	2,078,306	833,177	1,245,129	1,222,840	1.82%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	-	-	-	-	-
48	912 Demonstrating & Selling	-	-	-	-	-
49	913 Advertising	136,356	26,309	110,047	562,875	-80.45%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	136,356	26,309	110,047	562,875	-80.45%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	This Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	920 Administrative & General Salaries	10,990,859	2,647,493	8,343,366	10,070,017	-17.15%
4	921 Office Supplies & Expenses	4,275,581	1,239,357	3,036,224	3,170,405	-4.23%
5	922 Administrative Exp. Transferred-Cr.	(2,867,632)	(783,833)	(2,083,799)	(1,832,033)	-13.74%
6	923 Outside Services Employed	1,684,739	474,529	1,210,210	1,371,518	-11.76%
7	924 Property Insurance	378,526	86,604	291,922	229,082	27.43%
8	925 Legal & Claim Department	4,916,327	1,036,050	3,880,277	3,014,363	28.73%
9	926 Employee Pensions & Benefits	10,427,694	2,779,151	7,648,543	9,316,144	-17.90%
10	928 Regulatory Commission Expenses	4,673	-	4,673	3,658	27.75%
11	930 Miscellaneous General Expenses	5,487,280	398,594	5,088,686	5,536,718	-8.09%
12	931 Rents	699,719	177,134	522,585	593,420	-11.94%
13	**Total Operation-Admin. & General**	35,997,766	8,055,079	27,942,687	31,473,292	-11.22%
14	**Admin. & General - Maintenance**					
15	935 General Plant	661,697	57,349	604,348	586,544	3.04%
16	**Total Admin. & General Expenses**	36,659,463	8,112,428	28,547,035	32,059,836	-10.96%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 141,890,275	$ 50,274,217	$ 91,616,058	$ 91,545,189	0.08%
18						
19						
20						
21						
22						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	2,010,001	2,058,528	-2.36%
3	Property Taxes	35,059,260	33,503,361	4.64%
4	Crow Tribe RR and Utility Tax	124,836	124,836	0.00%
5	Blackfoot Possessory Tax	367,830	357,658	2.84%
6	City Tax	2,076	2,099	-1.10%
7	Consumer Counsel	177,129	182,178	-2.77%
8	Public Service Commission	696,016	696,563	-0.08%
9	Heavy Highway Use	8,417	6,683	25.95%
10	Vehicle Use Taxes	95,282	103,704	-8.12%
11	Gas Production Taxes	370,591	314,528	17.82%
12	Delaware Franchise Tax	55,060	55,012	0.09%
13				
14				
15				
16	**Canadian Taxes**			
17	Ad Valorem	16,775	17,458	-3.91%
18				
19				
20				
21				
22	**TOTAL TAXES OTHER THAN INCOME**	$38,983,273	$37,422,608	4.17%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	213,353
2	A&E ARCHITECTS P C	Architectural Services	89,537
3	ACE ELECTRIC INC	Electric Construction Service	311,572
4	ACI PAYMENTS, INC.	Customer Payment Processing	110,671
5	ACUREN INSPECTION INC	Inspection Services	206,389
6	AFFCO INC	Hydro Construction Services	1,669,384
7	AION ENERGY LLC	Program Management Services	297,135
8	ALME CONSTRUCTION, INC.	Construction	571,628
9	ALTERNATIVE TECHNOLOGIES INC	Oil and Gas Sample Analysis	78,177
10	AMERICAN INNOVATIONS INC	Software Support Services	151,254
11	ANDRITZ HYDRO CORP	Hydro Upgrade Services	277,560
12	ARCADIS US INC	Engineering Services	1,759,029
13	ARCOS LLC	Call-out Services	142,781
14	ASCEND ANALYTICS LLC	Hydro Expert Analysis	711,748
15	ASPLUNDH TREE EXPERT LLC	Tree Trimming	5,285,792
16	ASSOCIATED UNDERWATER SERVICE	Inspection Services	80,268
17	AURITAS LLC	Computer Consulting Services	173,385
18	AUTOMOTIVE RENTALS INC	Fleet Management	7,931,463
19	AVEVA SOFTWARE, LLC	Computer Support Services	426,711
20	BANNER ASSOCIATES INC	Engineering Services	92,169
21	BART ENGINEERING COMPANY	Engineering Services	501,220
22	BEACON COMMUNICATIONS LLC	Software Maintenance	346,510
23	BERGY'S LLC	Construction	829,300
24	BEVERIDGE INCORPORATED	Drilling Services	252,204
25	BIG SKY COMMUNICATION & CABLE	Communications Construction	81,800
26	BIG SKY LAND RESOURCES, LLC	Excavation Contractor	197,505
27	BILLINGS FLYING SERVICE, INC.	Powerline Services	110,430
28	BISON ENGINEERING INC	Engineering Services	356,394
29	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	329,756
30	BLUE SKY CONSTRUCTION LLC	Well Services	83,780
31	BRANDENBURG INDUSTRIAL SERVIC	Demolition Services	1,181,880
32	BROADRIDGE ICS	Shareholder Services	102,112
33	BURK EXCAVATION AND UTILITIES	Construction	328,811
34	CATERPILLAR POWER GENERATION	Generation Services	19,709,419
35	CENTERPOINT ENERGY SERVICES I	Energy	2,721,121
36	CENTRON SERVICES INC	Customer Collection service	91,353
37	CHARLES RIVER ASSOCIATES	EIM MBR Analysis	75,000
38	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	557,925
39	CN UTILITY CONSULTING INC	Utility Consulting Services	549,980
40	CONTINENTAL STEEL WORKS	Fabrication Services	1,009,275
41	COPPER CREEK LLC	Construction	328,383
42	CRANE SERVICES & INSPECTIONS	DOT Inspections	157,602
43	CRIST, KROGH, BUTLER & NORD L	Legal Services	131,767
44	CROWLEY FLECK PLLP	Legal Services	121,709
45	CRUX SUBSURFACE INC	Construction	2,240,305
46	CTA INC.	Energy Conservation Consultants	1,323,942
47	D & A TRENCHING INC	Excavating Services	143,122
48	DAKOTA DIRECTIONAL LLC	Boring Services	200,828
49	DAVEY TREE SURGERY COMPANY	Tree Trimming	4,187,271
50	DDC ADVOCACY LLC	Consulting Services	180,942
51	DELOITTE & TOUCHE LLP	Audit Services	1,570,831
52	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	1,321,150
53	DGR ENGINEERING	Engineering Services	349,465
54	DHC INC	Boring Services	121,674
55	DICK ANDERSON CONSTRUCTION INC	Construction	1,270,144
56	DIETZEL ENTERPRISES INC	Construction	836,435
57	DIRECTIONAL ZONE INC	Boring Services	109,789
58	DJ&A P C CONSULTING ENGINEER	Surveying Services	77,005
59	DJL ENGINEERING SERVICES, PLLC	Engineering Services	103,159
60	DNV GL ENERGY INSIGHTS USA INC	Software Support Services	76,125

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	DOBLE ENGINEERING CO	Maintenance Service	169,577
62	DORSEY & WHITNEY LLP	Legal Services	1,332,384
63	DOWL HKM	Geotechnical Services	127,681
64	E SOURCE COMPANIES LLC	Consulting Services	90,668
65	EARHART BUILDERS INC	Maintenance Service	98,889
66	EEC, INC.	Construction Service	211,865
67	EIDE BAILLY LLP	Accounting Services	99,620
68	ELITE COMMERCIAL CLEANING	Cleaning Services	84,635
69	ELLIOT CONSTRUCTION INC	Boring Services	1,077,702
70	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	4,051,652
71	ENERGY AND ENVIRONMENTAL ECON	Consulting Services	98,298
72	ENERGY CONTRACT SERVICES LLC	Inspection Services	308,248
73	ENERGY LABORATORIES INC	Environmental Consultants	87,072
74	ENERGY SHARE OF MONTANA	USBC Services	973,315
75	EVERGREEN CAISSONS INC	Construction	1,565,507
76	FAGEN, INC	Construction	13,816,298
77	FENCECRAFTERS HELENA INC	Repair Services	132,950
78	FIRSTMARK CONSTRUCTION	Construction	204,710
79	FLYNN WRIGHT INC	Advertising Services	988,847
80	FOOTHILLS RIG SERVICE	Well Services	76,914
81	FOUR CORNERS RECYCLING, LLC	Recovery Services	98,286
82	G & L WATER	Hauling & Other Services	155,980
83	GARDEN CITY PLUMBING & HEATING	Plant Services	120,365
84	GARTNER INC	Information Technology Consulting	601,495
85	GE RENEWABLES GRID, LLC	Software Support Services	430,892
86	GEI CONSULTANTS INC	Environmental Consultants	302,635
87	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	4,553,222
88	GEODIGITAL INTERNATIONAL CORP	Data Collection Services	159,218
89	GEOENGINEERS, INC	Engineering Services	99,140
90	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	156,652
91	GRAND ISLAND ABSTRACT ESCRO &	Escrow and Title Services	77,051
92	GREGG ENGINEERING	Informational Technology Simulation	89,245
93	GUY TABACCO CONSTRUCTION	Construction	186,648
94	H & H ASPHALT & MAINTENANCE L	Asphalt Services	202,171
95	H & H CONTRACTING INC	Concrete and Asphalt Services	495,161
96	H2E INC	Engineering Services	629,811
97	HAIDER CONSTRUCTION INC	Boring Services	508,737
98	HDR ENGINEERING INC	Engineering Services	4,883,457
99	HEATH CONSULTANTS INC	Gas Leak Surveys	656,057
100	HIGHMARK MEDIA	Safety Training	106,160
101	HUNTER BROTHERS CONSTRUCTION	Construction	488,972
102	HYDRO CONSULTING & MAINTENANCE	Repair Services	301,935
103	HYDROINSIGHT LLC	Rewind & Restack Services	89,573
104	IMCO GENERAL CONSTRUCTION INC	Construction	3,566,846
105	INFOSYS LIMITED	Consulting Services	190,000
106	INTEC SERVICES INC	Pole Inspection Services	3,301,375
107	ITRON INC	Meter Installation	3,043,522
108	IVANS BORING	Boring Services	573,302
109	J D POWER AND ASSOCIATES	Energy Study	87,990
110	J2 BUSINESS PRODUCTS	Copier Maintenance	103,229
111	JACKOLA ENGINEERING & ARCHITE	Architectural Services	85,384
112	JACOBSEN TREE EXPERTS	Tree Trimming	996,874
113	JARES FENCE COMPANY INC	Fence Materials/Installation	97,856
114	JEFFERY CONTRACTING LLC	Construction	1,767,664
115	JODY KLESSENS CONSTRUCTION LLC	Construction Service	88,032
116	JONES DAY	Legal Services	150,293
117	KARV LLC	Boring Services	214,857
118	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	88,185
119	KENNEBEC TELEPHONE CO., INC	Boring Services	128,009
120	KM CONSTRUCTION CO INC	Construction	316,485
121	KNIFE RIVER	Construction	149,756
122	LAKESIDE EXCAVATION	Concrete Services	250,000
123	LEARJET INC	Repair Services	99,210
124	LIEN TRANSPORTATION CO	Transport Services	336,009

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
125	LIQUID GOLD WELL SERVICE INC	Well Services	152,084
126	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	485,910
127	LOCKMER SHEET METAL	Installation Services	76,099
128	LODGEPOLE LAND SERVICES LLC	Real Estate Services	104,464
129	M & P EXCAVATING	Excavation Services	325,553
130	M&D CONSTRUCTION INC	Construction	402,501
131	MAP MECHANCIAL CONTRACTORS, I	Demolition Services	2,795,961
132	MCMILLEN LLC	Design Services	99,300
133	MERCER HUMAN RESOURCE CONSULT	HR Consulting	163,183
134	MERIDIAN IT INC	Information Technology Services	265,944
135	MERKEL ENGINEERING INC	Consulting Services	978,524
136	MICHAELS FENCE & SUPPLY CO	Installation Services	107,988
137	MICHELS CORPORATION	Construction	2,206,073
138	MIDCON UNDERGROUND CONSTRUCTI	Construction	891,826
139	MINUTEMAN AVIATION INC.	Helicopter Charter Services	169,318
140	MISSOULA CONCRETE CONSTRUCTION	Construction	83,060
141	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	781,043
142	MONTANA HELICA PIERS	Construction Service	78,996
143	MOODY'S ANALYTICS	Analytic Services	177,654
144	MOODY'S INVESTORS SERVICE	Debt Rating Services	187,500
145	MORGAN, LEWIS & BOCKIUS LLP	Legal Services	627,867
146	MORRISON MAIERLE INC	Engineering Services	335,290
147	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	26,369,110
148	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	475,438
149	MP ENVIRONMENTAL SERVICES INC	Excavation Services	76,739
150	MP SYSTEMS	Electric Construction Service	212,139
151	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	196,852
152	NAES CORPORATON	Generation Services	130,701
153	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	387,937
154	NEELY ELECTRIC INC	Electric Services	138,231
155	NORTHERN HYDRAULICS INC	Construction	134,289
156	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,896
157	NORTHWEST TOWER	Construction Service	163,550
158	OLSSON ASSOCIATES	Surveying Services	100,411
159	ONSITE DISTRIBUTED POWER, LLC	Installation Services	135,327
160	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	718,987
161	OUTBACK POWER COMPANY	Construction Service	450,415
162	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	16,382,673
163	PINNACLE RESEARCH & CONSULTING	Consulting Services	323,804
164	PIONEER TECHNICAL SERVICES INC	Environmental Services	128,997
165	PIONEER WIRELINE SERVICES	Rig Services	206,654
166	POTEET CONSTRUCTION	Traffic Safety Services	153,387
167	POWER SETTLEMENTS CONSULTING &	Consulting Services	170,000
168	POWERPLAN INC	Software Support Services	1,288,520
169	POWERS HEATING LLC	Meter Installation	93,571
170	PRICKLY PEAR LAND TRUST INC	Construction Service	132,428
171	PRO PIPE CORPORATION	Welding Services	1,603,473
172	PUETZ CORPORATION	Design Services	283,514
173	QUANTA UTILITY ENGINEERING	Engineering Services	7,243,240
174	RAY PETERSON ELECTRIC INC	Electrical Services	208,783
175	RIVER DESIGN GROUP INC	Engineering Services	440,728
176	RIZING, LLC	Information Technology Consulting	389,840
177	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	30,706,074
178	ROCKY MOUNTAIN ROTORS MONTANA	Line Maintenance	202,337
179	ROD TABBERT CONSTRUCTION INC	Construction	295,079
180	ROSEN USA INC	Inspection Services	584,060
181	ROUNDS BROTHERS TRENCHING	Boring Services	830,783
182	SANDERSON STEWART	Engineering Services	276,182
183	SAPERE CONSULTING	Consulting Services	102,863
184	SCENIC CITY ENTERPRISES INC	Construction	127,959
185	SCHNABEL ENGINEERING LLC	Consulting Services	384,108
186	SCHOENFELDER CONSTRUCTION INC	Construction Service	370,509
187	SIDEWINDERS LLC	Generator Repair Services	2,708,255
188	SILVERTECH, INC.	Website Redesign	195,000

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
189	SPEEDPAY INC	Bill Paying Services	154,784
190	SPHERION STAFFING	Temporary Labor	78,525
191	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	115,000
192	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,114,415
193	STEPHEN P ADIK	Board of Director Fees	125,000
194	STINSON LEONARD STREET LLP	Legal Services	693,672
195	STREAM WORKS INC	Construction	91,405
196	SUMTOTAL SYSTEMS INC	Installation Services	266,890
197	SUPERIOR CONCRETE PRODUCTS INC	Construction	323,256
198	TDW SERVICES INC	Inspection Services	524,818
199	TERRA REMOTE SENSING (USA) INC	Surveying Services	385,344
200	TERRACON CONSULTANTS INC	Geotechnical Services	88,052
201	THE ELECTRIC COMPANY OF SOUTH	Construction	1,454,417
202	THE MOSAIC COMPANY	Training	947,434
203	THOMPSON HINE LLP	Benefits Audit Services	125,927
204	TIMBERLINE SECURITY & SERVICES	Security Services	100,194
205	TLC SEPTIC SERVICE	Excavation Contractor	193,461
206	TODD O BRUESKE CONSTRUCTION	Construction	876,723
207	TRADEMARK ELECTRIC INC	Construction	580,807
208	TRI-COUNTY MECHANICAL & ELECT	Construction	77,562
209	TROUTMAN SANDERS LLP	Legal Services	96,565
210	ULTEIG ENGINEERS INC	Project Manager Services	286,714
211	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	935,427
212	UNDERGROUND CONSTRUCTION	Construction	377,985
213	UNITED ELECTRIC LLC	Electric Services	82,370
214	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	211,675
215	UTILICAST LLC	Consulting Services	1,443,295
216	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	180,997
217	VAISALA INC	Wind Forecasting Services	109,404
218	VARSITY CONTRACTORS INC	Janitorial Services	267,245
219	VEOLIA ES TECNICAL SOLUTIONS	Oil Recycling	194,113
220	VERTEX	Billing Services and Programming	2,908,096
221	VERTIV CORPORATION	Maintenance Service	96,431
222	VIKOR	Construction	105,001
223	VINE ENTERPRISES,INC	Fence Materials/Installation	161,468
224	WARREN TRANSPORT INC	Hauling Services	226,707
225	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	795,495
226	WATSON TRUCKING OF HAVRE LLC	Hauling Services	93,975
227	WELFL CONSTRUCTION CO	Construction Service	2,962,662
228	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	449,067
229	WILLIS TOWERS WATSON US LLC	Compensation Services	121,248
230	WRIGHT AND SUDLOW INC	Construction Service	81,144
231	ZACHA UNDERGROUND CONSTRUCTIO	Construction	140,218
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	Total of Payments Set Forth Above		**$ 250,418,963**

1/ This schedule includes payments for professional services over $75,000.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2				
3	There are three employee political action committees			
4	(PAC)s:			
5				
6	a. NorthWestern Energy Montana Employee PAC for			
7	Montana employees;			
8				
9	b. Employees of NorthWestern Corporation			
10	(NorthWestern Energy) PAC for South Dakota			
11	employees;			
12				
13	c. NorthWestern Public Service Employees PAC for			
14	Nebraska employees.			
15				
16				
17	All of the money contributed by members is			
18	dedicated to support political candidates, state and			
19	local political party organizations, and ballot issues.			
20	No company funds may be spent in support of a			
21	political candidate. Nominal administrative costs			
22	for such things as duplicating, postage, and			
23	meeting expenses are paid by the company as			
24	provided by law. These costs are charged to			
25	shareholder expense.			
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40	**TOTAL Contributions**	$ -	$ -	

Sch. 14	**Pension Costs** 1/

1	Plan Name: NorthWestern Energy Pension Plan	
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ________________________
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No
5		

	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 675,493,587	$ 592,485,431	14.01%
8	Service cost	10,239,856	8,796,395	16.41%
9	Interest cost	21,063,387	24,205,284	-12.98%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	79,799,204	76,705,761	4.03%
13	Acquisition	-	-	-
14	Benefits paid	(29,196,611)	(26,699,284)	-9.35%
15	Benefit obligation at end of year	$ 757,399,423	$ 675,493,587	12.13%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 545,796,194	$ 466,697,791	16.95%
18	Actual return on plan assets	92,274,164	96,797,687	-4.67%
19	Acquisition	-	-	-
20	Employer contribution	10,201,263	9,000,000	13.35%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(29,196,611)	(26,699,284)	-9.35%
23	Fair value of plan assets at end of year	$ 619,075,010	$ 545,796,194	13.43%
24	**Funded Status**	$ (138,324,413)	$ (129,697,393)	-6.65%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (138,324,413)	$ (129,697,393)	-6.65%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	2.30%	3.20%	-28.13%
32	Expected return on plan assets	4.49%	5.06%	-11.26%
33	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.00% Union & 2.67% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 10,239,856	$ 8,796,395	16.41%
36	Interest cost	21,063,387	24,205,284	-12.98%
37	Expected return on plan assets	(24,029,522)	(23,034,532)	-4.32%
38	Amortization of prior service cost	-	-	-
39	Recognized net actuarial gain	5,027,792	6,544,238	-23.17%
40	Net periodic benefit cost (SEC Basis)	$ 12,301,513	$ 16,511,385	-25.50%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 10,201,263	$ 9,000,144	13.35%
43	Pension Costs Capitalized	2,515,102	2,081,747	20.82%
44	Accumulated Pension Asset (Liability) at Year End	$ (138,324,413)	$ (129,697,393)	-6.65%
45	Number of Company Employees:	-	-	
46	Covered by the Plan 2/	2,539	2,588	-1.89%
47	Not Covered by the Plan 2/	799	735	8.71%
48	Active	570	633	-9.95%
49	Retired	1,654	1,647	0.43%
50	Deferred Vested Terminated 2/	315	308	2.27%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.

2/This plan was closed to new entrants effective 10/03/08.

Sch. 14a	Pension Costs 1/			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 413,343,235	$ 356,074,413	-13.86%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 11,118,667	$ 10,958,378	1.46%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 456,200,434	$ 413,343,235	10.37%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 8,506,877	$ 8,317,152	2.28%
44	401(k) Plan Defined Contribution Costs Capitalized	2,097,355	1,923,770	9.02%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,538	1,530	0.52%
48	Not Covered by the Plan			
49	Active - Participating	1,527	1,520	0.46%
50	Retired			
51	Vested Former Employees, Retirees and Active-	312	310	0.65%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2018.2.12			
4	Order number: 7604U			
5	Amount recovered through rates	($1,399,829)	($1,150,620)	-21.66%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	1.80%	2.80%	-35.71%
8	Expected return on plan assets	4.71%	4.79%	-1.67%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate annually	5.00% fixed rate anually	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.00% Union & 2.67% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for the fiscal year ending December 31, 2018.			

1/ Obtained from NorthWestern Energy-Montana's 2020 FASB 106 Valuation. Assumptions and data are as of December 31, 2020.
2/ Obtained from NorthWestern Energy-Montana's 2019 FASB 106 Valuation. Assumptions and data are as of December 31, 2019.
3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$14,641,862	$15,201,801	-3.68%
10	Service cost	318,337	283,867	12.14%
11	Interest Cost	435,820	536,543	-18.77%
12	Plan participants' contributions	920,456	942,033	-2.29%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	2,496,048	766,140	225.80%
15	Acquisition	-	-	-
16	Benefits paid	(3,040,949)	(3,088,522)	1.54%
17	Benefit obligation at end of year	$15,771,574	$14,641,862	7.72%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$21,479,179	$18,671,114	15.04%
20	Actual return on plan assets	2,723,057	3,804,534	-28.43%
21	Acquisition	-	-	-
22	Employer contribution	1,013,472	1,150,020	-11.87%
23	Plan participants' contributions	920,456	942,033	-2.29%
24	Benefits paid	(3,040,949)	(3,088,522)	1.54%
25	Fair value of plan assets at end of year	$23,095,215	$21,479,179	7.52%
26	**Funded Status**	$7,323,641	$6,837,317	7.11%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$7,323,641	$6,837,317	7.11%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$318,337	$283,867	12.14%
33	Interest cost	435,820	536,543	-18.77%
34	Expected return on plan assets	(982,650)	(869,332)	-13.04%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,032,850)	(2,032,848)	0.00%
37	Recognized net actuarial loss/(gain)	-	-	-
38	Net periodic benefit cost	($2,261,343)	($2,081,770)	-8.63%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	1,013,472	1,150,020	-11.87%
43	TOTAL	$1,013,472	$1,150,020	-11.87%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(1,399,829)	(1,150,620)	-21.66%
47	TOTAL	($1,399,829)	($1,150,620)	-21.66%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($1,399,829)	($1,150,620)	-21.66%
50	Pension Costs Capitalized	(345,125)	($266,140)	-29.68%
51	Accumulated Pension Asset (Liability) at Year End	7,323,641	6,837,317	7.11%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,444	1,551	-6.90%
54	Not Covered by the Plan	1,940	1,808	7.30%
55	Active	545	612	-10.95%
56	Retired	812	843	-3.68%
57	Spouses/Dependants covered by the Plan	87	96	-9.38%

4/ There is approximately an additional $3,374,035 and $5,630,347 in other company OPEBS liabilities outstanding at December 31, 2020 and 2019, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Note: This schedule includes the ten most highly compensated employees assigned or allocated to Montana that are not already included on Sch 17.

Line No.	Name/Title	Base Salary 1/	Bonuses 2/		Other 3/		Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation 4/
1	Michael R. Cashell Vice President, Transmission	304,668	87,687	A	30,400 188,048 394,487 4,128 1,298	B C D E F	1,010,716	984,267	2.7%
2	John D. Hines Vice President, Supply & Montana Government Affairs	308,705	89,297	A	36,310 189,136 188,071 10,321 1,298 10,410	B C D E F G	833,548	785,265	6.1%
3	Jason Merkel General Manager, Operations & Construction	213,623	38,570	A	34,676 49,688 307,450 2,580	B C D E	646,587	582,577	11.0%
4	Crystal D. Lail Vice President & Controller	284,849	80,492	A	35,232 159,437 35,517 2,328	B C D E	597,855	574,545	4.1%
5	Michael L. Nieman Chief Audit and Compliance Officer	250,418	42,707	A	57,607 59,124 38,634 6,711	B C D E	455,201	464,504	-2.0%
6	Daniel L. Rausch Treasurer	237,582	42,621	A	53,696 56,192 27,831 8,105	B C D E	426,027	434,781	-2.0%
7	Jeanne M. Vold Business Technology Officer	226,116	42,125	A	32,468 50,991 22,027	B C D	373,727	367,584	1.7%
8	Bleau J. LaFave Director, Long-Term Resources	189,036	29,340	A	49,113 35,643 26,618 7,326	B C D E	337,076	340,446	-1.0%
9	Travis E. Meyer Director, Corporate Finance & Investor Relations Officer	197,606	29,310	A	48,933 37,064 21,251	B C D	334,164	333,481	0.2%
10	Timothy P. Olson Corporate Counsel & Corporate Secretary	198,886	28,559	A	48,117 37,579	B C	313,141	317,787	-1.5%

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation 4/

1/ Base pay in 2020 reflects the results of 27 pay periods. There were 26 pay periods in 2019.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2020 Annual Incentive Compensation Plan. Amounts were earned in 2020 and paid in the first quarter of 2021. Based on company performance against plan, the incentive plan was funded at 74% of target. Salary and incentive in current rate recovery are based on a 2017 test period.

3/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical, dental, vision, employee assistance program, group term life, health savings account, wellness incentive, 401(k) match, and non-elective 401(k) contribution, as applicable.

C> Values reflect the grant date fair value for performance stock awards. Stock based compensation is not included in rate recovery.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020.

E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.

F> Imputed income on shares withheld to cover FICA taxes upon vestings of deferred equity awards

G> Miscellaneous payment

4/ % Increase Total Compensation includes the actuarial change in pension value. Excluding the change in pension value, individual compensation changed as follows:

Cashell	-0.7%	Rausch	-1.8%
Hines	5.1%	Vold	1.7%
Merkel	5.8%	LaFave	-1.0%
Lail	3.3%	Meyer	-0.5%
Nieman	-2.0%	Olson	-1.5%

SCHEDULE 17

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation 4/	Total Compensation Reported Last Year	% Increase Total Compensation 5/
1	Robert C. Rowe President & Chief Executive Officer	687,206	493,397 A	43,406 B 1,698,500 C 165,530 D 2,341 E 11,668 F	3,102,048	3,298,304	-6.0%
2	Brian B. Bird Chief Financial Officer	475,329	204,765 A	54,843 B 564,353 C 28,446 D 3,828 F	1,331,564	1,422,261	-6.4%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	448,293	177,025 A	52,239 B 468,154 C 2,787 F	1,148,498	1,205,895	-4.8%
4	Curtis T. Pohl Vice President, Distribution	322,988	92,759 A	54,576 B 245,757 C 52,154 D 2,193 F	770,427	807,876	-4.6%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	306,000	88,071 A	54,592 B 203,244 C 38,170 D 1,516 F 59 G	691,652	708,974	-2.4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation 4/	Total Compensation Reported Last Year	% Increase Total Compensation 5/

1/ Base pay in 2020 reflects the results of 27 pay periods. There were 26 pay periods in 2019.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2020 Annual Incentive Compensation Plan. Amounts were earned in 2020 and paid in the first quarter of 2021. Based on company performance against plan, the incentive plan was funded at 74% of target. Salary and incentive in current rate recovery are based on a 2017 test period.

3/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical, dental, vision, employee assistance program, group term life, health savings account, wellness incentive, 401(k) match, and non-elective 401(k) contribution, as applicable.

C> Values reflect the grant date fair value for performance stock awards. Stock based compensation is not included in rate recovery.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020.

E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.

F> Imputed income on shares withheld to cover FICA taxes upon vesting of deferred equity awards

G> Noncash taxable award and tax gross-up on award

4/ Stock-based compensation is paid by shareholders.

Recovery of non-stock-based compensation is based on 2017 ("test year") costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff. There is no specific recovery of these or most other expenses.

Shareholders vote on executive compensation, and have consistently approved at above 96%, most recently 98.5%.

Our Chief Executive Officer's compensation is 78% at-risk. Overall executive compensation is discussed in the Compensation Disclosure and Analysis section of our annual Proxy Statement.

5/ % Increase Total Compensation includes the actuarial change in pension value. Excluding the change in pension value, individual compensation changed as follows:

Rowe	-6.9%
Bird	-6.3%
Grahame	-4.8%
Pohl	-4.1%
Schroeppel	-2.4%

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$6,398,242,253	$6,120,077,623	$278,164,630	4.55%
4	101.1 Property Under Capital Leases	43,061,890	43,891,413	(829,523)	-1.89%
5	103 Experimental Electric Plant Unclassified	2,928,663	1,631,264	1,297,399	79.53%
6	105 Plant Held for Future Use	5,499,197	4,903,851	595,346	12.14%
7	107 Construction Work in Progress	166,454,010	88,677,933	$77,776,077	87.71%
8	108 Accumulated Depreciation Reserve	(2,365,692,029)	(2,254,708,460)	($110,983,569)	4.92%
9	108.1 Accumulated Depreciation - Capital Leases	(29,151,894)	(27,141,417)	($2,010,477)	7.41%
10	111 Accumulated Amortization & Depletion Reserves	(89,972,714)	(82,964,465)	($7,008,249)	8.45%
11	114 Electric Plant Acquisition Adjustments	481,574,396	481,574,396	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(61,628,544)	(51,378,623)	(10,249,921)	19.95%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	36,196,864	35,192,358	1,004,506	2.85%
15	**Total Utility Plant**	4,945,097,619	4,717,341,400	227,756,219	4.83%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(29,180)	(29,180)	-	0.00%
19	123.1 Investments in Assoc Companies and Subsidiaries	(118,287,100)	(122,612,624)	4,325,524	-3.53%
20	124 Other Investments	45,234,617	47,501,223	(2,266,606)	-4.77%
21	128 Miscellaneous Special Funds	250,000	250,000	-	0.00%
23	**Total Other Property & Investments**	(72,144,858)	(74,203,776)	2,058,918	-2.77%
24	**Current and Accrued Assets**				
25	131 Cash	5,600,771	4,673,108	927,663	19.85%
26	134 Other Special Deposits	9,670,292	5,202,171	4,468,121	85.89%
27	135 Working Funds	22,950	23,150	(200)	-0.86%
30	142 Customer Accounts Receivable	73,728,730	76,136,135	(2,407,405)	-3.16%
31	143 Other Accounts Receivable	14,106,165	11,411,798	2,694,367	23.61%
32	144 Accumulated Provision for Uncollectible Accounts	(5,609,532)	(2,346,427)	(3,263,105)	139.07%
34	146 Accounts Receivable-Associated Companies	1,752,345	1,307,288	445,057	34.04%
35	151 Fuel Stock	6,561,464	6,354,506	206,958	3.26%
36	154 Plant Materials and Operating Supplies	43,691,819	42,194,053	1,497,766	3.55%
37	164 Gas Stored - Current	10,010,097	4,607,138	5,402,959	117.27%
38	165 Prepayments	15,375,451	13,354,236	2,021,215	15.14%
41	172 Rents Receivable	49,263	100,788	(51,525)	-51.12%
42	173 Accrued Utility Revenues	80,492,128	83,344,000	(2,851,872)	-3.42%
43	174 Miscellaneous Current & Accrued Assets	194,030	203,131	(9,101)	-4.48%
48	**Total Current & Accrued Assets**	255,645,973	246,565,075	9,080,898	3.68%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	13,376,263	12,355,991	1,020,272	8.26%
51	182 Regulatory Assets	712,384,890	651,438,813	60,946,077	9.36%
52	183 Preliminary Survey and Investigation Charges	2,286,180	-	2,286,180	100.00%
53	184 Clearing Accounts	3,635	2,634	1,001	38.00%
55	186 Miscellaneous Deferred Debits	7,565,277	5,095,671	2,469,606	48.46%
56	189 Unamortized Loss on Reacquired Debt	28,350,312	31,089,217	(2,738,905)	-8.81%
57	190 Accumulated Deferred Income Taxes	178,891,654	158,673,379	20,218,275	12.74%
58	191 Unrecovered Purchased Gas Costs	5,905,571	34,065,519	(28,159,948)	-82.66%
59	**Total Deferred Debits**	948,763,782	892,721,224	56,042,558	6.28%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 6,077,362,516	$ 5,782,423,923	$ 294,938,593	5.10%

Sch. 18	cont. **BALANCE SHEET 1/**				
	Account Title	This Year	Last Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 541,448	$ 539,992	$ 1,456	0.27%
6	211 Miscellaneous Paid-In Capital	1,513,785,478	1,508,968,799	4,816,679	0.32%
10	216 Unappropriated Retained Earnings	667,969,228	633,103,630	34,865,598	5.51%
12	217 Reacquired Capital Stock	(98,075,421)	(96,014,713)	(2,060,708)	2.15%
13	219 Accumulated Other Comprehensive Income	(5,126,145)	(7,505,099)	2,378,954	-31.70%
14	**Total Proprietary Capital**	2,079,094,588	2,039,092,609	40,001,979	1.96%
15	**Long Term Debt**				
16	221 Bonds	2,079,660,000	1,929,660,000	150,000,000	7.77%
18	224 Other Long Term Debt	248,976,900	315,976,900	(67,000,000)	-21.20%
20	**Total Long Term Debt**	2,328,636,900	2,245,636,900	83,000,000	3.70%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	16,379,639	19,742,260	(3,362,621)	-17.03%
24	228.2 Accumulated Provision for Injuries and Damages	6,050,644	7,650,043	(1,599,399)	-20.91%
25	228.3 Accumulated Provision for Pensions and Benefits	10,240,902	10,393,155	(152,253)	-1.46%
26	228.4 Accumulated Miscellaneous Operating Provisions	106,746,764	121,180,549	(14,433,785)	-11.91%
27	229 Accumulated Provision for Rate Refunds	10,712,124	17,019,084	(6,306,960)	-37.06%
28	230 Asset Retirement Obligations	45,355,157	42,449,270	2,905,887	6.85%
29	**Total Other Noncurrent Liabilities**	195,485,230	218,434,361	(22,949,131)	-10.51%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	100,000,000	-	100,000,000	-
32	232 Accounts Payable	104,724,988	105,556,235	(831,247)	-0.79%
34	234 Accounts Payable to Associated Companies	1,775,914	1,715,201	60,713	3.54%
35	235 Customer Deposits	6,000,316	4,372,087	1,628,229	37.24%
36	236 Taxes Accrued	61,045,637	60,825,677	219,960	0.36%
37	237 Interest Accrued	18,073,738	17,537,539	536,199	3.06%
40	241 Tax Collections Payable	1,432,362	1,696,553	(264,191)	-15.57%
41	242 Miscellaneous Current and Accrued Liabilities	75,300,722	52,128,884	23,171,838	44.45%
42	243 Obligations Under Capital Leases-Current	3,912,103	3,855,092	57,011	1.48%
45	**Total Current and Accrued Liabilities**	372,265,780	247,687,268	124,578,512	50.30%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	65,186,426	56,869,680	8,316,746	14.62%
48	253 Other Deferred Credits	199,645,159	170,566,702	29,078,457	17.05%
49	254 Regulatory Liabilities	187,832,431	197,585,036	(9,752,605)	-4.94%
50	255 Accumulated Deferred Investment Tax Credits	278,674	281,903	(3,229)	-1.15%
52	281-283 Accumulated Deferred Income Taxes	648,937,328	606,269,464	42,667,864	7.04%
53	**Total Deferred Credits**	1,101,880,018	1,031,572,785	70,307,233	6.82%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,077,362,516	$ 5,782,423,923	$ 294,938,593	5.10%
55					
56	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
57	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
58	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
59	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.				
60					
61					
62					
63					
64					Schedule 18A

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 743,000 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases. The preparation of financial statements in conformity with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810, Consolidation. ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 4). The other significant differences consist of the following:

- Earnings per share and footnotes for revenue from contracts with customers, segment and related information, and quarterly financial data (unaudited) are not presented;

- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $464.7 million and $442.1 million as of December 31, 2020 and December 31, 2019, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;

- Goodwill is reflected in the Balance Sheets as a utility plant adjustments of $357.6 million as of December 31, 2020 and December 31, 2019, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);

- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2020 and December 31, 2019, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;

- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to inventory for GAAP purposes;

- Operating lease right of use assets of $2.9 million are classified in the Balance Sheets as capital leases in accordance with regulatory treatment, as compared to non-current assets for GAAP purposes;

- Operating lease liabilities of $2.9 million are reflected as current and long term obligations under capital leases in the Balance Sheets, as compared to accrued expenses and long term liabilities for GAAP purposes;

- Unamortized debt expense is classified in the Balance Sheets as deferred debits in accordance with regulatory treatment, as compared to long-term debt for GAAP purposes;

- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while current and long-term debt are presented separately for GAAP reporting;

- The current portion of the provision for injuries and damages and the expected insurance proceeds receivable related to the provision for injuries and damages are reported as a current liability for GAAP purposes, as compared to a non-current liability for FERC purposes;

- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross non-current deferred debits and credits, respectively, while GAAP presentation reflects a net non-current deferred tax liability;

- Stranded tax effects associated with the Tax Cuts and Jobs Act are included in accumulated other comprehensive income (AOCI) in accordance with regulatory treatment, while included in retained earnings for GAAP purposes;

- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes;

- Net periodic benefit costs and net periodic post retirement benefit costs are reflected in operating expense for FERC purposes, as compared to the GAAP presentation, which reflects the current service costs component of the net periodic benefit costs in operating expenses and the other components outside of income from operations. In addition, only the service cost component of net periodic benefit cost is eligible for capitalization for GAAP purposes, as compared to the total net periodic benefit costs for FERC purposes;

- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are presented separately for GAAP;

- Unbilled revenue is reflected in the Balance Sheets in Accrued utility revenues in accordance with regulatory treatment, as compared to Accounts receivable, net for GAAP purposes;

- Implementation costs associated with cloud computing arrangements are reflected on the Balance Sheets as Miscellaneous Intangible Plant in accordance with regulatory treatment, as compared to Other current assets for GAAP purposes. Additionally, these cash outflows are presented within investing activities cash outflows in the Statement of Cash Flows in accordance with regulatory treatment, as compared to operating activities cash outflows for GAAP purposes; and

- GAAP revenue differs from FERC revenue primarily due to the equity method of accounting as discussed above, netting of electric purchases and sales for resale in revenue for the GAAP presentation as compared to a gross presentation for FERC purposes (with the exception of those transactions in a regional transmission organization (RTO)), the netting of RTO transmission transactions for the GAAP presentation as compared to a gross presentation for FERC purposes, and the classification of regulatory amortizations in revenue for GAAP purposes as compared to expense for FERC purposes.

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting requires us 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 and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncertain tax position reserves, asset retirement obligations, regulatory assets and liabilities, allowances for uncollectible accounts, our Qualifying Facilities (QF) liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

The Company recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $5.6 million and $2.3 million at December 31, 2020 and December 31, 2019. Unbilled revenues were $80.5 million and $83.3 million at December 31, 2020 and December 31, 2019, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2020	2019
Fuel stock	$ 6,561	$ 6,355
Plant materials and operating supplies	43,692	42,194
Gas stored underground (including the non-current portion reflected in utility plant)	46,207	39,799
Total Inventories	$ 96,460	$ 88,348

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, Regulated Operations. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (Accumulated Provision for Rate Refunds).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statements of Income at that time. This would result in a charge to earnings and AOCI, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, Derivatives and Hedging. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statements of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 9 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Utility Plant

Utility Plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. This rate averaged 6.7% and 6.9% for Montana for 2020 and 2019, respectively. This rate averaged 6.7% and 6.6% for South Dakota for 2020 and 2019, respectively. AFUDC capitalized totaled $9.8 million and $8.2 million for the years ended December 31, 2020 and 2019, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 2 to 96 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.8% for 2020 and 2019, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Statements of Income and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Supplemental Cash Flow Information

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ 115	$ (6,737)
Interest	84,922	83,776
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	21,430	33,473

The following table provides a reconciliation of cash, working funds, other special funds, and special deposits reported within the Balance Sheets that sum to the total of the same such amounts shown in the Statements of Cash Flows (in thousands):

	December 31,	
	2020	2019
Cash	$ 5,601	$ 4,673
Working funds	23	23
Other special funds	250	250
Special deposits	9,670	5,202
Total shown in the Statement of Cash Flows	$ 15,554	$ 10,148

Other special funds and Special deposits consist primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounting Standards Issued

At this time, we are not expecting the adoption of recently issued accounting standards to have a material impact to our financial condition, results of operations, and cash flows.

(3) Regulatory Matters

FERC Filing - Montana Transmission Service Rates

In May 2019, we submitted a filing with the Federal Energy Regulatory Commission (FERC) for our Montana transmission assets. In June 2019, the FERC issued an order accepting our filing, granting interim rates (subject to refund) effective July 1, 2019, establishing settlement procedures and terminating our related Tax Cuts and Jobs Act filing. A settlement judge was appointed and after months of settlement negotiations, the parties reached agreement on all issues. In November 2020, we filed the settlement and implemented settlement rates on December 1, 2020. In January 2021, the FERC approved our settlement and during the first quarter of 2021 we refunded approximately $20.5 million to our FERC regulated wholesale customers.

Revenues from FERC regulated wholesale customers associated with our Montana FERC assets are reflected in our Montana Public Service Commission (MPSC) jurisdictional rates as a credit to retail customers. In March 2021, we submitted a compliance filing with the MPSC adjusting the revenue credit in our Montana retail rates to reflect the FERC approved settlement rates and a refund to retail customers of the difference between the FERC interim rates and the FERC approved settlement rates that were collected during the period from July 1, 2019 through March 31, 2021. The MPSC approved, on an interim basis, both the updated revenue credit, effective April 1, 2021, and amount of the refund that will be completed over a one-year period beginning April 1, 2021. As of March 31, 2021, we had cumulative deferred revenue of approximately $12.8 million.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2020, approximately 65 MW of CREPs. While we have made progress towards meeting this obligation by acquiring approximately 50 MW of CREPs, we have been unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC's action as it related to waivers granted for 2015 and 2016 has been challenged legally and we are waiting on a final decision from the Montana Supreme Court. We have also filed waiver requests for 2017, 2018, 2019, and 2020. The Montana Legislature is considering legislation that would repeal the statewide CREP mandate. If the legislation does not pass and the Montana Supreme Court rules that the 2015 and 2016 waivers were invalid or if the requested waivers for 2017 through 2020 are not granted, we are likely to be liable for penalties. If the MPSC imposes a penalty, the amount of the penalty would depend on how the MPSC calculated the energy that a CREP would have produced. However, we do not believe any such penalty would be material.

(4) Equity Investments

The following table presents our equity investments reflected in the investments in subsidiary companies on the Balance Sheets (in thousands):

	December 31,	
	2020	2019
Colstrip Unit 4 Basis Adjustment	$ (137,401)	$ (141,154)
Havre Pipeline Company, LLC	13,219	12,672
NorthWestern Services, LLC	2,018	1,972
NorthWestern Energy Solutions, Inc.	2,629	1,302
Risk Partners Assurance, Ltd.	1,248	2,595
Total Investments in Subsidiary Companies	**$ (118,287)**	**$ (122,613)**

(5) Regulatory Assets and Liabilities

We prepare our Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. These regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2020		December 31, 2019	
			(in thousands)			
Flow-through income taxes	14	Plant Lives	$	420,925	$	376,548
Pension	16	Undetermined		138,567		132,000
Excess deferred income taxes	14	Plant Lives		67,256		73,670
Employee related benefits	16	Undetermined		22,516		18,622
State & local taxes & fees		Various		17,904		7,141
Environmental clean-up	19	Various		11,127		11,179
Other		Various		34,090		32,279
Total Regulatory Assets			**$**	**712,385**	**$**	**651,439**
Excess deferred income taxes	14	Plant Lives	$	165,434	$	172,784
Unbilled revenue		1 Year		12,072		13,467
Gas storage sales		19 years		7,887		8,307
State & local taxes & fees		1 Year		1,783		1,846
Environmental clean-up		Various		656		1,181
Total Regulatory Liabilities			**$**	**187,833**	**$**	**197,585**

Income Taxes

Flow-through income taxes primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, and removal costs that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. Excess deferred income tax assets and liabilities are recorded as a result of the Tax Cuts and Jobs Act and will be recovered or refunded in future rates. See Note 14 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 19 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

Unbilled Revenue

In accordance with regulatory guidance in South Dakota, we recognize revenue when it is billed. Accordingly, we record a regulatory liability to offset unbilled revenue.

(6) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	Estimated Useful Life	December 31,	
		2020	2019
	(years)	(in thousands)	
Land and improvements	53 – 96	$ 165,620	$ 164,293
Building and improvements	23 – 73	516,678	482,911
Storage, distribution, and transmission	15 – 95	3,881,961	3,669,658
Generation	23 – 72	2,003,072	1,983,756
Construction work in process	-	166,454	88,678
Other equipment	2 – 45	363,976	351,460
Total utility plant		7,097,760	6,740,756
Less accumulated depreciation		(2,546,445)	(2,416,192)
Net utility plant		$ 4,551,315	$ 4,324,564

Net utility plant under capital (finance) lease were $11.3 million and $13.3 million as of December 31, 2020 and 2019, respectively, which included $11.1 million and $13.1 million as of December 31, 2020 and 2019, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2020				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 153,632	$ 62,927	$ 51,586	$ 317,438
Accumulated depreciation	44,329	37,000	41,402	106,679
December 31, 2019				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 155,662	$ 62,565	$ 52,448	$ 311,399
Accumulated depreciation	44,695	35,823	41,765	98,415

(7) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our utility plant and asset retirement obligations (ARO). The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the rate making process. We record regulatory assets and liabilities for differences in timing of asset retirement costs recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our ARO (in thousands):

	December 31,	
	2020	2019
Liability at January 1,	$ 42,449	$ 40,659
Accretion expense	2,070	2,051
Liabilities incurred	—	—
Liabilities settled	(4,061)	(46)
Revisions to cash flows	4,897	(215)
Liability at December 31,	$ 45,355	$ 42,449

During the twelve months ended December 31, 2020 our ARO liability decreased $4.1 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities. Additionally, during the twelve months ended December 31, 2020, our ARO liability increased $4.9 million related to changes in both the timing and amount of retirement cost estimates.

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates.

(8) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2020 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Financial Statements at December 31, 2020 and 2019. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCI to Income	Amount Reclassified from AOCI into Income during the Year Ended December 31, 2020
Interest rate contracts	Interest on long-term debt	$ 614

A pre-tax loss of approximately $14.6 million is remaining in AOCI as of December 31, 2020, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCI into interest on long-term debt during the next twelve months. These amounts relate to terminated swaps.

(10) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, and accounts payable, the carrying amount of each such items approximates fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 9 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2020	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Special deposits	$ 9,670	$ —	$ —	$ —	$ 9,670
Rabbi trust investments	27,027	—	—	—	27,027
Total	**$ 36,697**	**$ —**	**$ —**	**$ —**	**$ 36,697**
December 31, 2019					
Special deposits	$ 5,202	$ —	$ —	$ —	$ 5,202
Rabbi trust investments	29,288	—	—	—	29,288
Total	**$ 34,490**	**$ —**	**$ —**	**$ —**	**$ 34,490**

Special deposits represent amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2020		December 31, 2019	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,328,637	$ 2,643,131	$ 2,245,637	$ 2,429,170

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(11) Notes Payable and Credit Arrangements

Notes Payable

In April 2020, we entered into a $100 million Term Loan and borrowed the full amount. The Term Loan bears interest at variable rates tied to the Eurodollar rate plus a credit spread of 1.5 percent. Proceeds were used to repay a portion of our outstanding revolving credit facility borrowings and for general corporate purposes. All principal and unpaid interest under the Term Loan is due and payable on April 2, 2021. The Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The Term Loan requires us to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. It also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Term Loan; however a default on the Term Loan would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

Credit Facility

On September 2, 2020, we entered into a new $425 million Credit Facility to replace our existing facility. The Credit Facility increased the capacity from that of the prior facility by $25 million to $425 million and extended the maturity date to September 2, 2023 (from December 12, 2021), with uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. A total of ten banks participate in the facility, with no one bank providing more than 16 percent of the total availability. Commitment fees for the Credit Facility were $0.6 million and $0.3 million for the years ended December 31, 2020 and 2019.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2020	2019
Unsecured revolving line of credit, expiring September 2023	$ 425.0	$ —
Unsecured revolving line of credit, expiring December 2021	—	400.0
Unsecured revolving line of credit, expiring March 2022	25.0	25.0
	450.0	**425.0**
Amounts outstanding at December 31:		
Eurodollar borrowings	222.0	289.0
Letters of credit	—	—
	222.0	**289.0**
Net availability as of December 31	**$ 228.0**	**$ 136.0**

The Credit Facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Credit

Facility; however a default on the Credit Facility would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

(12) Long-Term Debt

Long-term debt consisted of the following (in thousands):

	Due	December 31, 2020	2019
Unsecured Debt:			
Unsecured Revolving Line of Credit	2023	$ 222,000	$ —
Unsecured Revolving Line of Credit	2021	—	289,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—3.21%	2030	50,000	—
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	150,000
Montana—3.21%	2030	100,000	—
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Total Long-Term Debt		$ 2,328,637	$ 2,245,637

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. These bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In June 2019, we priced $150 million aggregate principal amount of Montana First Mortgage Bonds, at a fixed interest rate of 3.98 percent maturing in 2049. We issued $50 million of these bonds in June 2019 and the remaining $100 million of these bonds in September 2019 in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana.

In May 2020, we issued $100 million principal amount of Montana First Mortgage Bonds and $50 million principal amount of South Dakota First Mortgage Bonds, each at a fixed interest rate of 3.21 percent maturing on May 15, 2030. These bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana and South Dakota.

As of December 31, 2020, we were in compliance with our financial debt covenants.

Other Long-Term Debt

The New Market Tax Credit (NMTC) financing is pursuant to Section 45D of the Internal Revenue Code of 1986 as amended, which was issued in association with a tax credit program related to the development and construction of a new office building in Butte, Montana. This financing agreement is structured with unrelated third party financial institutions (the Investor) and their wholly-owned community development entities (CDEs) in connection with our participation in qualified transactions under the NMTC program. Upon closing of this transaction in 2014, we entered into two loans totaling $27.0 million payable to the CDEs sponsoring the project, and provided an $18.2 million investment. In exchange for substantially all of the benefits derived from the tax credits, the Investor contributed approximately $8.8 million to the project. The NMTC is subject to recapture for a period of seven years. If the expected tax benefits are delivered without risk of recapture to the Investor and our performance obligation is relieved, we expect $7.9 million of the loan to be forgiven in July 2021. If we do not meet the conditions for loan forgiveness, we would be required to repay $27.0 million and would concurrently receive the return of our $18.2 million investment. The loans of $27.0 million are recorded in long-term debt and the investment of $18.2 million is recorded in other investments in the Balance Sheets.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are $366.7 million in 2023 and $300.0 million in 2025.

(13) Related Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31, 2020	December 31, 2019
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 1,673	$ 1,238
NorthWestern Energy Solutions, Inc.	61	51
Risk Partners Assurance, Ltd.	18	18
	$ 1,752	$ 1,307
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,776	$ 1,715

(14) Income Taxes

Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The income tax benefit during the twelve months ended December 31, 2019, reflects the release of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, net of tax, due to the lapse of statutes of limitation in the second quarter of 2019.

The components of the net deferred income tax assets and liabilities recognized in our Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2020	2019
Production tax credit	$ 63,542	$ 50,440
Pension / postretirement benefits	31,866	30,041
Customer advances	17,165	14,975
Unbilled revenue	14,429	9,820
Compensation accruals	11,748	13,163
NOL carryforward	16,525	16,054
Reserves and Accruals	6,265	7,069
Environmental liability	6,039	5,938
Interest rate hedges	3,171	3,956
Other, net	8,142	7,217
Deferred Tax Asset	**178,892**	**158,673**
Excess tax depreciation	(423,181)	(400,918)
Goodwill amortization	(91,647)	(82,595)
Flow through depreciation	(80,938)	(71,679)
Regulatory assets and other	(53,450)	(51,359)
Deferred Tax Liability	**(649,216)**	**(606,551)**

At December 31, 2020 our total federal NOL carryforward was approximately $78.6 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $0.4 million in 2036 and $78.2 million in 2037. Our state NOL carryforward as of December 31, 2020 was approximately $38.1 million. If unused, our state NOL carryforwards will expire in 2024. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2020	2019
Unrecognized Tax Benefits at January 1	$ 35,085	$ 56,150
Gross increases - tax positions in prior period	120	539
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,714)	(1,489)
Lapse of statute of limitations	—	(20,115)
Unrecognized Tax Benefits at December 31	$ 33,491	$ 35,085

Our unrecognized tax benefits include approximately $28.0 million related to tax positions as of December 31, 2020 and 2019, that if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest related to uncertain tax positions in interest expense. As of December 31, 2020 and December 31, 2019, we did not have any amounts accrued for the payment of interest. During the year ended December 31, 2019, we released $2.7 million of accrued interest in the Statements of Income.

Tax years 2017 and forward remain subject to examination by the IRS and state taxing authorities. In addition, the available federal net operating loss carryforward may be reduced by the IRS for losses originating in certain tax years from 2003 forward.

(15) Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	December 31,					
	2020			2019		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ 88	$ —	$ 88	$ (35)	$ —	$ (35)
Reclassification of net income (loss) on derivative instruments	614	(162)	452	613	(160)	453
Postretirement medical liability adjustment	2,462	(623)	1,839	(175)	44	(131)
Other comprehensive income (loss)	$ 3,164	$ (785)	$ 2,379	$ 403	$ (116)	$ 287

Balances by classification included within AOCI on the Balance Sheets are as follows, net of tax (in thousands):

	December 31, 2020	December 31, 2019
Foreign currency translation	$ 1,501	$ 1,413
Derivative instruments designated as cash flow hedges	(8,579)	(9,031)
Postretirement medical plans	1,952	113
Accumulated other comprehensive loss	$ (5,126)	$ (7,505)

The following table displays the changes in AOCI by component, net of tax (in thousands):

	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
		December 31, 2020			
		Year Ended			
Beginning balance		$ (9,031)	$ 113	$ 1,413	$ (7,505)
Other comprehensive income before reclassifications		—	—	88	88
Amounts reclassified from AOCI	Interest on long-term debt	452	—	—	452
Amounts reclassified from AOCI		—	1,839	—	1,839
Net current-period other comprehensive income		452	1,839	88	2,379
Ending Balance		$ (8,579)	$ 1,952	$ 1,501	$ (5,126)

	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
		December 31, 2019			
		Year Ended			
Beginning balance		$ (9,484)	$ 244	$ 1,448	$ (7,792)
Other comprehensive income before reclassifications		—	—	(35)	(35)
Amounts reclassified from AOCI	Interest on long-term debt	453	—	—	453
Amounts reclassified from AOCI		—	(131)	—	(131)
Net current-period other comprehensive income (loss)		453	(131)	(35)	287
Ending Balance		$ (9,031)	$ 113	$ 1,413	$ (7,505)

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our Financial Statements. See Note 5 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2020	2019	2020	2019
Change in benefit obligation:				
Obligation at beginning of period	$ 735,564	$ 649,626	$ 20,272	$ 20,611
Service cost	11,116	9,637	370	331
Interest cost	22,840	26,488	492	609
Actuarial loss	84,479	83,364	123	997
Settlements	—	(4,065)	390	390
Benefits paid	(33,020)	(29,486)	(2,501)	(2,666)
Benefit Obligation at End of Period	$ 820,979	$ 735,564	$ 19,146	$ 20,272
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 609,000	$ 525,310	$ 21,479	$ 18,670
Return on plan assets	101,075	107,041	2,723	3,805
Employer contributions	11,401	10,200	1,395	1,670
Settlements	—	(4,065)	—	—
Benefits paid	(33,020)	(29,486)	(2,501)	(2,666)
Fair value of plan assets at end of period	$ 688,456	$ 609,000	$ 23,096	$ 21,479
Funded Status	$ (132,523)	$ (126,564)	$ 3,950	$ 1,207
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	7,001	4,333	8,436	7,783
Total Assets	7,001	4,333	8,436	7,783
Current liability	(11,200)	(11,401)	(1,712)	(2,113)
Noncurrent liability	(128,324)	(119,496)	(2,774)	(4,463)
Total Liabilities	(139,524)	(130,897)	(4,486)	(6,576)
Net amount recognized	$ (132,523)	$ (126,564)	$ 3,950	$ 1,207
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	3,857	5,890
Net actuarial loss	(115,987)	(111,449)	(497)	259
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(246)	(397)
Net actuarial gain	—	—	3,246	934
Total	$ (115,987)	$ (111,449)	$ 6,360	$ 6,686

The actuarial gain/loss is primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts.

The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2020	2019
Projected benefit obligation	$ 757.4	$ 675.5
Accumulated benefit obligation	757.4	675.5
Fair value of plan assets	619.1	545.8

As of December 31, 2020, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2020	2019	2020	2019
Components of Net Periodic Benefit Cost				
Service cost	$ 11,116	$ 9,637	$ 370	$ 331
Interest cost	22,840	26,488	492	609
Expected return on plan assets	(26,162)	(25,443)	(983)	(869)
Amortization of prior service cost (credit)	—	—	(1,882)	(1,882)
Recognized actuarial loss (gain)	5,028	6,544	(61)	(96)
Settlement loss recognized	—	198	390	390
Net Periodic Benefit Cost (Credit)	$ 12,822	$ 17,424	$ (1,674)	$ (1,517)
Regulatory deferral of net periodic benefit cost (1)	(2,100)	(7,510)	—	—
Previously deferred costs recognized (1)	71	728	861	931
Amount Recognized in Income	$ 10,793	$ 10,642	$ (813)	$ (586)

(1) Net periodic benefit costs for pension and postretirement benefit plans are recognized for financial reporting based on the authorization of each regulatory jurisdiction in which we operate. A portion of these costs are recorded in regulatory assets and recognized in the Statements of Income as those costs are recovered through customer rates.

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2020 and 2019. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The decrease in discount rate during 2020 increased our projected benefit obligation by approximately $92.1 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we decreased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 4.17 percent and decreased our assumption on the NorthWestern Corporation Pension Plan to 3.01 percent for 2021.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2020	2019	2020	2019
Discount rate	2.20-2.30 %	3.10-3.20 %	1.80 %	2.80 %
Expected rate of return on assets	3.45-4.49	4.23-5.06	4.71	4.79
Long-term rate of increase in compensation levels (non-union)	2.84	2.84	2.84	2.84
Long-term rate of increase in compensation levels (union)	2.00	2.00	2.00	2.00
Interest crediting rate	3.30-6.00	3.60-6.00	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00 percent fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, Prudent Man Rule of the Employee Retirement Income Security Act of 1974 and liability-based considerations. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- Pension Plan portfolio risk is described by volatility in the funded status of the Plans;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the pension plans overall funded status, (such assets will be described as Fixed Income Security assets);
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5 percent, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2020	2019	2020	2019	2020	2019
Fixed income securities	55.0 %	55.0 %	80.0 %	80.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	4.0	4.0	2.0	2.0	—	—
Global equities	41.0	41.0	18.0	18.0	60.0	60.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2020	2019	2020	2019	2020	2019
Cash and cash equivalents	— %	— %	0.7 %	0.9 %	1.0 %	1.0 %
Fixed income securities	52.7	53.8	77.3	77.0	37.9	37.8
Non-U.S. fixed income securities	3.8	4.0	2.6	2.6	—	—
Global equities	43.5	42.2	19.4	19.5	61.1	61.2
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in global equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the Securities and Exchange Commission (SEC). Investments in a collective investment vehicle are valued by multiplying the investee company’s net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT’s investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT’s investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. During 2019, due to proposed changes in the John Hancock participating group annuity contract held by the NorthWestern Corporation plan, we elected to discontinue the contract effective January 1, 2020.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. We expect to continue to make contributions to the pension plans in 2021 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2020 and 2019 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2020	2019
NorthWestern Energy Pension Plan (MT)	$ 10,201	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 11,401	$ 10,200

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2021	$ 35,200	$ 2,729
2022	36,533	2,469
2023	37,847	2,331
2024	39,189	1,615
2025	40,210	1,457
2026-2030	209,556	5,699

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2020 and 2019 were $11.1 million and $11.0 million, respectively.

(17) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2020, there were 216,647 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals. These awards contain both market- and performance-based components. The performance goals are independent of each other and equally weighted, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance unit awards. The fair value of the earnings per share component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2020	2019
Risk-free interest rate	1.42 %	2.47 %
Expected life, in years	3	3
Expected volatility	14.9% to 19.7%	16.4% to 20.9%
Dividend yield	3.1 %	3.5 %

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2020, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	178,245	$ 53.00
Granted	62,116	73.13
Vested	(105,512)	47.99
Forfeited	(4,278)	63.57
Remaining nonvested grants	130,571	$ 66.27

We recognized compensation expense of $2.2 million and $6.5 million for the years ended December 31, 2020 and 2019, respectively, and related income tax (benefit) expense of $(0.6) million and $0.2 million for the years ended December 31, 2020 and 2019, respectively. As of December 31, 2020, we had $9.1 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $5.1 million and $4.2 million for the years ended December 31, 2020 and 2019, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2020, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	72,858	$ 51.35
Granted	20,199	44.57
Vested	(15,090)	44.77
Forfeited	—	—
Remaining nonvested grants	77,967	$ 50.86

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100 percent of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director’s compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years).

Following is a summary of the components of DSUs issued and compensation expense attributable to the DSUs (in millions, except DSU amounts):

	December 31,	
	2020	2019
DSUs Issued	21,434	19,027
Compensation expense	$ 1.5	$ 1.3
Change in value of shares	(2.9)	2.4
Total compensation (benefit) expense	$ (1.4)	$ 3.7
DSUs withdrawn	613	3,708
Value of DSUs withdrawn	$ 0.1	$ 0.3

(18) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,865,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 17 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 35,378 and 25,329 during the years ended December 31, 2020 and 2019, respectively, and are reflected in reacquired capital stock. These shares were credited to reacquired capital stock based on their fair market value on the vesting date.

(19) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act (PURPA). These contracts require us to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. As of December 31, 2020, our estimated gross contractual obligation related to these contracts was approximately $552.0 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $448.5 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Operation expenses and Operating revenues in our Statements of Income. The present value of the remaining liability is recorded in Accumulated miscellaneous operating provisions in our Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2020	2019
Beginning QF liability	$ 92,937	$ 102,260
Unrecovered amount (1)	(18,665)	(17,257)
Interest on long-term debt	7,107	7,934
Ending QF liability	$ 81,379	$ 92,937

(1) The change in the unrecovered amount includes (i) a lower periodic adjustment of $1.1 million due to actual price escalation, which was less than previously modeled, and (ii) higher costs of approximately $2.2 million, due to a $0.9 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $3.1 million reduction in costs in the prior period.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2021	$ 77,722	$ 60,136	$ 17,586
2022	79,572	60,639	18,933
2023	81,646	61,280	20,366
2024	79,384	60,706	18,678
2025	65,041	52,950	12,091
Thereafter	168,592	152,837	15,755
Total	$ 551,957	$ 448,548	$ 103,409

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in Operating expenses in the Statements of Income and were approximately $206.6 million and $222.5 million for the years ended December 31, 2020 and 2019, respectively. As of December 31, 2020, our commitments under these contracts were $211.5 million in 2021, $190.9 million in 2022, $195.1 million in 2023, $173.2 million in 2024, $170.1 million in 2025, and $1.3 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $28.4 million between 2021 and 2040. These commitments are not reflected in our Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us, is estimated to range between $26.6 million to $32.2 million. As of December 31, 2020, we had a reserve of approximately $28.9 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

The following summarizes the change in our environmental liability (in thousands):

	December 31,	
	2020	2019
Liability at January 1,	$ 30,276	$ 29,741
Deductions	(2,977)	(2,232)
Charged to costs and expense	1,596	2,767
Liability at December 31,	$ 28,895	$ 30,276

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or results of operations.

Manufactured Gas Plants - Approximately $22.7 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2020, the reserve for remediation costs at this site was approximately $8.2 million, and we estimate that approximately $3.1 million of this amount will be incurred during the next five years.

Nebraska - We own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the MDEQ voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and soil, groundwater, and vapor intrusion work was conducted in 2020. We expect work at the Helena site will continue in 2021.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party is assuming the lead role at the site and has expressed its intent to pursue a voluntary remediation at the Missoula site. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

Global Climate Change **-** National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide (CO_2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, investor activism and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In 2019, the EPA finalized the Affordable Clean Energy Rule (ACE), which repealed the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. The U.S. Court of Appeals for the District of Columbia Circuit issued an opinion on January 19, 2021, vacating the ACE and remanding it to EPA for further action. It is widely expected that the Biden Administration will develop an alternative plan for reducing GHG emissions from coal-fired plants.

We cannot predict whether or how GHG emission regulations will be applied to our plants, including any actions taken by relevant state authorities. In addition, it is unclear how litigation relating to GHG matters will impact us. As GHG regulations are implemented, it could result in additional compliance costs impacting our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions may not be available within a timeframe consistent with the implementation of any such requirements. Physical impacts of climate change also may present potential risks for severe weather, such as droughts, fires, floods, ice storms and tornadoes, in the locations where we operate or have interests. These potential risks may impact costs for electric and natural gas supply and maintenance of generation, distribution, and transmission facilities.

Jointly Owned Plants **-** We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures **-** The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

Regional Haze Rules **-** In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

By July 31, 2021, Montana must develop and submit to the EPA for approval a revised plan that demonstrates reasonable progress toward eliminating man-made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In March 2017, we filed a Petition for Review of these amendments with the D.C. Circuit, which was consolidated with other petitions challenging the final rule. The D.C. Circuit has granted the EPA's request to hold the case in abeyance while the EPA considers further administrative action to revisit the rule.

The North Dakota Department of Environmental Quality (ND DEQ) is expected to decide on statewide reduction strategy in 2021 which could impact the Coyote generating facility. Once the ND DEQ establishes a State Implementation Plan (SIP) for regional haze compliance, the SIP will be submitted for approval to the North Dakota Governor's office and finally to EPA for approval. Following EPA's approval, which is not expected to occur until the second half of 2021 or later, the joint owners of the Coyote generating facility will assess the requirements, if any, and determine whether to move forward with the installation of additional emissions controls. Additional controls, if any, to meet new emission restrictions would have to be in place by the end of 2028 under the current schedule.

Other **-** We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating with PNWS in early 2016 to purchase the output from 21 of its proposed facilities pursuant to our standard QF-1 Tariff, which is applicable to projects no larger than 3 MWs.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for that category of solar projects, which included the projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had both submitted a signed power purchase agreement and had executed an interconnection agreement with us by June 16, 2016. Although we had signed four power purchase agreements with PNWS as of that date, we had not entered into interconnection agreements with PNWS for any of those projects. As a result, none of the PNWS projects in Montana qualified for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and a judicial declaration that some or all of the 21 proposed power purchase agreements it had proposed to us were in effect despite the MPSC's Order. We removed the state lawsuit to the United States District Court for the District of Montana (Court).

PNWS also requested the MPSC to exempt its projects from the tariff suspension and allow those projects to receive the QF-1 tariff rate that had been in effect prior to the suspension. We joined in PNWS's request for relief with respect to four of the projects, but the MPSC did not grant any of the relief requested by PNWS or us.

In August 2017, pursuant to a non-monetary, partial settlement with us, PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the amount of damages sought by the plaintiff was reduced to approximately $8 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and subsequent settlement efforts also have been unsuccessful. A jury trial was scheduled to begin on June 2, 2020, but the trial was postponed because of the court closure due to the COVID-19 pandemic and has not yet been rescheduled.

We dispute the remaining claims in PNWS' lawsuit and will continue to vigorously defend against them. We cannot currently predict an outcome in this litigation. If the plaintiff prevails and obtains damages for a breach of contract, we may seek to recover those damages in rates from customers. We cannot predict the outcome of any such effort.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen's, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history. In 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). The State filed a motion to remand. Following briefing and argument, on October 10, 2017, the Federal District Court entered an order denying the State's motion.

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier-filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed from "the head of the Black Eagle Falls to the foot of the Great Falls." In particular, the dismissal pertained to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. While the dismissal of these four facilities may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant and removing claims of ownership for the hydroelectric facilities on the Great Falls Reach, except for the Morony and the Black Eagle Developments. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. The Federal District Court held a scheduling conference on June 18, 2020 at which it approved a plan for discovery, and set deadlines in the case, including a trial date of September 27, 2021 on the issue of navigability. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable. The parties are engaged in discovery and the State has served its expert reports. We, along with the other Defendants, served our expert reports and the State has filed rebuttal expert reports. Expert discovery is ongoing and is due to conclude in May 2021.

We dispute the State's claims and intend to vigorously defend the lawsuit. At this time, we cannot predict an outcome. If the Federal District Court determines the riverbeds are navigable under the remaining six facilities that were not dismissed and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $3.8 million commencing when we acquired the facilities in November 2014. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$12,873	0.00%
3	2302 Franchises and Consents	114,169	114,169	0.00%
4	2303 Miscellaneous Intangible Plant	275,607	478,448	-42.40%
5	**Total Intangible Plant**	402,650	$605,490	-33.50%
6				
7	**Production Plant**			
8	2325 Gas Leaseholds	74,864,890	74,849,087	0.02%
9	2327 Field Compressor Structure	64,803	64,803	0.00%
10	2328 Field Mea & Reg Structure	642,881	505,762	27.11%
11	2330 Well Construction	4,818,870	4,818,870	0.00%
12	2331 Well Equipment	5,178,227	5,032,456	2.90%
13	2332 Field Lines	2,579,503	2,579,460	0.00%
14	2333 Field Compressor Equipment	1,522,902	1,522,902	0.00%
15	2334 Measuring & Regulating Equip.	2,137,711	2,137,711	0.00%
16	2337 Other Equipment	63,672	63,672	0.00%
17	**Total Production Plant**	91,873,460	91,574,725	0.33%
18				
19	**Underground Storage Plant**			
20	2350 Land and Land Rights	4,943,533	4,898,423	0.92%
21	2351 Structures and Improvements	3,233,438	3,272,083	-1.18%
22	2352 Wells	9,403,054	8,661,632	8.56%
23	2353 Lines	15,171,116	14,798,171	2.52%
24	2354 Compressor Station Equipment	13,144,892	13,132,996	0.09%
25	2355 Measuring & Regulating Equip.	2,988,464	2,988,464	0.00%
26	2356 Purification Equipment	567,763	567,763	0.00%
27	2357 Other Equipment	1,307,943	1,005,724	30.05%
28	**Total Underground Storage Plant**	50,760,202	49,325,255	2.91%
29				
30	**Transmission Plant**			
31	2365 Rights of Way	11,978,184	11,905,191	0.61%
32	2366 Structures and Improvements	29,057,925	17,790,607	63.33%
33	2367 Mains	240,808,482	236,466,752	1.84%
34	2368 Compressor Station Equipment	44,401,105	44,255,528	0.33%
35	2369 Meas. & Reg. Station Equipment	26,325,279	24,878,192	5.82%
36	2370 Communication Equipment	-	-	-
37	2371 Other Equipment	433,949	351,179	23.57%
38	**Total Transmission Plant**	353,004,923	335,647,450	5.17%
39				
40	**Distribution Plant**			
41	2374 Land and Land Rights	1,299,692	1,299,366	0.03%
42	2375 Structures and Improvements	293,084	271,865	7.80%
43	2376 Mains	211,942,707	198,189,349	6.94%
44	2377 Compressor Station Equipment	-	-	-
45	2378 M&R Station Equip.-General	4,751,325	4,533,387	4.81%
46	2379 M&R Station Equip.-City Gate	-	-	-
47	2380 Services	94,557,048	88,759,291	6.53%
48	2381 Customers Meters and Regulators	77,324,810	74,395,055	3.94%
49	2382 Meter Installations			-
50	2383 House Regulators			-
51	2384 House Regulator Installations			-
52	2385 M&R Station Equip.-Industrial	96,629	95,843	0.82%
53	2386 Other Prop. on Customers' Premises			-
54	2387 Other Equipment	76,604	52,889	44.84%
55	**Total Distribution Plant**	390,341,898	367,597,046	6.19%

Sch. 19	cont. MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	0.00%
4	2390 Structures and Improvements	2,488,751	2,500,751	-0.48%
5	2391 Office Furniture and Equipment	195,419	195,419	0.00%
6	2392 Transportation Equipment	16,299,211	14,602,484	11.62%
7	2393 Stores Equipment	198,972	198,972	0.00%
8	2394 Tools, Shop & Garage Equipment	7,250,533	7,068,189	2.58%
9	2395 Laboratory Equipment	365,625	365,625	0.00%
10	2396 Power Operated Equipment	5,111,320	4,991,594	2.40%
11	2397 Communication Equipment	3,322,707	3,644,630	-8.83%
12	2398 Miscellaneous Equipment	104,235	104,235	0.00%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	35,438,448	33,773,574	4.93%
15	**Total Gas Plant in Service**	921,821,582	878,523,540	4.93%
16				
17	4101 Gas Plant Allocated from Common	55,122,988	50,595,148	8.95%
18	2105 Gas Plant Held for Future Use	29,866	29,866	0.00%
19	2107 Gas Construction Work in Progress	25,669,068	11,818,632	117.19%
20	2117 Gas in Underground Storage	44,744,243	38,576,213	15.99%
21				
22				
23	**TOTAL GAS PLANT**	$1,047,387,746	$979,543,399	6.93%
24				
25				
26	**CONSOLIDATED**	December 31,		
27	**PLANT IN SERVICE**	2020	2019	
28				
29	Montana Electric	$ 4,024,698,866	$ 3,836,098,729	
30	Yellowstone National Park	21,309,430	20,566,048	
31	Montana Natural Gas (Includes CMP)	921,821,582	878,523,540	
32	Common	170,239,284	156,276,853	
33	Townsend Propane	1,523,174	1,523,174	
34	South Dakota Electric	946,530,965	919,455,466	
35	South Dakota Natural Gas	220,364,733	214,087,657	
36	South Dakota Common	63,763,314	65,126,233	
37	Asset Retirement Obligation	27,990,906	28,419,923	
38	**TOTAL PLANT**	$ 6,398,242,253	$ 6,120,077,623	

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	91,873,460	$42,834,125	$38,523,158	5.36%
4					
5	Underground Storage	50,760,202	26,302,603	26,004,812	1.68%
6					
7	Other Storage	-	-	-	-
8					
9	Transmission	353,004,923	129,013,372	123,605,060	1.73%
10					
11	Distribution	390,341,898	156,767,577	148,645,590	2.67%
12					
13	General and Intangible	35,841,097	24,594,444	22,591,228	10.30%
14					
15	Common	55,122,988	15,872,008	14,391,911	6.65%
16					
17					
18	**Total Accum Depreciation**	$976,944,568	$395,384,130	$373,761,759	2.82%
19					
20					
21					

		December 31,	
22	**Consolidated**		
23	**Accumulated Depreciation**	2020	2019
24			
25	Montana Electric	$1,538,688,590	$1,457,741,356
26	Yellowstone National Park	10,775,157	10,362,821
27	Montana Natural Gas (Includes CMP)	379,512,122	359,369,848
28	Common	44,485,802	39,758,905
29	Townsend Propane	1,006,510	965,806
30	South Dakota Electric	321,722,932	308,635,918
31	South Dakota Natural Gas	99,910,123	96,070,624
32	South Dakota Common	20,058,902	18,924,500
33	Acquisition Writedown	43,276,641	45,981,130
34	Basin Creek Capital Lease	29,151,894	27,141,417
35	FIN 47	2,584,933	5,934,936
36	CWIP-Capital Retirement Clearing	-6,356,971	-6,072,919
37	**Total Consolidated Accum Depreciation**	$2,484,816,637	$2,364,814,342

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	-	-	-
5	Construction	-	-	-
6	Storage Plant	$ 255,118	$ 266,531	-4.28%
7	Transmission Plant	1,724,290	1,764,847	-2.30%
8	Distribution Plant	3,121,381	3,189,803	-2.15%
9				
10	**Total MT Materials and Supplies**	$5,100,789	$5,221,181	-2.31%
11			-	
12				
13	**Consolidated**	December 31,		
14	**Materials and Supplies**	2020	2019	
15				
16	Montana Natural Gas	$5,100,789	$5,221,181	
17	Montana Electric	27,003,447	26,945,411	
18	South Dakota	11,587,583	10,027,461	
19				
20	**Total Consolidated Materials and Supplies**	$43,691,819	$42,194,053	

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
1				
2	Docket Number: 2016.9.68			
3	Order Number : 7522g			
4	Effective Date : September 1, 2017			
5				
6	Common Equity	46.79%	9.55%	4.47%
7	Long Term Debt	53.21%	4.67%	2.49%
8				
9	**TOTAL**	100.00%		6.96%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(Decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 155,215,334	$ 202,120,237	-23.21%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	151,822,661	143,573,417	5.75%
6	Amortization, Net	32,493,241	34,025,653	-4.50%
7	Other Noncash Charges to Net Income, Net	9,164,507	12,601,984	-27.28%
8	Deferred Income Taxes, Net	(8,915,420)	(15,202,199)	41.35%
9	Investment Tax Credit Adjustments, Net	(3,229)	(11,504)	71.93%
10	Change in Operating Receivables, Net	2,531,086	(734,853)	>300.00%
11	Change in Materials, Supplies & Inventories, Net	(7,107,682)	(3,034,752)	-134.21%
12	Change in Operating Payables & Accrued Liabilities, Net	36,683,477	(22,950,788)	259.84%
13	Allowance for Funds Used During Construction (AFUDC)	(6,890,979)	(5,767,108)	-19.49%
14	Change in Other Assets & Liabilities, Net	25,733,749	(49,866,185)	151.61%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(4,306,292)	(2,490,895)	-72.88%
17	Change in Regulatory Assets	(22,881,012)	3,192,037	>-300.00%
18	Change in Regulatory Liabilities	(9,752,604)	864,407	>-300.00%
19	**Net Cash Provided by Operating Activities**	353,786,837	296,319,450	19.39%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(407,029,942)	(315,726,633)	-28.92%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(41,825)	(135,049)	69.03%
24	Proceeds from Sale of Assets	-	-	-
25	**Net Cash Used in Investing Activities**	(407,071,767)	(315,861,683)	-28.88%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	150,000,000	150,000,000	0.00%
29	Issuance of Notes Payable	100,000,000	-	100.00%
30	Line of Credit Borrowings, Net	-	-	100.00%
31	Proceeds From Issuance of Common Stock, Net	-	-	100.00%
32	Payments for Retirement of:			
33	Repayments of Short Term Borrowings, Net	-	-	-
34	Line of Credit Repayments, Net	(67,000,000)	(19,000,000)	-252.63%
35	Dividends on Common Stock	(120,349,736)	(115,126,908)	-4.54%
36	Other Financing Activities:			
37	Debt Financing Costs	(2,577,869)	(1,114,915)	-131.22%
38	Treasury Stock Activity	(1,391,881)	1,431,891	-197.21%
39	**Net Cash Used in Financing Activities**	58,680,515	16,190,069	262.45%
40	**Net Increase/Decrease in Cash and Cash Equivalents**	5,395,584	(3,352,164)	260.96%
41	**Cash and Cash Equivalents at Beginning of Year**	10,148,429	13,500,593	-24.83%
42	**Cash and Cash Equivalents at End of Year**	$ 15,544,013	$ 10,148,429	53.17%
43				
44	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
45	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
46	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
47	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
48				
49				
50				
51				
52				

Sch. 24	MONTANA LONG TERM DEBT 2020								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
4	5.71% Series ($55M), Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
5	5.01% Series ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
6	4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
7	4.30% Series($40M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
8	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	730,647	4.87%
9	3.99% Series($35M), Due 2028	12/19/13	12/19/28	35,000,000	34,836,556	35,000,000	3.99%	1,409,343	4.03%
10	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,743,514	450,000,000	4.18%	19,570,295	4.35%
11	3.11% Series($75M), Due 2025	06/23/15	07/01/25	75,000,000	74,563,893	75,000,000	3.11%	2,746,650	3.66%
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11%	5,367,425	4.29%
13	4.03% Series ($250M) Due 2047	11/06/17	11/06/47	250,000,000	248,817,402	250,000,000	4.03%	10,644,517	4.26%
14	3.98% Series($50M), Due 2049	06/26/19	06/26/49	50,000,000	49,538,281	50,000,000	3.98%	2,005,911	4.01%
14	3.98% Series($150M), Due 2049	09/17/19	09/17/49	100,000,000	99,493,713	100,000,000	3.98%	3,997,195	4.00%
15	3.21% Series($100M) Due 2030	05/15/20	05/15/30	100,000,000	99,516,844	100,000,000	3.21%	3,269,948	3.27%
16	**Total First Mortgage Bonds**			$ 1,516,000,000	$ 1,505,611,161	$ 1,516,000,000		$ 65,715,460	4.33%
17									
18	**Pollution Control Bonds**								
19	2.00% Series ($144.7M), Due 2023	08/11/16	08/01/23	$ 144,660,000	$ 138,906,956	$ 144,660,000	2.000%	$ 3,627,593	2.51%
20									
21	**Total Pollution Control Bonds**			$ 144,660,000	$ 138,906,956	$ 144,660,000		$ 3,627,593	2.51%
22									
23	**Other Long-Term Debt**								
24	New Market Tax Credit Financing - New G.O Bldg	07/01/14	07/01/46	$ 26,976,900	$ 26,292,348	$ 26,976,900	1.146%	$ 353,344	1.31%
25									
26	**Total Other Long Term Debt**			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 353,344	1.31%
27									
28	**TOTAL LONG TERM DEBT**			$ 1,687,636,900	$ 1,670,810,464	$ 1,687,636,900		$ 69,696,398	4.13%

31 This schedule does not reflect our obligations under capital lease which total $16,311,620.

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not Applicable									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	50,466,670	$40.78				$77.34	$69.69	
February	50,563,706	41.03				80.52	69.49	
March	50,566,520	40.75	$1.00	0.600		78.08	45.06	
April	50,569,582	40.96				65.38	56.36	
May	50,570,632	41.06				61.42	52.10	
June	50,574,016	40.60	0.43	0.600		64.17	51.00	
July	50,576,089	40.75				57.26	50.87	
August	50,577,470	41.04				58.51	51.41	
September	50,581,138	40.62	0.58	0.600		53.53	47.43	
October	50,582,738	40.73				56.65	48.22	
November	50,584,191	41.10				62.82	52.16	
December	50,587,203	41.10	$1.06	0.600		59.41	53.39	
TOTAL Year End	50,559,208	$41.10	$3.07	$2.40	21.82%	$57.73		18.8

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2020.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$939,793,504	$885,712,694	6.11%
3	108 Accumulated Depreciation	(385,969,201)	(365,762,888)	-5.52%
4				
5	**Net Plant in Service**	$553,824,303	$519,949,806	6.51%
6	Additions:			
7	154, 156 Materials & Supplies	$9,966,761	$8,883,151	12.20%
8	165 Prepayments			
9	Other Additions	44,584,701	42,324,481	5.34%
10				
11	**Total Additions**	$54,551,463	$51,207,632	6.53%
12	Deductions:			
13	190 Accumulated Deferred Income Taxes	$37,380,818	$45,951,202	-18.65%
14	252 Customer Advances for Construction	13,766,686	12,219,463	12.66%
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions	52,217,672	53,728,961	-2.81%
17				
18	**Total Deductions**	$103,365,176	$111,899,626	-7.63%
19	**Total Rate Base**	$505,010,589	$459,257,813	9.96%
20	**Adjusted Rate Base**	$505,010,589	$459,257,813	9.96%
21	**Net Earnings**	$ 28,801,361	$ 40,068,782	-28.12%
22	**Rate of Return on Average Rate Base**	5.703%	8.725%	-34.63%
23	**Rate of Return on Average Equity 1/**	7.794%	14.194%	-45.09%
24				
25	**Major Normalizing and**			
26	**Commission Ratemaking Adjustments**			
27	Rate Schedule Revenues	$2,771,101	($11,761,790)	123.56%
28				
29				
30	Non-Allowables:			
31	Advertising	117,508	563,505	-79.15%
32	Dues, Contributions, Other	23,114	39,003	-40.74%
33				
34	Associated Income Taxes 2/	1,399,305	4,783,631	-70.75%
35				
36	**Total Adjustments**	$4,311,028	($6,375,651)	167.62%
37	**Revised Net Earnings**	$33,112,389	$33,693,131	-1.72%
38				
39	**Rate Base Adjustment**			
40	Stipulation with MCC 3/	($8,113,895)	($8,540,268)	4.99%
41				
42	**Revised Rate Base**	$496,896,694	$450,717,545	10.25%
43	**Adjusted Rate of Return on Average Rate Base**	6.664%	7.475%	-10.86%
44	**Adjusted Rate of Return on Average Equity 1/**	8.844%	10.565%	-16.29%
45				
46	1/ Return on Equity calculated using the capital structure approved in Docket No. D2016.9.68.			
47				
48	2/ Associated Income taxes include an interest synchronization adjustment based upon the approved			
49	capital structure in Docket No. D2016.9.68.			
50				
51	3/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting one-third of the $38.8 million			
52	allocated to natural gas as a rate base reduction.			
53				
54				
55				
56				
57				
58				
59				

Sch. 27	cont.	MONTANA EARNED RATE OF RETURN - GAS		
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	Gas Stored Underground	35,735,152	33,336,707	7.19%
4	Cost of Refinancing Debt	8,843,315	8,852,694	-0.11%
5	MPSC/MCC Taxes	6,234	135,079	-95.38%
6				
7	**Total Other Additions**	$44,584,701	$42,324,481	5.34%
8				
9	**Detail - Other Deductions**			
10	Personal Injury and Property Damage	$2,286,318	$2,103,006	8.72%
11	Storage Gas Sales 2000 & 2001	8,097,235	8,500,230	-4.74%
12	Gross Cash Requirements	14,051,515	14,033,523	0.13%
13	Regulatory Liability (TCJA)	$27,782,605	$29,092,202	-4.50%
14				
15				
16	**Total Other Deductions**	$52,217,672	$53,728,961	-2.81%

Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 976,944,569
5	105	Plant Held for Future Use	29,866
6	107	Construction Work in Progress	25,669,068
7	117	Gas in Underground Storage	44,744,243
8	151-163	Materials & Supplies	5,100,789
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	395,384,130
11	252	Customer Advances	14,852,544
12	**NET BOOK COSTS**		642,251,860
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	181,976,229
17			
18	**Total Operating Revenues**		181,976,229
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	86,492,386
21	403-407	Depreciation, Depletion, & Amortization Expenses	25,901,449
22	408.1	Taxes Other than Income Taxes	38,983,273
23	409-411	Federal & State Income Taxes	1,797,760
24			
25	**Total Operating Expenses**		153,174,868
26	**Net Operating Income**		28,801,361
27			
28	415-421.1	Other Income	1,538,702
29	421.2-426.5	Other Deductions	263,854
30	**NET INCOME BEFORE INTEREST EXPENSE**		$ 30,076,209
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	177,339
34		Commercial	24,498
35		Industrial	231
36		Other (including interdepartmental)	152
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		202,220
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	78.3
41		Average Annual Residential Cost per (Dkt)	$7.44
42		Average Residential Monthly Bill	$48.61
43			
44		Plant in Service (Gross) per Customer	$4,831

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	488	77	1	566
2	Amsterdam	180	56	12	-	68
3	Anaconda	9,298	3,436	331	5	3,772
4	Augusta	309	199	49	1	249
5	Belfry	218	4	-	-	4
6	Belgrade	7,389	6,674	1,175	1	7,850
7	Big Mountain	-	265	34	-	299
8	Big Sandy	598	292	72	-	364
9	Big Timber	1,641	945	189	7	1,141
10	Bigfork	4,270	1,609	231	-	1,840
11	Billings	104,170	26	3	-	29
12	Bonner	1,663	80	22	-	102
13	Boulder	1,183	459	81	2	542
14	Bozeman	37,280	26,287	3,858	6	30,151
15	Browning	2,801	1,104	158	4	1,266
16	Buffalo	-	7	1	-	8
17	Butte	33,525	13,011	1,479	33	14,523
18	Cardwell	50	19	4	-	23
19	Carter	58	27	10	-	37
20	Chester	847	357	137	1	495
21	Chinook	1,203	711	140	5	856
22	Choteau	1,684	887	183	4	1,074
23	Churchill	902	465	46	-	511
24	Clancy	1,661	754	38	-	792
25	Clinton	1,052	376	18	1	395
26	Columbia Falls	4,688	3,658	389	3	4,050
27	Columbus	1,893	1,126	182	4	1,312
28	Conrad	2,570	1,135	220	10	1,365
29	Coram	539	120	26	-	146
30	Corbin	-	1	-	-	1
31	Corvallis	976	1,351	103	-	1,454
32	Cut Bank	2,869	44	12	1	57
33	Deer Lodge	3,111	1,614	220	5	1,839
34	Dillon	4,134	2,146	354	5	2,505
35	Drummond	309	200	50	2	252
36	East Glacier Park	363	141	49	1	191
37	East Helena	1,984	2,169	133	3	2,305
38	Elliston	219	103	14	-	117
39	Essex	-	102	21	1	124
40	Fairfield	708	418	88	4	510
41	Florence	765	1,339	89	1	1,429
42	Floweree	-	40	9	-	49
43	Fort Belknap	1,293	321	62	-	383
44	Fort Benton	1,464	653	159	-	812
45	Fort Harrison	-	-	10	57	67
46	Fort Shaw	280	111	13	-	124
47	Galata	-	2	-	-	2
48	Gallatin Gateway	856	186	44	-	230
49	Garneill	-	7	2	-	9
50	Garrison	96	21	8	-	29
51	Gildford	179	73	24	-	97
52	Grantsdale	-	16	1	-	17
53	Great Falls	58,505	983	68	2	1,053

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Greycliff	112	45	6	-	51
2	Hall	-	61	12	-	73
3	Hamilton	4,348	4,303	724	7	5,034
4	Harlem	808	329	64	1	394
5	Harlowton	997	528	102	2	632
6	Havre	10,026	4,599	684	9	5,292
7	Helena	53,457	19,736	2,510	28	22,274
8	Hingham	118	81	32	-	113
9	Hungry Horse	826	231	35	-	266
10	Inverness	55	35	12	-	47
11	Jefferson City	472	214	15	2	231
12	Joplin	157	95	24	-	119
13	Judith Gap	126	66	14	-	80
14	Kalispell	19,927	12,993	2,156	19	15,168
15	Kremlin	98	47	18	-	65
16	Laurel	6,718	23	3	-	26
17	Ledger	-	7	-	-	7
18	Lewistown	5,901	2,985	508	7	3,500
19	Livingston	7,044	4,367	613	13	4,993
20	Logan	99	39	6	-	45
21	Lohman	-	2	1	-	3
22	Lolo	3,892	1,787	103	-	1,890
23	Loma	85	44	16	-	60
24	Manhattan	1,520	887	125	2	1,014
25	Martin City	500	117	17	-	134
26	Marysville	80	1	-	-	1
27	Milltown	-	70	11	-	81
28	Missoula	66,788	31,864	3,977	43	35,884
29	Montana City	2,715	838	79	-	917
30	Moore	193	3	1	-	4
31	Philipsburg	820	446	94	-	540
32	Power	-	-	1	-	1
33	Ramsay	-	40	7	-	47
34	Red Lodge	2,125	2,040	303	7	2,350
35	Reedpoint	193	118	16	1	135
36	Roberts	361	177	21	-	198
37	Rocker	-	47	6	-	53
38	Rudyard	258	126	28	-	154
39	Ryegate	245	3	1	-	4
40	Shawmut	42	23	6	-	29
41	Shelby	3,376	9	4	-	13
42	Sheridan	642	447	77	-	524
43	Silver Star	-	22	4	-	26
44	Silverbow	-	3	3	2	8
45	Simms	354	158	17	-	175
46	Somers	1,109	412	23	-	435
47	Stevensville	1,809	1,872	274	5	2,151
48	Sun River	124	105	17	-	122
49	Three Forks	1,869	881	142	1	1,024
50	Turah	306	135	4	-	139
51	Twin Bridges	375	204	60	-	264

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Valier	509	307	69	4	380
2	Vaughn	658	338	24	-	362
3	Victor	745	492	77	1	570
4	Walkerville	675	235	12	-	247
5	Warm Springs	-	13	1	-	14
6	West Glacier	227	107	40	3	150
7	Whitefish	6,357	4,723	501	3	5,227
8	Whitehall	1,038	692	111	1	804
9	Whitlash	-	1	1	-	2
10	Williamsburg	-	1	-	-	1
11	Willow Creek	210	97	12	-	109
12	Wolf Creek	-	50	28	-	78
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47						
48	**Total**	512,422	177,339	24,550	331	202,220

1/ Customer populations represent an average of the 12 month period from 01/01/20 through 12/31/20.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	139	136	138
5	Finance	154	160	157
6	Distribution	449	457	453
7	Transmission	312	313	313
8	Supply	125	124	125
9	Legal	27	27	27
10		`	`	
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,208	1,219	1,214

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2021 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Transmission - Rainbow-Two Dot 100kv line compliance	$9,958,669	$9,958,669
4	MT Transmission - 2nd Laurel City 100kv line capacity	7,657,502	7,657,502
5	MT Transmission - Meadow to Midway reconductor capacity	7,413,784	7,413,784
6	MT Transmission - Billings Rimrock substation rebuild capacity	7,126,151	7,126,151
7	MT Distribution - LED street lights program	7,038,828	7,038,828
8	MT Distribution - Butte MT Street substation rework capacity	5,096,522	5,096,522
9	MT Distribution - LED yard lights replacement program	4,113,200	4,113,200
10	SD Transmission - Aberdeen A-Tap switchin substation maintenance	3,598,962	-
11	MT Transmission - Millcreek bank 3 substation capacity	3,466,517	3,466,517
12	MT Transmission - Pole replacement Thompson Falls to Kerr A	3,249,523	3,249,523
13	SD Transmission - Aberdeen reconductor 115Kv I.P.	2,855,974	0
14	MT Distribution - Big Sky Midway feeders capacity	2,851,913	2,851,913
15	MT Transmission - Great Falls Switchyard to Riverview NW reconductor	2,812,714	2,812,714
16	MT Transmission - South Butte 161-100kv's substation capacity	2,412,537	2,412,537
17	MT Transmission - Bonner-Mill Creek A pole replacements	2,356,480	2,356,480
18	SD Transmission - Huron GTS relay upgrade	1,831,972	-
19	MT Transmission - Rattlesnake to Kerr A pole replacements	1,821,959	1,821,959
20	MT Transmission - Mill Creek 161-100's substation capacity	1,649,013	1,649,013
21	MT Distribution - Missoula Wildfire Mitigation and Refurbishment	1,599,376	1,599,376
22	MT Transmission - South Butte - Three Rivers pole replacements	1,442,636	1,442,636
23	MT Distribution - Base distribution management system	1,425,022	1,425,022
24	SD Transmission - Yankton Menno-Meridian 34.5Kv	1,398,305	-
25	SD Distribution - System spare transformers	1,352,245	-
26	MT Transmission - Great Falls switchyard 100kv bus substation	1,339,474	1,339,474
27	MT Distribution - Helena Wildfire Mitigation and Refurbishment	1,328,953	1,328,953
28	MT Transmission - Loweth Auto substation capacity	1,296,222	1,296,222
29	MT Transmission - substation Taft rebuild maintenance	1,258,266	1,258,266
30	MT Transmission - substation Alkali Creek 230kv maintenance	1,238,485	1,238,485
31	MT Transmission - Billings Shilo 100kv proactive	1,223,193	1,223,193
32	MT Distribution - Havre City 4160 substation upgrade	1,097,952	1,097,952
33	MT Distribution - Lewistown base pole replacements	1,061,792	1,061,792
34	MT Distribution - Havre base pole replacements	1,029,825	1,029,825
35			
36	All Other Projects < $1 Million Each and blankets	126,524,188	100,697,903
37	**Total Electric Utility Construction Budget**	**221,928,155**	**185,064,412**
38			
39	**Natural Gas Operations**		
40	MT Transmission - Morel-Butte transmission line replacement	$11,955,474	$11,955,474
41	MT Transmission - Byron pipeline purchase and upgrade	8,456,604	8,456,604
42	MT Distribution - Butte Division base gas one plan	5,177,307	5,177,307
43	MT Distribution - Bozeman Division base gas one plan	1,588,160	1,588,160
44	MT Distribution - Whitefish Mountain capacity upgrade	1,375,263	1,375,263
45	NE Distribution - Grand Island system capacity upgrade	1,140,315	-
46			
47	All Other Projects < $1 Million Each and blankets	34,583,256	$21,405,936
48	**Total Natural Gas Utility Construction Budget**	**64,276,379**	**49,958,743**
49			
50	**Common**		
51	MT Common - Distribution AMI Metering and Infrastructure	$17,609,922	$17,609,922
52	MT Common - BT SAP Hana implementation	11,597,617	11,597,617
53	MT Common - Fleet vehicles and equipment	4,544,000	4,544,000
54	MT Common - Transmission Cal-Iso Energy Imbalance Market	1,777,717	1,777,717
55	MT Common - Facilities Capital One Building and remodel	1,473,420	1,473,420
56	MT Common - Communications Helena Valley Tap	1,402,891	1,402,891
57	MT Common - Land and Permitting Yellowtail-Billings 230kv permit	1,400,521	1,400,521
58	MT Common - Land and Permitting Crow Reservation easement renewal	1,363,301	1,363,301
59	MT Common - Land and Permitting Heart Mtn Pipeline permit	1,361,588	1,361,588
60	SD Common - BT SAP Hana implementation	2,523,696	-
61	SD Common - Fleet vehicles and equipment	1,566,000	-
62	SD Common - Facilities Yankton facility design and build	1,191,397	-
63			
64	All Other Projects < $1 Million Each and blankets	18,580,213	$14,632,070
65	(Includes BT, Communications, Facilities, Land, Customer Service)		
66	**Total Common Utility Construction Budget**	**66,392,283**	**57,163,047**
67			
68	**MT/SD Generation**		
69	SD Generation - Huron Generating Station	$39,882,486	-
70	MT Generation - Hydro Maroney Sillway Gate Upgrade	12,449,809	12,449,809
71	MT Generation - CU4 Capital Items	8,209,500	8,209,500
72	SD Generation - Aberdeen Generating Station	3,572,874	-
73	MT Generation - Hydro Holter Unit 3 Turbine upgrade	3,286,925	3,286,925
74	MT Generation - Hydro Mystic replace B Line	2,596,300	2,596,300
75	MT Generation - Hydro Hauser Unit 5 turbine upgrade	2,547,022	2,547,022
76	MT Generation - CCH intake screen upgrade	2,416,358	2,416,358
77	SD Generation - Big Stone capital upgrades	2,404,053	-
78	MT Generation - Hydro Black Eagle Unit 1 turbine upgrade	1,826,683	1,826,683
79	MT Generation - Hydro Holter Unit 3 generator rewind	1,507,329	1,507,329
80	MT Generation - Hydro Old Rainbow powerhouse demolition	1,418,341	1,418,341
81	MT Generation - Hydro Black Eagle Unit 3 turbine upgrade	1,195,096	1,195,096
82	MT Generation - Hydro Thompson Falls relicensing	1,105,943	1,105,943
83			
84	All Other Projects < $1 Million Each and blankets	$14,064,464	$12,618,066
85	**Total MT/SD Generation**	**98,483,183**	**51,177,372**
86	**TOTAL CONSTRUCTION BUDGET**	**$451,080,000**	**$343,363,575**

Sch. 32	MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS						
	Transmission System-Sales and Transportation						
		Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
1	January		1/14/2020		276,388		5,924,807
2	February		2/18/2020		229,053		5,654,360
3	March		3/14/2020		244,242		5,047,327
4	April		4/18/2020		184,473		4,030,730
5	May		5/12/2020		200,061		3,039,393
6	June		6/7/2020		194,944		2,559,026
7	July		7/5/2020		179,589		2,283,246
8	August		8/9/2020		145,891		1,927,594
9	September		9/27/2020		146,874		2,292,249
10	October		10/25/2020		220,445		3,254,217
11	November		11/7/2020		216,272		4,733,432
12	December		12/13/2020		219,771		5,433,166
13	TOTAL						46,179,547
14							
15							
16	Distribution System-Sales and Transportation						
17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
19	January		3,255,726		132,947		3,388,673
20	February		2,949,694		112,288		3,061,982
21	March		2,803,898		108,370		2,912,268
22	April		2,314,053		90,160		2,404,214
23	May		1,298,918		48,623		1,347,541
24	June		821,274		32,228		853,502
25	July		568,170		26,096		594,265
26	August		423,804		22,384		446,188
27	September		474,410		24,446		498,856
28	October		854,806		36,633		891,438
29	November		2,128,620		76,647		2,205,267
30	December		2,823,624		101,892		2,925,516
31	TOTAL		20,716,996		812,713		21,529,709
32							
33							
34	Storage System-Sales and Transportation						
35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Montana		Energy Supply	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			6,026	3,206,589		1,951,906
39	February			1,681	3,242,553		2,158,637
40	March			297,022	1,227,804		487,033
41	April			1,413,751	234,082	449006	
42	May			2,934,062	19,781	1,406,163	
43	June			2,981,675	210,799	1,597,622	
44	July			3,194,401	18,682	2,096,835	
45	August			2,695,756	1,285	2,029,584	
46	September			2,223,497	7,155	1,276,767	
47	October			942,909	470,707	115,741	
48	November			83,639	1,851,333		1,349,739
49	December			3,570	3,665,735		2,417,214
50	TOTAL			16,777,989	14,156,505	8,971,718	8,364,529
51							
52							
53	1/ Data is not accumulated on a daily basis. Therefore the peak day and peak day volumes are not available.						
54							
55							

Sch. 33	SOURCES OF MONTANA CORE NATURAL GAS SUPPLY				
	Supply Location	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	13,992,763		$1.2031	
3	Havre Pipeline	908,344		1.2357	
4	Encana Pipeline	2,682,158		1.1905	
	Colorado Interstate Pipeline	505,000		3.6741	
5	Company Owned Production 1/	4,581,863		0.2990	
6	Intra Montana Purchase	416,877		1.4452	
7	**TOTAL CORE SUPPLY LAST YEAR**	23,087,004		$1.1361	
8					
9	Canadian Pipeline		15,637,140		$1.6594
10	Havre Pipeline		806,482		1.6127
11	Encana Pipeline		1,044,485		1.8211
12	Colorado Interstate Pipeline		154,437		1.5694
13	Company Owned Production 1/		4,345,437		0.3078
14	Intra Montana Purchase		419,520		1.8251
15	**TOTAL CORE SUPPLY THIS YEAR**		22,407,501		$1.5689
16					
17	1/ Average commodity cost for Company Owned Production reflects royalties and production taxes only.				
18					
19					

Sch. 34	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS						
	Program Description (These are Natural Gas DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2020 E+ Natural Gas Business Partners Program	$ 183,621	$ 30,594	500.19%	35,548	24,209	(11,339)
3	- Initiated 2005, 2020 weighted average program life = 16 years, 2 participants.						
4	*2020 Northwest Energy Efficiency Alliance (NEEA)	$ 1,282,896	$ 1,220,999	5.07%	0	20,057	20,057
5	- Initiated natural gas savings in 2006, program life is 15 years						
6							
7	2020 General Expenses All Natural Gas DSM Programs	$ 391	$ 79	394.81%	-	-	-
8	-NA						
9							
10	A program participant is a Montana commercial						
11	natural gas customer who installs eligible						
12	energy conservation measures and receives financial						
13	incentives/rebates either directly or indirectly.						
14							
15	*Note: 2020 NEEA expeditures are allocated to electric DSM						
16	but there are gas savings as a result of some NEEA initiatives.						
17	Participant has not been defined or counted for NEEA.						
18							
19	Units reported are in dekatherms ("Dkt")						
20							
21	COVID-19 impacted 2020 USB revenues and activities.						
22	COVID-19 resulted in activities planned for 2020 being postponed and						
23	funds carried forward to 2021 as allowed by statute and with extensions						
24	of time granted by the Department of Revenue as allowed by						
25	Administrative Rules (ARM) of Montana.						
26							
27	**TOTAL**	$ 1,466,907	$ 1,251,671	17.20%	35,548	44,266	8,717

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS						
		Operating Revenues 1/		Dkt Sold 1/		Average Customers	
	Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 103,440,553	$ 109,389,702	13,894,255	15,261,502	177,339	174,867
4	Commercial	51,345,995	55,667,878	7,165,513	8,115,250	24,498	24,209
5	Industrial Firm	840,088	995,758	121,779	151,075	231	240
6	Public Authorities	600,602	630,338	93,980	98,250	100	98
7	Interdepartmental	322,825	381,244	47,682	57,174	52	67
8	Sales to Other Utilities	771,245	820,171	206,222	22,629	2	1
9	TOTAL SALES	$ 157,321,308	$ 167,885,091	21,529,430	23,705,880	202,222	199,482
10		Operating Revenues		Dkt Transported		Average Customers	
11		Current	Previous	Current	Previous	Current	Previous
12		Year	Year	Year	Year	Year	Year
13	Transportation of Gas						
14							
15	On System Transportation	$ 22,538,340	$ 23,094,862	23,795,327	463,568	279	276
16	Off System Transportation & Storage	2,690	157	150,000	25,389,408	1	4
17	Canadian Montana Pipeline	263,125	258,848	-		-	
18	TOTAL TRANSPORTATION	$ 22,804,155	$ 23,353,867	23,945,327	25,852,976	280	280
30	1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.						

Sch. 36a	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Expenditures	Contracted or Committed Expenditures	Total Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	$ 603,705	$ -	$ 603,705	1,761	2012
3	NWE Promotion	$ 93,001	$ -	$ 93,001		
4	NWE Labor	$ 19,906	$ -	$ 19,906		
5	NWE Admin. Non-labor	$ 11	$ -	$ 11		
6	USB Interest & Svc Chg	$ (352)	$ -	$ (352)		
7	Low Income					
8	Bill Assistance	$ 764,477	$ -	$ 764,477		
9	Free Weatherization	$ 1,321,150	$ -	$ 1,321,150	3,800	2012
10	Energy Share	$ 336,000	$ -	$ 336,000		
11	NWE Promotion	$ 16	$ -	$ 16		
12	NWE Labor	$ 36,638	$ -	$ 36,638		
13	NWE Admin. Non-labor	$ 29	$ -	$ 29		
14	USB Interest & Svc Chg	$ (894)	$ -	$ (894)		
15	Total	$ 3,173,686	$ -	$ 3,173,686	5,561	
16	Number of customers that received low income rate discounts				7,230	
17	Average monthly bill discount amount ($/mo)				$ 17.62 [(a)]	
18	Average LIEAP-eligible household income				n/a	
19	Number of customers that received weatherization assistance				173 [(b)]	
20	Expected average annual bill savings from weatherization				22 dKt	
21	Number of residential audits performed				429 [(b)]	
22	Number of residential virtual assessments performed				21 [(b)]	
23	(a) Average monthly bill discount is for the six (6) month time period that the natural gas low income rate discount is in effect.					
24	(b) Total savings and number of customers are reported for the 2020 natural gas USB funds spent in 2020. Due to COVID-19, 2019 nor 2020 electric USB funds were spent on the E+ Audit and E+ Free Weatherization and Fuel Switch programs.					
25	*Note: Order 6679e, allows NorthWestern to track on an annual basis its Natural Gas USB expenditures and revenues and adjust the Natural Gas USB Charge for any over or under collections.*					
26	COVID-19 impacted 2020 USB revenues and activities. COVID-19 resulted in activities planned for 2020 being postponed and funds carried forward to 2021 as allowed by statute and with extensions of time granted by the Department of Revenue as allowed by Administrative Rules (ARM) of Montana.					

Sch. 36b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Natural Gas USB Programs)	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	$ 603,705	$ -	$ 603,705	1,761	2012
3						
4	Market Transformation					
5	*Building Operator Certification (BOC)	$ 2,000	$ -	$ 2,000	-	2012
6						
7	Low Income					
8	Free Weatherization	$ 1,321,150	$ -	$ 1,321,150	3,800	2012
9						
10	*Note: BOC expeditures are allocated to electric USB					
11	but there are typically gas savings as a result of BOC.					
12						
13	COVID-19 impacted 2020 USB revenues and activities.					
14	COVID-19 resulted in activities planned for 2020 being postponed and					
15	funds carried forward to 2021 as allowed by statute and with extensions					
16	of time granted by the Department of Revenue as allowed by					
17	Administrative Rules (ARM) of Montana.					
18						
19	Total	$ 1,926,855	$ -	$ 1,926,855	5,561	2012