YEAR ENDING 2021

ANNUAL REPORT

OF

NorthWestern Energy

GAS UTILITY

Docket 2022.01.001

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	
1		
2	Legal Name of Respondent:	NorthWestern Corporation
3		
4	Name Under Which Respondent Does Business:	NorthWestern Energy
5		
6	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912
7		Natural Gas - Jan 01, 1933
8		Propane - Oct 13, 1995
9		
10	Person Responsible for Report:	Jeff B. Berzina
11		
12	Telephone Number for Report Inquiries:	(406) 497-2759
13		
14	Address for Correspondence Concerning Report:	11 East Park Street
15		Butte, MT 59701
16		
17		
18		

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
	Chief Executive Officer	Executive	Robert Rowe
	President and Chief Operating Officer	Distribution Operations - MT/SD/NE	Brian Bird
		Supply Operations	
		Transmission Operations	
		Business Technology	
		Energy Risk Management	
		Flight Services, Executive Compensation	
	Vice President,	Legal Services	Heather Grahame
	General Counsel and Regulatory and	Corporate Secretary	
	Federal Government Affairs	Risk Management	
		Regulatory Affairs	
		Federal Governmental Affairs	
	Vice President,	Distribution Operations - MT/SD/NE	Curt Pohl
	Distribution	Construction, Asset Management	
		Labor and Operational Performance	
		Project Management	
		Safety/Health/Environmental Services	
		Business Development and Strategic Support	
	Vice President,	Transmission Planning, Engineering, Construction,	Michael Cashell
	Transmission	and Operations	
		Gas Transmission & Storage	
		Substation Operations	
		Transmission Policy, Services, and Operations	
		Transmission Market Strategy	
		Grid Real Time and Scada Operations	
		FERC and NERC Compliance	
		Support Services	
	Vice President,	Thermal and Wind Generation	John Hines
	Supply and Montana Government Affairs	Hydro Operations	
		Environmental and Lands Permitting & Compliance	
		Long Term Resources	
		Energy Supply Marketing Operations	
		Montana Government Affairs	
		Brand, Advertising, and	Bobbi Schroeppel
	Vice President,	Customer Communications	
	Customer Care, Communications and	Customer Experience and Support	
	Human Resources	Customer Interaction	
		Community Connections	
		Revenue Cycle Management	
		Human Resources	
	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
		Enterprise Risk and Business Continuity	
	Vice President and Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
		Financial Planning & Analysis	
		Controller and Treasury Functions	
		Investory Relations and Corporate Finance	
	Vice President,	Business Technology	Jeanne Vold
	Technology	Customer Systems & Solutions	
		Data & Analytics	
		Operation Technology	
		Security	

Reflects active officers as of December 31, 2021.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 183,106**	**98.00%**
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		**$ 3,734**	**2.00%**
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		**$ 186,840**	**100.00%**

Sch. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
4	Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting, Regulatory Affairs Finance and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$19,322,654	83.23%	$3,892,247
9	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.	19,896,187	71.43%	7,957,351
15	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.	17,919,953	78.32%	4,959,156
20	Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Architecture & Governanace	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	24,963,730	78.73%	6,743,226
25	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.	3,600,329	76.40%	1,111,928
30	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.	851,286	78.00%	240,106
35	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.	49,415	78.00%	13,937
40	**TOTAL**			$86,603,554	77.66%	$24,917,951

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	$249,654		
13						
14	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,786,709		
15		transmission, & compression	transmission & compression			
16			are at tariffed rates			
17	**Total Utility Subsidiaries Revenues**			$3,036,363		
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	1,398,864.85	37.5%	$1,398,865
15						
16	**Total Utility Subsidiaries**			1,899,264.85		$1,899,265
17	**Total Utility Subsidiaries Expenses**			$3,548,889		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,899,265		$1,899,265

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	$ 305,517,468	$ 84,870,139	$ 220,647,329	$ 181,976,229	21.25%
3						
4	**Total Operating Revenues**	305,517,468	84,870,139	220,647,329	181,976,229	21.25%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	188,427,420	66,826,874	121,600,546	85,597,993	42.06%
9	402 Maintenance Expense	7,196,382	1,307,869	5,888,513	6,018,065	-2.15%
10	403 Depreciation Expense	27,212,203	5,817,856	21,394,347	19,985,798	7.05%
11	404-405 Amort. & Depletion of Gas Plant	6,023,121	210,263	5,812,858	5,915,651	-1.74%
12	406 Amort. of Plant Acquisition Adj.	(846,505)	(846,505)	-	-	-
13	407.3 Regulatory Amortizations - Debit	3,414,161	2,006,807	1,407,354	84,042	>300.00%
14	407.4 Regulatory Amortizations - Credit	(5,237,036)	(52,446)	(5,184,590)	(5,207,714)	0.44%
15	408.1 Taxes Other Than Income Taxes	40,762,302	2,153,439	38,608,863	38,983,273	-0.96%
16	409.1 Income Taxes-Federal	4,996,172	(1,591,771)	6,587,943	4,279	>300.00%
17	-Other	2,562,400	226,638	2,335,762	3,423	>300.00%
18	410.1 Deferred Income Taxes-Dr.	27,889,964	7,399,763	20,490,201	28,563,714	-28.26%
19	411.1 Deferred Income Taxes-Cr.	(33,064,436)	(5,541,800)	(27,522,636)	(26,773,656)	-2.80%
20	411.4 Investment Tax Credit Adj.	(38,735)	(38,735)	-	-	-
21						
22	**Total Operating Expenses**	269,297,413	77,878,252	191,419,161	153,174,868	24.97%
23	**NET OPERATING INCOME**	$ 36,220,055	$ 6,991,887	$ 29,228,168	$ 28,801,361	1.48%

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	$ 173,583,115	$ 47,560,576	$ 126,022,539	$ 103,440,553	21.83%
5	442.1 Commercial	95,179,466	30,501,695	64,677,771	51,345,995	25.96%
6	442.2 Industrial Firm	1,133,808	-	1,133,808	840,088	34.96%
7	445 Public Authorities	861,757	-	861,757	600,602	43.48%
8	448 Interdepartmental Sales	554,754	-	554,754	322,825	71.84%
9	491.2 CNG Station	-	-	-	-	-
10						
11	**Total Sales to Core DBUs**	271,312,900	78,062,271	193,250,629	156,550,063	23.44%
12						
13	447 Sales for Resale	1,028,355	-	1,028,355	771,245	33.34%
14						
15	**Total Sales of Natural Gas**	272,341,255	78,062,271	194,278,984	157,321,308	23.49%
16						
17	496.1 Provision for Rate Refunds	-	-	-	-	-
18						
19	**Total Revenue Net of Rate Refunds**	272,341,255	78,062,271	194,278,984	157,321,308	23.49%
20						
21	489.1 Gathering	809,026	-	809,026	771,372	
22	489.2 Transmission	30,346,880	6,386,331	23,960,549	22,804,155	5.07%
23						
24	**Total Revenues From Transportation**	31,155,906	6,386,331	24,769,575	23,575,527	5.06%
25						
26	Miscellaneous Revenues	2,020,307	421,537	1,598,770	1,079,394	48.12%
27						
28	**Total Other Operating Revenue**	2,020,307	421,537	1,598,770	1,079,394	48.12%
29	**TOTAL OPERATING REVENUE**	$ 305,517,468	$ 84,870,139	$ 220,647,329	$ 181,976,229	21.25%
30						
31						
32						
33						
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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	206,443	-	206,443	188,700	9.40%
15	751 Maps & Records	-	-	-	-	-
16	752 Gas Wells Expenses	674,491	-	674,491	724,747	-6.93%
17	753 Field Lines Expenses	18,044	-	18,044	8,588	110.11%
18	754 Field Compressor Station Expense	3,418,843	-	3,418,843	3,355,246	1.90%
19	755 Field Comp. Station Fuel & Power	(193,420)	-	(193,420)	(51,516)	-275.46%
20	756 Field Meas. & Reg. Station Expense	109,676	-	109,676	95,598	14.73%
21	757 Dehydration Expense	11,898	-	11,898	11,995	-0.81%
22	758 Gas Well Royalties	1,861,606	-	1,861,606	995,459	87.01%
23	759 Other Expenses	897,535	-	897,535	1,187,876	-24.44%
24	760 Rents	255,387	-	255,387	270,964	-5.75%
25	**Total Oper.-Production & Gathering**	7,260,503	-	7,260,503	6,787,657	6.97%
26						
27	**Production Maintenance**					
28	762 Maint. of Gathering Structures	-	-	-	-	-
29	763 Maint. of Producing Gas Wells	1,476	-	1,476	-	-
30	764 Maint. of Field Lines	95,900	-	95,900	79,163	21.14%
31	765 Maint. of Field Compressor Stations	134,444	-	134,444	204,326	-34.20%
32	766 Maint. of Field Meas. & Reg. Stations	9,776	-	9,776	885	>300.00%
33	767 Maint. of Purification Equipment	29,618	-	29,618	100,453	-70.52%
34	769 Maint. of Other Equipment	85	-	85	202	-57.92%
35	**Total Maintenance - Production**	271,299	-	271,299	385,029	-29.54%
36	**TOTAL Natural Gas Production & Gathering**	7,531,802	-	7,531,802	7,172,686	5.01%
37						
38	**Other Gas Supply Expense-Operation**					
39	800 NG Wellhead Purchases	60,888,077	-	60,888,077	30,242,388	101.33%
40	803 NG Transmission Line Purchases	4,884,226	-	4,884,226	3,576,322	36.57%
41	805 Other Gas Purchases	53,494,674	52,695,115	799,559	130,021	>300.00%
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	278,903	498	278,405	483,207	-42.38%
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.	(6,498,381)	-	(6,498,381)	(5,386,063)	-20.65%
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**	113,047,499	52,695,613	60,351,886	29,045,875	107.78%
58	**Total Production Expenses**	120,579,301	52,695,613	67,883,688	36,218,561	87.43%

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	101,990	-	101,990	19,859	>300.00%
5	815 Maps & Records	-	-	-	-	-
6	816 Wells	384,403	-	384,403	350,789	9.58%
7	817 Lines	59,857	-	59,857	71,093	-15.80%
8	818 Compressor Station	491,293	-	491,293	460,896	6.60%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	24,746	-	24,746	23,532	5.16%
11	821 Purification	120,148	-	120,148	133,088	-9.72%
12	823 Gas Losses	-	-	-	565,283	-100.00%
13	824 Other Expenses	64,031	-	64,031	129,956	-50.73%
14	825 Storage Well Royalties	2,476	-	2,476	2,204	12.34%
15	826 Rents	-	-	-	-	-
16	**Total Operation-Underground Storage**	1,248,944	-	1,248,944	1,756,700	-28.90%
17						
18	**Underground Storage-Maintenance**					
19	830 Supervision & Engineering	6,491	-	6,491	8,850	-26.66%
20	831 Structures & Improvements	411,978	-	411,978	403,145	2.19%
21	832 Reservoirs & Wells	40,676	-	40,676	20,602	97.44%
22	833 Lines	11,067	-	11,067	53,055	-79.14%
23	834 Compressor Station Equipment	203,855	-	203,855	82,074	148.38%
24	835 Meas. & Reg. Station Equipment	9,554	-	9,554	64	>300.00%
25	836 Purification Equipment	31,401	-	31,401	46,529	-32.51%
26	837 Other Equipment	-	-	-	124	-100.00%
27	**Total Maintenance-Underground Storage**	715,022	-	715,022	614,443	16.37%
28	**Total Underground Storage Expenses**	1,963,966	-	1,963,966	2,371,143	-17.17%
29	**Transmission Expenses**	1				
30	**Transmission-Operation**					
31	850 Supervision & Engineering	3,418,864	22,786	3,396,078	2,854,205	18.99%
32	851 System Control & Load Dispatching	734,045	-	734,045	806,000	-8.93%
33	853 Compressor Station Labor & Expense	747,383	-	747,383	561,062	33.21%
34	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
35	856 Mains	793,357	24,589	768,768	848,669	-9.41%
36	857 Measuring & Regulating Station	633,633	275	633,358	695,951	-8.99%
37	858 Transmission & Comp.-By Others	-	-	-	-	-
38	859 Other Expenses	961,734	4,279	957,455	1,997,978	-52.08%
39	860 Rents	-	-	-	-	-
40	**Total Operation-Transmission**	7,289,016	51,929	7,237,087	7,763,865	-6.78%
41	**Transmission-Maintenance**					
42	861 Supervision & Engineering	158,190	-	158,190	263,859	-40.05%
43	862 Structures & Improvements	192,346	2,926	189,420	108,635	74.36%
44	863 Mains	634,250	-	634,250	1,068,439	-40.64%
45	864 Compressor Station Equipment	460,207	-	460,207	418,061	10.08%
46	865 Meas. & Reg. Station Equipment	345,950	790	345,160	167,034	106.64%
47	867 Other Equipment	-	-	-	2,816	-100.00%
48	**Total Maintenance-Transmission**	1,790,943	3,716	1,787,227	2,028,844	-11.91%
49	**Total Transmission Expenses**	9,079,959	55,645	9,024,314	9,792,709	-7.85%

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	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	2,094,297	861,329	1,232,968	1,362,611	-9.51%
4	871 Load Dispatching	155,498	155,498	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	5,538,776	2,565,943	2,972,833	2,895,136	2.68%
8	875 Meas. & Reg. Station-General	309,805	151,386	158,419	167,562	-5.46%
9	876 Meas. & Reg. Station-Industrial	-	-	-	-	-
10	877 Meas. & Reg. Station-City Gate	106,626	68,105	38,521	150,388	-74.39%
11	878 Meter & House Regulator	1,529,662	510,802	1,018,860	1,008,680	1.01%
12	879 Customer Installations	1,261,089	223,926	1,037,163	1,233,513	-15.92%
13	880 Other Expenses	1,115,123	215,533	899,590	767,906	17.15%
14	881 Rents	4,504	-	4,504	4,021	12.01%
15	**Total Operation-Distribution**	12,115,380	4,752,522	7,362,858	7,589,817	-2.99%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	844,221	278,196	566,025	586,504	-3.49%
18	886 Structures & Improvements			-	-	-
19	887 Mains	593,878	251,008	342,870	279,195	22.81%
20	889 Meas. & Reg. Station Exp.-General	129,710	85,871	43,839	54,324	-19.30%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	42,667	42,667	-	-	-
23	892 Services	506,114	203,159	302,955	303,169	-0.07%
24	893 Meters & House Regulators	1,515,141	329,019	1,186,122	1,162,209	2.06%
25	894 Other Equipment	-	-	-	-	-
26	**Total Maintenance-Distribution**	3,631,731	1,189,920	2,441,811	2,385,401	2.36%
27	**Total Distribution Expenses**	15,747,111	5,942,442	9,804,669	9,975,218	-1.71%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	758,582	135,135	623,447	590,600	5.56%
32	903 Customer Records & Collection	3,046,211	783,324	2,262,887	2,169,251	4.32%
33	904 Uncollectible Accounts	84,341	136,084	(51,743)	596,440	-108.68%
34	905 Miscellaneous Customer Accounts	49,323	36,282	13,041	(75)	>300.00%
35	**Total Customer Accounts Expenses**	3,938,457	1,090,825	2,847,632	3,356,216	-15.15%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	1,522,053	702,824	819,229	834,613	-1.84%
41	909 Inform. & Instructional Advertising	621,633	228,540	393,093	410,516	-4.24%
42	910 Misc. Customer Service & Inform.	-	-	-	-	-
43	**Total Customer Service & Information Exp.**	2,143,686	931,364	1,212,322	1,245,129	-2.63%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	-	-	-	-	-
48	912 Demonstrating & Selling	-	-	-	-	-
49	913 Advertising	148,266	27,071	121,195	110,047	10.13%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	148,266	27,071	121,195	110,047	10.13%

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	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	920 Administrative & General Salaries	12,313,269	2,897,201	9,416,068	8,343,366	12.86%
4	921 Office Supplies & Expenses	4,800,179	1,365,088	3,435,091	3,036,224	13.14%
5	922 Administrative Exp. Transferred-Cr.	(3,082,979)	(791,746)	(2,291,233)	(2,083,799)	-9.95%
6	923 Outside Services Employed	2,461,871	552,560	1,909,311	1,210,210	57.77%
7	924 Property Insurance	407,180	98,107	309,073	291,922	5.88%
8	925 Legal & Claim Department	6,028,197	667,381	5,360,816	3,880,277	38.16%
9	926 Employee Pensions & Benefits	12,801,718	1,949,369	10,852,349	7,648,543	41.89%
10	928 Regulatory Commission Expenses	1,570	-	1,570	4,673	-66.40%
11	930 Miscellaneous General Expenses	4,841,433	381,615	4,459,818	5,088,686	-12.36%
12	931 Rents	663,231	157,975	505,256	522,585	-3.32%
13	**Total Operation-Admin. & General**	41,235,669	7,277,550	33,958,119	27,942,687	21.53%
14	**Admin. & General - Maintenance**					
15	935 General Plant	787,387	114,233	673,154	604,348	11.39%
16	**Total Admin. & General Expenses**	42,023,056	7,391,783	34,631,273	28,547,035	21.31%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 195,623,802	$ 68,134,743	$ 127,489,059	$ 91,616,058	39.16%
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	2,010,926	2,010,001	0.05%
3	Property Taxes	34,137,945	35,059,260	-2.63%
4	Crow Tribe RR and Utility Tax	124,836	124,836	0.00%
5	Blackfoot Possessory Tax	356,455	367,830	-3.09%
6	City Tax	327	2,076	-84.26%
7	Consumer Counsel	183,385	177,129	3.53%
8	Public Service Commission	771,044	696,016	10.78%
9	Heavy Highway Use	6,560	8,417	-22.06%
10	Vehicle Use Taxes	103,779	95,282	8.92%
11	Gas Production Taxes	839,005	370,591	126.40%
12	Delaware Franchise Tax	55,021	55,060	-0.07%
13				
14				
15				
16	**Canadian Taxes**			
17	Ad Valorem	19,580	16,775	16.72%
18				
19				
20				
21				
22	**TOTAL TAXES OTHER THAN INCOME**	$38,608,863	$38,983,273	-0.96%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	148,804.75
2	ACUREN INSPECTION INC	Inspection Services	88,392.60
3	AFFCO INC	Hydro Construction Services	1,352,481.02
4	AION ENERGY LLC	Program Management Services	168,023.09
5	AMERICAN INNOVATIONS INC	Software Support Services	134,740.95
6	ANDRITZ HYDRO CORP	Hydro Upgrade Services	3,140,965.27
7	ARCADIS US INC	Engineering Services	136,211.08
8	ARCOS LLC	Call-out Services	142,354.58
9	ASCEND ANALYTICS LLC	Hydro Expert Analysis	406,623.89
10	ASPLUNDH TREE EXPERT LLC	Tree Trimming	5,668,597.07
11	ASSOCIATED UNDERWATER SERVICE	Inspection Services	218,488.10
12	AURITAS LLC	Computer Consulting Services	251,577.50
13	AUTOMOTIVE RENTALS INC	Fleet Management	8,336,656.78
14	AVEVA SOFTWARE, LLC	Computer Support Services	731,571.15
15	BART ENGINEERING COMPANY	Engineering Services	535,620.00
16	BEACON COMMUNICATIONS LLC	Software Maintenance	531,293.13
17	BERGY'S LLC	Construction	1,267,631.54
18	BIG SKY LAND RESOURCES, LLC	Excavation Contractor	742,897.13
19	BILLINGS FLYING SERVICE, INC.	Powerline Services	112,290.00
20	BISON ENGINEERING INC	Engineering Services	238,324.41
21	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	508,220.84
22	BRANDENBURG INDUSTRIAL SERVIC	Demolition Services	1,428,100.00
23	BROADRIDGE ICS	Shareholder Services	90,459.98
24	BURK EXCAVATION AND UTILITIES	Construction	160,404.56
25	CATERPILLAR POWER GENERATION	Generation Services	21,029,854.10
26	CENTRON SERVICES INC	Customer Collection service	125,768.03
27	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	123,966.10
28	CN UTILITY CONSULTING INC	Utility Consulting Services	556,455.86
29	CONTINENTAL STEEL WORKS	Fabrication Services	1,804,034.43
30	COPPER CREEK LLC	Construction	358,729.57
31	CORNERSTONE ENERGY SERVICES	Energy Services	290,821.39
32	CRANE SERVICES & INSPECTIONS	DOT Inspections	124,517.23
33	CRIST, KROGH, BUTLER & NORD L	Legal Services	330,189.78
34	CROWLEY FLECK PLLP	Legal Services	91,252.40
35	CTA INC.	Energy Conservation Consultants	1,477,806.00
36	D & A TRENCHING	Excavating Services	295,141.00
37	DAKOTA DIRECTIONAL LLC	Boring Services	76,206.85
38	DAVEY TREE SURGERY COMPANY	Tree Trimming	3,930,139.00
39	DELOITTE & TOUCHE	Audit Services	1,388,153.08
40	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	1,839,320.24
41	DHC INC	Boring Services	129,123.00
42	DIETZEL ENTERPRISES INC	Construction	597,724.64
43	DIRECTIONAL ZONE INC	Boring Services	195,978.00
44	DJ&A P C CONSULTING ENGINEER	Engineering Services	147,722.89
45	DNV GL ENERGY INSIGHTS USA INC	Software Support Services	4,490,491.02
46	DGR ENGINEERING	Engineering Services	582,285.32
47	DOBLE ENGINEERING CO	Engineering Services	196,871.50
48	DORSEY & WHITNEY LLP	Legal Services	1,518,948.72
49	DOWL HKM	Geotechnical Services	172,276.17
50	E SOURCE COMPANIES LLC	Consulting Services	217,228.00
51	ELLIOT CONSTRUCTION	Boring Services	1,514,509.11
52	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notificat	4,521,173.05
53	ENERGY AND ENVIRONMENTAL ECON	Consulting Services	90,723.75
54	ENERGY CONTRACT SERVICES LLC	Inspection Services	1,155,798.75
55	ENERGY LABORATORIES INC	Environmental Consultants	90,046.00
56	ENERGY SHARE OF MONTANA	USBC Services	1,101,245.00
57	EVERGREEN CAISSONS INC	Construction	124,000.00
58	FAGEN	Construction	23,150,029.01
59	FENCECRAFTERS HELENA INC	Repair Services	77,690.00

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
60	FIRSTMARK CONSTRUCTION	Construction	323,652.00
61	FLYNN WRIGHT INC	Advertising Services	1,553,174.21
62	FOUR CORNERS RECYCLING, LLC	Recovery Services	158,403.50
63	GARTNER INC	Information Technology Consulting	345,863.81
64	GE RENEWABLES GRID, LLC	Software Support Services	530,446.75
65	GEI CONSULTANTS INC	Environmental Consultants	551,485.63
66	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	6,251,736.58
67	GEOSPATIAL INNOVATIONS INC	Data Collection Services	158,218.00
68	GREGG ENGINEERING	Informational Technology Simulation	97,720.00
69	GUY TABACCO CONSTRUCTION	Construction	699,063.18
70	H & H ASPHALT & MAINTENANCE L	Asphalt Services	111,378.68
71	H & H CONTRACTING INC	Concrete and Asphalt Services	690,665.51
72	HAIDER CONSTRUCTION	Boring Services	411,819.46
73	H2E INC	Engineering Services	844,106.00
74	HDR ENGINEERING INC	Engineering Services	4,915,874.30
75	HEATH CONSULTANTS INC	Gas Leak Surveys	538,554.02
76	HIGHMARK MEDIA	Safety Training	110,825.00
77	IMCO GENERAL CONSTRUCTION INC	Construction	2,315,678.94
78	INFOSYS LIMITED	Consulting Services	402,116.88
79	INTEC SERVICES INC	Pole Inspection Services	2,753,688.29
80	ITRON INC	Meter Installation	21,326,927.44
81	IVANS BORING	Boring Services	471,024.92
82	J D POWER AND ASSOCIATES	Energy Study	92,030.00
83	J2 BUSINESS PRODUCTS	Copier Maintenance	129,494.97
84	JACOBSEN TREE	Tree Trimming	999,759.33
85	JAN HORSFALL	Board of Director Fees	80,000.00
86	JARES FENCE COMPANY INC	Fence Materials/Installation	108,144.00
87	JEFFERY CONTRACTING LLC	Construction	1,534,489.10
88	JEFFREY W YINGLING	Board of Director Fees	77,611.57
89	JODY KLESSENS CONSTRUCTION LLC	Construction Service	88,886.40
90	JONES DAY	Legal Services	229584.5
91	KARV LLC	Boring Services	197,132.40
92	KM CONSTRUCTION CO INC	Construction	137,080.50
93	KNIFE RIVER	Construction	186,342.97
94	LIEN TRANSPORTATION SERVICE	Transport Services	167,252.09
95	LIQUID GOLD WELL SERVICE INC	Well Services	77,188.50
96	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	287,022.09
97	LOCKMER SHEET METAL	Installation Services	160,198.23
98	M & P EXCAVATING	Excavation Services	424,717.40
99	M&D CONSTRUCTION INC	Construction	341,987.90
100	MAHVASH MAYA YAZDI	Board of Director Fees	82965.39
101	MAP MECHANICAL CONTRACTORS	Demolition Services	452632.02
102	MCMILLEN LLC	Design Services	11,443,418.66
103	MERCER HUMAN RESOURCE CONSULT	HR Consulting	196,458.00
104	MERIDIAN IT INC	Information Technology Services	108,242.45
105	MERKEL ENGINEERING INC	Consulting Services	537,929.38
106	MICHAELS FENCE & SUPPLY CO	Installation Services	121,757.62
107	MICHELS CORPORATION	Construction	8,657,658.10
108	MIDCON UNDERGROUND CONSTRUCTI	Construction	1,199,930.94
109	MINUTEMAN AVIATION INC.	Helicopter Charter Services	160,643.50
110	MISSOULA CONCRETE CONSTRUCTION	Construction	109,805.00
111	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	785,665.88
112	MOODY'S INVESTORS SERVICE	Debt Rating Services	223,500.00
113	MORGAN, LEWIS & BOCKIUS LLP	Legal Services	136,654.80
114	MORRISON MAIERLE INC	Engineering Services	497,461.52
115	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	26,232,113.71
116	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	547,942.15
117	MP SYSTEMS	Electric Construction Service	212,138.66
118	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	438,056.96
119	NAES CORPORATON	Generation Services	117,636.38

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
120	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	463,433.83
121	NEELY ELECTRIC INC	Electric Services	148,572.70
122	NORTHERN HYDRAULICS INC	Construction	81,393.93
123	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,895.60
124	OLSSON ASSOCIATES	Surveying Services	121,767.03
125	OMEGA MORAN INC	Traffic Safety Services	174,073.50
126	ONSITE DISTRIBUTED POWER, LLC	Installation Services	702,456.00
127	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	1,018,435.55
128	OUTBACK POWER COMPANY	Construction Service	330,364.36
129	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	22,169,543.90
130	PINNACLE RESEARCH & CONSULTING	Consulting Services	399,108.31
131	PIONEER TECHNICAL SERVICES INC	Environmental Services	219,606.36
132	PIONEER WIRELINE SERVICES	Rig Services	195,393.54
133	POTEET CONSTRUCTION	Traffic Safety Services	109,857.00
134	POWER SETTLEMENTS CONSULTING &	Consulting Services	266,000.00
135	POWERPLAN INC	Software Support Services	2,353,786.06
136	PRICEWATERHOUSECOOPERS LLP	Consulting Services	2,989,991.27
137	PRO PIPE CORPORATION	Welding Services	124,797.50
138	QUANTA UTILITY ENGINEERING	Engineering Services	7,398,841.44
139	RIVER DESIGN GROUP INC	Engineering Services	205,212.90
140	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	34,497,196.17
141	ROCKY MOUNTAIN ROTORS MONTANA	Line Maintenance	249,471.58
142	ROD TABBERT CONSTRUCTION INC	Construction	281,926.91
143	ROSEN USA INC	Inspection Services	757,146.00
144	ROUNDS BROTHERS TRENCHING	Boring Services	876,913.27
145	SCENIC CITY ENTERPRISES INC	Construction	131,350.00
146	SCHNABEL ENGINEERING LLC	Consulting Services	618,706.19
147	SHAW PIPELINE SERVICES	Construction Service	362,013.89
148	SIDEWINDERS LLC	Generator Repair Services	1,143,823.87
149	SILVERTECH, INC.	Website Redesign	359,612.00
150	SPHERION STAFFING	Temporary Labor	123,359.51
151	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	228,000.00
152	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	531,988.14
153	STEPHEN P ADIK	Board of Director Fees	76,216.29
154	STINSON LEONARD STREET LLP	Legal Services	616,190.63
155	SUPERIOR CONCRETE PRODUCTS INC	Construction	550,389.00
156	TERRA REMOTE SENSING (USA) INC	Surveying Services	664,262.75
157	TERRACON CONSULTANTS INC	Geotechnical Services	85,705.61
158	THE ELECTRIC COMPANY OF SOUTH	Construction	1,362,562.53
159	THE MOSAIC COMPANY	Training	576,382.50
160	THOMPSON HINE LLP	Benefits Audit Services	229,289.63
161	TIMBERLINE SECURITY & SERVICES	Security Services	246,806.96
162	TLC SEPTIC SERVICE	Excavation Contractor	288,779.90
163	TODD O BRUESKE CONSTRUCTION	Construction	447,204.23
164	TOWNSEND CONTROLS & ELECTRIC	Construction	89,784.55
165	TRADEMARK ELECTRIC INC	Construction	1,066,480.74
166	TROUTMAN SANDERS LLP	Legal Services	96,092.50
167	ULTEIG ENGINEERS INC	Project Manager Services	230,431.63
168	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	1,004,115.92
169	UNDERGROUND CONSTRUCTION	Construction	95,723.00
170	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	215,200.00
171	UTILICAST LLC	Consulting Services	1,359,863.39
172	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	235,325.15
173	VAISALA INC	Wind Forecasting Services	148,782.00
174	VARSITY CONTRACTORS INC(KELLER BERGENSONS SERVICE)	Janitorial Services	253,303.86
175	VEOLIA ES TECNICAL SOLUTIONS	Oil Recycling	147,059.46
176	VERMILLON CONSULTING	Consulting Services	75,499.94
177	VERTEX	Billing Services and Programming	2,844,616.00

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
178	VERTIV CORPORATION	Maintenance Service	83,977.06
179	VINE ENTERPRISES,INC	Fence Materials/Installation	80,550.46
180	WARREN TRANSPORT INC	Hauling Services	76,537.31
181	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	1,260,280.12
182	WATSON TRUCKING OF HAVRE LLC	Hauling Services	102,485.00
183	WELFL CONSTRUCTION CO	Construction Service	1,128,690.09
184	WILLIS TOWERS WATSON US LLC	Compensation Services	138,290.60
185	WRIGHT AND SUDLOW INC	Construction Service	118,276.18
186	ZACHA UNDERGROUND CONSTRUCTIO	Construction	99,277.84
	Total of Payments Set Forth Above		**$ 300,612,376**

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.			
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$ -	$ -	0.00%

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	$ 757,399,423	$ 675,493,587	12.13%
8	Service cost	12,104,357	10,239,856	18.21%
9	Interest cost	17,383,148	21,063,387	-17.47%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(26,749,118)	79,799,204	-133.52%
13	Settlements	(93,487,667)	-	-
14	Benefits paid	(30,378,468)	(29,196,611)	-4.05%
15	Benefit obligation at end of year	$ 636,271,675	$ 757,399,423	-15.99%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 619,075,010	$ 545,796,194	13.43%
18	Actual return on plan assets	33,662,299	92,274,164	-63.52%
19	Settlements	(93,487,667)	-	-
20	Employer contribution	9,000,000	10,201,263	-11.78%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(30,378,468)	(29,196,611)	-4.05%
23	Fair value of plan assets at end of year	$ 537,871,174	$ 619,075,010	-13.12%
24	**Funded Status**	$ (98,400,501)	$ (138,324,413)	28.86%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (98,400,501)	$ (138,324,413)	28.86%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	2.75%	2.30%	19.57%
32	Expected return on plan assets	4.17%	4.49%	-7.13%
33	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.00% Union & 2.67% Non-Union	0.00%
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 12,104,357	$ 10,239,856	18.21%
36	Interest cost	17,383,148	21,063,387	-17.47%
37	Expected return on plan assets	(25,006,749)	(24,029,522)	-4.07%
38	Settlement (gain) loss recognized	11,291,216	-	-
39	Recognized net actuarial gain	6,535,904	5,027,792	30.00%
40	Net periodic benefit cost (SEC Basis)	$ 22,307,876	$ 12,301,513	81.34%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 9,000,000	$ 10,201,263	-11.78%
43	Pension Costs Capitalized	2,222,709	2,515,102	-11.63%
44	Accumulated Pension Asset (Liability) at Year End	$ (98,400,501)	$ (138,324,413)	28.86%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,497	2,539	-1.65%
47	Not Covered by the Plan 2/	890	799	11.39%
48	Active	528	570	-7.37%
49	Retired	1,668	1,654	0.85%
50	Deferred Vested Terminated 2/	301	315	-4.44%

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			0.00%
8	Service cost			0.00%
9	Interest cost			0.00%
10	Plan participants' contributions	Not Applicable		
11	Amendments			0.00%
12	Actuarial loss			0.00%
13	Acquisition			0.00%
14	Benefits paid			0.00%
15	Benefit obligation at end of year	$ -	$ -	0.00%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 456,200,434	$ 413,343,235	-9.39%
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 2/	$ 11,789,193	$ 11,118,667	6.03%
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 2/	$ 492,289,539	$ 456,200,434	7.91%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss		0	0.00%
26	Unrecognized prior service cost		0	0.00%
27	Prepaid (accrued) benefit cost	$ -	$ -	0
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate		0.00%	0.00%
31	Expected return on plan assets		0.00%	0.00%
32	Rate of compensation increase		0.00%	0.00%
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			0.00%
36	Interest cost			0.00%
37	Expected return on plan assets			0.00%
38	Amortization of prior service cost			0.00%
39	Recognized net actuarial loss			0.00%
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	0
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 9,118,650	$ 8,506,877	7.19%
44	401(k) Plan Defined Contribution Costs Capitalized	2,252,012	2,097,355	7.37%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,494	1,538	-2.86%
48	Not Covered by the Plan		0	0.00%
49	Active - Participating	1,475	1,527	-3.41%
50	Retired		0	0.00%
51	Vested Former Employees, Retirees and Active-	372	312	19.23%
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	($1,560,428)	($1,399,829)	-11.47%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	2.40%	1.80%	33.33%
8	Expected return on plan assets	4.08%	4.71%	-13.38%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate annually	5.00% fixed rate annually	
10	Actuarial Cost Method	Method Allocated from the Date of Hire		
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			

1/ Obtained from NorthWestern Energy-Montana's 2021 FASB 106 Valuation. Assumptions and data are as of December 31, 2021.

2/ Obtained from NorthWestern Energy-Montana's 2020 FASB 106 Valuation. Assumptions and data are as of December 31, 2020.

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			0.00%
3	Not Covered by the Plan			0.00%
4	Active			0.00%
5	Retired			0.00%
6	Spouses/Dependants covered by the Plan			0.00%
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$15,771,574	$14,641,862	7.72%
10	Service cost	356,316	318,337	11.93%
11	Interest Cost	279,258	435,820	-35.92%
12	Plan participants' contributions	1,043,792	920,456	13.40%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	566,496	2,496,048	-77.30%
15	Acquisition	-	-	-
16	Benefits paid	(3,727,430)	(3,040,949)	-22.57%
17	Benefit obligation at end of year	$14,290,006	$15,771,574	-9.39%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$23,095,215	$21,479,179	7.52%
20	Actual return on plan assets	3,349,308	2,723,057	23.00%
21	Acquisition	-	-	-
22	Employer contribution	1,528,139	1,013,472	50.78%
23	Plan participants' contributions	1,043,792	920,456	13.40%
24	Benefits paid	(3,727,430)	(3,040,949)	-22.57%
25	Fair value of plan assets at end of year	$25,289,024	$23,095,215	9.50%
26	**Funded Status**	$10,999,018	$7,323,641	50.19%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$10,999,018	$7,323,641	50.19%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$356,316	$318,337	11.93%
33	Interest cost	279,258	435,820	-35.92%
34	Expected return on plan assets	(919,362)	(982,650)	6.44%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(1,986,424)	(2,032,850)	2.28%
37	Recognized net actuarial loss/(gain)	-	-	-
38	Net periodic benefit cost	($2,270,212)	($2,261,343)	-0.39%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	1,528,139	1,013,472	50.78%
43	TOTAL	$1,528,139	$1,013,472	50.78%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(1,560,428)	(1,399,829)	-11.47%
47	TOTAL	($1,560,428)	($1,399,829)	-11.47%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($1,560,428)	($1,399,829)	-11.47%
50	Pension Costs Capitalized	($385,375)	($345,125)	-11.66%
51	Accumulated Pension Asset (Liability) at Year End	$10,999,018	$7,323,641	50.19%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,357	1,444	-6.02%
54	Not Covered by the Plan	1,996	1,940	2.89%
55	Active	503	545	-7.71%
56	Retired	776	812	-4.43%
57	Spouses/Dependants covered by the Plan	78	87	-10.34%

4/ There is approximately an additional $3,017,963 and $3,374,035 in other company OPEBS liabilities outstanding at December 31, 2021 and 2020, 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	John D. Hines Vice President, Supply & Montana Government Affairs	305,021	129,830 A	34,166 B 227,164 C 45,614 D 5,221 E	747,016	833,548	-10.4%
	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	300,832	128,048 A	54,834 B 224,045 C 1,509 D	709,268	691,652	2.5%
3	Michael R. Cashell Vice President, Transmission	299,523	127,490 A	30,944 B 223,070 C 0 D 6,196 E	687,223	1,010,716	-32.0%
4	Jeanne M. Vold Vice President, Technology	246,398	106,000 A	46,418 B 150,000 C 5,430 D 6,096 E 2,776 F	563,118	373,727	50.7%
5	Michael L. Nieman Chief Audit and Compliance Officer	246,138	65,521 A	58,238 B 60,750 C 0 D 1,227 E	431,874	455,201	-5.1%
6	Daniel L. Rausch Treasurer	238,892	64,105 A	55,851 B 57,596 C 2,536 D 8,307 E	427,287	426,027	0.3%
7	Jeffrey B. Berzina Controller	222,981	59,625 A	48,551 B 52,501 C	383,658		
8	Jason Merkel General Manager, Operations & Construction	210,798	56,078 A	34,665 B 52,122 C 0 D 2,406 E	356,069	646,587	-44.9%
9	Bleau J. LaFave Director, Long-Term Resources	192,554	44,520 A	48,309 B 36,712 C 0 D 7,942 E	330,037	337,076	-2.1%
10	Timothy P. Olson Corporate Counsel & Corporate Secretary	195,104	41,522 A	46,648 B 38,593 C	321,867	313,141	2.8%

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 2021 reflects the results of 26 pay periods. There were 27 pay periods in 2020.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2021 Annual Incentive Compensation Plan. Amounts were earned in 2021 and paid in the first quarter of 2022. Based on company

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, 2021.

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

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

Hines	15.7%	Rausch	7.3%
Schroeppel	8.5%	Berzina	
Cashell	11.5%	Merkel	5.0%
Vold	60.1%	Lafave	6.3%
Nieman	3.7%	Olson	2.8%

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 Chief Executive Officer	674,138	717,359 A	40,921 B 1,906,246 C 77,372 D 29,331 E	3,445,367	3,102,048	11.1%
2	Brian B. Bird President & Chief Operating Officer	494,774	397,500 A	58,615 B 850,000 C 8,196 D 2,776 F 766 G	1,812,627	1,331,564	36.1%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	439,769	257,380 A	52,981 B 501,825 C 182 E	1,252,137	1,148,498	9.0%
4	Crystal D. Lail Vice President, Chief Financial Officer	362,307	198,750 A	41,737 B 431,250 C 1,954 D 6,680 E 2,776 F	1,045,454	597,855	74.9%
5	Curtis T. Pohl Vice President, Distribution	316,847	134,864 A	55,003 B 251,640 C 2,553 D 2,516 E	763,423	770,427	-0.9%

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 2021 reflects the results of 26 pay periods. There were 27 pay periods in 2020.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2021 Annual Incentive Compensation Plan. Amounts were earned in 2021 and paid in the first quarter of 2022. Based on company

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, 2021.

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

F> Value of executive physical examination and associated tax gross-up.

G> Imputed income - facilities

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 98.7%.

Our Chief Executive Officer's compensation is 79% 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	14.7%
Bird	38.5%
Grahame	9.0%
Lail	85.6%
Pohl	5.9%

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	$6,684,746,970	$6,398,242,253	$286,504,717	4.48%
4	101.1 Property Under Capital Leases	42,280,372	43,061,890	(781,518)	-1.81%
5	103 Experimental Electric Plant Unclassified	4,092,785	2,928,663	1,164,122	39.75%
6	105 Plant Held for Future Use	5,492,985	5,499,197	(6,212)	-0.11%
7	107 Construction Work in Progress	284,729,122	166,454,010	$118,275,112	71.06%
8	108 Accumulated Depreciation Reserve	(2,475,484,210)	(2,365,692,029)	($109,792,181)	4.64%
9	108.1 Accumulated Depreciation - Capital Leases	(31,162,371)	(29,151,894)	($2,010,477)	6.90%
10	111 Accumulated Amortization & Depletion Reserves	(94,343,642)	(89,972,714)	($4,370,928)	4.86%
11	114 Electric Plant Acquisition Adjustments	481,574,396	481,574,396	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(71,878,462)	(61,628,544)	(10,249,918)	16.63%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	36,190,017	36,196,864	(6,847)	-0.02%
15	**Total Utility Plant**	5,223,823,489	4,945,097,619	278,725,870	5.64%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutilility Property	(29,270)	(29,180)	(90)	0.31%
19	123.1 Investments in Assoc Companies and Subsidiaries	(114,137,258)	(118,287,100)	4,149,842	-3.51%
20	124 Other Investments	20,451,942	45,234,617	(24,782,675)	-54.79%
21	128 Miscellaneous Special Funds	-	250,000	(250,000)	-100.00%
22	LT Portion of Derivative Assets - Hedges	-	-	-	-
23	**Total Other Property & Investments**	(93,027,781)	(72,144,858)	(20,882,923)	28.95%
24	**Current and Accrued Assets**				
25	131 Cash	2,376,145	5,600,771	(3,224,626)	-57.57%
26	134 Other Special Deposits	14,658,170	9,670,292	4,987,878	51.58%
27	135 Working Funds	23,250	22,950	300	1.31%
28	142 Customer Accounts Receivable	86,846,850	73,728,730	13,118,120	17.79%
29	143 Other Accounts Receivable	8,867,792	14,106,165	(5,238,373)	-37.14%
30	144 Accumulated Provision for Uncollectible Accounts	(2,319,115)	(5,609,532)	3,290,417	-58.66%
31	146 Accounts Receivable-Associated Companies	2,818,214	1,752,345	1,065,869	60.83%
32	151 Fuel Stock	7,509,623	6,561,464	948,159	14.45%
33	154 Plant Materials and Operating Supplies	53,538,725	43,691,819	9,846,906	22.54%
34	164 Gas Stored - Current	18,828,613	10,010,097	8,818,516	88.10%
35	165 Prepayments	20,500,469	15,375,451	5,125,018	33.33%
36	172 Rents Receivable	54,488	49,263	5,225	10.61%
37	173 Accrued Utility Revenues	98,149,252	80,492,128	17,657,124	21.94%
38	174 Miscellaneous Current & Accrued Assets	258,106	194,030	64,076	33.02%
39	**Total Current & Accrued Assets**	312,110,582	255,645,973	56,464,609	22.09%
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	11,120,970	13,376,263	(2,255,293)	-16.86%
42	182 Regulatory Assets	685,148,784	712,384,890	(27,236,106)	-3.82%
43	183 Preliminary Survey and Investigation Charges	-	2,286,180	(2,286,180)	-100.00%
44	184 Clearing Accounts	4,169	3,635	534	14.69%
45	186 Miscellaneous Deferred Debits	8,619,588	7,565,277	1,054,311	13.94%
46	189 Unamortized Loss on Reacquired Debt	25,635,857	28,350,312	(2,714,455)	-9.57%
47	190 Accumulated Deferred Income Taxes	160,914,104	178,891,654	(17,977,550)	-10.05%
48	191 Unrecovered Purchased Gas Costs	94,663,379	5,905,571	88,757,808	>300.00%
49	**Total Deferred Debits**	986,106,851	948,763,782	37,343,069	3.94%
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,429,013,141	$ 6,077,362,516	$ 351,650,625	5.79%

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	$ 576,063	$ 541,448	$ 34,615	6.39%
4	211 Miscellaneous Paid-In Capital	1,716,226,995	1,513,785,478	202,441,517	13.37%
5	216 Unappropriated Retained Earnings	726,326,379	667,969,228	58,357,151	8.74%
6	217 Reacquired Capital Stock	(98,248,245)	(98,075,421)	(172,824)	0.18%
7	219 Accumulated Other Comprehensive Income	(5,167,596)	(5,126,145)	(41,451)	0.81%
8	**Total Proprietary Capital**	2,339,713,596	2,079,094,588	260,619,008	12.54%
9	**Long Term Debt**				
10	221 Bonds	2,179,660,000	2,079,660,000	100,000,000	4.81%
11	224 Other Long Term Debt	373,000,000	248,976,900	124,023,100	49.81%
12	226 (Less) Unamortized Discount on Long Term Debt-Debit	61,389	-	61,389	-
13	**Total Long Term Debt**	2,552,598,611	2,328,636,900	223,961,711	9.62%
14	**Other Noncurrent Liabilities**				
15	227 Obligations Under Capital Leases-Noncurrent	12,829,411	16,379,639	(3,550,228)	-21.67%
16	228.2 Accumulated Provision for Injuries and Damages	7,061,829	6,050,644	1,011,185	16.71%
17	228.3 Accumulated Provision for Pensions and Benefits	6,434,213	10,240,902	(3,806,689)	-37.17%
18	228.4 Accumulated Miscellaneous Operating Provisions	88,530,057	106,746,764	(18,216,707)	-17.07%
19	229 Accumulated Provision for Rate Refunds	-	10,712,124	(10,712,124)	-100.00%
20	230 Asset Retirement Obligations	40,747,410	45,355,157	(4,607,747)	-10.16%
21	**Total Other Noncurrent Liabilities**	155,602,920	195,485,230	(39,882,310)	-20.40%
22	**Current and Accrued Liabilities**				
23	231 Notes Payable	-	100,000,000	(100,000,000)	-100.00%
24	232 Accounts Payable	120,452,816	104,724,988	15,727,828	15.02%
25	234 Accounts Payable to Associated Companies	1,837,642	1,775,914	61,728	3.48%
26	235 Customer Deposits	8,573,478	6,000,316	2,573,162	42.88%
27	236 Taxes Accrued	45,815,514	61,045,637	(15,230,123)	-24.95%
28	237 Interest Accrued	18,567,598	18,073,738	493,860	2.73%
29	241 Tax Collections Payable	2,178,547	1,432,362	746,185	52.09%
30	242 Miscellaneous Current and Accrued Liabilities	63,691,699	75,300,722	(11,609,023)	-15.42%
31	243 Obligations Under Capital Leases-Current	4,012,828	3,912,103	100,725	2.57%
32	**Total Current and Accrued Liabilities**	265,130,122	372,265,780	(107,135,658)	-28.78%
33	**Deferred Credits**				
34	252 Customer Advances for Construction	80,779,904	65,186,426	15,593,478	23.92%
35	253 Other Deferred Credits	173,125,630	199,645,159	(26,519,529)	-13.28%
36	254 Regulatory Liabilities	185,656,769	187,832,431	(2,175,662)	-1.16%
37	255 Accumulated Deferred Investment Tax Credits	517,968	278,674	239,294	85.87%
38	281-283 Accumulated Deferred Income Taxes	675,887,621	648,937,328	26,950,293	4.15%
39	**Total Deferred Credits**	1,115,967,892	1,101,880,018	14,087,874	1.28%
40	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,429,013,141	$ 6,077,362,516	$ 351,650,625	5.79%
41					
42	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
43	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
44	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
45	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.				
46					
47					
48					
49					
50					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 753,600 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 $479.3 million and $464.7 million as of December 31, 2021 and December 31, 2020, 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, 2021 and December 31, 2020, 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, 2021 and December 31, 2020, 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 are reflected in the Balance Sheets as capital leases of $2.1 million and $2.9 million as of December 31, 2021 and December 31, 2020, respectfully, in accordance with regulatory treatment, as compared to non-current assets for GAAP purposes;
- Operating lease liabilities are reflected in the Balance Sheets as current and long term obligations under capital leases of $2.1 million and $2.9 million as of December 31, 2021 and December 31, 2020, respectfully, in accordance with regulatory treatment, 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 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 $2.3 million and $5.6 million at December 31, 2021 and December 31, 2020. Unbilled revenues were $98.1 million and $80.5 million at December 31, 2021 and December 31, 2020, respectively.

Inventories

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

	December 31,	
	2021	2020
Fuel stock	$ 7,510	$ 6,561
Plant materials and operating supplies	53,539	43,692
Gas stored underground (including the non-current portion reflected in utility plant)	55,019	46,207
Total Inventories	$ 116,068	$ 96,460

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 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 6.6% and 6.7% for Montana for 2021 and 2020, respectively. This rate averaged 6.4% and 6.7% for South Dakota for 2021 and 2020, respectively. AFUDC capitalized totaled $15.9 million and $9.8 million for the years ended December 31, 2021 and 2020, 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 2021 and 2020.

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,	
	2021	**2020**
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ 4,330	$ 115
Interest	87,221	84,922
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	29,034	21,430
NMTC debt extinguishment included in other noncurrent assets[1]	18,169	
NMTC debt extinguishment included in utility plant[1]	6,594	
NMTC debt extinguishment included in long-term debt[1]	1,259	

(1) See Note 12 - Long-Term Debt for further information regarding these non-cash transactions.

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,	
	2021	2020
Cash	$ 2,377	$ 5,601
Working funds	23	23
Other special funds	—	250
Special deposits	14,658	9,670
Total shown in the Statement of Cash Flows	$ 17,058	$ 15,554

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 Financial Audit

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, the issuance of certain securities, and incurrence of certain long-term debt, among other things. The Division of Audits and Accounting in the Office of Enforcement of FERC initiated a routine audit of NorthWestern Corporation for the period of January 1, 2018 to the present to evaluate our compliance with FERC accounting and financial reporting requirements. We responded to several sets of data requests as part of the audit process and in April 2022 received a draft audit report from FERC. Based on review of the draft report, we believe final resolution of the identified audit findings and recommendations will not have a material financial impact on us.

(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,	
	2021	2020
Colstrip Unit 4 Basis Adjustment	$ (133,648)	$ (137,401)
Havre Pipeline Company, LLC	12,130	13,219
NorthWestern Services, LLC	2,065	2,018
NorthWestern Energy Solutions, Inc.	4,126	2,629
Risk Partners Assurance, Ltd.	1,190	1,248
Total Investments in Subsidiary Companies	**$ (114,137)**	**$ (118,287)**

(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, 2021	December 31, 2020
			(in thousands)	
Flow-through income taxes	14	Plant Lives	$ 464,664	$ 420,925
Pension	16	See Note 16	98,336	138,567
Excess deferred income taxes	14	Plant Lives	60,813	67,256
Employee related benefits	16	Various	21,648	22,516
State & local taxes & fees		Various	6,514	17,904
Environmental clean-up	19	Various	11,262	11,127
Other		Various	21,912	34,090
Total Regulatory Assets			**$ 685,149**	**$ 712,385**
Excess deferred income taxes	14	Plant Lives	158,047	165,434
Unbilled revenue		1 Year	16,430	12,072
Gas storage sales		19 years	7,466	7,887
State & local taxes & fees		1 Year	3,021	1,783
Environmental clean-up and other		Various	693	656
Total Regulatory Liabilities			**$ 185,657**	**$ 187,832**

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, 2021	December 31, 2020
		(in thousands)	
Land and improvements	53 – 96	$ 169,843	$ 165,620
Building and improvements	23 – 73	510,994	516,678
Storage, distribution, and transmission	15 – 95	4,115,327	3,881,961
Generation	23 – 72	2,038,965	2,003,072
Construction work in process	—	284,729	166,454
Other equipment	2 – 45	383,059	363,976
Total utility plant		7,502,917	7,097,760
Less accumulated depreciation		(2,672,869)	(2,546,445)
Net utility plant		$ 4,830,048	$ 4,551,315

Net utility plant under capital (finance) lease were $9.2 million and $11.3 million as of December 31, 2021 and 2020, respectively, which included $9.0 million and $11.1 million as of December 31, 2021 and 2020, 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, 2021				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 154,375	$ 62,865	$ 51,652	$ 324,433
Accumulated depreciation	45,895	37,749	41,918	114,830
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

(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,	
	2021	2020
Liability at January 1,	$ 45,355	$ 42,449
Accretion expense	2,233	2,070
Liabilities incurred	—	—
Liabilities settled	(2,906)	(4,061)
Revisions to cash flows	(3,935)	4,897
Liability at December 31,	$ 40,747	$ 45,355

During the twelve months ended December 31, 2021 our ARO liability decreased $2.9 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities. Additionally, during the twelve months ended December 31, 2021, our ARO liability decreased $4.1 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, 2021 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, 2021 and 2020. 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, 2021
Interest rate contracts	Interest on long-term debt	$ 614

A pre-tax loss of approximately $14.0 million is remaining in AOCI as of December 31, 2021, 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, 2021	**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	$ 14,658	$ —	$ —	$ —	$ 14,658
Rabbi trust investments	18,234	—	—	—	18,234
Total	**$ 32,892**	**$ —**	**$ —**	**$ —**	**$ 32,892**
December 31, 2020					
Special deposits	$ 9,670	$ —	$ —	$ —	$ 9,670
Rabbi trust investments	27,027	—	—	—	27,027
Total	**$ 36,697**	**$ —**	**$ —**	**$ —**	**$ 36,697**

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, 2021		December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,552,660	$ 2,838,518	$ 2,328,637	$ 2,643,131

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) Unsecured Credit Facilities

Credit Facility

We have a $425 million Credit Facility which matures September 2, 2023. The Credit Facility includes 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 $0.4 million and $0.6 million for the years ended December 31, 2021 and 2020.

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

	2021	2020
Unsecured revolving line of credit, expiring September 2023	$ 425.0	$ 425.0
Unsecured revolving line of credit, expiring March 2023	25.0	25.0
	450.0	**450.0**
Amounts outstanding at December 31:		
Eurodollar borrowings	373.0	222.0
Letters of credit	—	—
	373.0	**222.0**
Net availability as of December 31	**$ 77.0**	**$ 228.0**

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, 2021	2020
Unsecured Debt:			
Unsecured Revolving Line of Credit	2023	$ 373,000	$ 222,000
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	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	100,000
Montana—1.00%	2024	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
Total Long-Term Debt		$ 2,552,660	$ 2,328,637

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 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.

In March 2021, we issued and sold $100 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00 percent maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

As of December 31, 2021, we were in compliance with our financial debt covenants.

Other Long-Term Debt

In July 2021, our two loans totaling $27.0 million associated with the New Market Tax Credit (NMTC) financing agreement were extinguished. These loans were satisfied with our $18.2 million investment in the entities created in relation to the NMTC transaction, investor forgiveness of $7.9 million for substantially all of the benefits derived from the tax credits, and cash payment of $0.9 million. In accordance with our last rate case filing in the state of Montana, the portion of the loan forgiven, less unamortized debt issuance costs of $1.3 million, was recorded as a reduction to the cost of the office building associated with the NMTC financing agreement. This cash payment is reflected within the financing activities section of our Statement of Cash Flows for the year ended December 31, 2021; however, the remaining reduction to Long-term debt, Other investments, and Utility plant are non-cash financing activities that are not reflected within our Statement of Cash Flows for the year ended December 31, 2021.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are $517.7 million in 2023, $100.0 million in 2024, $300.0 million in 2025 and $105.0 million in 2026.

(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,	
	2021	2020
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 2,729	$ 1,673
NorthWestern Energy Solutions, Inc.	71	61
Risk Partners Assurance, Ltd.	18	18
	$ 2,818	$ 1,752
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,837	$ 1,776

(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 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,	
	2021	2020
Production tax credit	$ 75,092	$ 63,542
Pension / postretirement benefits	21,435	31,866
Customer advances	21,271	17,165
Unbilled revenue	10,704	14,429
Compensation accruals	10,612	11,748
Environmental liability	5,704	6,039
Reserves and accruals	5,105	6,265
Interest rate hedges	3,158	3,171
NOL carryforward	—	16,525
Other, net	7,833	8,142
Deferred Tax Asset	**160,914**	**178,892**
Excess tax depreciation	(438,319)	(423,181)
Flow through depreciation	(92,502)	(80,938)
Goodwill amortization	(91,689)	(91,647)
Regulatory assets and other	(53,896)	(53,450)
Deferred Tax Liability	**(676,406)**	**(649,216)**

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):

	2021	2020
Unrecognized Tax Benefits at January 1	$ 33,491	$ 35,085
Gross increases - tax positions in prior period	293	120
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,735)	(1,714)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 32,049	$ 33,491

Our unrecognized tax benefits include approximately $28.1 million and $28.0 million related to tax positions as of December 31, 2021 and 2020 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, 2021, we have accrued $0.5 million for the payment of interest in the Balance Sheets. As of December 31, 2020, we did not have any amounts accrued for the payment of interest.

Tax years 2018 and forward remain subject to examination by the IRS and state taxing authorities.

(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,					
	2021			2020		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ (58)	$ —	$ (58)	$ 88	$ —	$ 88
Reclassification of net income (loss) on derivative instruments	614	(162)	452	614	(162)	452
Postretirement medical liability adjustment	(585)	149	(436)	2,462	(623)	1,839
Other comprehensive income (loss)	$ (29)	$ (13)	$ (42)	$ 3,164	$ (785)	$ 2,379

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

	December 31, 2021	December 31, 2020
Foreign currency translation	$ 1,443	$ 1,501
Derivative instruments designated as cash flow hedges	(8,127)	(8,579)
Postretirement medical plans	1,516	1,952
Accumulated other comprehensive loss	$ (5,168)	$ (5,126)

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

	December 31, 2021 Year Ended				
	Affected Line Item in the Statements of Income	**Interest Rate Derivative Instruments Designated as Cash Flow Hedges**	**Postretirement Medical Plans**	**Foreign Currency Translation**	**Total**
Beginning balance		$ (8,579)	$ 1,952	$ 1,501	$ (5,126)
Other comprehensive income before reclassifications				(58)	(58)
Amounts reclassified from AOCI	Interest on long-term debt	452			452
Amounts reclassified from AOCI			(436)		(436)
Net current-period other comprehensive income		452	(436)	(58)	(42)
Ending Balance		$ (8,127)	$ 1,516	$ 1,443	$ (5,168)

	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)

(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 Plans' 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,	
	2021	2020	2021	2020
Change in benefit obligation:				
Obligation at beginning of period	$ 820,979	$ 735,564	$ 19,146	$ 20,272
Service cost	12,994	11,116	407	370
Interest cost	18,759	22,840	317	492
Actuarial loss	(28,905)	84,479	415	123
Settlements[1]	(93,488)	—	—	390
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Benefit Obligation at End of Period	$ 696,802	$ 820,979	$ 17,308	$ 19,146
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 688,456	$ 609,000	$ 23,096	$ 21,479
Return on plan assets	33,868	101,075	3,349	2,723
Employer contributions	10,200	11,401	1,821	1,395
Settlements[1]	(93,488)	—	—	—
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Fair value of plan assets at end of period	$ 605,499	$ 688,456	$ 25,289	$ 23,096
Funded Status	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	8,297	7,001	11,914	8,436
Total Assets	8,297	7,001	11,914	8,436
Current liability	(11,200)	(11,200)	(1,575)	(1,712)
Noncurrent liability	(88,400)	(128,324)	(2,358)	(2,774)
Total Liabilities	(99,600)	(139,524)	(3,933)	(4,486)
Net amount recognized	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	1,870	3,857
Net actuarial loss	(62,448)	(115,987)	1,366	(497)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(95)	(246)
Net actuarial gain	—	—	2,500	3,246
Total	$ (62,448)	$ (115,987)	$ 5,641	$ 6,360

(1) In December 2021, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 1,062 NorthWestern Energy Pension Plan participants. We purchased the contract with $93.5 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2022. This transaction settled $93.5 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2021, we recorded a non-cash, non-operating settlement charge of $11.3 million. This charge is recorded within operating expenses, net on the Statements of Income. As discussed within Note 5 – Regulatory Assets and Liabilities, this charge was deferred as a regulatory asset on the Balance Sheets, with a corresponding decrease to operating expenses on the Statements of Income.

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,	
	2021	2020
Projected benefit obligation	$ 636.3	$ 757.4
Accumulated benefit obligation	636.3	757.4
Fair value of plan assets(1)	537.9	619.1

As of December 31, 2021, 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.

(1) Fair value of plan assets was impacted by the group annuity contract discussed above.

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,	
	2021	2020	2021	2020
Components of Net Periodic Benefit Cost				
Service cost	$ 12,994	$ 11,116	$ 407	$ 370
Interest cost	18,759	22,840	327	492
Expected return on plan assets	(27,061)	(26,162)	(919)	(983)
Amortization of prior service cost (credit)	—	—	(1,835)	(1,882)
Recognized actuarial loss (gain)	6,536	5,028	(898)	(61)
Settlement loss recognized(1)	11,291	—	—	390
Net Periodic Benefit Cost (Credit)	$ 22,519	$ 12,822	$ (2,918)	$ (1,674)
Regulatory deferral of net periodic benefit cost(2)	(13,308)	(2,100)	—	—
Previously deferred costs recognized(2)	—	71	709	861
Amount Recognized in Income	$ 9,211	$ 10,793	$ (2,209)	$ (813)

(1) Settlement loss is related to partial annuitization of NorthWestern Energy Pension Plan effective December 1, 2021.

(2) 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, 2021 and 2020. 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 increase in the discount rate during 2021 decreased our projected benefit obligation by approximately $45.1 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 increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 4.26 percent and decreased our assumption on the NorthWestern Corporation Pension Plan to 2.66 percent for 2022.

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

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2021	2020	2021	2020
Discount rate	2.65-2.75 %	2.20-2.30 %	2.35-2.40 %	1.8 %
Expected rate of return on assets	3.01-4.17	3.45-4.49	4.08	4.71
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	3.30-6.00	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,	
	2021	2020	2021	2020	2021	2020
Fixed income securities	55.0 %	55.0 %	90.0 %	80.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	4.0	4.0	1.0	2.0	—	—
Global equities	41.0	41.0	9.0	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,	
	2021	2020	2021	2020	2021	2020
Cash and cash equivalents	0.1 %	— %	0.4 %	0.7 %	0.1 %	1.0 %
Fixed income securities	53.8	52.7	89.5	77.3	33.7	37.9
Non-U.S. fixed income securities	3.9	3.8	0.9	2.6	—	—
Global equities	42.2	43.5	9.2	19.4	66.2	61.1
	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. Additional funding relief was passed in the American Rescue Plan Act of 2021, providing for longer amortization and interest rate smoothing, which we elected to use. We expect to continue to make contributions to the pension plans in 2022 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 2021 and 2020 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2021	2020
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 10,201
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 10,200	$ 11,401

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

	Pension Benefits	Other Postretirement Benefits
2022	$ 28,842	$ 2,579
2023	30,368	2,296
2024	31,933	1,952
2025	33,410	1,435
2026	34,692	1,381
2027-2031	183,671	5,352

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, 2021 and 2020 were $11.8 million and $11.1 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, 2021, there were 828,486 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:

	2021	2020
Risk-free interest rate	0.19 %	1.42 %
Expected life, in years	3	3
Expected volatility	28.2% to 38.5%	14.9% to 19.7%
Dividend yield	4.3 %	3.1 %

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, 2021, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date
Beginning nonvested grants	130,571	$ 66.27
Granted	104,927	$ 50.53
Vested	(69,867)	$ 60.41
Forfeited	(3,108)	$ 59.14
Remaining nonvested grants	162,523	$ 58.76

We recognized compensation expense of $3.9 million and $2.2 million for the years ended December 31, 2021 and 2020, respectively, and related income tax benefit of $(0.2) million and $(0.6) million for the years ended December 31, 2021 and 2020, respectively. As of December 31, 2021, we had $5.7 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 $4.2 million and $5.1 million for the years ended December 31, 2021 and 2020, 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, 2021, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	77,967	$ 50.86
Granted	24,385	43.29
Vested	(15,033)	45.78
Forfeited	—	—
Remaining nonvested grants	87,319	$ 49.63

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,	
	2021	2020
DSUs Issued	18,741	21,434
Compensation expense	1.1	1.5
Change in value of shares	1.3	(2.9)
Total compensation (benefit) expense	$ 2.4	$ (1.4)
DSUs withdrawn	186,137	613
Value of DSUs withdrawn	$ 12.1	$ 0.1

(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 16,880 and 35,378 during the years ended December 31, 2021 and 2020, 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.

Issuance of Common Stock

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. This is a three-year agreement, expiring on February 11, 2024. During the twelve months ended December 31, 2021, we issued 1,966,117 shares of our common stock under the ATM program at an average price of $63.81, for net proceeds of $124.2 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We do not anticipate needing to issue equity through the ATM program during 2022.

On November 17, 2021, we announced a registered public offering of 6,074,767 shares of our common stock at a public offering price of $53.50 per share, for an issuance amount of $325.0 million. In conjunction with this offering, we granted the underwriters an option to purchase up to 911,215 additional shares, which was subsequently exercised in full, for an additional issuance amount of $48.8 million. Of the total 6,985,982 shares of common stock offered, we initially sold 1,401,869 shares, $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing. The remaining 5,584,113 shares were sold under forward sales agreements which provide for settlement on a settlement date or dates to be specified at our discretion, but which is expected to occur on or prior to February 28, 2023. The cumulative shares issued under the forward sales agreement is limited to one and one-half times the base number of shares within the agreement, or 8,376,170 shares.

The forward sales agreements will be physically settled with common shares issued by us, unless we elect to settle the agreements in cash or to net share settle the agreements, subject to certain conditions. On a settlement date or dates, if we decide to physically settle the forward sales agreement, we will issue shares of common stock to the forward purchaser at the then-applicable forward sale price and receive issuance proceeds at that time. The forward sale price will initially be $51.8950 per share, which is subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on certain dates specified in the forward sale agreement by amounts related to expected dividends on shares of common stock during the term of the forward sale agreement.

At December 31, 2021, we could have settled the forward sale agreement with physical delivery of 5,584,113 shares of common stock to the counterparty in exchange for cash of $286.1 million. The forward sale could have also been settled at December 31, 2021, with delivery of approximately $24.2 million of cash or approximately 435,522 shares of common stock to the counterparty, if we had elected to net cash or net share settle, respectfully.

The forward sale agreement has been classified as an equity transaction because it is indexed to our common stock, physical settlement is within our control, and the other requirements necessary for equity classification are met. As a result of the equity classification, no gain or loss will be recognized within earnings due to subsequent changes in the fair value of the forward sales agreement.

(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 Practices Act (PURPA). These contracts require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. As of December 31, 2021, our estimated gross contractual obligation related to these contracts was approximately $466.9 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $388.4 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,	
	2021	2020
Beginning QF liability	$ 81,379	$ 92,937
Settlements[(1)]	(22,497)	(18,665)
Interest on long-term debt	6,061	7,107
Ending QF liability	$ 64,943	$ 81,379

(1) The settlements amount includes (i) a higher periodic adjustment of $4.3 million due to actual price escalation, which was more than previously modeled; (ii) lower costs of approximately $1.7 million, due to a $2.6 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $0.9 million reduction in costs in

the prior period; and (iii) a favorable adjustment of approximately $7.0 million decreasing the QF liability associated with a one-time clarification in contract term.

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

	Gross Obligation	Recoverable Amounts	Net
2022	$ 80,355	$ 60,639	$ 19,716
2023	82,452	61,280	21,172
2024	75,113	60,706	14,407
2025	60,360	52,950	7,410
2026	55,393	46,274	9,119
Thereafter	113,199	106,563	6,636
Total[1]	$ 466,872	$ 388,412	$ 78,460

(1) This net unrecoverable amount represents the undiscounted difference between the total gross obligations and recoverable amounts. The ending QF liability in the table above represents the present value of this net unrecoverable amount.

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 $286.7 million and $206.6 million for the years ended December 31, 2021 and 2020, respectively. As of December 31, 2021, our commitments under these contracts were $283.2 million in 2022, $269.7 million in 2023, $221.8 million in 2024, $219.4 million in 2025, $172.2 million in 2026, and $1.5 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 $26.7 million between 2022 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 or for which we are responsible, is estimated to range between $24.1 million to $30.7 million. As of December 31, 2021, we had a reserve of approximately $26.9 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.

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.

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

	December 31,	
	2021	2020
Liability at January 1,	$ 28,895	$ 30,276
Deductions	(2,799)	(2,977)
Charged to costs and expense	770	1,596
Liability at December 31,	$ 26,866	$ 28,895

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 $22.1 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 Agriculture and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2021, the reserve for remediation costs at this site was approximately $8.1 million, and we estimate that approximately $3.0 million of this amount will be incurred through 2025.

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 Montana Department of Environmental Quality (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 we expect work at the Helena site to continue into 2022.

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 has assumed the lead role at the site and has submitted a voluntary remediation plan for the Missoula site to MDEQ. 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 (CO2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, state level activity, 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 regarding GHG emissions from coal fired plants, 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. The United States Supreme Court agreed to review the case in October 2021 and oral argument regarding the scope of EPA's authority to regulate GHG emissions is scheduled to take place February 28, 2022, with a decision expected the following summer. It also is widely expected that the Biden Administration will develop an alternative plan for reducing GHG emissions from coal-fired plants, and in a memorandum dated February 12, 2021, EPA stated its belief that the January 19, 2021 opinion left neither the ACE nor the CPP rules in place.

We cannot predict whether or how GHG emission regulations will be applied to our plants, including any actions taken by the relevant state authorities. In addition, it is unclear how pending or future 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.

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.

The states of Montana, North Dakota and South Dakota are expected to develop and submit to EPA, for its approval, their respective State Implementation Plans (SIP) for Regional Haze compliance. While these states, among others, did not meet the EPA’s July 31, 2021 submission deadline, we still expect each state to submit its SIP in 2022. The draft Montana SIP does not require any additional controls at Colstrip Units 3 and 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility, however the EPA, following a preliminary review, has asked North Dakota to reassess its determination regarding Coyote. The draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are submitted and approved by EPA, the potential remains that installation of additional emissions controls might be required at these 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.

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, we entered into a non-monetary, partial settlement with PNWS in which 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 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.

On August 31, 2021, the Court ruled that the four agreements are valid and enforceable contracts and that NorthWestern breached the agreements on June 16, 2016 by refusing to go forward with the projects in spite of the MPSC's Orders. On December 15, 2021, after a three-day trial, the jury determined that PNWS had sustained $0.4 million in damages and the judge subsequently entered judgment against us in that amount.

We filed a post-trial motion on January 13, 2022 seeking to have the judgement set aside. On February 9, 2022, the judge denied our post-trial potion. The plaintiff did not seek any post-trial relief and the deadline for doing so has passed. On March 2, 2022, we filed a Notice of Appeal to the U.S. Court of Appeals for the Ninth Circuit. The plaintiff has fifteen days in which to file a cross-appeal.

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. A bench trial before the Federal District Court commenced January 4, 2022 and concluded on January 18, 2022. This bench trial addressed the issue of navigability of the segments at issue. The parties must submit amended findings of fact and conclusions of law, along with post-trial briefing, by April 29, 2022. A decision on navigability is expected following such submissions. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

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.

Colstrip Arbitration and Litigation

As part of the settlement of litigation brought by the Sierra Club and the Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them, the Ownership and Operation Agreement (O&O Agreement). Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we have incurred additional operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. We expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. Budgeting for 2022 was also delayed, with the same four joint owners demanding substantial budget reductions, but was ultimately approved on January 21, 2022. Such budgeting pressures may result in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

The Arbitration has given rise to three lawsuits concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert the Arbitration must be conducted under the O&O Agreement, with one arbitrator, in Spokane County, Washington, and pursuant to the Washington Arbitration Act. The fifth joint owner asserts the Arbitration must be conducted per the terms of Montana Senate Bill 265 (SB 265), which requires the Arbitration be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the Arbitration.

Since the Arbitration was initiated, and despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed upon process for the Arbitration.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen Montana, LLC, the operator of the Colstrip Steam Plant, in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with the Colstrip Steam Plant. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, as well as the other owners of the Colstrip Steam Plant, and Westmoreland Rosebud Mining LLC, as defendants. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties.

Since this lawsuit is in its early stages, we are unable to predict outcomes or estimate a range of reasonably possible losses.

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	62,817	275,607	-77.21%
5	**Total Intangible Plant**	189,859	402,650	-52.85%
6				
7	**Production Plant**			
8	2325 Gas Leaseholds	74,900,089	74,864,890	0.05%
9	2327 Field Compressor Structure	64,803	64,803	0.00%
10	2328 Field Mea & Reg Structure	642,881	642,881	0.00%
11	2330 Well Construction	4,824,852	4,818,870	0.12%
12	2331 Well Equipment	5,195,229	5,178,227	0.33%
13	2332 Field Lines	2,581,940	2,579,503	0.09%
14	2333 Field Compressor Equipment	1,555,808	1,522,902	2.16%
15	2334 Measuring & Regulating Equip.	2,141,030	2,137,711	0.16%
16	2337 Other Equipment	63,672	63,672	0.00%
17	**Total Production Plant**	91,970,305	91,873,460	0.11%
18				
19	**Underground Storage Plant**			
20	2350 Land and Land Rights	4,943,533	4,943,533	0.00%
21	2351 Structures and Improvements	3,233,438	3,233,438	0.00%
22	2352 Wells	10,140,887	9,403,054	7.85%
23	2353 Lines	15,209,947	15,171,116	0.26%
24	2354 Compressor Station Equipment	13,163,109	13,144,892	0.14%
25	2355 Measuring & Regulating Equip.	2,984,352	2,988,464	-0.14%
26	2356 Purification Equipment	567,763	567,763	0.00%
27	2357 Other Equipment	1,294,643	1,307,943	-1.02%
28	**Total Underground Storage Plant**	51,537,672	50,760,202	1.53%
29				
30	**Transmission Plant**			
31	2365 Rights of Way	12,150,547	11,978,184	1.44%
32	2366 Structures and Improvements	19,373,923	29,057,925	-33.33%
33	2367 Mains	245,600,288	240,808,482	1.99%
34	2368 Compressor Station Equipment	56,181,194	44,401,105	26.53%
35	2369 Meas. & Reg. Station Equipment	27,897,471	26,325,279	5.97%
36	2370 Communication Equipment	-	-	-
37	2371 Other Equipment	601,018	433,949	38.50%
38	**Total Transmission Plant**	361,804,441	353,004,923	2.49%
39				
40	**Distribution Plant**			
41	2374 Land and Land Rights	1,299,038	1,299,692	-0.05%
42	2375 Structures and Improvements	315,705	293,084	7.72%
43	2376 Mains	227,080,154	211,942,707	7.14%
44	2377 Compressor Station Equipment	-	-	-
45	2378 M&R Station Equip.-General	4,906,610	4,751,325	3.27%
46	2379 M&R Station Equip.-City Gate	-	-	-
47	2380 Services	100,184,156	94,557,048	5.95%
48	2381 Customers Meters and Regulators	79,811,802	77,324,810	3.22%
49	2382 Meter Installations			-
50	2383 House Regulators			-
51	2384 House Regulator Installations			-
52	2385 M&R Station Equip.-Industrial	103,320	96,629	6.93%
53	2386 Other Prop. on Customers' Premises			-
54	2387 Other Equipment	76,604	76,604	0.00%
55	**Total Distribution Plant**	413,777,390	390,341,898	6.00%

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	2,488,751	0.00%
5	2391 Office Furniture and Equipment	145,824	195,419	-25.38%
6	2392 Transportation Equipment	17,043,902	16,299,211	4.57%
7	2393 Stores Equipment	198,972	198,972	0.00%
8	2394 Tools, Shop & Garage Equipment	7,416,095	7,250,533	2.28%
9	2395 Laboratory Equipment	365,625	365,625	0.00%
10	2396 Power Operated Equipment	5,088,099	5,111,320	-0.45%
11	2397 Communication Equipment	3,037,451	3,322,707	-8.59%
12	2398 Miscellaneous Equipment	104,235	104,235	0.00%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	35,990,629	35,438,448	1.56%
15	**Total Gas Plant in Service**	955,270,296	921,821,582	3.63%
16				
17	4101 Gas Plant Allocated from Common	53,297,429	55,122,988	-3.31%
18	2105 Gas Plant Held for Future Use	29,866	29,866	0.00%
19	2107 Gas Construction Work in Progress	48,006,941	25,669,068	87.02%
20	2117 Gas in Underground Storage	51,242,624	44,744,243	14.52%
21				
22				
23	**TOTAL GAS PLANT**	1,107,847,156	1,047,387,746	5.77%
24				
25				

26	**CONSOLIDATED**	December 31,	
27	**PLANT IN SERVICE**	2021	2020
28			
29	Montana Electric	$ 4,230,419,003	$ 4,024,698,866
30	Yellowstone National Park	22,211,416	21,309,430
31	Montana Natural Gas (Includes CMP)	955,270,296	921,821,582
32	Common	163,830,981	170,239,284
33	Townsend Propane	1,523,174	1,523,174
34	South Dakota Electric	975,412,139	946,530,965
35	South Dakota Natural Gas	233,394,205	220,364,733
36	South Dakota Common	68,846,326	63,763,314
37	Asset Retirement Obligation	33,839,429	27,990,906
38	**TOTAL PLANT**	$ 6,684,746,970	$ 6,398,242,253

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	91,970,305	$46,748,841	$42,834,125	5.36%
4					
5	Underground Storage	51,537,672	26,745,634	26,302,603	1.67%
6					
7	Other Storage	-	-	-	-
8					
9	Transmission	361,804,441	133,374,804	129,013,372	1.73%
10					
11	Distribution	413,777,390	165,180,048	156,767,577	2.67%
12					
13	General and Intangible	36,180,488	26,457,923	24,594,444	8.94%
14					
15	Common	53,297,429	16,445,525	15,872,008	5.57%
16					
17					
18	**Total Accum Depreciation**	$1,008,567,725	$414,952,775	$395,384,130	2.82%
19					
20					
21					

	Consolidated Accumulated Depreciation	December 31, 2021	December 31, 2020
24			
25	Montana Electric	$1,616,088,021	$1,538,688,590
26	Yellowstone National Park	11,122,437	10,775,157
27	Montana Natural Gas (Includes CMP)	398,507,251	379,512,122
28	Common	46,114,248	44,485,802
29	Townsend Propane	1,047,214	1,006,510
30	South Dakota Electric	339,038,874	321,722,932
31	South Dakota Natural Gas	104,065,010	99,910,123
32	South Dakota Common	21,986,176	20,058,902
33	Acquisition Writedown	40,572,152	43,276,641
34	Basin Creek Capital Lease	31,162,371	29,151,894
35	FIN 47	273,733	2,584,933
36	CWIP-Capital Retirement Clearing	-8,987,263	-6,356,971
37	**Total Consolidated Accum Depreciation**	$2,600,990,223	$2,484,816,637

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	$ 272,450	$ 255,118	6.79%
7	Transmission Plant	1,862,287	1,724,290	8.00%
8	Distribution Plant	3,275,571	3,121,381	4.94%
9				
10	**Total MT Materials and Supplies**	$5,410,308	$5,100,789	6.07%
11				
12				

13	**Consolidated**	December 31,	
14	**Materials and Supplies**	2021	2020
15			
16	Montana Natural Gas	$5,410,308	$5,100,789
17	Montana Electric	33,078,315	27,003,447
18	South Dakota	15,050,102	11,587,583
19			
20	**Total Consolidated Materials and Supplies**	$53,538,725	$43,691,819

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%
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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	$ 186,839,752	$ 155,215,334	20.37%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	159,403,530	151,822,661	4.99%
6	Amortization, Net	32,746,162	32,493,241	0.78%
7	Other Noncash Charges to Net Income, Net	13,533,571	9,164,507	47.67%
8	Deferred Income Taxes, Net	971,152	(8,915,420)	110.89%
9	Investment Tax Credit Adjustments, Net	239,294	(3,229)	>300.00%
10	Change in Operating Receivables, Net	(22,324,551)	2,531,086	>-300.00%
11	Change in Materials, Supplies & Inventories, Net	(19,613,582)	(7,107,682)	-175.95%
12	Change in Operating Payables & Accrued Liabilities, Net	(4,575,338)	36,683,477	-112.47%
13	Allowance for Funds Used During Construction (AFUDC)	(11,082,078)	(6,890,979)	-60.82%
14	Change in Other Assets & Liabilities, Net	(121,016,076)	25,733,749	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,599,655)	(4,306,292)	39.63%
17	Change in Regulatory Assets	10,802,572	(22,881,012)	147.21%
18	Change in Regulatory Liabilities	(2,175,661)	(9,752,604)	77.69%
19	**Net Cash Provided by Operating Activities**	221,149,090	353,786,837	-37.49%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(435,651,210)	(407,029,942)	-7.03%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(1,505,221)	(41,825)	>-300.00%
24	Proceeds from Sale of Assets	-	-	-
25	**Net Cash Used in Investing Activities**	(437,156,431)	(407,071,767)	-7.39%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	99,915,000	150,000,000	-33.39%
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	196,246,244	-	100.00%
32	Payments for Retirement of:			
33	Repayments of Short Term Borrowings, Net	(100,000,000)	-	-
34	Repayments of Long Term Borrowings, Net	(955,280)	-	-
35	Line of Credit Repayments, Net	151,000,000	(67,000,000)	>300.00%
36	Dividends on Common Stock	(128,482,602)	(120,349,736)	-6.76%
37	Other Financing Activities:			
38	Debt Financing Costs	(909,219)	(2,577,869)	64.73%
39	Treasury Stock Activity	706,750	(1,391,881)	150.78%
40	**Net Cash Used in Financing Activities**	217,520,893	58,680,515	270.69%
41	**Net Increase/Decrease in Cash and Cash Equivalents**	1,513,552	5,395,584	-71.95%
42	**Cash and Cash Equivalents at Beginning of Year**	15,544,013	10,148,429	53.17%
43	**Cash and Cash Equivalents at End of Year**	$ 17,057,565	$ 15,544,013	9.74%
44				
45	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
46	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
47	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
48	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
49				
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52				
53				

Sch. 24	MONTANA LONG TERM DEBT 2021								
	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	14,905,880	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	34,807,797	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	445,072,899	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	248,778,070	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%	2,005,288	4.01%
14	3.98% Series($150M), Due 2049	09/17/19	09/17/49	100,000,000	99,389,221	100,000,000	3.98%	3,996,904	4.00%
14	3.21% Series($100M) Due 2030	05/15/20	05/15/30	100,000,000	99,516,844	100,000,000	3.21%	3,269,953	3.27%
15	1.00% Series($100M) Due 2024	03/26/21	03/26/24	100,000,000	99,442,399	99,938,611	1.00%	1,228,950	1.23%
16	**Total First Mortgage Bonds**			$ 1,616,000,000	$ 1,604,186,291	$ 1,615,938,611		$ 66,943,501	4.14%
17									
18	**Pollution Control Bonds**								
19	2.00% Series ($144.7M), Due 2023	08/11/16	08/01/23	$ 144,660,000	$ 143,067,684	$ 144,660,000	2.000%	$ 3,627,593	2.51%
20									
21	**Total Pollution Control Bonds**			$ 144,660,000	$ 143,067,684	$ 144,660,000		$ 3,627,593	2.51%
22									
23	**Other Long-Term Debt**								
24									
25									
26	**Total Other Long Term Debt**			$ -	$ -	$ -		$ -	
27									
28	**TOTAL LONG TERM DEBT**			$ 1,760,660,000	$ 1,747,253,975	$ 1,760,598,611		$ 70,571,094	4.01%
29									
30									
31	This schedule does not reflect our obligations under capital lease which total $12,796,408								
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45									

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										
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31										
32	**TOTAL**					0		0	0	

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 High	Market Price Low	Price/ Earnings Ratio
January	50,601,501	$41.51				$59.61	53.16	
February	50,672,048	41.98				61.10	53.71	
March	50,675,247	41.71	$1.25	0.620		66.27	58.05	
April	50,706,342	41.93				70.80	64.30	
May	51,074,734	42.35				69.63	62.46	
June	51,560,053	42.23	0.72	0.620		65.28	59.29	
July	51,561,266	42.59				64.63	58.92	
August	52,088,451	43.09				65.05	61.15	
September	52,605,730	42.71	0.68	0.620		65.62	57.23	
October	52,653,710	42.93				60.40	56.09	
November	54,057,097	43.44				58.98	53.66	
December	54,060,648	43.28	$0.96	0.620		57.65	54.14	
TOTAL Year End	51,709,229	$43.28	$3.61	$2.48	31.30%	$56.83		15.7

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2021.

Sch. 27

MONTANA EARNED RATE OF RETURN - GAS

Account	Description	This Year	Last Year	% Change
	Rate Base			
101	Plant in Service	$988,924,893	$939,793,504	5.23%
108	Accumulated Depreciation	(406,463,571)	(385,969,201)	-5.31%
	Net Plant in Service	$582,461,322	$553,824,303	5.17%
	Additions:			
154, 156	Materials & Supplies	$10,421,167	$9,966,761	4.56%
165	Prepayments			
	Other Additions	43,724,451	44,584,701	-1.93%
	Total Additions	$54,145,618	$54,551,463	-0.74%
	Deductions:			
190	Accumulated Deferred Income Taxes	$36,752,624	$37,380,818	-1.68%
252	Customer Advances for Construction	16,820,602	13,766,686	22.18%
255	Accumulated Def. Investment Tax Credits			
	Other Deductions	52,298,761	52,217,672	0.16%
	Total Deductions	$105,871,987	$103,365,176	2.43%
	Total Rate Base	$530,734,953	$505,010,589	5.09%
	Adjusted Rate Base	$530,734,953	$505,010,589	5.09%
	Net Earnings	$ 29,228,168	$ 28,801,361	1.48%
	Rate of Return on Average Rate Base	5.507%	5.703%	-3.44%
	Rate of Return on Average Equity 1/	7.382%	7.794%	-5.29%
	Major Normalizing and			
	Commission Ratemaking Adjustments			
	Rate Schedule Revenues	$3,898,159	$2,771,101	40.67%
	Environmental True-up MGP Sites 2/	1,876,150		-
	Non-Allowables:			
	Advertising	122,410	117,508	4.17%
	Dues, Contributions, Other	23,294	23,114	0.78%
	Associated Income Taxes 3/	732,628	1,399,305	-47.64%
	Total Adjustments	$6,652,641	$4,311,028	54.32%
	Revised Net Earnings	$35,880,808	$33,112,389	8.36%
	Rate Base Adjustment			
	Stipulation with MCC 4/	($7,687,522)	($8,113,895)	5.25%
	Revised Rate Base	$523,047,431	$496,896,694	5.26%
	Adjusted Rate of Return on Average Rate Base	6.860%	6.664%	2.94%
	Adjusted Rate of Return on Average Equity 1/	9.272%	8.844%	4.84%

1/ Return on Equity calculated using the capital structure approved in Docket No. D2016.9.68.

2/ Removal of increase to MGP liability recorded in 2021.

3/ Associated Income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket No. D2016.9.68.

4/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting one-third of the $38.8 million allocated to natural gas as a rate base reduction.

Sch. 27	cont. **MONTANA EARNED RATE OF RETURN - GAS**			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	Gas Stored Underground	36,167,272	35,735,152	1.21%
4	Cost of Refinancing Debt	7,557,179	8,843,315	-14.54%
5	MPSC/MCC Taxes	0	6,234	-100.00%
6				
7	**Total Other Additions**	$43,724,451	$44,584,701	-1.93%
8				
9	**Detail - Other Deductions**			
10	Personal Injury and Property Damage	$1,932,605	$2,286,318	-15.47%
11	Storage Gas Sales 2000 & 2001	7,676,719	8,097,235	-5.19%
12	Gross Cash Requirements	15,588,271	14,051,515	10.94%
13	Regulatory Liability (TCJA)	$27,101,167	$27,782,605	-2.45%
14				
15				
16	**Total Other Deductions**	$52,298,761	$52,217,672	0.16%
17				
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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)	$ 1,008,567,725
5	105	Plant Held for Future Use	29,866
6	107	Construction Work in Progress	48,006,941
7	117	Gas in Underground Storage	51,242,624
8	151-163	Materials & Supplies	5,410,308
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	414,952,775
11	252	Customer Advances	14,852,544
12	**NET BOOK COSTS**		683,452,145
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	220,647,329
17			
18	**Total Operating Revenues**		220,647,329
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	123,711,823
21	403-407	Depreciation, Depletion, & Amortization Expenses	27,207,205
22	408.1	Taxes Other than Income Taxes	38,608,863
23	409-411	Federal & State Income Taxes	1,891,270
24			
25	**Total Operating Expenses**		191,419,161
26	**Net Operating Income**		29,228,168
27			
28	415-421.1	Other Income	861,407
29	421.2-426.5	Other Deductions	490,345
30	**NET INCOME BEFORE INTEREST EXPENSE**		$ 29,599,229
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	179,642
34		Commercial	24,930
35		Industrial	228
36		Other (including interdepartmental)	166
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		204,966
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	77.3
41		Average Annual Residential Cost per (Dkt)	9.08
42		Average Residential Monthly Bill	$ 58.46
43			
44		Plant in Service (Gross) per Customer	$4,921

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	489	76	1	566
2	Amsterdam	180	56	12	-	68
3	Anaconda	9,298	3,447	336	5	3,788
4	Augusta	309	200	49	1	250
5	Belfry	218	4	-	-	4
6	Belgrade	7,389	6,988	1,237	1	8,226
7	Big Mountain	-	276	34	-	310
8	Big Sandy	598	293	72	-	365
9	Big Timber	1,641	949	191	6	1,146
10	Bigfork	4,270	1,635	233	-	1,868
11	Billings	104,170	26	3	-	29
12	Bonner	1,663	80	25	-	105
13	Boulder	1,183	455	82	3	540
14	Bozeman	37,280	26,799	3,989	9	30,797
15	Browning	2,801	1,082	156	5	1,243
16	Buffalo	-	7	1	-	8
17	Butte	33,525	13,056	1,506	32	14,594
18	Cardwell	50	19	4	-	23
19	Carter	58	27	9	-	36
20	Chester	847	357	137	1	495
21	Chinook	1,203	714	142	5	861
22	Choteau	1,684	891	182	5	1,078
23	Churchill	902	466	45	-	511
24	Clancy	1,661	764	40	-	804
25	Clinton	1,052	377	18	1	396
26	Columbia Falls	4,688	3,710	396	3	4,109
27	Columbus	1,893	1,120	184	4	1,308
28	Conrad	2,570	1,130	222	10	1,362
29	Coram	539	122	27	-	149
30	Corbin	-	1	-	-	1
31	Corvallis	976	1,392	104	-	1,496
32	Cut Bank	2,869	44	12	1	57
33	Deer Lodge	3,111	1,627	220	5	1,852
34	Dillon	4,134	2,172	360	5	2,537
35	Drummond	309	202	52	2	256
36	East Glacier Park	363	144	49	1	194
37	East Helena	1,984	2,266	149	3	2,418
38	Elliston	219	105	14	-	119
39	Essex	-	103	21	1	125
40	Fairfield	708	419	90	4	513
41	Florence	765	1,366	90	1	1,457
42	Floweree	-	40	9	-	49
43	Fort Belknap	1,293	322	63	-	385
44	Fort Benton	1,464	652	162	-	814
45	Fort Harrison	-	-	11	57	68
46	Fort Shaw	280	114	13	-	127
47	Galata	-	2	-	-	2
48	Gallatin Gateway	856	187	46	-	233
49	Garneill	-	7	2	-	9
50	Garrison	96	21	8	-	29
51	Gildford	179	72	25	-	97
52	Grantsdale	-	16	1	-	17
53	Great Falls	58,505	987	73	2	1,062

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	-	62	14	-	76
3	Hamilton	4,348	4,382	731	7	5,120
4	Harlem	808	332	61	1	394
5	Harlowton	997	530	103	2	635
6	Havre	10,026	4,596	692	9	5,297
7	Helena	53,457	19,881	2,544	27	22,452
8	Hingham	118	81	32	-	113
9	Hungry Horse	826	230	36	-	266
10	Inverness	55	35	12	-	47
11	Jefferson City	472	225	15	2	242
12	Joplin	157	96	24	-	120
13	Judith Gap	126	65	14	-	79
14	Kalispell	19,927	13,297	2,182	19	15,498
15	Kremlin	98	47	18	-	65
16	Laurel	6,718	24	3	-	27
17	Ledger	-	7	-	-	7
18	Lewistown	5,901	2,999	514	7	3,520
19	Livingston	7,044	4,406	623	13	5,042
20	Logan	99	39	6	-	45
21	Lohman	-	2	1	-	3
22	Lolo	3,892	1,797	103	-	1,900
23	Loma	85	45	17	-	62
24	Manhattan	1,520	916	128	2	1,046
25	Martin City	500	116	17	-	133
26	Marysville	80	1	-	-	1
27	Milltown	-	70	11	-	81
28	Missoula	66,788	32,024	4,008	47	36,079
29	Montana City	2,715	847	80	-	927
30	Moore	193	3	-	-	3
31	Philipsburg	820	458	96	-	554
32	Power	-	-	1	-	1
33	Ramsay	-	40	7	-	47
34	Red Lodge	2,125	2,100	301	9	2,410
35	Reedpoint	193	121	16	1	138
36	Roberts	361	182	21	-	203
37	Rocker	-	48	6	-	54
38	Rudyard	258	127	28	-	155
39	Ryegate	245	3	1	-	4
40	Shawmut	42	23	7	-	30
41	Shelby	3,376	9	4	-	13
42	Sheridan	642	450	77	-	527
43	Silver Star	-	22	5	-	27
44	Silverbow	-	3	3	2	8
45	Simms	354	159	17	-	176
46	Somers	1,109	426	22	-	448
47	Stevensville	1,809	1,912	279	5	2,196
48	Sun River	124	106	17	-	123
49	Three Forks	1,869	889	143	-	1,032
50	Turah	306	144	4	-	148
51	Twin Bridges	375	205	60	-	265

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	332	25	-	357
3	Victor	745	499	77	1	577
4	Walkerville	675	237	12	-	249
5	Warm Springs	-	13	1	-	14
6	West Glacier	227	107	41	3	151
7	Whitefish	6,357	4,872	513	5	5,390
8	Whitehall	1,038	698	111	1	810
9	Whitlash	-	1	1	-	2
10	Williamsburg	-	-	-	-	-
11	Willow Creek	210	99	14	-	113
12	Wolf Creek	-	50	27	-	77
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48	**Total**	512,422	179,642	24,983	341	204,966

1/ Customer populations represent an average of the 12 month period from 01/01/21 through 12/31/21.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	3	3
4	Customer Care	136	151	144
5	Finance	160	156	158
6	Distribution	457	442	450
7	Transmission	313	305	309
8	Supply	124	116	120
9	Legal	27	23	25
10		`	`	
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,219	1,196	1,208

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2022 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Transmission - Billings Rimrock Substation rebuild	$20,718,587	$20,718,587
4	MT Distribution - Transformer purchases new connects	10,495,778	10,495,778
5	MT Distribution - Missoula City Substation rebuild	7,078,542	7,078,542
6	MT Distribution - System Rural Reliability initiative	6,000,000	6,000,000
7	MT Transmission - Line Creek to Red Lodge 50Kv rebuild	4,923,581	4,923,581
8	MT Transmission - 2nd Laurel City 100kv capacity	4,593,134	4,593,134
9	MT Transmission - Meadow to Midway reconductor capacity	3,382,978	3,382,978
10	MT Transmission - Bonner to Mill Creek A pole replacements	2,421,718	2,421,718
11	MT Transmission - South Butte 161-100kv's substation capacity	2,415,537	2,415,537
12	MT Distribution - Lewistown base pole replacements	2,306,370	2,306,370
13	MT Distribution - LED street lights program	2,272,005	2,272,005
14	MT Distribution - Great Falls base pole replacements	2,097,868	2,097,868
15	MT Transmission - Three Rivers to Clyde Park pole replacements	2,024,093	2,024,093
16	MT Transmission - Rattlesnake to Kerr A pole replacements	1,899,423	1,899,423
17	MT Transmission - Laurel Auto Substation rebuild	1,840,381	1,840,381
18	MT Transmission - East Gallatin transformer capacity upgrade	1,815,008	1,815,008
19	MT Transmission - Thompson Falls to Kerr A pole replacements	1,733,723	1,733,723
20	MT Distribution - Helena division forest management program	1,551,335	1,551,335
21	MT Transmission - Mill Creek to Dillon Salmon pole replacements	1,504,874	1,504,874
22	MT Transmission - Great Falls Switchyard to Riverview NW reconductor	1,476,799	1,476,799
23	MT Distribution - capacity Skalkaho cutover	1,349,621	1,349,621
24	MT Transmission - Steamplant 230kv cap and pin substation	1,307,341	1,307,341
25	MT Distribution - Missoula division forrest management program	1,284,053	1,284,053
26	MT Distribution - Misoula Reserve St Bank 3 substation capacity	1,235,514	1,235,514
27	MT Distribution - LED yard lights replacement program	1,226,987	1,226,987
28	MT Distribution - Bozeman base pole replacements	1,219,297	1,219,297
29	MT Transmission - Chester Capacitor sub maintenance	1,203,384	1,203,384
30	MT Transmission - Rainbow-Two Dot 100kv line compliance	1,202,717	1,202,717
31	MT Transmission - South Butte Bank 3 substation capacity	1,136,918	1,136,918
32	MT Distribution - Butte Base Pole Replacements	1,070,676	1,070,676
33	MT Transmission - Hamilton Heights substation maintenance	1,060,734	1,060,734
34	MT Distribution - Billings Meridian 84 46th St W underground cable	1,057,663	1,057,663
35	MT Transmission - Millcreek 230kv cap and pin substation	1,050,838	1,050,838
36	SD Distribution - Huron Alpena LSI capacity	3,127,861	0
37	SD Distribution - LED proactive light replacements	1,500,410	0
38	20 SD Transmission Worst Circuit	1,444,702	0
39			
40	All Other Projects < $1 Million Each and blankets	103,609,948	77,559,404
41	**Total Electric Utility Construction Budget**	**207,640,399**	**175,516,883**
42			
43	**Natural Gas Operations**		
44	MT Transmission - Morel-Butte transmission line replacement	$21,697,162	$21,697,162
45	MT Transmission - Byron pipeline purchase and upgrade	8,206,448	$8,206,448
46	MT Transmission - Marias Valier pipeline Loop	6,463,260	$6,463,260
47	MT Transmission - Meriwether compressor addition	5,858,022	$5,858,022
48	MT Distribution - Butte Division base gas one plan	4,370,824	$4,370,824
49	MT Transmission - LNG facilitiy east line	2,143,934	$2,143,934
50	MT Facilities - Kalispell gas garage addition	1,585,056	$1,585,056
51	MT Transmission - CARCB pipeline Loop	1,566,463	1,566,463
52	MT Distribution - gas meters and regulators	1,497,750	1,497,750
53	MT Distribution - Bozeman Division base gas one plan	1,396,608	1,396,608
54	MT Distribution - Whitefish Mountain capacity upgrade	1,271,171	1,271,171
55	MT Distribution - compliance NPRM required projects	1,012,881	1,012,881
56	SD Transmission - Millbank line reroute and DOT	3,485,687	0
57	SD Distribution - Yankton Full Circle capacity	2,019,343	0
58			
59	All Other Projects < $1 Million Each and blankets	33,513,432	$20,462,176
60	**Total Natural Gas Utility Construction Budget**	**$96,088,045**	**$77,531,758**
61			
62	**Common**		
63	MT Common - Distribution AMI Metering and Infrastructure	$32,502,123	$32,502,123
64	MT Common - Fleet vehicles and equipment	5,745,000	5,745,000
65	MT Common - BT SAP Hana implementation	2,390,545	2,390,545
66	SD Common - Fleet vehicles and equipment	1,528,000	-
67	SD Common - BT SAP Hana implementation	455,915	-
68			
69	All Other Projects < $1 Million Each and blankets	18,237,475	$14,750,644
70	(Includes BT, Communications, Facilities, Land, Customer Service)		
71	**Total Common Utility Construction Budget**	**60,859,058**	**55,388,312**
72			
73	**MT/SD Generation**		
74	MT Yellowstone Generation Station	$167,889,926	167,889,926
75	MT Hydro Maroney Spillway Gate Upgrade	13,559,010	13,559,010
76	MT Generation Interconnect - Laurel Auto Network	4,107,995	4,107,995
77	MT Hydro CCH Intake Screen Upgrade	3,659,278	3,659,278
78	MT Hydro CCH U2 Turbine Upgrade	2,727,688	2,727,688
79	MT Hydro Hauser U5 Turb-Gen Upgrade	2,471,904	2,471,904
80	MT Hydro Black Eagle U3 Turbine Upgrade	1,961,581	1,961,581
81	Mt Hydro Holter U1 Turbine Upgrade	1,697,259	1,697,259
82	MT Hydro CCH U2 Gen Restack & Rewind	1,552,975	1,552,975
83	MT Hydro Holter U1 Generator Rewind	1,325,862	1,325,862
84	MT Hydro Mystic Bridge Across Slide Area	1,203,918	1,203,918
85	MT Generation Interconnect - Laurel Auto TPIF	1,184,326	1,184,326
86	MT Hydro Holter U3 Turbine Upgrade	1,035,515	1,035,515
87	MT Generation Thompson Falls Relicensing	1,001,101	1,001,101
88	SD Generation - Huron Bob Glanzer Generating Station	3,492,277	-
89			
90	All Other Projects < $1 Million Each and blankets	$12,761,221	$10,751,520
91	**Total MT/SD Generation**	**221,631,836**	**216,129,858**
92	**TOTAL CONSTRUCTION BUDGET**	**$586,219,337**	**$524,566,811**

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		26		233,904		5,796,545
2	February		11		324,238		5,798,660
3	March		29		180,926		5,378,783
4	April		15		191,824		3,956,434
5	May		23		158,282		3,373,665
6	June		11		189,339		2,629,025
7	July		1		150,189		2,048,539
8	August		16		168,191		2,149,817
9	September		28		177,607		2,733,247
10	October		31		174,999		3,318,259
11	November		17		187,262		4,306,774
12	December		27		295,807		5,078,496
13	TOTAL						46,568,244
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		3,090,077		112,294		3,202,371
20	February		3,378,837		113,040		3,491,877
21	March		3,092,607		131,324		3,223,931
22	April		2,195,103		80,910		2,276,013
23	May		1,479,895		51,663		1,531,558
24	June		929,110		36,942		966,052
25	July		453,720		27,699		481,419
26	August		384,483		21,443		405,926
27	September		524,475		22,655		547,130
28	October		838,892		32,572		871,464
29	November		1,690,583		53,306		1,743,889
30	December		2,590,451		84,097		2,674,548
31	TOTAL		20,648,233		767,943		21,416,176
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			3,819	3,657,652		2,320,396
39	February			1,373	3,255,053		1,812,755
40	March			16,576	1,852,018		1,248,606
41	April			1,049,221	344,105	606,158	
42	May			1,743,542	32,795	1,295,972	
43	June			2,761,998	42,864	1,956,906	
44	July			2,516,798	24,672	1,981,467	
45	August			2,833,463	23,886	1,687,159	
46	September			2,328,751	26,764	1,223,995	
47	October			838,536	377,405	269,436	
48	November			174,362	1,597,301		1,070,702
49	December			2,139	3,605,110		2,421,844
50	TOTAL			14,270,578	14,839,625	9,021,093	8,874,303
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	15,637,140		$1.6594	
3	Havre Pipeline	806,482		1.6127	
4	Encana Pipeline	1,044,485		1.8211	
	Colorado Interstate Pipeline	154,437		1.5694	
5	Company Owned Production 1/	4,345,437		0.3078	
6	Intra Montana Purchase	419,520		1.8251	
7	**TOTAL CORE SUPPLY LAST YEAR**	22,407,501		$1.5689	
8					
9	Canadian Pipeline		15,305,968		$2.9914
10	Havre Pipeline		779,585		2.8872
11	Encana Pipeline		589,840		2.4775
12	Colorado Interstate Pipeline		519,000		18.6629
13	Company Owned Production 1/		4,064,339		0.6631
14	Intra Montana Purchase		549,717		3.0992
15	**TOTAL CORE SUPPLY THIS YEAR**		21,808,448		$3.1395
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	2021 E+ Natural Gas Business Partners Program	$ 1,197	$ 183,621	-99.35%	207	66	(141)
3	- Initiated 2005, 2020 weighted average program life = 19 years, 1 participant.						
4	*2021 Northwest Energy Efficiency Alliance (NEEA)	$ 1,282,896	$ 1,282,896	0.00%	0	17,329	17,329
5	- Initiated natural gas savings in 2006, program life is 15 years						
6	2021 E+ Residential Natural Gas Existing Construction Program	$ 40,742	$0	0.00%	10,484	3,345	(7,139)
7	- Reinitiated 2021, 2021 weighted average program life = 15 years, 164 participants.						
8	2021 E+ Commercial Natural Gas Existing Construction Program	$ 1,899	$0	0.00%	-	-	-
9	- Reinitiated 2021, 2021 weighted average program life = 0 years, 0 participants.						
10	2021 General Expenses All Natural Gas DSM Programs	$ 1,299	$ 391	232.51%	-	-	-
11	-NA						
12							
13	A program participant is a Montana commercial or residential						
14	natural gas customer who installs eligible						
15	energy conservation measures and receives financial						
16	incentives/rebates either directly or indirectly.						
17							
18	*Note: 2021 NEEA expeditures are allocated to electric DSM						
19	but there are gas savings as a result of some NEEA initiatives.						
20	Participant has not been defined or counted for NEEA.						
21							
22	Units reported are in dekatherms ("Dkt")						
23							
24	COVID-19 impacted 2021 DSM activities.						
25							
26	**TOTAL**	$ 1,328,032	$ 1,466,907	-9.47%	10,691	20,740	10,049

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	$ 126,022,539	$ 103,440,553	13,885,165	13,894,255	179,642	177,339
4	Commercial	64,677,771	51,345,995	7,445,638	7,165,513	24,930	24,498
5	Industrial Firm	1,133,808	840,088	135,354	121,779	228	231
6	Public Authorities	861,757	600,602	110,803	93,980	113	100
7	Interdepartmental	554,754	322,825	66,960	47,682	53	52
8	Sales to Other Utilities	1,028,355	771,245	197,682	206,222	2	2
9	TOTAL SALES	$ 194,278,984	$ 157,321,308	21,841,601	21,529,430	204,968	202,222
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	$ 23,960,549	$ 22,538,340	24,767,464	23,795,327	277	279
16	Off System Transportation & Storage	13,502	2,690	752,843	150,000	4	1
17	Canadian Montana Pipeline	249,654	263,125	-	-	-	0
18	TOTAL TRANSPORTATION	$ 24,223,705	$ 22,804,155	25,520,307	23,945,327	281	280
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30	1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.						
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							

Sch. 36a	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Expenditures	Contracted or Committed to Spend	Total Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	$ 623,810	$ -	$ 623,810	2,765	2012
3	NWE Promotion	$ 46,936	$ -	$ 46,936		
4	NWE Labor	$ 29,849	$ -	$ 29,849		
5	NWE Admin. Non-labor	$ 22	$ -	$ 22		
6	USB Interest & Svc Chg	$ (58)	$ -	$ (58)		
7	Low Income					
8	Bill Assistance	$ 830,509	$ -	$ 830,509		
9	Free Weatherization	$ 1,393,000	$ -	$ 1,393,000	5,767	2012
10	Energy Share	$ 336,000	$ -	$ 336,000		
11	NWE Promotion	$ 758	$ -	$ 758		
12	NWE Labor	$ 33,754	$ -	$ 33,754		
13	NWE Admin. Non-labor	$ 29	$ -	$ 29		
14	USB Interest & Svc Chg	$ (154)	$ -	$ (154)		
15	Total	$ 3,294,454	$ -	$ 3,294,454	8,532	
16	Number of customers that received low income rate discounts				5,984	
17	Average monthly bill discount amount ($/mo)				$ 23.13 (a)	
18	Average LIEAP-eligible household income				n/a	
19	Number of customers that received weatherization assistance				252 (b)	
20	Expected average annual bill savings from weatherization				23 dKt	
21	Number of residential audits performed				- (b)	
22	Number of residential virtual assessments performed				848 (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) 2021 Total savings and number of customers are reported. Due to COVID-19, 2019, 2020, nor 2021 electric USB funds were spent on the E+ Audit or 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 2021 USB revenues and activities. COVID-19 resulted in activities planned for 2021 being postponed and funds carried forward to 2022 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 to Spend	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	$ 623,810	$ -	$ 623,810	2,765	2012
3						
4	Market Transformation					
5	*Building Operator Certification (BOC)	$ 29,100	$ -	$ 29,100	803	2012
6						
7	Low Income					
8	Free Weatherization	$ 1,393,000	$ -	$ 1,393,000	5,767	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 2021 USB revenues and activities.					
14	COVID-19 resulted in activities planned for 2021 being postponed and					
15	funds carried forward to 2022 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	$ 2,045,910	$ -	$ 2,045,910	9,335	2012