YEAR ENDING 2022

ANNUAL REPORT

OF

NorthWestern Energy

GAS UTILITY

Docket 2023.01.001

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.	
4		
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1			
2	Chief Executive Officer	Executive	Robert Rowe
3			
4	President and Chief Operating Officer	Distribution Operations - MT/SD/NE	Brian Bird
5		Supply Operations	
6		Transmission Operations	
7		Business Technology	
8		Energy Risk Management	
9		Flight Services, Executive Compensation	
10			
11	Vice President,	Legal Services	Heather Grahame
12	General Counsel and Regulatory and	Corporate Secretary	
13	Federal Government Affairs	Risk Management	
14		Regulatory Affairs	
15		Federal Governmental Affairs	
16			
17	Vice President,	Asset and Project Management	Curt Pohl
18	Asset Management and Business Development	Business Development and Strategic Support	
19			
20	Vice President,	Distribution Operations - MT/SD/NE	Jason Merkel
21	Distribution	Construction	
22			
23	Vice President,	Transmission Planning, Engineering, Construction,	Michael Cashell
24	Transmission	and Operations	
25		Gas Transmission & Storage	
26		Substation Operations	
27		Transmission Policy, Services, and Operations	
28		Transmission Market Strategy	
29		Grid Real Time and Scada Operations	
30		FERC and NERC Compliance	
31		Support Services	
32			
33	Vice President,	Thermal and Wind Generation	John Hines
34	Supply and Montana Government Affairs	Hydro Operations	
35		Environmental and Lands Permitting & Compliance	
36		Long Term Resources	
37		Energy Supply Marketing Operations	
38		Montana Government Affairs	
39			
40	Vice President,	Brand, Advertising, and	Bobbi Schroeppel
41	Customer Care, Communications and	Customer Communications	
42	Human Resources	Customer Experience and Support	
43		Customer Interaction	
44		Community Connections	
45		Revenue Cycle Management	
46		Human Resources	
47		Health/Environmental Services	
48		Safety and Labor Relations	
49			
50	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
51		Enterprise Risk and Business Continuity	
52			
53	Vice President and Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
54		Financial Planning & Analysis	
55		Controller and Treasury Functions	
56		Investory Relations and Corporate Finance	
57			
58	Vice President,	Business Technology	Jeanne Vold
59	Technology	Customer Systems & Solutions	
60		Data & Analytics	
61		Operation Technology	
62		Security	
63			
64			

Reflects active officers as of December 31, 2022.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 179,287**	**97.97 %**
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		**$ 3,721**	**2.03 %**
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		**$ 183,008**	**100.00 %**

Sch. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1						
2						
3						
4	Controller	Includes the following departments: Controller, Accounting,	Overhead costs not charged directly are	$5,248,849	80.50%	$1,271,427
5		Accounts Payable, Payroll, Financial Reporting, Regulatory Affairs Finance	typically allocated based on a 3-factor			
6		and Risk Management	formula consisting of gross plant, labor,			
7			and margin.			
8						
9	Customer Care	Includes the following departments:	Overhead costs not charged directly are	24,156,393	74.07%	8,458,260
10		Customer Care Combined, Customer Care SD&NE	typically allocated based on a 3-factor			
11		CC MT, Business Develop, Contributions, Print Services	formula consisting of gross plant, labor,			
12		CC - Assoc & Dispatch Human Resources, and Regulatory	and margin.			
13		Support Services				
14						
15	Legal Department	Includes the following departments:	Overhead costs not charged directly are	18,477,423	79.16%	4,864,063
16		Chief Legal, Contracts Administration, Regulatory Affairs MT,	typically allocated based on a 3-factor			
17		SD & NE Public and Regulartory Affairs and Risk Management	formula consisting of gross plant, labor,			
18			and margin.			
17						
18	Business Technology	Includes the following departments:	Overhead costs not charged directly are	20,704,088	79.00%	5,503,616
17		Applications, Architecture, Governanace	typically allocated based on a 3-factor formula			
18			consisting of gross plant, labor, and margin.			
19						
20	Finance	Includes the following departments: CFO, Treasury, FP&A	Overhead costs not charged directly are	13,255,442	76.09%	4,164,169
21		Tax , Investor Relations, Corporate Aircraft,	typically allocated based on a 3-factor			
22		and Compensation & Benefits	formula consisting of gross plant, labor,			
23			and margin.			
24						
25	Executive Department	Includes the following departments:	Overhead costs not charged directly are	4,384,468	77.53%	1,270,579
26		CEO, COO and Board of Directors	typically allocated based on a 3-factor			
27			formula consisting of gross plant, labor,			
28			and margin.			
29						
30	Audit & Controls	Includes the following departments:	Overhead costs not charged directly are	934,745	79.00%	248,476
31		Internal Audit and Enterprise Risk Management	typically allocated based on a 3-factor			
32			formula consisting of gross plant, labor,			
33			and margin.			
34						
35	Distribution	Includes the following departments:	Overhead costs not charged directly are	115,146	77.25%	33,902
36		Sioux Falls Facilities and Helena Building	typically allocated based on a 3-factor			
37			formula consisting of gross plant, labor,			
38			and margin.			
39						
40	**TOTAL**			$ 87,276,554	77.17%	$ 25,814,492

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	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,686,054		
13		transmission, & compression	transmission & compression			
14			are at tariffed rates			
15						
16						
17	**Total Utility Subsidiaries Revenues**			$2,686,054		
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	14.90 %	500,400
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,003,371	34.00 %	1,003,371
15						
16	**Total Utility Subsidiaries**			1,503,771		$ 1,503,771
17	**Total Utility Subsidiaries Expenses**			3,130,598		
18	**TOTAL AFFILIATE TRANSACTIONS**			1,503,771		$ 1,503,771

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	$ 396,277,722	$ 132,563,063	$ 263,714,659	$ 220,647,329	19.52 %
3						
4	**Total Operating Revenues**	396,277,722	132,563,063	263,714,659	220,647,329	19.52 %
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	264,461,092	113,679,837	150,781,255	121,600,546	24.00 %
9	402 Maintenance Expense	8,883,255	1,801,400	7,081,855	5,888,513	20.27 %
10	403 Depreciation Expense	27,271,157	6,107,228	21,163,929	21,394,347	(1.08)%
11	404-405 Amort. & Depletion of Gas Plant	5,728,398	263,440	5,464,958	5,812,858	(5.99)%
12	406 Amort. of Plant Acquisition Adj.	(846,483)	(846,505)	22	—	-
13	407.3 Regulatory Amortizations - Debit	17,075,387	2,940,333	14,135,054	1,407,354	>300.00%
14	407.4 Regulatory Amortizations - Credit	(17,344,557)	(739,107)	(16,605,450)	(5,184,590)	(220.28)%
15	408.1 Taxes Other Than Income Taxes	44,687,232	2,146,055	42,541,177	38,608,863	10.19 %
16	409.1 Income Taxes-Federal	6,841,202	794,275	6,046,927	6,587,943	(8.21)%
17	-Other	2,307,686	195,448	2,112,238	2,335,762	(9.57)%
18	410.1 Deferred Income Taxes-Dr.	34,505,957	9,196,090	25,309,867	20,490,201	23.52 %
19	411.1 Deferred Income Taxes-Cr.	(41,936,125)	(11,509,733)	(30,426,392)	(27,522,636)	(10.55)%
20	411.4 Investment Tax Credit Adj.	—	—	—	—	-
21						
22	**Total Operating Expenses**	351,634,201	124,028,761	227,605,440	191,419,161	18.90 %
23	**NET OPERATING INCOME**	$ 44,643,521	$ 8,534,302	$ 36,109,219	$ 29,228,168	23.54 %

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
	Core Distribution Business Units (DBUs)					
	440 Residential	$ 227,236,747	$ 74,933,696	$ 152,303,051	$ 126,022,539	20.85 %
	442.1 Commercial	129,825,246	50,557,959	79,267,287	64,677,771	22.56 %
	442.2 Industrial Firm	1,519,549	—	1,519,549	1,133,808	34.02 %
	445 Public Authorities	1,047,176	—	1,047,176	861,757	21.52 %
	448 Interdepartmental Sales	884,589	—	884,589	554,754	59.46 %
	491.2 CNG Station	—	—	—	—	-
	Total Sales to Core DBUs	360,513,307	125,491,655	235,021,652	193,250,629	21.61 %
	447 Sales for Resale	1,326,341	—	1,326,341	1,028,355	28.98 %
	Total Sales of Natural Gas	361,839,648	125,491,655	236,347,993	194,278,984	21.65 %
	496.1 Provision for Rate Refunds	—	—	—	—	-
	Total Revenue Net of Rate Refunds	361,839,648	125,491,655	236,347,993	194,278,984	21.65 %
	489.1 Gathering	768,069	—	768,069	809,026	
	489.2 Transmission	31,287,359	6,546,751	24,740,608	23,960,549	3.26 %
	Total Revenues From Transportation	32,055,428	6,546,751	25,508,677	24,769,575	2.98 %
	Miscellaneous Revenues	2,382,646	524,657	1,857,989	1,598,770	16.21 %
	Total Other Operating Revenue	2,382,646	524,657	1,857,989	1,598,770	16.21 %
	TOTAL OPERATING REVENUE	$ 396,277,722	$ 132,563,063	$ 263,714,659	$ 220,647,329	19.52 %

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	13	13	—	—	-
5	**Total Operation-Gas Raw Materials**	13	13	—	—	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements			—	—	-
9	**Total Maintenance-Gas Raw Materials**	—	—	—	—	-
10	**Total Gas Raw Materials**	13	13	—	—	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	216,787	—	216,787	206,443	5.01 %
15	751 Maps & Records	—	—	—	—	-
16	752 Gas Wells Expenses	727,953	—	727,953	674,491	7.93 %
17	753 Field Lines Expenses	15,171	—	15,171	18,044	(15.92)%
18	754 Field Compressor Station Expense	3,488,497	—	3,488,497	3,418,843	2.04 %
19	755 Field Comp. Station Fuel & Power	(338,272)	—	(338,272)	(193,420)	(74.89)%
20	756 Field Meas. & Reg. Station Expense	90,030	—	90,030	109,676	(17.91)%
21	757 Dehydration Expense	9,259	—	9,259	11,898	(22.18)%
22	758 Gas Well Royalties	2,549,285	—	2,549,285	1,861,606	36.94 %
23	759 Other Expenses	490,690	—	490,690	897,535	(45.33)%
24	760 Rents	224,571	—	224,571	255,387	(12.07)%
25	**Total Oper.-Production & Gathering**	7,473,971	—	7,473,971	7,260,503	2.94 %
26						
27	**Production Maintenance**					
28	762 Maint. of Gathering Structures	—	—	—	—	-
29	763 Maint. of Producing Gas Wells	—	—	—	1,476	(100.00)%
30	764 Maint. of Field Lines	89,021	—	89,021	95,900	(7.17)%
31	765 Maint. of Field Compressor Stations	159,086	—	159,086	134,444	18.33 %
32	766 Maint. of Field Meas. & Reg. Stations	7,105	—	7,105	9,776	(27.32)%
33	767 Maint. of Purification Equipment	28,380	—	28,380	29,618	(4.18)%
34	769 Maint. of Other Equipment	283	—	283	85	232.94 %
35	**Total Maintenance - Production**	283,875	—	283,875	271,299	4.64 %
36	**TOTAL Natural Gas Production & Gathering**	7,757,846	—	7,757,846	7,531,802	3.00 %
37						
38	**Other Gas Supply Expense-Operation**					
39	800 NG Wellhead Purchases	97,328,182	—	97,328,182	60,888,077	59.85 %
40	803 NG Transmission Line Purchases	4,804,538	—	4,804,538	4,884,226	(1.63)%
41	805 Other Gas Purchases	95,403,059	98,706,903	(3,303,844)	799,559	-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	404,871	—	404,871	278,405	45.43 %
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.	(6,688,970)	—	(6,688,970)	(6,498,381)	(2.93)%
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**	191,251,680	98,706,903	92,544,777	60,351,886	53.34 %
58	**Total Production Expenses**	199,009,526	98,706,903	100,302,623	67,883,688	47.76 %

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	168,462	—	168,462	101,990	65.18 %
5	815	Maps & Records	—	—	—	—	-
6	816	Wells	422,774	—	422,774	384,403	9.98 %
7	817	Lines	55,496	—	55,496	59,857	(7.29)%
8	818	Compressor Station	596,546	—	596,546	491,293	21.42 %
9	819	Compressor Station Fuel & Power	—	—	—	—	-
10	820	Measuring & Regulating Station	21,925	—	21,925	24,746	(11.40)%
11	821	Purification	45,606	—	45,606	120,148	(62.04)%
12	823	Gas Losses	—	—	—	—	-
13	824	Other Expenses	138,781	—	138,781	64,031	116.74 %
14	825	Storage Well Royalties	4,017	—	4,017	2,476	62.24 %
15	826	Rents	—	—	—	—	-
16	**Total Operation-Underground Storage**		1,453,607	—	1,453,607	1,248,944	16.39 %
17							
18	**Underground Storage-Maintenance**						
19	830	Supervision & Engineering	2,398	—	2,398	6,491	(63.06)%
20	831	Structures & Improvements	230,397	—	230,397	411,978	(44.08)%
21	832	Reservoirs & Wells	45,121	—	45,121	40,676	10.93 %
22	833	Lines	8,638	—	8,638	11,067	(21.95)%
23	834	Compressor Station Equipment	194,023	—	194,023	203,855	(4.82)%
24	835	Meas. & Reg. Station Equipment	8,129	—	8,129	9,554	(14.92)%
25	836	Purification Equipment	10,631	—	10,631	31,401	(66.14)%
26	837	Other Equipment	—	—	—	—	-
27	**Total Maintenance-Underground Storage**		499,337	—	499,337	715,022	(30.16)%
28	**Total Underground Storage Expenses**		1,952,944	—	1,952,944	1,963,966	(0.56)%
29	**Transmission Expenses**						
30	**Transmission-Operation**						
31	850	Supervision & Engineering	3,416,151	39,507	3,376,644	3,396,078	(0.57)%
32	851	System Control & Load Dispatching	716,890	—	716,890	734,045	(2.34)%
33	853	Compressor Station Labor & Expense	738,791	—	738,791	747,383	(1.15)%
34	855	Other Fuel & Power for Comp. Stat.	—	—	—	—	-
35	856	Mains	986,763	20,612	966,151	768,768	25.68 %
36	857	Measuring & Regulating Station	653,268	729	652,539	633,358	3.03 %
37	858	Transmission & Comp.-By Others	—	—	—	—	-
38	859	Other Expenses	850,122	2,696	847,426	957,455	(11.49)%
39	860	Rents	—	—	—	—	-
40	**Total Operation-Transmission**		7,361,985	63,544	7,298,441	7,237,087	0.85 %
41	**Transmission-Maintenance**						
42	861	Supervision & Engineering	155,767	217	155,550	158,190	(1.67)%
43	862	Structures & Improvements	210,509	91	210,418	189,420	11.09 %
44	863	Mains	805,682	749	804,933	634,250	26.91 %
45	864	Compressor Station Equipment	735,469	—	735,469	460,207	59.81 %
46	865	Meas. & Reg. Station Equipment	278,210	6,856	271,354	345,160	(21.38)%
47	867	Other Equipment	—	—	—	—	-
48	**Total Maintenance-Transmission**		2,185,637	7,913	2,177,724	1,787,227	21.85 %
49	**Total Transmission Expenses**		9,547,622	71,457	9,476,165	9,024,314	5.01 %

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	2,099,546	752,672	1,346,874	1,232,968	9.24 %
4	871	Load Dispatching	27,594	27,594	—	—	-
5	872	Compressor Station Labor & Expense	—	—	—	—	-
6	873	Compressor Station Fuel and Power	—	—	—	—	-
7	874	Mains and Services	6,153,434	2,867,813	3,285,621	2,972,833	10.52 %
8	875	Meas. & Reg. Station-General	308,872	157,595	151,277	158,419	(4.51)%
9	876	Meas. & Reg. Station-Industrial	—	—	—	—	-
10	877	Meas. & Reg. Station-City Gate	129,857	94,329	35,528	38,521	(7.77)%
11	878	Meter & House Regulator	1,422,851	518,088	904,763	1,018,860	(11.20)%
12	879	Customer Installations	1,448,848	267,872	1,180,976	1,037,163	13.87 %
13	880	Other Expenses	840,233	189,016	651,217	899,590	(27.61)%
14	881	Rents	5,134	—	5,134	4,504	13.99 %
15	**Total Operation-Distribution**		12,436,369	4,874,979	7,561,390	7,362,858	2.70 %
16	**Distribution-Maintenance**						
17	885	Supervision & Engineering	1,026,010	295,222	730,788	566,025	29.11 %
18	886	Structures & Improvements	—	—	—	—	-
19	887	Mains	669,303	294,057	375,246	342,870	9.44 %
20	889	Meas. & Reg. Station Exp.-General	118,091	81,403	36,688	43,839	(16.31)%
21	890	Meas. & Reg. Station Exp.-Industrial	—	—	—	—	-
22	891	Meas. & Reg. Station Exp.-City Gate	62,877	62,877	—	—	-
23	892	Services	489,754	205,201	284,553	302,955	(6.07)%
24	893	Meters & House Regulators	1,421,002	496,510	924,492	1,186,122	(22.06)%
25	894	Other Equipment	—	—	—	—	-
26	**Total Maintenance-Distribution**		3,787,037	1,435,270	2,351,767	2,441,811	(3.69)%
27	**Total Distribution Expenses**		16,223,406	6,310,249	9,913,157	9,804,669	1.11 %
28		**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**						
30	901	Supervision	—	—	—	—	-
31	902	Meter Reading	646,872	129,893	516,979	623,447	(17.08)%
32	903	Customer Records & Collection	3,284,297	905,989	2,378,308	2,262,887	5.10 %
33	904	Uncollectible Accounts	573,094	214,670	358,424	(51,743)	>300.00%
34	905	Miscellaneous Customer Accounts	34,322	34,330	(8)	13,041	(100.06)%
35	**Total Customer Accounts Expenses**		4,538,585	1,284,882	3,253,703	2,847,632	14.26 %
36							
37		**Customer Service & Information Expenses**					
38	**Customer Service-Operation**						
39	907	Supervision	—	—	—	—	-
40	908	Customer Assistance	1,562,248	723,438	838,810	819,229	2.39 %
41	909	Inform. & Instructional Advertising	476,262	99,067	377,195	393,093	(4.04)%
42	910	Misc. Customer Service & Inform.	—	—	—	—	-
43	**Total Customer Service & Information Exp.**		2,038,510	822,505	1,216,005	1,212,322	0.30 %
44							
45		**Sales Expenses**					
46	**Sales-Operation**						
47	911	Supervision	—	—	—	—	-
48	912	Demonstrating & Selling	—	—	—	—	-
49	913	Advertising	448,717	59,458	389,259	121,195	221.18 %
50	916	Miscellaneous Sales	—	—	—	—	-
51	**Total Sales Expenses**		448,717	59,458	389,259	121,195	221.18 %

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	12,344,706	3,024,521	9,320,185	9,416,068	(1.02)%
4	921 Office Supplies & Expenses	6,081,917	1,610,386	4,471,531	3,435,091	30.17 %
5	922 Administrative Exp. Transferred-Cr.	(3,339,712)	(926,418)	(2,413,294)	(2,291,233)	(5.33)%
6	923 Outside Services Employed	2,064,596	609,283	1,455,313	1,909,311	(23.78)%
7	924 Property Insurance	306,593	—	306,593	309,073	(0.80)%
8	925 Legal & Claim Department	4,398,344	594,346	3,803,998	5,360,816	(29.04)%
9	926 Employee Pensions & Benefits	9,922,233	2,425,183	7,497,050	10,852,349	(30.92)%
10	928 Regulatory Commission Expenses	76,608	—	76,608	1,570	>300.00%
11	930 Miscellaneous General Expenses	5,074,086	403,258	4,670,828	4,459,818	4.73 %
12	931 Rents	528,284	126,994	401,290	505,256	(20.58)%
13	**Total Operation-Admin. & General**	37,457,655	7,867,553	29,590,102	33,958,119	(12.86)%
14	**Admin. & General - Maintenance**					
15	935 General Plant	2,127,369	358,217	1,769,152	673,154	162.82 %
16	**Total Admin. & General Expenses**	39,585,024	8,225,770	31,359,254	34,631,273	(9.45)%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 273,344,347	$ 115,481,237	$ 157,863,110	$ 127,489,059	23.82 %
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	1,981,457	2,010,926	(1.47)%
3	Property Taxes	37,681,843	34,137,945	10.38 %
4	Crow Tribe RR and Utility Tax	124,836	124,836	— %
5	Blackfoot Possessory Tax	367,540	356,455	3.11 %
6	City Tax	—	327	(100.00)%
7	Consumer Counsel	217,096	183,385	18.38 %
8	Public Service Commission	848,472	771,044	10.04 %
9	Heavy Highway Use	5,043	6,560	(23.13)%
10	Vehicle Use Taxes	—	103,779	(100.00)%
11	Gas Production Taxes	1,241,439	839,005	47.97 %
12	Delaware Franchise Tax	55,060	55,021	0.07 %
13				
14				
15				
16	**Canadian Taxes**			
17	Ad Valorem	18,391	19,580	(6.07)%
18				
19				
20				
21				
22	**TOTAL TAXES OTHER THAN INCOME**	$ 42,541,177	$ 38,608,863	10.19 %

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	AFFCO INC	Hydro Construction Services	1,619,030
2	A EXCAVATION	Excavation Contractor	212,046
3	AMERICAN INNOVATIONS INC	Software Support Services	328,446
4	ANDRITZ HYDRO CORP	Hydro Upgrade Services	4,170,240
5	ARCADIS US INC	Engineering Services	297,910
6	ARCOS LLC	Call-out Services	142,357
7	ASCEND ANALYTICS LLC	Hydro Expert Analysis	640,626
8	ASPLUNDH TREE EXPERT LLC	Tree Trimming	6,301,417
9	ASSOCIATED UNDERWATER SERVICE	Inspection Services	182,717
10	AUTOMOTIVE RENTALS INC	Fleet Management	6,560,369
11	AVEVA SOFTWARE, LLC	Computer Support Services	396,630
12	BART ENGINEERING COMPANY	Engineering Services	544,571
13	BASELOAD POWER GENERATION PARTS Total	Engineering Services	299,318
14	BEACON COMMUNICATIONS LLC	Software Maintenance	440,594
15	BEVERIDGE INCORPORATED	Drilling Services	225,546
16	BIG HORN WIRELINE, LLC Total	Storage	130,898
17	BIG SKY COMMUNICATION & CABLE	Communications Construction	225,546
18	BIG SKY LAND RESOURCES, LLC	Excavation Contractor	543,502
19	BILLINGS FLYING SERVICE, INC.	Powerline Services	182,728
20	BISON ENGINEERING INC	Engineering Services	166,625
21	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	988,324
22	BROADRIDGE ICS	Shareholder Services	107,090
23	BRY ENTERPRISE Total	Road Bore Services	427,625
24	BURK EXCAVATION AND UTILITIES	Construction	366,276
25	BUTLER MACHINERY COMPANY Total	Inspection	569,626
26	CATERPILLAR POWER GENERATION	Generation Services	30,720,501
27	CENTERPOINT ENERGY SERVICES I	Energy Services	138,656
28	CENTRON SERVICES INC	Customer Collection service	82,871
29	CHARLOTTE ST. ADVISORS, LLC Total	Tactical Planning Prof Services	506,235
30	CHAZNLINE, LLC Total	Heavy Haul Services	1,105,906
31	CN UTILITY CONSULTING INC	Utility Consulting Services	599,014
32	CONTINENTAL STEEL WORKS	Fabrication Services	3,080,215
33	CRIST, KROGH, BUTLER & NORD L	Legal Services	500,755
34	CROWLEY FLECK PLLP	Legal Services	376,017
35	CTA INC.	Energy Conservation Consultants	1,363,929
36	D & A TRENCHING INC	Excavating Services	118,726
37	DAVEY TREE SURGERY COMPANY	Tree Trimming	4,437,461
38	DELOITTE & TOUCHE LLP	Audit Services	1,582,733
39	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	2,436,168
40	DHC INC	Boring Services	93,758
41	DICK ANDERSON CONSTRUCTION INC	Construction	633,906
42	DIETZEL ENTERPRISES INC	Construction	194,028
43	DIRECTIONAL ZONE INC	Boring Services	618,878
44	DJ&A P C CONSULTING ENGINEER	Surveying Services	114,913
45	DNV ENERGY SERVICES USA INC Total	Commercial Lighting program	5,617,109
46	DNV GL ENERGY INSIGHTS USA INC	Software Support Services	128,626
47	DOBLE ENGINEERING CO	Maintenance Service	214,571
48	DORSEY & WHITNEY LLP	Legal Services	1,683,962
49	DOWL HKM	Geotechnical Services	91,844
50	E SOURCE COMPANIES LLC	Consulting Services	92,228
51	EIDE BAILLY LLP	Accounting Services	131,718
52	ELLIOT CONSTRUCTION INC	Boring Services	1,779,817
53	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	3,986,794
54	ENERGY CONTRACT SERVICES LLC	Inspection Services	1,649,058
55	ENERGY SHARE OF MONTANA	USBC Services	1,201,306
56	EVERGREEN CAISSONS INC	Construction	204,627
57	FAGEN, INC	Construction	2,360,597
58	FENCECRAFTERS HELENA INC	Repair Services	83,000
59	FITCH RATINGS INC Total	Annual Credit Ratings	79,875

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
60	FLYNN WRIGHT INC	Advertising Services	1,642,409
61	FOOTHILLS RIG SERVICE	Well Services	105,240
62	FOSTER ASSOCIATES CONSULTANTS LLC Total	Depreciation Studies	170,195
63	FYREROK RESERVOIR CONSULTING Total	Engineering Services-Well Testing	102,320
64	GARTNER INC	Information Technology Consulting	829,300
65	GE ENERGY MANAGEMENT SERVICES, LLC Total	E-Terra Source Upgrade Assist	331,241
66	GE RENEWABLES GRID, LLC	Software Support Services	473,611
67	GEI CONSULTANTS INC	Environmental Consultants	448,040
68	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	845,111
69	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	166,129
70	GREGG ENGINEERING	Informational Technology Simulation	97,720
71	GUY TABACCO CONSTRUCTION	Construction	501,260
72	H & H ASPHALT & MAINTENANCE L	Asphalt Services	174,603
73	H & H CONTRACTING INC	Concrete and Asphalt Services	439,397
74	H2E INC	Engineering Services	1,060,970
75	HAIDER CONSTRUCTION INC	Boring Services	640,533
76	HDR ENGINEERING INC	Engineering Services	3,250,864
77	HEATH CONSULTANTS INC	Gas Leak Surveys	780,452
78	HIGHMARK MEDIA	Safety Training	112,540
79	HITACHI ENERGY USA INC Total	Engineering Consulting	443,108
80	IMCO GENERAL CONSTRUCTION INC	Construction	233,179
81	INFOSYS LIMITED	Consulting Services	78,590
82	INTEC SERVICES INC	Pole Inspection Services	2,097,815
83	ITRON INC	Meter Installation	17,698,257
84	IVANS BORING	Boring Services	346,039
85	J D POWER AND ASSOCIATES	Energy Study	92,030
86	J2 BUSINESS PRODUCTS	Copier Maintenance	116,989
87	JACOBSEN TREE EXPERTS	Tree Trimming	268,968
88	JARES FENCE COMPANY INC	Fence Materials/Installation	139,795
89	JEFFERY CONTRACTING LLC	Construction	814,572
90	JODY KLESSENS CONSTRUCTION LLC	Construction Service	108,255
91	JONES DAY	Legal Services	225,124
92	K & K ROOFING AND EXCAVATION INC Total	Roofing and Insulation	267,725
93	KARV LLC	Boring Services	275,870
94	KELLERMEYER BERGENSONS SERVICES LLC Total	Cleaning Services	359,441
95	KM CONSTRUCTION CO INC	Construction	110,020
96	KNIFE RIVER	Construction	2,076,281
97	LEARJET INC	Repair Services	351,823
98	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	265,644
99	M & P EXCAVATING	Excavation Services	336,785
100	M&D CONSTRUCTION INC	Construction	202,874
101	MANAGEMENT APPLICATIONS CONSULTING Total	Regulatory Compliance Services	249,611
102	MCMILLEN LLC	Design Services	11,412,337
103	MERCER HUMAN RESOURCE CONSULT	HR Consulting	272,018
104	MERKEL ENGINEERING INC	Consulting Services	167,250
105	MICHAELS FENCE & SUPPLY CO	Installation Services	157,561
106	MICHELS CORPORATION	Construction	16,724,325
107	MIDCON UNDERGROUND CONSTRUCTI	Construction	488,022
108	MINUTEMAN AVIATION INC.	Helicopter Charter Services	150,014
109	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	796,353
110	MOODY'S INVESTORS SERVICE	Debt Rating Services	132,000
111	MORRISON MAIERLE INC	Engineering Services	288,788
112	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	33,029,548
113	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	364,616
114	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	456,354
115	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	541,966
116	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,896
117	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	857,432
118	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	19,383,063
119	PECK SPRAYING SERVICE Total	Concrete Removal	116,068

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
120	PINNACLE RESEARCH & CONSULTING	Consulting Services	354,367
121	PIONEER TECHNICAL SERVICES INC	Environmental Services	174,774
122	POTEET CONSTRUCTION	Traffic Safety Services	154,299
123	POWER SETTLEMENTS CONSULTING &	Consulting Services	363,670
124	POWERPLAN INC	Software Support Services	1,381,527
125	POWERS HEATING LLC	Meter Installation	112,772
126	PRO PIPE CORPORATION	Welding Services	303,203
127	QUANTA UTILITY ENGINEERING	Engineering Services	7,380,583
128	REGULATED CAPITAL CONSULTANTS, LLC Total	Tax Remediation	571,262
129	RIVER DESIGN GROUP INC	Engineering Services	106,650
130	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	31,863,154
131	ROD TABBERT CONSTRUCTION INC	Construction	233,860
132	ROSEN USA INC	Inspection Services	266,817
133	ROUNDS BROTHERS TRENCHING	Boring Services	916,021
134	SANDERSON STEWART	Engineering Services	77,188
135	SCENIC CITY ENTERPRISES INC	Construction	126,843
136	SCHNABEL ENGINEERING LLC	Consulting Services	738,633
137	SHAW PIPELINE SERVICES INC Total	Pipeline Service Reroute	999,164
138	SIDEWINDERS LLC	Generator Repair Services	2,224,617
139	SOLAR TURBINES INC Total	Commissioning New Controls	335,147
140	SPHERION STAFFING	Temporary Labor	95,479
141	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	121,000
142	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	804,540
143	STINSON LEONARD STREET LLP	Legal Services	467,201
144	STREAM WORKS INC	Construction	96,065
145	SULLIVAN BROS. CONSTRUCTION INC Total	Boring Services	218,027
146	SUPERIOR CONCRETE PRODUCTS INC	Construction	2,468,141
147	TAYLOR SERVICES INC Total	Excavator Services	222,283
148	TBC CONSTRUCTION LLC Total	Pipeline Service Reroute	1,223,411
149	TERRA REMOTE SENSING (USA) INC	Surveying Services	314,256
150	THE ELECTRIC COMPANY OF SOUTH	Construction	1,554,147
151	THE MOSAIC COMPANY	Training	945,353
152	THOMPSON HINE LLP	Benefits Audit Services	134,774
153	TIMBERLINE SECURITY & SERVICES	Security Services	275,850
154	TLC SEPTIC SERVICE	Excavation Contractor	222,897
155	TODD O BRUESKE CONSTRUCTION	Construction	343,105
156	TRADEMARK ELECTRIC INC	Construction	1,076,502
157	TROUTMAN SANDERS LLP	Legal Services	160,589
158	ULTEIG ENGINEERS INC	Project Manager Services	329,733
159	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	1,146,747
160	UNDERGROUND CONSTRUCTION	Construction	112,966
161	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	218,920
162	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	269,704
163	VAISALA INC	Wind Forecasting Services	145,728
164	VERTEX	Billing Services and Programming	3,108,755
165	VERTIV CORPORATION	Maintenance Service	87,537
166	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	617,602
167	WATSON TRUCKING OF HAVRE LLC	Hauling Services	117,918
168	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	373,127
169	WILLIS TOWERS WATSON US LLC	Compensation Services	240,794
170	ZACHA UNDERGROUND CONSTRUCTIO	Construction	104,611
171	ZAYO GROUP LLC Total	Communications Construction	148,290
	Total of Payments Set Forth Above		**$ 286,481,803**
	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**	$ —	$ —	— %

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	$ 636,271,675	$ 757,399,423	(15.99)%
8	Service cost	9,469,971	12,104,357	(21.76)%
9	Interest cost	17,240,996	17,383,148	(0.82)%
10	Plan participants' contributions	—	—	-
11	Amendments	—	—	-
12	Actuarial (gain) loss	(163,649,996)	(26,749,118)	>-300.00%
13	Settlements	—	(93,487,667)	100.00 %
14	Benefits paid	(24,385,388)	(30,378,468)	19.73 %
15	Benefit obligation at end of year	$ 474,947,258	$ 636,271,675	(25.35)%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 537,871,174	$ 619,075,010	(13.12)%
18	Actual return on plan assets	(131,792,405)	33,662,299	>-300.00%
19	Settlements	—	(93,487,667)	100.00 %
20	Employer contribution	7,000,000	9,000,000	(22.22)%
21	Plan participants' contributions	—	—	-
22	Benefits paid	(24,385,388)	(30,378,468)	19.73 %
23	Fair value of plan assets at end of year	$ 388,693,381	$ 537,871,174	(27.73)%
24	**Funded Status**	$ (86,253,877)	$ (98,400,501)	12.34 %
26	Unrecognized net actuarial gain (loss)	—	—	-
27	Unrecognized prior service cost	—	—	-
29	Prepaid (accrued) benefit cost	$ (86,253,877)	$ (98,400,501)	12.34 %
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.20 %	2.75 %	89.09 %
32	Expected return on plan assets	4.26 %	4.17 %	2.16 %
33	Rate of compensation increase	4.00% Union & 4.00% Non-Union	1.00% Union & 2.67% Non-Union	— %
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 9,469,971	$ 12,104,357	(21.76)%
36	Interest cost	17,240,996	17,383,148	(0.82)%
37	Expected return on plan assets	(22,400,489)	(25,006,749)	10.42 %
38	Settlement (gain) loss recognized	—	11,291,216	(100.00)%
39	Recognized net actuarial gain	382,939	6,535,904	(94.14)%
40	Net periodic benefit cost (SEC Basis)	$ 4,693,417	$ 22,307,876	(78.96)%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 7,000,000	$ 9,000,000	(22.22)%
43	Pension Costs Capitalized	2,032,818	2,222,709	(8.54)%
44	Accumulated Pension Asset (Liability) at Year End	$ (86,253,877)	$ (98,400,501)	12.34 %
45	**Number of Company Employees:**			
46	Covered by the Plan 2/	1,367	2,497	(45.25)%
47	Not Covered by the Plan 2/	1,009	890	13.37 %
48	Active	451	528	(14.58)%
49	Retired	611	1,668	(63.37)%
50	Deferred Vested Terminated 2/	305	301	1.33 %

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			0.00%
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 2/	$ 12,323,206	$ 11,789,193	4.53%
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 2/			0.00%
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	$ —	$ —	0.00%
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate		— %	0.00%
31	Expected return on plan assets		— %	0.00%
32	Rate of compensation increase		— %	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)	$ —	$ —	0.00%
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 9,564,174	$ 9,118,650	4.89%
44	401(k) Plan Defined Contribution Costs Capitalized	2,784,910	2,252,012	23.66%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,529	1,494	2.34%
48	Not Covered by the Plan			0.00%
49	Active - Participating	1,516	1,475	2.78%
50	Retired			0.00%
51	Vested Former Employees, Retirees and Active-	397	372	6.72%
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	$ (2,120,027)	$ (1,560,428)	(35.86)%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.20 %	2.40 %	116.67%
8	Expected return on plan assets	4.23 %	4.08 %	3.68%
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	4.00% Union & 4.00% Non-Union	1.00% Union & 2.67% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for the fiscal year ending December 31, 2018.			

1/ Obtained from NorthWestern Energy-Montana's 2022 FASB 106 Valuation. Assumptions and data are as of December 31, 2022.

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

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	$ 14,290,006	$ 15,771,574	(9.39)%
10	Service cost	307,609	356,316	(13.67)%
11	Interest Cost	313,259	279,258	12.18 %
12	Plan participants' contributions	1,372,626	1,043,792	31.50 %
13	Amendments	—	—	-
14	Actuarial loss/(gain)	(656,282)	566,496	(215.85)%
15	Acquisition	—	—	-
16	Benefits paid	(3,556,609)	(3,727,430)	4.58 %
17	Benefit obligation at end of year	$ 12,070,609	$ 14,290,006	(15.53)%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$ 25,289,024	$ 23,095,215	9.50 %
20	Actual return on plan assets	(4,097,998)	3,349,308	(222.35)%
21	Acquisition	—	—	-
22	Employer contribution	1,048,028	1,528,139	(31.42)%
23	Plan participants' contributions	1,372,626	1,043,792	31.50 %
24	Benefits paid	(3,556,609)	(3,727,430)	4.58 %
25	Fair value of plan assets at end of year	$ 20,055,071	$ 25,289,024	(20.70)%
26	**Funded Status**	$ 7,984,462	$ 10,999,018	(27.41)%
27	Unrecognized net transition (asset)/obligation	—	—	-
28	Unrecognized net actuarial loss/(gain)	—	—	-
29	Unrecognized prior service cost	—	—	-
30	Prepaid (accrued) benefit cost	$ 7,984,462	$ 10,999,018	(27.41)%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$ 307,609	$ 356,316	(13.67)%
33	Interest cost	313,259	279,258	12.18 %
34	Expected return on plan assets	(1,046,911)	(919,362)	(13.87)%
35	Amortization of transitional (asset)/obligation	—	—	-
36	Amortization of prior service cost	(1,986,418)	(1,986,424)	0.00 %
37	Recognized net actuarial loss/(gain)	—	—	-
38	Net periodic benefit cost	$ (2,412,461)	$ (2,270,212)	(6.27)%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ —	$ —	-
41	Amount Funded through 401(h)	—	—	-
42	Amount Funded through other - Company funds	1,048,028	1,528,139	(31.42)%
43	TOTAL	$ 1,048,028	$ 1,528,139	(31.42)%
44	Amount that was tax deductible - VEBA	$ —	$ —	-
45	Amount that was tax deductible - 401(h)	—	—	-
46	Amount that was tax deductible - Other	(2,120,027)	(1,560,428)	(35.86)%
47	TOTAL	$ (2,120,027)	$ (1,560,428)	(35.86)%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$ (2,120,027)	$ (1,560,428)	(35.86)%
50	Pension Costs Capitalized	(622,388)	(385,375)	(61.50)%
51	Accumulated Pension Asset (Liability) at Year End	7,984,462	10,999,018	(27.41)%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,228	1,357	(9.51)%
54	Not Covered by the Plan	1,486	1,996	(25.55)%
55	Active	432	503	(14.12)%
56	Retired	731	776	(5.80)%
57	Spouses/Dependants covered by the Plan	65	78	(16.67)%

4/ There is approximately an additional $3,336,830 and $3,017,963 in other company OPEBS liabilities outstanding at December 31, 2022 and 2021, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

5/ The decrease in Montana Employees Not Covered by the Plan is due to the partial annuitization of Montana's pension plan.

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	313,515	121,404 A	31,611 B 231,643 C — D 6,183 E	704,356	747,016	(5.7)%
2	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	311,428	120,896 A	59,696 B 229,066 C — D 6,547 E	727,633	709,268	2.6 %
3	Michael R. Cashell Vice President, Transmission	310,073	120,370 A	32,459 B 228,070 C — D 3,307 E	694,279	687,223	1.0 %
4	Jeanne M. Vold Vice President, Technology	255,510	98,880 A	60,430 B 151,500 C — D 7,031 E 73 G	573,424	563,118	1.8 %
5	Michael L. Nieman Chief Audit and Compliance Officer	251,791	59,607 A	55,089 B 61,813 C — D	428,300	431,874	(0.8)%
6	Daniel L. Rausch Treasurer	246,347	58,318 A	59,699 B 60,476 C — D 7,676 E	432,516	427,287	1.2 %
7	Jeffrey B. Berzina Controller	235,744	58,660 A	54,375 B 56,250 C 15,000 H 25,000 I	445,029	383,658	16.0 %
8	Jason Merkel VP - Distribution	227,963	69,281 A	31,929 B 52,904 C — D	382,077	356,069	7.3 %
9	Bleau J. LaFave Director, Long-Term Resources	204,408	45,089 A	52,320 B 40,000 C — D 8,654 E 132 G	350,603	330,037	6.2 %
10	John Kasperick Director, Financial Planning & Analysis	199,315	38,542 A	34,252 B 39,074 C — D 8,979 E 15,000 H	335,162		

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	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2022 Annual						
4	Incentive Compensation Plan. Amounts were earned in 2022 and paid in the first quarter of 2023. Based on company						
5							
6	on a 2017 test period.						
7							
8	2/ All Other Compensation for named employees consists of the following:						
9							
10	B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical,						
11	dental, vision, employee assistance program, group term life, health savings account, wellness incentive,						
12	401(k) match, and non-elective 401(k) contribution, as applicable.						
13							
14	C> Values reflect the grant date fair value for performance stock awards. Stock based compensation is not included in rate recovery.						
15							
16	D> Change in pension value over previous year. The present value of accumulated benefits was calculated						
17	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
18	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
19	in our Annual Report on Form 10-K for the year ended December 31, 2021.						
20							
21	The decrease in pension value was the result of significantly higher discount rates used to determine the actuarial present						
22	value of these benefits when compared to the prior year. The present value decreased for most participants and the change						
23	in pension value is shown as zero for those participants. Participants with an increase in pension value had a large						
24	enough percentage increase in the pension benefit to offset the impact of the higher discount rates.						
25							
26	Actual Change in Pension Value						
27	Bobbi Schroeppel	(49,322)					
28	Mike Cashell	(519,109)					
29	John Hines	(134,794)					
30	Jeanne Vold	(18,977)					
31	Jason Merkel	(385,552)					
32	Mike Nieman	(59,106)					
33	Dan Rausch	(30,701)					
34	Jeff Berzina	—					
35	John Kasperick	(417,386)					
36							
37	E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.						
38							
39	F> Value of executive physical examination and associated tax gross-up.						
40							
41	G> Non-Cash taxable award and gross up of taxes for the award						
42							
43	H> Bonus payment						
44							
45	I> Relocation Lump-Sum Allowance						
46							

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	691,669	669,175 A	39,544 B 1,940,931 C — D 31,235 E 3,015 F	3,375,569	3,445,367	(2.0)%
2	Brian B. Bird President & Chief Operating Officer	511,019	370,800 A	61,218 B 1,731,750 C — D	2,674,787	1,812,627	47.6%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	451,204	240,092 A	55,604 B 511,008 C 5,094 E 1,436 G	1,264,438	1,252,137	1.0%
4	Crystal D. Lail Vice President, Chief Financial Officer	402,548	217,800 A	49,821 B 498,750 C — D 13,116 E	1,182,035	1,045,454	13.1%
5	Curtis T. Pohl Vice President, Distribution	323,334	124,889 A	57,617 B 255,893 C — D 1,835 E 3,015 F	766,583	763,423	0.4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2022 Annual Incentive Compensation Plan. Amounts were earned in 2022 and paid in the first quarter of 2023. Based on company performance against plan, the incentive plan was funded at 96% of target. Salary and incentive in current rate recovery are based on a 2017 test period.

2/ 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, 2022.

The decrease in pension value was the result of significantly higher discount rates used to determine the actuarial present value of these benefits when compared to the prior year. The present value decreased for most participants and the change in pension value is shown as zero for those participants. Participants with an increase in pension value had a large enough percentage increase in the pension benefit to offset the impact of the higher discount rates.

Actual Change in Pension Value

Bob Rowe	(84,797)
Brian Bird	(13,270)
Crystal Lail	(49,875)
Heather Grahame	—
Curt Pohl	(56,118)

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> Non-Cash taxable award and gross up of taxes for the award

3/ 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 97.6%.

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.

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	$ 7,193,730,425	$ 6,684,746,970	$ 508,983,455	7.61 %
4	101.1 Property Under Capital Leases	41,504,922	42,280,372	(775,450)	(1.83)%
5	103 Experimental Electric Plant Unclassified	4,244,173	4,092,785	151,388	3.70 %
6	105 Plant Held for Future Use	4,327,381	5,492,985	(1,165,604)	(21.22)%
7	107 Construction Work in Progress	300,649,215	284,729,122	$ 15,920,093	5.59 %
8	108 Accumulated Depreciation Reserve	(2,600,452,294)	(2,475,484,210)	$ (124,968,084)	5.05 %
9	108.1 Accumulated Depreciation - Capital Leases	(33,172,848)	(31,162,371)	$ (2,010,477)	6.45 %
10	111 Accumulated Amortization & Depletion Reserves	(100,549,894)	(94,343,642)	$ (6,206,252)	6.58 %
11	114 Electric Plant Acquisition Adjustments	481,574,396	481,574,396	—	— %
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(82,128,381)	(71,878,462)	(10,249,919)	14.26 %
13	116 Utility Plant Adjustments	357,585,527	357,585,527	—	— %
14	117 Gas Stored Underground-Noncurrent	36,209,611	36,190,017	19,594	0.05 %
15	**Total Utility Plant**	5,603,522,233	5,223,823,489	379,698,744	7.27 %
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	—	— %
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(65,534)	(29,270)	(36,264)	123.89 %
19	123.1 Investments in Assoc Companies and Subsidiaries	(109,534,834)	(114,137,258)	4,602,424	(4.03)%
20	124 Other Investments	21,035,719	20,451,942	583,777	2.85 %
21	128 Miscellaneous Special Funds	—	—	—	-
22	LT Portion of Derivative Assets - Hedges	—	—	—	-
23	**Total Other Property & Investments**	(87,877,844)	(93,027,781)	5,149,937	(5.54)%
24	**Current and Accrued Assets**				
25	131 Cash	8,069,935	2,376,145	5,693,790	239.62 %
26	134 Other Special Deposits	12,761,965	14,658,170	(1,896,205)	(12.94)%
27	135 Working Funds	23,450	23,250	200	0.86 %
28	142 Customer Accounts Receivable	106,890,490	86,846,850	20,043,640	23.08 %
29	143 Other Accounts Receivable	26,793,906	8,867,792	17,926,114	202.15 %
30	144 Accumulated Provision for Uncollectible Accounts	(2,451,237)	(2,319,115)	(132,122)	5.70 %
31	146 Accounts Receivable-Associated Companies	32,854,005	2,818,214	30,035,791	>300.00%
32	151 Fuel Stock	7,724,941	7,509,623	215,318	2.87 %
33	154 Plant Materials and Operating Supplies	71,154,247	53,538,725	17,615,522	32.90 %
34	164 Gas Stored - Current	27,722,831	18,828,613	8,894,218	47.24 %
35	165 Prepayments	23,739,746	20,500,469	3,239,277	15.80 %
36	172 Rents Receivable	213,473	54,488	158,985	291.78 %
37	173 Accrued Utility Revenues	117,418,484	98,149,252	19,269,232	19.63 %
38	174 Miscellaneous Current & Accrued Assets	2,372,751	258,106	2,114,645	>300.00%
39	**Total Current & Accrued Assets**	435,288,987	312,110,582	123,178,405	39.47 %
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	9,254,937	11,120,970	(1,866,033)	(16.78)%
42	182 Regulatory Assets	729,084,376	685,148,784	43,935,592	6.41 %
44	184 Clearing Accounts	37,192	4,169	33,023	>300.00%
45	186 Miscellaneous Deferred Debits	9,558,916	8,619,588	939,328	10.90 %
46	189 Unamortized Loss on Reacquired Debt	22,619,741	25,635,857	(3,016,116)	(11.77)%
47	190 Accumulated Deferred Income Taxes	163,943,624	160,914,104	3,029,520	1.88 %
48	191 Unrecovered Purchased Gas Costs	100,874,939	94,663,379	6,211,560	6.56 %
49	**Total Deferred Debits**	1,035,373,725	986,106,851	49,266,874	5.00 %
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,986,307,101	$ 6,429,013,141	$ 557,293,960	8.67 %

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	$ 632,783	$ 576,063	$ 56,720	9.85 %
4	211 Miscellaneous Paid-In Capital	1,999,375,991	1,716,226,995	283,148,996	16.50 %
5	216 Unappropriated Retained Earnings	769,270,841	726,326,379	42,944,462	5.91 %
6	217 Reacquired Capital Stock	(98,392,040)	(98,248,245)	(143,795)	0.15 %
7	219 Accumulated Other Comprehensive Income	(5,705,664)	(5,167,596)	(538,068)	10.41 %
8	**Total Proprietary Capital**	2,665,181,911	2,339,713,596	325,468,315	13.91 %
9	**Long Term Debt**				
10	221 Bonds	2,179,660,000	2,179,660,000	—	— %
11	224 Other Long Term Debt	450,000,000	373,000,000	77,000,000	20.64 %
12	226 (Less) Unamortized Discount on Long Term Debt-Debit	33,056	61,389	(28,333)	(46.15)%
13	**Total Long Term Debt**	2,629,626,944	2,552,598,611	77,028,333	3.02 %
14	**Other Noncurrent Liabilities**				
15	227 Obligations Under Capital Leases-Noncurrent	9,389,857	12,829,411	(3,439,554)	(26.81)%
16	228.2 Accumulated Provision for Injuries and Damages	4,365,711	7,061,829	(2,696,118)	(38.18)%
17	228.3 Accumulated Provision for Pensions and Benefits	10,546,632	6,434,213	4,112,419	63.91 %
18	228.4 Accumulated Miscellaneous Operating Provisions	72,588,961	88,530,057	(15,941,096)	(18.01)%
19	229 Accumulated Provision for Rate Refunds	—	—	—	-
20	230 Asset Retirement Obligations	40,893,877	40,747,410	146,467	0.36 %
21	**Total Other Noncurrent Liabilities**	137,785,038	155,602,920	(17,817,882)	(11.45)%
22	**Current and Accrued Liabilities**				
23	231 Notes Payable	92,403	—	92,403	-
24	232 Accounts Payable	214,538,889	120,452,817	94,086,072	78.11 %
25	234 Accounts Payable to Associated Companies	(1,884,037)	1,837,642	(3,721,679)	(202.52)%
26	235 Customer Deposits	10,853,645	8,573,478	2,280,167	26.60 %
27	236 Taxes Accrued	90,471,745	45,815,514	44,656,231	97.47 %
28	237 Interest Accrued	18,349,945	18,567,598	(217,653)	(1.17)%
29	241 Tax Collections Payable	2,441,695	2,178,547	263,148	12.08 %
30	242 Miscellaneous Current and Accrued Liabilities	72,418,219	63,691,698	8,726,521	13.70 %
31	243 Obligations Under Capital Leases-Current	3,802,179	4,012,828	(210,649)	(5.25)%
32	**Total Current and Accrued Liabilities**	411,084,683	265,130,122	145,954,561	55.05 %
33	**Deferred Credits**				
34	252 Customer Advances for Construction	95,393,208	80,779,904	14,613,304	18.09 %
35	253 Other Deferred Credits	158,152,503	173,125,630	(14,973,127)	(8.65)%
36	254 Regulatory Liabilities	171,400,902	185,656,769	(14,255,867)	(7.68)%
37	255 Accumulated Deferred Investment Tax Credits	388,447	517,968	(129,521)	(25.01)%
38	281-283 Accumulated Deferred Income Taxes	717,293,465	675,887,621	41,405,844	6.13 %
39	**Total Deferred Credits**	1,142,628,525	1,115,967,892	26,660,633	2.39 %
40	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,986,307,101	$ 6,429,013,141	$ 557,293,960	8.67 %
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					

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 764,200 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 $502.2 million and $479.3 million as of December 31, 2022 and December 31, 2021, 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, 2022 and December 31, 2021, 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, 2022 and December 31, 2021, 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 $1.3 million and $2.1 million as of December 31, 2022 and December 31, 2021, 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 $1.3 million and $2.1 million as of December 31, 2022 and December 31, 2021, 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 $2.5 million and $2.3 million at December 31, 2022 and December 31, 2021, respectively. Unbilled revenues were $117.4 million and $98.1 million at December 31, 2022 and December 31, 2021, respectively.

Inventories

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

	December 31,	
	2022	2021
Fuel stock	$ 7,725	$ 7,510
Plant materials and operating supplies	71,154	53,539
Gas stored underground (including the non-current portion reflected in utility plant)	63,933	55,019
Total Inventories	$ 142,812	$ 116,068

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. As of December 31, 2022, the only derivative instruments we have qualify for the normal purchases and normal sales exception.

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 6.4% and 6.6% for Montana for 2022 and 2021, respectively. This rate averaged 6.4% for South Dakota for 2022 and 2021. AFUDC capitalized totaled $20.2 million and $15.9 million for the years ended December 31, 2022, 2021 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 2022 and 2021

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 Statement 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

	Twelve Months Ended	
	2022	2021
	(in thousands)	
Cash paid for:		
Income taxes	$ 4,707	$ 4,330
Interest	95,400	87,221
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	64,758	29,034
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 this non-cash transaction.

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,	
	2022	2021
Cash	$ 8,070	$ 2,376
Working funds	23	23
Special deposits	12,762	14,658
Total shown in the Statement of Cash Flows	$ 20,855	$ 17,058

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

Montana Rate Review

On August 8, 2022, we filed a Montana electric and natural gas rate review with the Montana Public Service Commission (MPSC) requesting an annual increase to electric and natural gas utility rates. On September 28, 2022, the MPSC approved the recommendations of the MPSC Staff for interim rates effective October 1, 2022, subject to refund. Subsequently, we modified our request through rebuttal testimony. On April 3, 2023, we filed a settlement with certain parties in our Montana electric and natural gas rate review, which is subject to approval by the MPSC. The details of our request, as so modified, the interim rates granted, and the settlement agreement are set forth below:

Requested Revenue Increase Through Rebuttal Testimony (in millions)		
	Electric	Natural Gas
Base Rates	$90.6	$22.4
PCCAM(1)	$69.7	n/a
Property Tax (tracker true-up)(1)	$14.5	$4.2
Total Revenue Increase Requested through Rebuttal Testimony	$174.8	$26.6

Interim Revenue Increase Granted (in millions)		
	Electric	Natural Gas
Base Rates	$29.4	$1.7
Power Cost & Credit Mechanism (PCCAM)(1)	$61.1	n/a
Property Tax (tracker true-up)(1)(2)	$10.8	$2.9
Total Interim Revenue Granted	$101.3	$4.6

Requested Revenue Increase Through Settlement Agreement (in millions)		
	Electric	Natural Gas
Base Rates	$67.4	$14.1
PCCAM(1)	$69.7	n/a
Property Tax (tracker true-up)(1)	$14.5	$4.2
Total Revenue Increase Requested Through Settlement Agreement	$151.6	$18.3

(1) These items are flow-through costs.

(2) While our requested interim property tax base increases were denied from interim rates, these rates went into effect on January 1, 2023, as part of our 2023 property tax tracker period true-up.

The settlement includes, among other things, agreement on electric and natural gas base revenue increases, allocated cost of service, rate design, updates to the base amount of revenues associated with property taxes and electric supply costs, and regulatory policy issues related to requested changes in regulatory mechanisms. The settlement is based on a 48.02 percent equity component of our capital structure and an authorized return on equity of 9.65 percent for electric operations and 9.55 percent for natural gas operations, which are consistent with current authorized return on equity amounts.

The settlement agreement provides for an update to the PCCAM by adjusting the base costs from $138.7 million to $208.4 million and providing for more timely quarterly recovery of deferred balances instead of annual recovery. It also addresses the potential for future recovery of certain operating costs associated with the Yellowstone County Generating Station and provides for the deferral of incremental operating costs related to our Enhanced Wildfire Mitigation Plan. The settling parties agreed to terminate the pilot decoupling program (Fixed Cost Recovery Mechanism) and that the proposed business technology rider will not be implemented.

A hearing commenced on April 11, 2023 and concluded on April 18, 2023. Interim rates will remain in effect on a refundable basis until the MPSC issues a final order.

Holding Company Filings

As previously reported, on June 1, 2022, we filed a legal corporate restructuring application (Restructuring Plan) with the state commissions in Montana, South Dakota and Nebraska and the Federal Energy Regulatory Commission (FERC). Currently, our utility businesses are held in the same legal entity. Under the proposed Restructuring Plan, we would legally separate our Montana public utility business from our South Dakota and Nebraska public utility business and establish a holding company to hold the ownership interests of all of the subsidiaries. The purpose of the reorganization is to segregate our organizational structure to be more transparent and in line with the public utility industry.

The Restructuring Plan does not propose and we do not expect any procedural or substantive change in how the state public utility commissions regulate those services. Implementation of the Restructuring Plan is subject to receipt of all regulatory approvals. During 2022, we received approvals from the Nebraska Public Service Commission, South Dakota Public Service Commission, and the FERC. On February 21, 2023, the MPSC approved the Restructuring Plan. We are currently developing implementation timing to effectuate the Restructuring Plan.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2020, approximately 65 MW of CREPs. While we made progress towards meeting this obligation by acquiring approximately 50 MW of CREPs, we were unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC’s action as it related to waivers granted for 2015 and 2016 has been challenged legally and was fully briefed before the Montana Supreme Court.

On May 14, 2021, the Montana Governor signed a bill that eliminated the state's Renewable Portfolio Standard, including repeal of the CREP requirement. We notified the Montana Supreme Court of the repeal. We also dismissed our pending application filed with the MPSC for a waiver from full compliance for years 2017 through 2020.

On September 7, 2021, the Montana Supreme Court remanded the case challenging the 2015 and 2016 waivers to the District Court to determine whether the repeal of the CREP requirement made the petition moot. On May 9, 2022, the District Court imposed a $2.5 million penalty against us, payable to the Universal Low Income Assistance Fund in Montana, in connection with a petition filed by the MEIC challenging the MPSC's decision granting our waiver requests from CREP compliance in 2015 and 2016. The expense associated with this penalty was accrued for within our 2022 results. We filed an appeal with the Montana Supreme Court and that appeal is now fully briefed.

(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,	
	2022	2021
Colstrip Unit 4 Basis Adjustment	$ (129,895)	$ (133,648)
Havre Pipeline Company, LLC	$ 11,399	$ 12,130
NorthWestern Services, LLC	2,091	2,065
NorthWestern Energy Solutions, Inc.	5,738	4,126
Risk Partners Assurance, Ltd.	1,132	1,190
Total Investments in Subsidiary Companies	**$ (109,535)**	**$ (114,137)**

(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. Of these regulatory assets and liabilities, energy supply costs, excluding the Montana PCCAM, are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2022	December 31, 2021
			(in thousands)	
Flow-through income taxes	14	Plant Lives	$ 509,038	$ 464,664
Pension	16	See Note 16	87,965	98,336
Excess deferred income taxes	14	Plant Lives	54,364	60,813
Employee related benefits	16	See Note 16	27,920	21,648
State & local taxes & fees		1 Year	15,643	6,514
Environmental clean-up	19	Undetermined	10,963	11,262
Other		Various	23,191	21,912
Total Regulatory Assets			**$ 729,084**	**$ 685,149**
Excess deferred income taxes	14	Plant Lives	148,989	158,047
Unbilled revenue		1 Year	11,536	16,430
Gas storage sales		17 years	7,046	7,466
State & local taxes & fees		1 Year	2,327	3,021
Environmental clean-up and other		1 Year	1,503	693
Total Regulatory Liabilities			**$ 171,401**	**$ 185,657**

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):

	December 31,	
	2022	2021 (1)
	(in thousands)	
Electric Plant	5,563,314	5,205,831
Natural Gas Plant	1,307,060	1,188,665
Plant acquisition adjustment	481,574	481,574
Common and Other Plant	373,433	342,118
Construction work in process	300,649	284,729
Total utility plant	8,026,030	7,502,917
Less accumulated depreciation	(2,816,303)	(2,672,869)
Net utility plant	$ 5,209,727	$ 4,830,048

(1) The December 31, 2021 balances reported above have been reclassified to conform with the December 31, 2022 presentation of major classifications of property, plant and equipment. The reclassification has no impact on the presentation of total property, plant and equipment. These reclassifications were done in an effort to better convey the nature of these balances.

Net utility plant under capital (finance) lease were $7.2 million and $9.2 million as of December 31, 2022 and 2021, respectively, which included $7.0 million and $9.0 million as of December 31, 2022 and 2021, 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.

On January 16, 2023, we entered into a definitive agreement (Agreement) with Avista Corporation (Avista) to acquire Avista's 15 percent interest in each of Units 3 and 4 at the Colstrip Generating Station, a coal-fired, base-load electric generation facility located in Colstrip, Montana. As noted in the table below, we currently have a 30 percent interest in Unit 4. The Agreement provides that the purchase price will be $0 and that we will acquire Avista's interest effective December 31, 2025, subject to the satisfaction of the closing conditions contained within the agreement. Under the terms of this Agreement, we will be responsible for operating costs starting on January 1, 2026; while Avista will retain responsibility for its pre-closing share of environmental and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommission and demolition costs associated with the existing facilities that comprise Avista's interest.

The Agreement contains customary representations and warranties, covenants, and indemnification obligations, and the Agreement is subject to customary conditions and approvals, including approval from the FERC. Closing also is conditioned on our ability to enter into a new coal supply agreement for Colstrip by December 31, 2024. Such coal supply agreement must provide a sufficient amount of coal to Colstrip to permit the generation of electric power by the maximum permitted capacity of the interest in Colstrip then held by us during the period from January 1, 2026 through, December 31, 2030.

Either party may terminate the Agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing. The Agreement may be subject to the exercise by other Colstrip owners of a right of first refusal set forth in the O&O Agreement. Should any other owners exercise such rights, we intend to exercise our right of first refusal under the O&O Agreement to the fullest extent permitted, and Avista has agreed that it will not exercise its right of first refusal.

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, 2022				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 155,567	$ 63,032	$ 51,796	$ 326,584
Accumulated depreciation	46,748	39,077	42,465	122,938
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

(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,	
	2022	2021
Liability at January 1,	$ 40,631	$ 45,355
Accretion expense	1,853	2,233
Liabilities incurred	—	—
Liabilities settled	(4,004)	(2,906)
Revisions to cash flows	2,414	(3,935)
Liability at December 31,	$ 40,894	$ 40,747

During the twelve months ended December 31, 2022 our ARO liability decreased $4.0 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities and natural gas pipeline segments. Additionally, during the twelve months ended December 31, 2022, our ARO liability increased $2.4 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, 2022 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, 2022 and 2021. 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	$	612

A pre-tax loss of approximately $13.4 million is remaining in AOCI as of December 31, 2022, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCI into interest expense 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 item 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, 2022	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Special deposits	$ 12,762	$ —	$ —	$ —	$ 12,762
Rabbi trust investments	20,895	—	—	—	20,895
Total	**$ 33,657**	**$ —**	**$ —**	**$ —**	**$ 33,657**
December 31, 2021					
Special deposits	$ 14,658	$ —	$ —	$ —	$ 14,658
Rabbi trust investments	18,234	—	—	—	18,234
Total	**$ 32,892**	**$ —**	**$ —**	**$ —**	**$ 32,892**

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, 2022		December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,629,660	$ 2,327,478	$ 2,552,660	$ 2,838,518

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

On May 18, 2022, we amended our existing $425 million credit facility to, among other things, change the Eurodollar rate to the secured overnight financing rate as administered by the Federal Reserve Bank of New York (SOFR) and extend the maturity date of the facility from September 2, 2023 to May 18, 2027. The amended and restated credit facility (the Primary Credit Facility) maintains the same capacity at $425 million and uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size of the facility by up to an additional $75 million. The Primary Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

On October 28, 2022, we entered into a $100 million Credit Agreement (the Additional Credit Facility) to supplement our existing $425 million revolving credit facility. The Additional Credit Facility has a maturity date of April 28, 2024. The Additional Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

On March 25, 2022, we amended our existing $25 million swingline credit facility (the Swingline Facility) to, among other things, change the Eurodollar rate to the secured overnight financing rate as administered by the Federal Reserve Bank of New York (SOFR) and extend the maturity date of the facility from March 27, 2023 to March 27, 2024. The Swingline Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a margin of 90.0 basis points, or (b) a base rate, plus a margin of 12.5 basis points.

Commitment fees for the unsecured revolving lines of credit were $0.1 million and $0.4 million for the years ended December 31, 2022 and 2021.

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

	2022	2021
Unsecured revolving line of credit, expiring May 2027	$ 425.0	$ 425.0
Unsecured revolving line of credit, expiring April 2024	100.0	—
Unsecured revolving line of credit, expiring March 2024	25.0	25.0
	550.0	**450.0**
Amounts outstanding at December 31:		
SOFR borrowings	450.0	—
Eurodollar borrowings	—	373.0
Letters of credit	—	—
	450.0	**373.0**
Net availability as of December 31	**$ 100.0**	**$ 77.0**

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, 2022	December 31, 2021
Unsecured Debt:			
Unsecured Revolving Line of Credit	2027	$ 425,000	$ —
Unsecured Revolving Line of Credit	2024	25,000	—
Unsecured Revolving Line of Credit	2023	—	373,000
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	100,000
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Total Long-Term Debt		$ 2,629,660	$ 2,552,660

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 March 2021, we issued and sold $100.0 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 $100.0 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.

On March 30, 2023, we issued and sold $239.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.57 percent maturing on March 30, 2033. On this same day, we issued and sold $31.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.57 percent maturing on March 30, 2033. We received proceeds from the South Dakota First Mortgage Bonds and $189.0 million of the $239.0 million Montana First Mortgage Bonds, totaling $220.0 million, on March 30, 2023. We will receive the remaining $50.0 million proceeds of the Montana First Mortgage Bonds on May 1, 2023. These bonds were issued in transactions 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.

On March 29, 2023, we priced an additional $30.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.42 percent. We expect to complete the issuance and sale of these bonds on May 1, 2023 and they will mature on May 1, 2033.

As of December 31, 2022, 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 $144.7 million in 2023, $125.0 million in 2024, $300.0 million in 2025, $105.0 million in 2026 and $425.0 million in 2027.

(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, 2022	December 31, 2021
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 3,201	$ 2,729
NorthWestern Energy Solutions, Inc.	16	71
Risk Partners Assurance, Ltd.	(74)	18
	$ 3,143	$ 2,818
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	2,045	1,837
	$ 2,045	**$ 1,837**

(14) Income Taxes

Our effective tax rate typically differs from the federal statutory tax rate primarily due to production tax credits and the regulatory impact of flowing through the federal and state tax benefit of repairs deductions and state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable). 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,	
	2022	2021
Production tax credit	$ 80,097	$ 75,092
Pension / postretirement benefits	19,291	21,435
Customer advances	25,119	21,271
Unbilled revenue	9,440	10,704
Compensation accruals	10,306	10,612
Environmental liability	6,009	5,704
Reserves and accruals	4,015	5,105
Interest rate hedges	3,372	3,158
Other, net	6,295	7,833
Deferred Tax Asset	**163,944**	**160,914**
Excess tax depreciation	(462,895)	(438,319)
Flow through depreciation	(104,976)	(92,502)
Goodwill amortization	(91,746)	(91,689)
Regulatory assets and other	(58,065)	(53,896)
Deferred Tax Liability	**(717,682)**	**(676,406)**
Deferred Tax Liability, net	**$ (553,738)**	**$ (515,492)**

At December 31, 2022, our total production tax credit carryforward was approximately $80.1 million. If unused, our production tax credit carryforwards will expire as follows: $8.9 million in 2036, $11.0 million in 2037, $10.9 million in 2038, $11.5 million in 2039, $13.1 million in 2040, $11.5 million in 2041, and $13.2 million in 2042. We believe it is more likely than not that sufficient taxable income will be generated to utilize these production tax credit carryforwards.

Uncertain Tax Positions

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

	2022	2021
Unrecognized Tax Benefits at January 1	$ 32,049	$ 33,491
Gross increases - tax positions in prior period	—	293
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,719)	(1,735)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 30,330	$ 32,049

Our unrecognized tax benefits include approximately $27.9 million and $28.1 million related to tax positions as of December 31, 2022 and 2021, 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, 2022, we have accrued $1.4 million for the payment of interest in the Balance Sheets. As of December 31, 2021, we had $0.5 million accrued for the payment of interest.

Tax years 2019 and forward remain subject to examination by the Internal Revenue Service (IRS) and state taxing authorities. During the first quarter of 2023 the IRS commenced a limited scope examination of the Company's 2019 amended federal income tax return.

(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,					
	2022			2021		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ (8)	$ —	$ (8)	$ (58)	$ —	$ (58)
Reclassification of net income (loss) on derivative instruments	612	(160)	452	614	(162)	452
Postretirement medical liability adjustment	(1,359)	377	(982)	(585)	149	(436)
Other comprehensive income (loss)	$ (755)	$ 217	$ (538)	$ (29)	$ (13)	$ (42)

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

	December 31,	
	2022	2021
Foreign currency translation	$ 1,435	$ 1,443
Derivative instruments designated as cash flow hedges	(7,675)	(8,127)
Postretirement medical plans	534	1,516
Accumulated other comprehensive loss	$ (5,706)	$ (5,168)

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

	Year Ended December 31, 2022				
	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,127)	$ 1,516	$ 1,443	$ (5,168)
Other comprehensive income before reclassifications				(8)	(8)
Amounts reclassified from AOCI	Interest on long-term debt	452			452
Amounts reclassified from AOCI			(982)		(982)
Net current-period other comprehensive income		452	(982)	(8)	(538)
Ending Balance		$ (7,675)	$ 534	$ 1,435	$ (5,706)

	Year Ended December 31, 2021				
	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated Cash	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)

(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,	
	2022	2021	2022	2021
Change in benefit obligation:				
Obligation at beginning of period	$ 696,802	$ 820,979	$ 19,146	$ 19,146
Service cost	10,223	12,994	407	407
Interest cost	18,787	18,759	317	317
Actuarial loss	(176,389)	(28,905)	415	415
Settlements[(1)]	—	(93,488)	—	—
Benefits paid	(27,625)	(33,537)	(2,977)	(2,977)
Benefit Obligation at End of Period	$ 521,798	$ 696,802	$ 17,308	$ 17,308
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 605,499	$ 688,456	$ 23,096	$ 23,096
Return on plan assets	(144,535)	33,868	3,349	3,349
Employer contributions	8,200	10,200	1,821	1,821
Settlements[(1)]	—	(93,488)	—	—
Benefits paid	(27,625)	(33,537)	(2,977)	(2,977)
Fair value of plan assets at end of period	$ 441,539	$ 605,499	$ 25,289	$ 25,289
Funded Status	$ (80,259)	$ (91,303)	$ 7,981	$ 7,981
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	7,195	8,297	11,914	11,914
Total Assets	7,195	8,297	11,914	11,914
Current liability	(11,200)	(11,200)	(1,575)	(1,575)
Noncurrent liability	(76,254)	(88,400)	(2,358)	(2,358)
Total Liabilities	(87,454)	(99,600)	(3,933)	(3,933)
Net amount recognized	$ (80,259)	$ (91,303)	$ 7,981	$ 7,981
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	(116)	1,870
Net actuarial loss	(54,383)	(62,448)	(3,123)	1,366
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	—	(95)
Net actuarial gain	—	—	1,046	2,500
Total	$ (54,383)	$ (62,448)	$ (2,193)	$ 5,641

(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 expense 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,	
	2022	2021
Projected benefit obligation	$ 474.9	$ 636.3
Accumulated benefit obligation	474.9	636.3
Fair value of plan assets	388.7	537.9

As of December 31, 2022, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2022	2021	2022	2021
Components of Net Periodic Benefit Cost				
Service cost	$ 10,223	$ 12,994	$ 351	$ 407
Interest cost	18,787	18,759	359	327
Expected return on plan assets	(24,173)	(27,061)	(1,047)	(919)
Amortization of prior service cost (credit)	—	—	(1,891)	(1,835)
Recognized actuarial loss (gain)	383	6,536	(897)	(898)
Settlement loss recognized(1)	—	11,291	—	—
Net Periodic Benefit Cost (Credit)	$ 5,220	$ 22,519	$ (3,125)	$ (2,918)
Regulatory deferral of net periodic benefit cost(2)	2,307	(13,308)	—	—
Previously deferred costs recognized(2)	—	—	292	709
Amount Recognized in Income	$ 7,527	$ 9,211	$ (2,833)	$ (2,209)

(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, 2022 and 2021. 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. During 2022, the plan's actuary conducted an experience study to review five years of plan experience and update these assumptions.

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 2022 decreased our projected benefit obligation by approximately $179.2 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 6.44 percent and increased our assumption on the NorthWestern Corporation Pension Plan to 4.83 percent for 2023.

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

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2022	2021	2022	2021
Discount rate	5.20 %	2.65-2.75 %	5.15-5.20 %	2.35-2.40 %
Expected rate of return on assets	2.66-4.26	3.01-4.17	4.23	4.08
Long-term rate of increase in compensation levels (non-union)	4.00	2.84	4.00	2.84
Long-term rate of increase in compensation levels (union)	4.00	2.00	4.00	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;
- Private real estate and broad global opportunistic fixed income asset classes can provide diversification to both equity and liability hedging fixed income investments and that a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy Pension Plan investments over full market cycles;
- 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,	
	2022	2021	2022	2021	2022	2021
Fixed income securities	45.0 %	55.0 %	90.0 %	90.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	4.0	1.0	1.0	—	—
Opportunistic fixed income	5.5	—	—	—	—	—
Global equities	44.0	41.0	9.0	9.0	60.0	60.0
Private real estate	5.5	—	—	—	—	—

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,	
	2022	2021	2022	2021	2022	2021
Cash and cash equivalents	— %	0.1 %	1.1 %	0.4 %	0.6 %	0.1 %
Fixed income securities	44.5	53.8	88.6	89.5	36.7	33.7
Non-U.S. fixed income securities	—	3.9	0.9	0.9	—	—
Opportunistic fixed income	5.5	—	—	—	—	—
Global equities	43.4	42.2	9.4	9.2	62.7	66.2
Private real estate	6.6	—	—	—		
	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. The guidelines allow for a transition to targets over time as assets are reallocated to newly-approved asset classes of opportunistic fixed income and private real estate. Debt securities consist of U.S. and international instruments including emerging markets and high yield instruments, as well as government, corporate, asset backed and mortgage backed securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Equity, real estate and fixed income portfolios may be comprised of both active and passive management strategies. 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. We also invest in global equities with exposure to developing and emerging markets. Equity investments may also be diversified across investment styles such as growth and value. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes. Real estate investments will consist of global equity or debt interests in tangible property consisting of land, buildings, and other improvements in commercial and residential sectors.

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.

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 2023 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 costs for 2022 and 2021 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2022	2021
NorthWestern Energy Pension Plan (MT)	$ 7,000	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 8,200	$ 10,200

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

	Pension Benefits	Other Postretirement Benefits
2023	$ 31,014	$ 2,520
2024	32,448	2,079
2025	33,904	1,584
2026	34,908	1,511
2027	35,490	1,372
2028-2032	185,939	6,060

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, 2022 and 2021 were $12.3 million and $11.8 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, 2022, there were 655,565 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:

	2022	2021
Risk-free interest rate	1.82 %	0.19 %
Expected life, in years	3	3
Expected volatility	28.2% to 38.8%	28.2% to 38.5%
Dividend yield	4.5 %	4.3 %

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, 2022, are as follows:

	Performance Unit Awards		
	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	162,523	$	58.76
Granted	92,970		51.61
Vested	(58,889)		73.13
Forfeited	(2,197)		54.25
Remaining nonvested grants	194,407	$	51.04

We recognized compensation expense of $4.2 million and $3.9 million for the years ended December 31, 2022 and 2021 respectively, and related income tax benefit of $(1.3) million and $(0.2) million for the years ended December 31, 2022 and 2021 respectively. As of December 31, 2022, we had $6.4 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 $4.3 million and $4.2 million for the years ended December 31, 2022 and 2021 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. Awards granted before 2022 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. Awards granted in 2022 and retirement/retention restricted share awards granted in the future no longer contain this performance measure, instead these awards will vest after five full calendar years if the employee remains employed during that service period. 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, 2022, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	87,319	$	49.63
Granted	25,360		47.04
Vested	(13,394)		52.20
Forfeited	—		—
Remaining nonvested grants	99,285	$	48.62

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,	
	2022	2021
DSUs Issued	12,109	18,741
Compensation expense	0.7	1.1
Change in value of shares	0.1	1.3
Total compensation (benefit) expense	$ 0.8	$ 2.4
DSUs withdrawn	4,022	186,137
Value of DSUs withdrawn	$ 0.2	$ 12.1

(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 16,120 and 16,880 during the years ended December 31, 2022 and 2021, respectively, and are reflected in reacquired capital. These shares were credited to reacquired capital 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 $124.0 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We did not 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 were physically settled with common shares issued by us. On settlement dates, we issued shares of common stock to the forward purchaser at the then-applicable forward sale price and received issuance proceeds at that time. The forward sale price was initially $51.8950 per share, which was 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 was 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.

On June 24, 2022, we partially settled the forward sale agreement by physically delivering 2,004,483 shares of common stock in exchange for cash proceeds of $99.9 million, net of issuance costs. On September 21, 2022, we partially settled the forward sale agreement by physically delivering 1,618,932 shares of common stock in exchange for cash proceeds of approximately $80.0 million, net of issuance costs. On November 28, 2022, we partially settled the forward sale agreement by physically delivering 1,409,702 shares of common stock in exchange for cash proceeds of approximately $70.0 million, net of issuance costs. On December 21, 2022, we settled the remaining portion of the forward sale agreement by physically delivering 550,996 shares of common stock in exchange for cash proceeds of approximately $27.1 million, net of issuance costs. The proceeds were used to pay down borrowings under our revolving credit facility and for other general corporate purposes.

The forward sale agreement was classified as an equity transaction because it was indexed to our common stock, physical settlement was within our control, and the other requirements necessary for equity classification were met. As a result of the equity classification, no gain or loss was 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, 2022, our estimated gross contractual obligation related to these contracts was approximately $386.1 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $327.8 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Operating expense 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,	
	2022	2021
Beginning QF liability	$ 64,943	$ 81,379
Settlements[1]	(20,076)	(22,497)
Interest on long-term debt	4,861	6,061
Ending QF liability	$ 49,728	$ 64,943

(1) The primary components of the change in settlement amounts includes (i) a lower periodic adjustment of $5.4 million due to actual price escalation, which was less than previously modeled; (ii) higher costs of approximately $0.8 million, due to a $1.8 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $2.6 million reduction in costs in the prior period; and (iii) a prior year 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
2023	$ 80,750	$ 61,280	$ 19,470
2024	76,393	60,706	15,687
2025	60,360	52,950	7,410
2026	55,393	46,274	9,119
2027	56,665	46,668	9,997
Thereafter	56,534	59,895	(3,361)
Total[1]	$ 386,095	$ 327,773	$ 58,322

(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 $328.0 million and $286.7 million for the years ended December 31, 2022 and 2021, respectively. As of December 31, 2022, our commitments under these contracts were $413.4 million in 2023, $247.5 million in 2024, $235.8 million in 2025, $247.0 million in 2026, $230.3 million in 2027, 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 $24.5 million between 2023 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 $21.6 million to $32.7 million. As of December 31, 2022, we had a reserve of approximately $26.4 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

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

	December 31,	
	2022	2021
Liability at January 1,	$ 26,866	$ 28,895
Deductions	(2,033)	(2,799)
Charged to costs and expense	1,534	770
Liability at December 31,	$ 26,367	$ 26,866

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 $20.5 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, 2022, the reserve for remediation costs at this site was approximately $7.8 million, and we estimate that approximately $2.8 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 field work was completed in 2022. We submitted a Remedial Investigation Report (RI Report) summarizing the work completed to MDEQ and are awaiting its review and comments as to any additional field work. We expect the MDEQ review of the RI Report to be concluded in 2023, and any additional field work to commence following that.

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 expressed its intention to submit 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 GHG including, most significantly, carbon dioxide (CO_2) and methane emissions from natural gas. These actions include legislative proposals, Executive, Congressional and 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. We have joint ownership interests in four coal-fired electric generating plants, all of which other companies operate. Despite efforts over the years, Congress has not passed any federal climate change legislation regarding GHG emissions from coal-fired plants. While, Section 111(d) of the Clean Air Act (CAA) confers authority on EPA and the states to regulate emissions, including GHGs, from existing stationary sources, no regulation has survived judicial review. In 2022 EPA opened a docket to collect public input to guide the EPA's next effort to reduce GHG emissions from new and existing coal fired plants and natural gas operations. EPA indicated that it intends to use this non-rulemaking docket to gather perspectives from a broad group of stakeholders in advance of an expected proposed rulemaking. Ultimately, we cannot predict whether or how future GHG emission legislation, regulations, investor activism or litigation will impact our plants. 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. These 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, wind, 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. 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 our customers.

***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 have developed and submitted to the 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, they were all submitted in 2022. The Montana SIP as drafted and submitted to EPA does not call for additional controls for our interest in Colstrip Unit 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility. Similarly, the draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are finalized 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.

On August 31, 2021, the District Court ruled that the four agreements were valid and enforceable contracts and that we 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 $0.5 million in damages and the judge subsequently entered judgment against us in that amount.

The appeal is fully briefed at the Ninth Circuit. Oral arguments were held on February 8, 2023.

Talen Montana Bankruptcy

On May 9, 2022 Talen Energy Supply, LLC (Talen Energy) along with 71 affiliated entities, filed bankruptcy in Houston, Texas, seeking reorganization under Chapter 11 (the Talen Bankruptcy). Talen Montana, LLC (Talen) was one of the affiliated entities that filed bankruptcy and is included as a part of the Talen Bankruptcy. Talen is one of the co-owners of Colstrip Units 1, 2 and 3, and the operator of Units 3 and 4. The Talen Bankruptcy filing, along with the automatic stay under §362 of the Bankruptcy Code, has affected pending legal proceedings in which both NorthWestern and Talen are involved, including the State of Montana-Riverbed Rents Litigation, the Colstrip Arbitration and Litigation, and the Colstrip Coal Dust Litigation, as described in the individual matters below. On December 15, 2022 the bankruptcy court confirmed Talen’s Chapter 11 Plan. Apart from the delays of legal proceedings due to the automatic stay, we have not noted any detrimental effect on the operation or Colstrip Units 3 and 4 caused by Talen’s bankruptcy.

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 state and federal court, including before the United States Supreme Court, as detailed in Note 18 of our Annual Report on Form 10-K for the year ended December 31, 2022. 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). On August 1, 2018, the Federal District Court granted our and Talen's motions to dismiss the State's Complaint as it pertains to the navigability of the riverbeds associated with four of our hydroelectric facilities near Great Falls. A bench trial before the Federal District Court commenced January 4, 2022, and concluded on January 18, 2022, which addressed the issue of navigability concerning our other six facilities. Damages were bifurcated by agreement and will be tried separately should the Federal District Court find any segments navigable. While we await the Federal District Court decision on navigability, the damages phase of the case remains stayed.

We dispute the State's claims and intend to continue 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

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. The six owners of Colstrip Units 3 and 4 currently share the operating costs pursuant to the terms of an Ownership and Operation Agreement (O&O Agreement). However, several of the owners are mandated by Washington and Oregon law to eliminate coal-fired resources in 2025 and 2029, respectively.

As a result of the mandate, the owners have disagreed on various operational funding decisions, including whether closure requires each owner's consent under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), to resolve the issues of whether closure requires each owner's consent and to clarify each owner's obligations to continue to fund operations until all joint owners agree on closure. The owners previously initiated efforts to identify arbitrators and have agreed to stay the Arbitration while they explore a potential resolution to their disagreements.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. Talen is one of the co-owners of Colstrip Unit 3, and the operator of Units 3 and 4. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with Colstrip. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, the other owners of Colstrip, 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 remains in its early stages, we are unable to predict outcomes or estimate a range of reasonably possible losses.

BNSF Demands for Indemnity and Remediation Costs

NorthWestern has received a demand for indemnity from BNSF Railway Company (BNSF) for past and future environmental investigation and remediation costs incurred by BNSF at one of the three operable units at the Anaconda Copper Mining (ACM) Smelter and Refinery Superfund Site, located near Great Falls, Montana. Smelter and refining operations at the site commenced in 1893 and continued until 1980.

According to U.S. EPA, the smelter and refining operations have contaminated soil, groundwater and surface water resources around the site with lead, arsenic and other metal wastes. ARCO (Atlantic Richfield Company) initiated reclamation and maintenance activities in the 1980s and 1990s. Between 2002 and 2008, the EPA conducted several site investigations. In March 2011, the EPA placed the ACM Smelter and Refinery Site on the Superfund program's National Priority List. The Superfund Site is 427 acres and contains three operable units: Operable Unit 1 (consisting of five subsections including the Railroad Corridor and four other "areas of interest"), Operable Unit 2 (the former smelter and refinery site), and Operable Unit 3 (the Missouri River that flows along the south sides of Operable Units 1 and 2).

NorthWestern owns property in the Railroad Corridor sub-section of Operable Unit 1. BNSF claims it is entitled to indemnity and contribution from NorthWestern for the costs it has and will incur to investigate and remediate contamination in Operable Unit 1. BNSF reports it has incurred in excess of $4.4 million, pending final resolution of response and oversight costs incurred by government agencies (EPA and Montana DEQ), in investigative and other response costs associated with Operable Unit 1, and that in the future it will incur additional costs to implement the final remedy for Operable Unit 1. In the Record of Decision (ROD) for Operable Unit 1 issued on August 21, 2021, the EPA estimated the costs to implement the selected remedies for the Railroad Corridor will be approximately $4.1 million. In the ROD, the EPA also estimated the costs to implement the selected remedy (including institutional controls) for the four "areas of interest" in Operable Unit 1 would be approximately $1.8 million, with annual operating costs of ten thousand dollars. We are evaluating BNSF's claim and are unable at this time to predict outcomes or estimate a range of reasonably possible losses.

Yellowstone County Generating Station Air Permit

On October 21, 2021, the Montana Environmental Information Center (MEIC) and the Sierra Club filed a lawsuit in Montana State Court, against the Montana Department of Environmental Quality (MDEQ) and NorthWestern, alleging that the environmental analysis conducted by MDEQ prior to issuance of the Yellowstone County Generating Station's air quality construction permit was inadequate. The Montana District Court judge held oral argument on June 20, 2022. On April 4, 2023, the Montana District Court issued an order finding MDEQ's environmental analysis was deficient in not addressing exterior lighting and greenhouse gases. The Montana District Court remanded it back to MDEQ to address the deficiencies and vacated the air quality permit pending that remand. As a result of the vacatur of the permit, we are required to stop construction and will not be able to recommence construction until the permit is reissued. On April 14, 2023, following entry of final judgment, we filed our motion to stay the order vacating the air quality permit. On April 17, 2023, we filed a notice of appeal with the Montana Supreme Court. This lawsuit, as well as additional legal challenges related to the Yellowstone County Generating Station, could delay the project timing and increase costs. At this time, we still expect the plant to be operational by the end of 2024.

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 our opinion, 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	— %
3	2302 Franchises and Consents	114,169	114,169	— %
4	2303 Miscellaneous Intangible Plant	22	62,817	(99.96)%
5	**Total Intangible Plant**	127,064	189,859	(33.07)%
6				
7	**Production Plant**			
8	2325 Gas Leaseholds	74,901,829	74,900,089	0.00 %
9	2327 Field Compressor Structure	64,803	64,803	— %
10	2328 Field Mea & Reg Structure	642,881	642,881	— %
11	2330 Well Construction	4,825,073	4,824,852	0.00 %
12	2331 Well Equipment	5,259,303	5,195,229	1.23 %
13	2332 Field Lines	2,581,940	2,581,940	— %
14	2333 Field Compressor Equipment	1,555,808	1,555,808	— %
15	2334 Measuring & Regulating Equip.	2,141,030	2,141,030	— %
16	2337 Other Equipment	63,672	63,673	(0.00)%
17	**Total Production Plant**	92,036,339	91,970,305	0.07 %
18				
19	**Underground Storage Plant**			
20	2350 Land and Land Rights	4,943,533	4,943,533	— %
21	2351 Structures and Improvements	3,308,792	3,233,438	2.33 %
22	2352 Wells	10,422,298	10,140,887	2.78 %
23	2353 Lines	15,282,203	15,209,947	0.48 %
24	2354 Compressor Station Equipment	13,777,187	13,163,109	4.67 %
25	2355 Measuring & Regulating Equip.	2,984,352	2,984,352	— %
26	2356 Purification Equipment	567,763	567,763	— %
27	2357 Other Equipment	1,296,312	1,294,643	0.13 %
28	**Total Underground Storage Plant**	52,582,440	51,537,672	2.03 %
29				
30	**Transmission Plant**			
31	2365 Rights of Way	12,948,523	12,150,547	6.57 %
32	2366 Structures and Improvements	20,299,947	19,373,923	4.78 %
33	2367 Mains	307,437,430	245,600,288	25.18 %
34	2368 Compressor Station Equipment	56,533,615	56,181,194	0.63 %
35	2369 Meas. & Reg. Station Equipment	31,458,243	27,897,471	12.76 %
36	2370 Communication Equipment	—	—	-
37	2371 Other Equipment	936,906	601,018	55.89 %
38	**Total Transmission Plant**	429,614,664	361,804,441	18.74 %
39				
40	**Distribution Plant**			
41	2374 Land and Land Rights	1,306,740	1,299,038	0.59 %
42	2375 Structures and Improvements	337,278	315,705	6.83 %
43	2376 Mains	241,534,998	227,080,154	6.37 %
44	2377 Compressor Station Equipment	—	—	-
45	2378 M&R Station Equip.-General	4,974,029	4,906,610	1.37 %
46	2379 M&R Station Equip.-City Gate	—	—	-
47	2380 Services	107,201,461	100,184,156	7.00 %
48	2381 Customers Meters and Regulators	91,531,086	79,811,802	14.68 %
49	2382 Meter Installations			-
50	2383 House Regulators			-
51	2384 House Regulator Installations			-
52	2385 M&R Station Equip.-Industrial	103,320	103,320	— %
53	2386 Other Prop. on Customers' Premises			-
54	2387 Other Equipment	86,720	76,605	13.20 %
55	**Total Distribution Plant**	447,075,632	413,777,390	8.05 %

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	— %
4	2390	Structures and Improvements	2,480,751	2,488,751	(0.32)%
5	2391	Office Furniture and Equipment	134,729	145,824	(7.61)%
6	2392	Transportation Equipment	17,393,871	17,043,902	2.05 %
7	2393	Stores Equipment	208,654	198,972	4.87 %
8	2394	Tools, Shop & Garage Equipment	7,390,549	7,416,095	(0.34)%
9	2395	Laboratory Equipment	360,957	365,625	(1.28)%
10	2396	Power Operated Equipment	5,530,785	5,088,099	8.70 %
11	2397	Communication Equipment	2,989,904	3,037,451	(1.57)%
12	2398	Miscellaneous Equipment	108,495	104,235	4.09 %
13	2399	Other Tangible Property	—	—	-
14	**Total General Plant**		36,700,370	35,990,629	1.97 %
15	**Total Gas Plant in Service**		1,058,136,509	955,270,296	10.77 %
16					
17	4101	Gas Plant Allocated from Common	60,719,777	53,297,429	13.93 %
18	2105	Gas Plant Held for Future Use	29,866	29,866	— %
19	2107	Gas Construction Work in Progress	25,234,216	48,006,941	(47.44)%
20	2117	Gas in Underground Storage	57,931,594	51,242,624	13.05 %
21					
22					
23	**TOTAL GAS PLANT**		$ 1,202,051,962	$ 1,107,847,156	8.50 %
24					
25					

26	**CONSOLIDATED**	December 31,	
27	**PLANT IN SERVICE**	2022	2021
28			
29	Montana Electric	$ 4,478,577,275	$ 4,230,419,004
30	Yellowstone National Park	23,181,889	22,211,416
31	Montana Natural Gas (Includes CMP)	1,058,136,509	955,270,296
32	Common	191,541,317	163,830,981
33	Townsend Propane	1,528,962	1,523,173
34	South Dakota Electric	1,084,736,554	975,412,140
35	South Dakota Natural Gas	248,923,029	233,394,205
36	South Dakota Common	72,289,882	68,846,326
37	Asset Retirement Obligation	34,815,008	33,839,429
38	**TOTAL PLANT**	$ 7,193,730,425	$ 6,684,746,970

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	$ 92,036,339	$ 50,696,713	$ 46,748,841	5.36 %
4					
5	Underground Storage	52,582,440	27,125,825	26,745,634	1.67 %
6					
7	Other Storage	—	—	—	— %
8					
9	Transmission	429,614,664	138,614,945	133,374,804	1.73 %
10					
11	Distribution	447,075,632	170,692,999	165,180,048	2.67 %
12					
13	General and Intangible	36,700,370	27,561,750	26,457,923	8.94 %
14					
15	Common	60,719,777	17,649,698	16,445,525	5.57 %
16					
17					
18	**Total Accum Depreciation**	$ 1,118,729,222	$ 432,341,930	$ 414,952,775	2.82 %
19					
20					
21					

		December 31,	
22	**Consolidated**		
23	**Accumulated Depreciation**	2022	2021
24			
25	Montana Electric	$ 1,701,596,081	$ 1,616,088,020
26	Yellowstone National Park	11,497,472	11,122,437
27	Montana Natural Gas (Includes CMP)	414,692,232	398,507,250
28	Common	49,925,576	46,114,249
29	Townsend Propane	1,087,518	1,047,214
30	South Dakota Electric	361,933,145	339,038,874
31	South Dakota Natural Gas	108,399,684	104,065,010
32	South Dakota Common	22,856,513	21,986,176
33	Acquisition Writedown	37,867,662	40,572,152
34	Basin Creek Capital Lease	33,172,848	31,162,371
35	FIN 47	1,451,661	273,733
36	CWIP-Capital Retirement Clearing	(10,305,356)	(8,987,263)
37	**Total Consolidated Accum Depreciation**	$ 2,734,175,036	$ 2,600,990,223

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	$ 383,027	$ 272,450	40.59 %
7	Transmission Plant	2,575,596	1,862,287	38.30 %
8	Distribution Plant	5,954,848	3,275,571	81.80 %
9				-
10	**Total MT Materials and Supplies**	$ 8,913,471	$ 5,410,308	64.75 %
11				
12				
13	**Consolidated**	December 31,		
14	**Materials and Supplies**	2021	2020	
15				
16	Montana Natural Gas	$ 8,913,471	$ 5,410,308	
17	Montana Electric	44,380,570	33,078,315	
18	South Dakota	17,860,206	15,050,102	
19				
20	**Total Consolidated Materials and Supplies**	$ 71,154,247	$ 53,538,725	

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 %
10				
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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	$ 183,006,620	$ 186,839,752	(2.05)%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	167,066,420	159,403,530	4.81 %
6	Amortization, Net	33,241,101	32,746,162	1.51 %
7	Other Noncash Charges to Net Income, Net	11,976,972	13,533,571	(11.50)%
8	Deferred Income Taxes, Net	(8,261,582)	971,152	>-300.00%
9	Investment Tax Credit Adjustments, Net	(129,521)	239,294	(154.13)%
10	Change in Operating Receivables, Net	(36,275,911)	(22,324,551)	(62.49)%
11	Change in Materials, Supplies & Inventories, Net	(26,725,060)	(19,613,582)	(36.26)%
12	Change in Operating Payables & Accrued Liabilities, Net	78,691,017	(4,575,338)	>300.00%
13	Allowance for Funds Used During Construction (AFUDC)	(14,189,693)	(11,082,078)	(28.04)%
14	Change in Other Assets & Liabilities, Net	(65,946,236)	(121,016,076)	45.51 %
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,960,409)	(2,599,655)	(13.88)%
17	Change in Regulatory Assets	3,473,736	10,802,571	(67.84)%
18	Change in Regulatory Liabilities	(14,255,867)	(2,175,662)	>-300.00%
19	**Net Cash Provided by Operating Activities**	308,711,587	221,149,090	39.59 %
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(516,500,191)	(435,651,210)	(18.56)%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(1,731,829)	(1,505,221)	(15.05)
24	Proceeds from Sale of Assets	—	—	-
25	**Net Cash Used in Investing Activities**	(518,232,020)	(437,156,431)	(18.55)%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	—	99,915,000	(100.00)%
29	Issuance of Notes Payable	—	—	-
30	Line of Credit Borrowings, Net	—	—	-
31	Proceeds From Issuance of Common Stock, Net	276,971,002	196,246,244	41.13 %
32	Payments for Retirement of:			-
33	Repayments of Short Term Borrowings, Net	92,403	(100,000,000)	100.09 %
34	Repayments of Long Term Borrowings, Net	—	(955,280)	100.00 %
35	Line of Credit Repayments, Net	77,000,000	151,000,000	(49.01)%
36	Dividends on Common Stock	(140,062,161)	(128,482,602)	(9.01)%
37	Other Financing Activities:			-
38	Debt Financing Costs	(1,286,054)	(909,219)	(41.45)%
39	Treasury Stock Activity	603,028	706,750	(14.68)%
40	**Net Cash Used in Financing Activities**	213,318,218	217,520,893	(1.93)%
41	**Net Increase/Decrease in Cash and Cash Equivalents**	3,797,785	1,513,552	150.92 %
42	**Cash and Cash Equivalents at Beginning of Year**	17,057,565	15,544,013	9.74 %
43	**Cash and Cash Equivalents at End of Year**	$ 20,855,350	$ 17,057,565	22.26 %
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				
50				
51				
52				
53				

Sch. 24	MONTANA LONG TERM DEBT 2022								
	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	12/19/48	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	99,966,944	1.00 %	1,217,333	1.22 %
16	**Total First Mortgage Bonds**			$ 1,616,000,000	$ 1,604,186,290	$ 1,615,966,944		$ 66,931,884.00	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	2.00 %	$ 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	$ 1,747,253,974	$ 1,760,626,944		$ 70,559,477	4.01 %
29									
30									
31	This schedule does not reflect our obligations under capital lease which total $9,296,928								
32									
33									
34									
35									
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43									
44									
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										
5										
6										
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28										
29										
30										
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	54,072,786	$ 43.69				$ 59.05	$ 55.58	
February	54,133,091	44.09				60.93	56.31	
March	54,134,364	44.03	1.09	0.630		62.43	57.02	
April	54,138,215	44.03				63.06	56.53	
May	54,140,176	44.17				62.95	54.93	
June	56,146,912	43.89	0.55	0.630		61.69	54.28	
July	56,149,369	44.04				60.49	53.74	
August	56,152,990	44.31				56.75	52.75	
September	57,774,234	43.92	0.48	0.630		56.54	49.05	
October	57,777,967	44.13				53.82	48.68	
November	57,780,325	45.66				58.50	51.07	
December	59,742,074	44.61	1.16	0.630		60.10	55.85	
TOTAL Year End	51,709,229	$ 44.61	$ 3.28	$ 2.52	23.17 %	$ 58.66		17.9

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2022.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$ 1,061,317,009	$ 988,924,893	7.32 %
3	108	Accumulated Depreciation	(423,832,268)	(406,463,571)	(4.27)%
4					
5	**Net Plant in Service**		$ 637,484,741	$ 582,461,322	9.45 %
6		Additions:			
7	154, 156	Materials & Supplies	$ 13,709,246	$ 10,421,167	31.55 %
8	165	Prepayments			
9		Other Additions	42,555,173	43,724,451	(2.67)%
10					
11	**Total Additions**		$ 56,264,419	$ 54,145,618	3.91 %
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$ 36,293,391	$ 36,752,624	(1.25)%
14	252	Customer Advances for Construction	19,826,466	16,820,602	17.87 %
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	50,472,804	52,298,762	(3.49)%
17					
18	**Total Deductions**		$ 106,592,661	$ 105,871,988	0.68 %
19	**Total Rate Base**		$ 587,156,499	$ 530,734,952	10.63 %
20	**Adjusted Rate Base**		$ 587,156,499	$ 530,734,952	10.63 %
21	**Net Earnings**		$ 36,109,219	$ 29,228,168	23.54 %
22	**Rate of Return on Average Rate Base**		6.150 %	5.507 %	11.67 %
23	**Rate of Return on Average Equity 1/**		8.554 %	7.382 %	15.88 %
24					
25		**Major Normalizing and**			
26		**Commission Ratemaking Adjustments**			
27		Rate Schedule Revenues	$ (6,006,451)	$ 3,898,159	(254.08)%
28		Environmental True-up MGP Sites 2/	685,151	1,876,150	(63.48)%
29					
30		Non-Allowables:			
31		Advertising	463,011	122,410	278.25 %
32		Dues, Contributions, Other	30,886	23,294	32.59 %
33					
34		Associated Income Taxes 3/	3,253,547	732,628	>300.00%
35					
36	**Total Adjustments**		$ (1,573,856)	$ 6,652,641	(123.66)%
37	**Revised Net Earnings**		$ 34,535,363	$ 35,880,809	(3.75)%
38					
39		**Rate Base Adjustment**			
40		Stipulation with MCC 4/	$ (7,261,148)	$ (7,687,522)	5.55 %
41					
42	**Revised Rate Base**		$ 579,895,351	$ 523,047,430	10.87 %
43	**Adjusted Rate of Return on Average Rate Base**		5.955 %	6.860 %	(13.19)%
44	**Adjusted Rate of Return on Average Equity 1/**		7.350 %	9.272 %	(20.73)%
45					
46	1/ Return on Equity calculated using the capital structure approved in Docket No. D2016.9.68.				
47					
48	2/ Removal of expenses recorded in 2022 related to environmental costs not recovered from customers.				
49					
50	3/ Associated Income taxes include an interest synchronization adjustment based upon the approved				
51	capital structure in Docket No. D2016.9.68.				
52					
53	4/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting one-third of the $38.8 million				
54	allocated to natural gas as a rate base reduction.				
55					
56					
57					
58					
59					

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	Gas Stored Underground	36,167,272	36,167,272	— %
4	Cost of Refinancing Debt	6,938,082	7,557,179	(8.19)%
5	MPSC/MCC Taxes	(550,181)	—	-
6				
7	**Total Other Additions**	$ 42,555,173	$ 43,724,451	(2.67)%
8				
9	**Detail - Other Deductions**			
10	Personal Injury and Property Damage	$ 1,676,292	$ 1,932,605	(13.26)%
11	Storage Gas Sales 2000 & 2001	7,256,202	7,676,719	(5.48)%
12	Gross Cash Requirements	18,512,461	15,588,271	18.76 %
13	Regulatory Liability (TCJA)	$ 22,420,263	$ 27,101,167	(17.27)%
14	Environmental Reserve	607,585	—	-
15				
16	**Total Other Deductions**	$ 50,472,803	$ 52,298,762	(3.49)%
17				
18				
19				
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41				
42				

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)	$ 1,118,856,286
5	105	Plant Held for Future Use	29,866
6	107	Construction Work in Progress	25,234,216
7	117	Gas in Underground Storage	57,931,594
8	151-163	Materials & Supplies	8,913,471
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	432,341,930
11	252	Customer Advances	14,852,544
12	**NET BOOK COSTS**		763,770,959
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	263,714,659
17			
18	**Total Operating Revenues**		263,714,659
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	155,392,714
21	403-407	Depreciation, Depletion, & Amortization Expenses	26,628,909
22	408.1	Taxes Other than Income Taxes	42,541,177
23	409-411	Federal & State Income Taxes	3,042,640
24			
25	**Total Operating Expenses**		227,605,440
26	**Net Operating Income**		36,109,219
27			
28	415-421.1	Other Income	2,870,630
29	421.2-426.5	Other Deductions	200,720
30	**NET INCOME BEFORE INTEREST EXPENSE**		$ 38,779,129
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	181,882
34		Commercial	25,323
35		Industrial	233
36		Other (including interdepartmental)	181
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		207,619
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	84.2
41		Average Annual Residential Cost per (Dkt)	$ 9.94
42		Average Residential Monthly Bill	$ 69.78
43			
44		Plant in Service (Gross) per Customer	$ 5,389

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,000	492	77	1	570
2	Amsterdam	206	56	12	—	68
3	Anaconda	9,421	3,468	339	5	3,812
4	Augusta	316	202	52	1	255
5	Belfry	193	4	—	—	4
6	Belgrade	10,460	7,189	1,308	2	8,499
7	Big Mountain	—	289	36	—	325
8	Big Sandy	605	294	74	—	368
9	Big Timber	1,650	951	193	6	1,150
10	Bigfork	5,118	1,678	237	—	1,915
11	Billings	117,116	26	3	—	29
12	Bonner	1,690	80	26	1	107
13	Boulder	1,201	453	84	3	540
14	Bozeman	53,293	27,296	4,067	12	31,375
15	Browning	1,018	1,065	157	7	1,229
16	Buffalo	—	7	1	—	8
17	Butte	34,494	13,118	1,530	34	14,682
18	Cardwell	62	18	4	—	22
19	Carter	65	28	10	—	38
20	Chester	847	356	138	1	495
21	Chinook	1,185	717	144	5	866
22	Choteau	1,721	899	181	6	1,086
23	Churchill	1,030	464	47	—	511
24	Clancy	1,851	767	43	—	810
25	Clinton	1,018	378	18	1	397
26	Columbia Falls	5,308	3,752	398	4	4,154
27	Columbus	1,857	1,130	187	4	1,321
28	Conrad	2,318	1,129	225	10	1,364
29	Coram	572	124	28	—	152
30	Corbin	—	1	—	—	1
31	Corvallis	1,125	1,420	106	—	1,526
32	Cut Bank	3,056	46	12	1	59
33	Deer Lodge	2,938	1,636	223	4	1,863
34	Dillon	3,880	2,185	367	6	2,558
35	Drummond	272	202	52	2	256
36	East Glacier Park	354	141	47	1	189
37	East Helena	1,944	2,376	157	3	2,536
38	Elliston	227	108	14	—	122
39	Essex	44	108	21	1	130
40	Fairfield	759	422	89	4	515
41	Florence	821	1,398	95	1	1,494
42	Floweree	19	41	9	—	50
43	Fort Belknap	1,567	321	63	—	384
44	Fort Benton	1,449	655	165	1	821
45	Fort Harrison	—	—	13	57	70
46	Fort Shaw	256	113	13	—	126
47	Galata	—	2	—	—	2
48	Gallatin Gateway	967	188	50	—	238
49	Garneill	—	6	2	—	8
50	Garrison	115	22	8	—	30
51	Gildford	141	73	25	—	98
52	Grantsdale	—	17	1	—	18
53	Great Falls	60,442	995	79	3	1,077

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Greycliff	89	45	6	—	51
2	Hall	51	63	16	—	79
3	Hamilton	4,659	4,450	740	7	5,197
4	Harlem	769	332	61	1	394
5	Harlowton	955	535	104	2	641
6	Havre	9,362	4,599	696	10	5,305
7	Helena	32,091	20,050	2,573	27	22,650
8	Hil	—	2	—	—	2
9	Hingham	131	80	32	—	112
10	Hungry Horse	828	229	36	—	265
11	Inverness	77	36	11	—	47
12	Jefferson City	597	229	15	2	246
13	Joplin	159	95	25	—	120
14	Judith Gap	110	64	15	—	79
15	Kalispell	24,558	13,536	2,210	19	15,765
16	Kremlin	78	47	18	—	65
17	Laurel	7,222	25	3	—	28
18	Ledger	—	7	—	—	7
19	Lewistown	5,952	3,012	518	7	3,537
20	Livingston	8,040	4,449	626	13	5,088
21	Logan	72	40	6	—	46
22	Lohman	—	2	1	—	3
23	Lolo	4,399	1,809	102	—	1,911
24	Loma	65	45	17	—	62
25	Manhattan	2,086	957	133	2	1,092
26	Martin City	461	116	17	—	133
27	Marysville	82	1	—	—	1
28	Milltown	—	70	11	—	81
29	Missoula	73,489	32,228	4,043	49	36,320
30	Montana City	2,918	856	84	—	940
31	Moore	194	3	—	—	3
32	Philipsburg	841	465	96	—	561
33	Power	177	—	1	—	1
34	Ramsay	—	41	7	—	48
35	Red Lodge	2,257	2,165	304	9	2,478
36	Reedpoint	177	121	16	1	138
37	Roberts	304	184	21	—	205
38	Rocker	—	48	6	—	54
39	Rudyard	270	127	29	—	156
40	Ryegate	223	3	1	—	4
41	Shawmut	42	23	7	—	30
42	Shelby	3,169	9	4	—	13
43	Sheridan	694	459	77	—	536
44	Silver Star	46	23	5	—	28
45	Silverbow	—	3	3	2	8
46	Simms	361	158	17	—	175
47	Somers	1,049	430	22	—	452
48	Stevensville	2,002	1,944	283	5	2,232
49	Sun River	95	106	17	—	123
50	Three Forks	1,989	904	146	—	1,050
51	Turah	364	162	4	—	166

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Twin Bridges	330	208	60	—	268
2	Valier	530	307	69	4	380
3	Vaughn	737	331	25	—	356
4	Victor	789	509	80	1	590
5	Walkerville	639	237	13	—	250
6	Warm Springs	—	13	1	—	14
7	West Glacier	221	107	40	3	150
8	Whitefish	7,751	5,018	521	5	13,295
9	Whitehall	1,006	704	112	1	817
10	Whitlash	4	1	1	—	2
11	Williamsburg	—	1	—	—	1
12	Willow Creek	230	100	14	—	114
13	Wolf Creek	25	53	27	—	80
14						
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49	**Total**	541,807	181,882	25,378	357	207,617

1/ Customer populations represent an average of the 12 month period from 01/01/22 through 12/31/22.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	3	1	2
4	Customer Care	151	150	151
5	Finance	156	57	107
6	Information Technology 2/	0	98	49
7	Distribution	442	404	423
8	Asset Management 3/	0	39	20
9	Transmission	305	312	309
10	Supply	116	129	123
11	Legal	23	23	23
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,196	1,213	1,205

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.
2/ Previously reported under Finance department
3/ Previously reported under Distribution department

Sch. 31	MONTANA CONSTRUCTION BUDGET 2023 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Distribution - Transformer purchases new connects	$ 10,500,000	$ 10,500,000
4	SD Transmission - Chamberlain Tie substation capacity	6,873,923	—
5	MT Transmission - Billings Rimrock Substation rebuild	6,246,131	6,246,131
6	MT Transmission - Missoula Miller Creek substation rebuild	5,673,101	5,673,101
7	MT Transmission - Billings Line Creek-Red Lodge 50kv rebuild	4,407,108	4,407,108
8	MT Transmission - Waldorf Sub rebuild	3,952,458	3,952,458
9	MT Distribution - Rural reliability resource	3,707,381	3,707,381
10	MT Transmission - Benchland substation rebuild	3,465,175	3,465,175
11	MT Transmission - Crooked Falls-Great Falls ES capacity	3,183,127	3,183,127
12	MT Transmission - Great Falls 230 - Eastside capacity	3,183,127	3,183,127
13	MT Distribution - Great Falls base pole replacements	2,874,050	2,874,050
14	MT Transmission - 2nd Laurel Cith 100kv capacity	2,795,626	2,795,626
15	SD Distribution - LED street light replacements	2,371,450	—
16	MT Transmission - Bridger to Red Lodge upgrade	2,183,677	2,183,677
17	SD Distribution - Aberdeen A5200 reconductor	1,892,665	—
18	MT Distribution - Lewistown base pole replacements	1,867,384	1,867,384
19	MT Distribution - substation Bonner upgrade	1,826,469	1,826,469
20	MT Transmission - East Gallatin Transformer upgrade capacity	1,821,353	1,821,353
21	MT Transmission - Ovando - Great Falls 230kv pole replacements	1,614,905	1,614,905
22	MT Distribution - Great Falls division forest management	1,498,919	1,498,919
23	MT Distribution - Bozeman - Riverside substation bank 1	1,432,529	1,432,529
24	MT Distribution - Johnson Lane substation bank 1 upgrade	1,382,390	1,382,390
25	MT Distribution - Bozeman pole replacements	1,343,005	1,343,005
26	MT Distribution - Missoula Reserve Street substation bank 3	1,323,877	1,323,877
27	MT Distribution - Butte pole replacements	1,321,888	1,321,888
28	MT Distribution - Helena substation Spokane bank 1	1,280,081	1,280,081
29	MT Transmission - Pole replacements South Butte-3 Rivers 230	1,279,487	1,279,487
30	MT Transmission - Billings rimrock-east side-steam plant reconductor	1,257,253	1,257,253
31	SD Distribution - Huron GT Bank 1 sub upgrade	1,251,920	—
32	MT Transmission - Clyde Park substation rebuild	1,232,328	1,232,328
33	MT Transmission - Rattlesnake - Miller Creek B fire mitigation	1,195,827	1,195,827
34	MT Distribution - Missoula substation #5 bank 2	1,157,538	1,157,538
35	MT Distribution - Helena base pole replaements	1,119,621	1,119,621
36	MT Transmission - Rattlesnake - Kerr A pole replacements and fire mit	1,065,575	1,065,575
37	MT Distribution - Hamilton north substation upgrade	1,017,561	1,017,561
38	MT Distribution - Churchill bank 1 substation upgrade	1,008,931	1,008,931
39	MT Transmission - Bozeman Three Rivers Bank 1 substation capacity	1,007,650	1,007,650
40	MT Distribution - Darby bank 2 substation replacement	1,006,427	1,006,427
41	MT Distribution - Skalkaho capacity cutover	1,005,223	1,005,223
42	MT Transmission - Corvallis Hamilton Heights capacity	1,000,674	1,000,674
43			
44	All Other Projects < $1 Million Each and blankets	111,186,188	81,113,207
45	**Total Electric Utility Construction Budget**	**206,814,002**	**164,351,063**
46			
47	**Natural Gas Operations**		
48	MT Transmission - Carway pipeline loop capacity	$ 32,560,281	$ 32,560,281
49	MT Transmission - Marias Valier pipeline loop capacity	21,880,388	21,880,388
50	MT Storage - Dry Creek storage new well	8,939,147	8,939,147
51	MT Transmission - Riebeling reroute reliability	6,693,893	6,693,893
52	MT Distribution - Butte Base gas one upgrades	4,092,466	4,092,466
53	MT Transmission - HJEHL VS replacement compliance	3,357,602	3,357,602
54	MT Transmission - COLWL PL/VS/Fittings replace compliance	3,307,359	3,307,359
55	MT Transmission - EHBL VS/fitting/PL replace compliance	3,283,595	3,283,595
56	MT Transmission - UTHAL PL replace compliance	2,962,895	2,962,895
57	MT Distribution - Bozeman Base gas one upgrades	1,574,999	1,574,999
58	MT Distribution - Gas meters and regulators new connect	1,459,450	1,459,450
59	MT Transmission - Great Falls 15th Street CG/var replace compliance	1,185,367	1,185,367
60	MT Transmission - Helena - Three Forks pipeline capacity	1,137,627	1137627
61	MT Transmission - compliance NPRM required projects	1,050,036	1050036
62	MT Transmission - DC Storace N Lake Basin acquisition	1,026,921	1026921
63			
64	All Other Projects < $1 Million Each and blankets	31,976,637	$ 21,555,573
65	**Total Natural Gas Utility Construction Budget**	**$ 126,488,663**	**$ 116,067,599**
66			
67	**Common**		
68	MT Common - Distribution AMI Metering and Infrastructure	$ 22,742,929	$ 22,742,929
69	MT Common - Fleet vehicles and equipment	4,240,000	4,240,000
70	MT Common - Telecom Hamilton West Side Sub Comms	1,747,522	1,747,522
71	SD Common - Redfield facility design	2,965,088	—
72	SD Common - Fleet Vehicles and equipment	1,440,000	—
73			
74	All Other Projects < $1 Million Each and blankets	20,007,256	14,530,072
75	(Includes BT, Communications, Facilities, Land, Customer Service)		
76	**Total Common Utility Construction Budget**	**53,142,795**	**43,260,523**
77			
78	**MT/SD Generation**		
79	MT Generation - DGGS GG 743180 50k hour overhaul	$ 6,071,488	$ 6,071,488
80	MT Generation - DGGS GG 743182 50k hour overhaul	6,071,488	6,071,488
81	MT Generation - Hydro Maroney spillway gate upgrade	5,309,168	5,309,168
82	MT Generation - Hydro Cochrane radial hoist upgrade	4,200,483	4,200,483
83	MT Generation - DGGS PT 80403 Overhaul	3,474,023	3,474,023
84	MT Generation - DGGS PT 80402 Overhaul	3,437,733	3,437,733
85	MT Generation - Hydro Cochrane Unit 2 restack and rewind	3,003,989	3,003,989
86	MT Generation - Hydro Blackeagle spillway upgrade for ice	1,681,351	1,681,351
87	MT Generation - Hydro Madison flowline headgate & drive	1,588,377	1,588,377
88	MT Generation - Yellowstone generation station	59,286,502	59,286,502
89	MT Generation - Hydro Holter U1 turbine upgrade	2,755,788	2,755,788
90	MT Generation - Hydro Holter U2 turbine upgrade	2,662,922	2,662,922
91	MT Generation - Hydro Holter U3 turbine upgrade	2,333,110	2,333,110
92	MT Generation - Hydro Cochrane U2 turbine upgrade	2,278,506	2,278,506
93	MT Generation - Hydro Hauser U1 turbine upgrade	1,727,844	1,727,844
94	MT Generation - Hydro Holter U1 generator rewind	1,518,957	1,518,957
95	SD Generation - Neal 4 baseload plant upgrades	1,660,827	—
96	SD Generation - Big Stone baseload plant upgrades	1,261,999	—
96	MT Generation - Thompson Falls relicensing	1,377,398	1,377,398
97	MT Generation - CU4 plant upgrades	1,077,099	1,077,099
98	MT Generation - Hydro Holter Unit 2 generator rewind	1,433,392	1,433,392
99			
100	All Other Projects < $1 Million Each and blankets	$ 7,822,552	$ 7,019,559
101	**Total MT/SD Generation**	**122,034,996**	**118,309,177**
102	**TOTAL CONSTRUCTION BUDGET**	**$ 508,480,456**	**$ 441,988,362**

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
January		5		298,111		6,537,839
February		22		324,211		5,942,270
March		9		253,150		5,254,003
April		12		203,329		4,204,165
May		16		175,473		3,469,714
June		13		187,245		2,526,250
July		6		170,426		1,943,602
August		17		188,406		2,138,589
September		17		164,737		2,499,049
October		25		167,768		3,212,797
November		18		277,400		5,241,506
December		21		375,680		6,588,263
TOTAL						49,558,047

	Distribution System-Sales and Transportation					
	Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
January		3,911,251		130,562		4,041,813
February		3,173,638		117,052		3,290,690
March		3,109,205		109,893		3,219,098
April		2,357,804		75,559		2,433,363
May		1,725,995		59,126		1,785,120
June		1,019,167		37,894		1,057,061
July		547,101		25,593		572,694
August		384,794		18,969		403,763
September		433,219		22,891		456,109
October		706,173		26,112		732,285
November		1,973,171		59,996		2,033,167
December		3,673,663		126,382		3,800,045
TOTAL		23,015,181		810,029		23,825,208

	Storage System-Sales and Transportation					
	Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
	Total Company	Montana	Total Montana		Energy Supply	
Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
January			3,796	3,880,944		2,502,855
February			6,772	3,094,690		1,703,582
March			22,284	2,049,273		1,389,114
April			909,302	316,930	289,591	
May			2,080,444	22,930	1,403,598	
June			2,750,956	10,699	1,974,003	
July			2,983,108	21,909	2,071,201	
August			3,407,331	13,816	1,985,882	
September			2,571,254	15,673	1,679,003	
October			939,340	402,798	37,737	
November			13,012	3,222,689		2,548,316
December			802	3,625,688		2,416,442
TOTAL			15,688,401	16,678,039	9,441,015	10,560,309

1/ Data is not accumulated on a daily basis. Therefore the peak day and peak day volumes are not available.

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	15,305,968		$ 2.9914	
3	Havre Pipeline	779,585		2.8872	
4	Encana Pipeline	589,840		2.4775	
	Colorado Interstate Pipeline	519,000		18.6629	
5	Company Owned Production 1/	4,064,339		0.6631	
6	Intra Montana Purchase	549,717		3.0992	
7	**TOTAL CORE SUPPLY LAST YEAR**	21,808,449		$ 3.1395	
8					
9	Canadian Pipeline		17,740,957		$ 4.9675
10	Havre Pipeline		749,443		4.0806
11	Encana Pipeline		—		—
12	Colorado Interstate Pipeline		585,656		7.1304
13	Company Owned Production 1/		3,869,076		0.9557
14	Intra Montana Purchase		418,180		4.6995
15	**TOTAL CORE SUPPLY THIS YEAR**		23,363,312		$ 4.5298
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	2022 E+ Natural Gas Business Partners Program	$ 971	$ 1,197	(18.88)%	(5,575)	(2,322)	3,253
3	- Initiated 2005, 2022 weighted average program life = 18 years, 3 participants.						
4	*2022 Northwest Energy Efficiency Alliance (NEEA)	$ 1,605,973	$ 1,282,896	25.18 %	—	21,054	21,054
5	- Initiated natural gas savings in 2006, program life is 15 years						
6	2022 E+ Residential Natural Gas Existing Construction Program	$ 200,278	$ 40,742	391.58 %	19,039	7,930	(11,109)
7	- Reinitiated 2021, 2022 weighted average program life = 16 years, 359 participants.						
8	2022 E+ Residential Natural Gas New Construction Program	$ 1,279	$ —	— %	144	60	(84)
9	- Reinitiated 2022, 2022 weighted average program life = 19 years, 3 participants.						
10	2022 E+ Commercial Natural Gas Existing Construction Program	$ 10,334	$ 1,899	444.18 %	845	352	(493)
11	- Reinitiated 2021, 2022 weighted average program life = 22 years, 3 participants.						
12	2022 General Expenses All Natural Gas DSM Programs	$ 685	$ 1,299	(47.27)%	—	—	—
13	-NA						
14							
15	A program participant is a Montana commercial or residential						
16	natural gas customer who installs eligible						
17	energy conservation measures and receives financial						
18	incentives/rebates either directly or indirectly.						
19							
20	*Note: 2022 NEEA expeditures are allocated to electric DSM						
21	but there are gas savings as a result of some NEEA initiatives.						
22	Participant has not been defined or counted for NEEA.						
23							
24	Units reported are in dekatherms ("Dkt")						
25							
26	COVID-19 impacted 2022 DSM activities.						
27							
28	**TOTAL**	$ 1,819,520	$ 1,328,033	37.01 %	14,453	27,074	12,621

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						
3	Residential	$ 152,303,051	$ 126,022,539	15,319,271	13,885,165	181,882	179,642
4	Commercial	79,267,287	64,677,771	8,328,738	7,445,638	25,323	24,930
5	Industrial Firm	1,519,549	1,133,808	163,474	135,354	233	228
6	Public Authorities	1,047,176	861,757	121,246	110,803	124	113
7	Interdepartmental	884,589	554,754	97,747	66,960	55	53
8	Sales to Other Utilities	1,326,341	1,028,355	220,900	197,682	2	2
9	TOTAL SALES	$ 236,347,993	$ 194,278,984	24,251,376	21,841,602	207,619	204,968
10		Operating Revenues		Dkt Transported		Average Customers	
11–12		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
13	Transportation of Gas						
15	On System Transportation	$ 24,472,458	$ 23,960,549	26,509,478	24,767,464	275	277
16	Off System Transportation & Storage	—	13,502	—	752,843	5	4
17	Canadian Montana Pipeline	268,150	249,654	—	—	—	—
18	TOTAL TRANSPORTATION	$ 24,740,608	$ 24,223,705	26,509,478	25,520,307	280	281
30	1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.						

Sch. 36A	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Expenditures	Contracted or Committed to Spend	Total Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	$ 612,090	$ —	$ 612,090	2,415	2012
3	NWE Promotion	$ 14,394	$ —	$ 14,394		
4	NWE Labor	$ 31,360	$ —	$ 31,360		
5	NWE Admin. Non-labor	$ 1,915	$ —	$ 1,915		
6	USB Interest & Svc Chg	$ (67)	$ —	$ (67)		
7	Low Income					
8	Bill Assistance	$ 972,603	$ —	$ 972,603		
9	Free Weatherization	$ —	$ —	$ —	5,338	2012
10	Energy Share	$ 336,000	$ —	$ 336,000		
11	NWE Promotion	$ 307	$ —	$ 307		
12	NWE Labor	$ 30,126	$ —	$ 30,126		
13	NWE Admin. Non-labor	$ 2,175	$ —	$ 2,175		
14	USB Interest & Svc Chg	$ (184)	$ —	$ (184)		
15	Total	$ 2,000,719	$ —	$ 2,000,719	7,753	
16	Number of customers that received low income rate discounts				5,834	
17	Average monthly bill discount amount ($/mo)				$ 27.79	(a)
18	Average LIEAP-eligible household income				n/a	
19	Number of customers that received weatherization assistance				160	(b)
20	Expected average annual bill savings from weatherization				33	dKt
21	Number of residential audits performed				0	(b)
22	Number of residential virtual assessments performed				850	(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) 2022 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 2022 USB revenues and activities. COVID-19 resulted in activities planned for 2022 being postponed and funds carried forward to 2023 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	$ 612,090	$ —	$ 612,090	2,415	2012
3						
4	Market Transformation					
5	*Building Operator Certification (BOC)	$ 6,000	$ —	$ 6,000	577	2012
6						
7	Low Income					
8	Free Weatherization	$ —	$ —	$ —	5,338	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 2022 USB revenues and activities.					
14	COVID-19 resulted in activities planned for 2022 being postponed and					
15	funds carried forward to 2023 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	$ 618,090	$ —	$ 618,090	8,330	2012