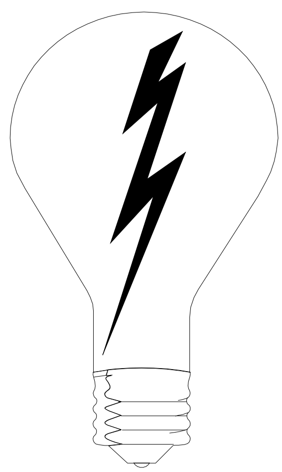
YEAR ENDING 2023

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY

Docket 2024.01.001



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

Electric Annual Report

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

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

Respondent is a wholly-owned, direct subsidiary of NorthWestern Energy Group, Inc. At December 31, 2023, NorthWestern Energy Group, Inc. owned 100% of the common stock of respondent.

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See NorthWestern Corporation's Annual Report FERC Form 1 page 105 for our	
3	Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1			
2	President and Chief Executive Officer	Executive	Brian Bird
3			
4	Vice President,	Legal Services	Shannon Heim
5	General Counsel and Federal	Corporate Secretary	
6	Government Affairs	Risk Management	
7		Contracts	
8		Federal Governmental Affairs	
9			
10	Vice President,	Regulatory Affairs	Cyndee Fang
11	Regulatory Affairs	DSM and Energy Efficiency	
12		Sustainability	
13		Governmental Affairs - Nebraska and South Dakota	
14			
15	Vice President,	Asset and Project Management	Bleau LaFave
16	Asset Management & Business Development	Business Development and Strategic Support	
17			
18	Vice President,	Distribution Operations - MT/SD/NE	Jason Merkel
19	Distribution	Construction	
20			
21	Vice President,	Transmission Planning, Engineering, Construction,	Michael Cashell
22	Transmission	and Operations	
23		Gas Transmission & Storage	
24		Substation Operations	
25		Transmission Policy, Services, and Operations	
26		Transmission Market Strategy	
27		Grid Real Time and Scada Operations	
28		FERC and NERC Compliance	
29		Support Services	
30			
31	Vice President,	Thermal and Wind Generation	John Hines
32	Supply and Montana Government Affairs	Hydro Operations	
33		Environmental and Lands Permitting & Compliance	
34		Long Term Resources	
35		Energy Supply Marketing Operations	
36		Montana Government Affairs	
37			
38		Brand, Advertising, and	Bobbi Schroeppel
39	Vice President,	Customer Communications	
40	Customer Care, Communications and	Customer Experience and Support	
41	Human Resources	Customer Interaction	
42		Community Connections	
43		Revenue Cycle Management	
44		Human Resources	
45		Safety/Health/Environmental Services	
46			
47	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
48		Enterprise Risk and Business Continuity	
49			
50	Vice President & Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
51		Financial Planning & Analysis	
52		Controller and Treasury Functions	
53		Investory Relations and Corporate Finance	
54		Flight Services	
55			
56	Vice President, Technology	Business Technology	Jeanne Vold
57		Customer Systems & Solutions	
58		Data & Analytics	
59		Operation Technology	
60		Security	
61			
	Reflects active officers as of December 31, 2023		

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 190,369**	**98.06%**
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		**$ 3,763**	**1.94%**
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, In	Non-regulated customer services		
Total Corporation		**$ 194,132**	**100.00%**

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Executive Department	Includes the following departments: CEO and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	4,957,856	77.87%	1,409,104
Legal Department	Includes the following departments: Chief Legal and Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	20,037,127	79.39%	5,201,808
Regulatory Affairs	Includes the following departments: Regulatory Affairs MT, SD & NE Public and Regulatory Affairs and Regulatory Support	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	1,885,733	73.82%	668,657
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	17,730,875	79.84%	4,477,065
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting & Regulatory Affairs Finance	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$5,321,177	80.01%	$1,329,365
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	1,034,150	79.00%	274,901
Business Technology	Includes the following departments: Applications, Architecture, Governance	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	21,594,629	79.03%	5,728,518
Distribution	Includes the following departments: Sioux Falls Facilities and Helena Building	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	80,620	65.80%	41,911
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, CC - Assoc & Dispatch, Business Develop Human Resources, Print Services and Charitable Contributions	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	25,453,138	74.82%	8,567,935
TOTAL			$98,095,303	77.98%	$27,699,263

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,	2,608,256		
13		transmission, & compression	transmission & compression			
14			are at tariffed rates			
15	**Total Utility Subsidiaries Revenues**			$2,608,256		
16	**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	13.4%	500,400
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,283,172	34.4%	$1,283,172
15						
16	**Total Utility Subsidiaries**			1,783,572		$1,783,572
17	**Total Utility Subsidiaries Expenses**			$3,733,451		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,783,572		$1,783,572

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 1,282,105,235	$ 187,729,685	$ 1,094,375,550	$ 933,152,758	17.28%
3						
4	**Total Operating Revenues**	1,282,105,235	187,729,685	1,094,375,550	933,152,758	17.28%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	646,055,016	95,076,898	550,978,118	444,341,970	24.00%
9	402 Maintenance Expense	47,406,239	10,533,079	36,873,160	39,375,949	-6.36%
10	403 Depreciation Expense	160,101,517	33,169,886	126,931,631	119,423,525	6.29%
11	404-405 Amort. of Electric Plant	9,619,264	1,443,726	8,175,538	5,929,330	37.88%
12	406 Amort. of Plant Acquisition Adj.	10,249,919	1,200,394	9,049,525	9,049,525	0.00%
13	407.3 Regulatory Amortizations - Debit	53,116,240	2,107,503	51,008,737	15,640,466	226.13%
14	407.4 Regulatory Amortizations - Credit	(25,928,597)	(1,458,429)	(24,470,168)	(27,892,497)	12.27%
15	408.1 Taxes Other Than Income Taxes	126,571,887	5,586,394	120,985,493	149,467,686	-19.06%
16	409.1 Income Taxes - Federal	1,629,962	1,812,154	(182,193)	(367,187)	50.38%
17	- Other	(390,930)	209,252	(600,182)	246,071	>-300.00%
18	410.1 Deferred Income Taxes-Dr.	219,290,850	41,280,751	178,010,098	74,332,445	139.48%
19	411.1 Deferred Income Taxes-Cr.	(210,627,440)	(48,543,410)	(162,084,029)	(70,499,723)	-129.91%
20	411.4 Investment Tax Credit Adj.	(129,482)	-	(129,482)	(129,482)	0.00%
21	411.6 Gain from Disposition of Property	-	-	-	—	-
22	411.7 Loss from Disposition of Property	-	-	-	—	-
23	411.8 SO2 Allowances	-	-	-	—	-
24						
25	**Total Operating Expenses**	1,036,964,444	142,418,198	894,546,246	758,918,078	17.87%
26	**NET OPERATING INCOME**	$ 245,140,790	$ 45,311,486	$ 199,829,304	$ 174,234,680	14.69%

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, 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 and the adjustment to a regulated basis for Colstrip Unit 4.

Sch. 9	MONTANA REVENUES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 476,229,860	$ 68,146,253	$ 408,083,607	$ 356,192,072	14.57%
5	442 Commercial	534,550,547	$ 108,666,399	425,884,148	363,006,690	17.32%
6	Industrial	57,856,955	$ -	57,856,955	52,696,221	9.79%
7	444 Public Street, Highway Lighting	-	$ -	-	-	0.00%
8	& Other Sales to Public Authorities	19,824,855	$ 2,730,925	17,093,930	14,388,533	18.80%
9	448 Interdepartmental Sales	1,031,286	$ -	1,031,286	879,131	17.31%
10						
11	**Total Sales to Ultimate Consumers**	1,089,493,503	179,543,577	909,949,925	787,162,647	15.60%
12	447 Sales for Resale	86,727,064	$ -	86,727,064	51,420,884	68.66%
13						
14	**Total Sales of Electricity**	1,176,220,566	179,543,577	996,676,989	838,583,531	18.85%
15	449.1 Provision for Rate Refunds	(9,378)	$ (9,378)	-	1,979,898	-100.00%
16		-	$ -	-	-	
17	**Total Revenue Net of Rate Refunds**	1,176,211,189	179,534,200	996,676,989	840,563,429	18.57%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	409,477	$ 409,477	-	-	-
21	451 Miscellaneous Service Revenue	191,471	$ 199,636	(8,165)	(2,835)	-188.02%
22	453 Sales of Water & Water Power	-	$ -	-	-	-
23	454 Rent From Electric Property	4,853,208	$ 324,215	4,528,992	4,148,415	9.17%
24	456 Other Electric Revenues	100,439,891	$ 7,262,156	93,177,734	88,443,749	5.35%
25						
26	**Total Other Operating Revenue**	105,894,046	8,195,485	97,698,561	92,589,329	5.52%
27	**TOTAL OPERATING REVENUE**	$ 1,282,105,235	$ 187,729,685	$ 1,094,375,550	$ 933,152,758	17.28%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2						
3	**Steam Power Generation-Operation**					
4	500 Supervision & Engineering	782,804	729,331	53,473	51,012	4.82%
5	501 Fuel	54,222,808	18,054,713	36,168,095	34,302,960	5.44%
6	502 Steam Expenses	2,770,956	1,376,881	1,394,076	1,438,024	-3.06%
7	503 Steam from Other Sources	-	-	-	-	-
8	505 Electric Plant	966,678	563,485	403,193	536,049	-24.78%
9	506 Miscellaneous Steam Power	4,187,054	1,347,952	2,839,102	2,379,298	19.33%
10	507 Rents	29,911	29,911	-	-	-
11	**Total Operation-Steam Power Gen.**	62,960,211	22,102,273	40,857,939	38,707,343	5.56%
12	**Steam Power Generation-Maintenance**	-	-	-	-	
13	510 Supervision & Engineering	896,280	625,842	270,438	521,165	-48.11%
14	511 Structures	1,062,779	328,576	734,202	727,634	0.90%
15	512 Steam Boiler Plant	7,299,279	2,325,108	4,974,170	4,289,231	15.97%
16	513 Electric Plant	1,513,816	981,820	531,996	685,935	-22.44%
17	514 Miscellaneous Steam Plant	1,035,120	556,304	478,815	398,284	20.22%
18	**Total Maintenance-Steam Power Gen.**	11,807,274	4,817,652	6,989,622	6,622,249	5.55%
19	**Total Steam Power Generation**	74,767,485	26,919,924	47,847,561	45,329,592	5.55%
20	**Hydro Power Generation-Operation**					
21	535 Supervision & Engineering	773,199	-	773,199	678,516	13.95%
22	536 Water for Power	1,010,210	-	1,010,210	949,611	6.38%
23	537 Hydraulic Expenses	3,726,277	-	3,726,277	3,654,685	1.96%
24	538 Electric Expenses	3,430,921	-	3,430,921	3,662,440	-6.32%
25	539 Miscellaneous Hydraulic Power	3,025,811	-	3,025,811	2,903,753	4.20%
26	540 Rents	824,957	-	824,957	808,039	2.09%
27	**Total Operation-Hydro Power Gen.**	12,791,375	-	12,791,375	12,657,044	1.06%
28	**Hydro Power Generation-Maintenance**					
29	541 Supervision & Engineering	650,985	-	650,985	560,468	16.15%
30	542 Structures	507,445	-	507,445	715,688	-29.10%
31	543 Reservoirs, Dams & Waterways	151,023	-	151,023	612,490	-75.34%
32	544 Electric Plant	1,036,087	-	1,036,087	1,228,566	-15.67%
33	545 Miscellaneous Hydro Plant	211,995	-	211,995	215,885	-1.80%
34	**Total Maintenance-Hydro Power Gen.**	2,557,535	-	2,557,535	3,333,097	-23.27%
35	**Total Hydraulic Power Generation**	15,348,910	-	15,348,910	15,990,141	-4.01%
36	**Other Power Generation-Operation**					
37	546 Supervision & Engineering	619,601	133,892	485,709	437,140	11.11%
38	547 Fuel	25,955,883	5,504,592	20,451,291	26,102,343	-21.65%
39	548 Generation Expenses	8,666,896	4,772,146	3,894,750	3,801,867	2.44%
40	549 Miscellaneous Other Power	1,302,761	512,065	790,697	1,808,099	-56.27%
41	550 Rents	-	-	-	-	-
42	**Total Operation-Other Power Gen.**	36,545,141	10,922,693	25,622,447	32,149,449	-20.30%
43	**Other Power Generation-Maintenance**					
44	551 Supervision & Engineering	63,598	63,598	-	-	-
45	552 Structures	105,114	105,114	-	1,130	-100.00%
46	553 Generating & Electric Plant	2,545,958	1,245,086	1,300,873	1,609,735	-19.19%
47	554 Miscellaneous Other Power Plant	147,267	53,704	93,563	60,392	54.93%
48	**Total Maintenance-Other Power Gen.**	2,861,938	1,467,502	1,394,436	1,671,257	-16.56%
49	**Total Other Power Generation**	39,407,078	12,390,196	27,016,883	33,820,706	-20.12%
50	**Other Power Supply Expenses**					
51	555 Purchased Power	281,449,711	17,117,597	264,332,114	274,045,809	-3.54%
52	556 System Control & Load Dispatch	348,013	348,013	-	-	-
53	557 Other Expenses	67,814,770	4,903,905	62,910,866	(47,735,182)	231.79%
54	**Total Other Power Supply Expenses**	349,612,494	22,369,515	327,242,980	226,310,627	44.60%
55	**Total Power Production Expenses**	479,135,968	61,679,634	417,456,333	321,451,066	29.87%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	This Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	3,061,390	184,127	2,877,263	2,464,420	16.75%
6	561 Load Dispatching	65,111	65,111	-	-	-
7	561.1 Load Dispatch - Reliability	920,115	-	920,115	936,249	-1.72%
8	561.2 Load Disp-Monitor/Op	878,169	-	878,169	965,381	-9.03%
9	561.3 Load Disp-Srv/Schedu	1,149,993	3,000	1,146,993	1,354,193	-15.30%
10	561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
11	561.5 Reliab, Plan, Stds	105,401	105,401	-	-	-
12	561.6 Transmission Service Studies	-	-	-	-	-
13	561.8 Sch,Sys&Ctrl Srv-RTO	-	-	-	-	-
14	562 Station Expenses	2,085,130	191,865	1,893,265	1,285,180	47.32%
15	563 Overhead Lines	962,080	256,363	705,716	1,038,394	-32.04%
16	564 Underground Lines	-	-	-	-	-
17	565 Transmission of Elec. by Others	25,984,742	19,298,804	6,685,938	6,570,785	1.75%
18	566 Miscellaneous Transmission	235,553	73,602	161,951	153,589	5.44%
19	567 Rents	1,050,206	17,294	1,032,912	1,076,543	-4.05%
20	**Total Operation-Transmission**	36,497,891	20,195,568	16,302,323	15,844,734	2.89%
21	**Transmission-Maintenance**	-	-	-	-	
22	568 Supervision & Engineering	571,893	93,684	478,209	517,276	-7.55%
23	569 Structures	35,350	14,641	20,709	48,248	-57.08%
24	569.1 Maintenance of Computer Hardware	1,312,307	-	1,312,307	1,442,191	-9.01%
25	569.2 Maintenance of Computer Software	13,110	-	13,110	2,874	>300.00%
26	569.3 Maint-Comm Equip	-	-	-	-	-
27	570 Station Equipment	692,016	18,060	673,956	656,901	2.60%
28	571 Overhead Lines	3,092,463	546,715	2,545,748	3,077,918	-17.29%
29	572 Underground Lines	188	188	-	-	-
30	573 Miscellaneous Transmission Plant	-	-	-	-	-
31	**Total Maintenance-Transmission**	5,717,328	673,289	5,044,039	5,745,408	-12.21%
32	**Total Transmission Expenses**	42,215,219	20,868,857	21,346,362	21,590,142	-1.13%
33		-	-	-	-	
34	**Regional Market Operation**	-	-	-	-	
35	575.1 Operation Supervision	-	-	-	-	-
36	575.2 Day-Ahead & Real-time Admin	388,799	388,799	-	-	-
37	575.3 Transmision Rights Mkt Admin	-	-	-	-	-
38	575.5 Ancillary Services Mkt Admin	111,085	111,085	-	-	-
39	575.6 Market Monitoring & Complaince	55,543	55,543	-	-	-
40	**Total Operation-Regional Market**	555,427	555,427	-	-	-
41		-	-	-	-	
42	**Distribution Expenses**	-	-	-	-	
43		-	-	-	-	
44	**Distribution-Operation**	-	-	-	-	
45	580 Supervision & Engineering	3,879,920	541,194	3,338,726	3,116,473	7.13%
46	581 Load Dispatching	-	-	-	-	-
47	582 Station Expenses	1,623,216	254,352	1,368,864	1,282,752	6.71%
48	583 Overhead Lines	2,265,267	446,276	1,818,991	1,740,040	4.54%
49	584 Underground Lines	2,912,074	567,519	2,344,555	2,164,410	8.32%
50	585 Street Lighting & Signal Systems	111,930	43,509	68,421	113,329	-39.63%
51	586 Meters	2,171,112	336,539	1,834,572	1,903,365	-3.61%
52	587 Customer Installations	1,812,434	179,182	1,633,252	1,716,955	-4.88%
53	588 Miscellaneous Distribution	3,462,625	971,194	2,491,431	2,391,164	4.19%
54	589 Rents	72,610	-	72,610	81,788	-11.22%
55	**Total Operation-Distribution**	18,311,189	3,339,765	14,971,423	14,510,276	3.18%
56	**Distribution-Maintenance**					
57	590 Supervision & Engineering	1,527,311	264,129	1,263,181	1,421,699	-11.15%
58	591 Structures	19,450	-	19,450	28,996	-32.92%
59	592 Station Equipment	607,353	144,845	462,508	460,435	0.45%
60	593 Overhead Lines	13,924,384	1,825,598	12,098,786	13,186,508	-8.25%
61	594 Underground Lines	1,579,984	223,679	1,356,305	1,330,094	1.97%
62	595 Line Transformers	81,150	40,283	40,867	47,053	-13.15%
63	596 Street Lighting, Signal Systems	592,961	197,333	395,628	365,502	8.24%
64	597 Meters	1,411,122	214,577	1,196,545	1,316,921	-9.14%
65	598 Miscellaneous Distribution Plant	19,443	19,443	-	-	-
66	**Total Maintenance-Distribution**	19,763,159	2,929,888	16,833,271	18,157,208	-7.29%
67	**Total Distribution Expenses**	38,074,348	6,269,653	31,804,695	32,667,484	-2.64%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	This Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	1,279,878	54,898	1,224,981	1,254,015	-2.32%
7	903 Customer Records & Collection	8,586,693	1,125,435	7,461,259	6,705,345	11.27%
8	904 Uncollectible Accounts	2,493,740	253,530	2,240,210	1,300,105	72.31%
9	905 Miscellaneous Customer Accts.	53,055	53,055	-	(21)	100.00%
10	**Total Customer Accounts Expenses**	12,413,367	1,486,917	10,926,450	9,259,444	18.00%
11		-	-	-	-	
12	**Customer Service & Information**	-	-	-	-	
13		-	-	-	-	
14	**Customer Service-Operation**	-	-	-	-	
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	3,705,679	1,036,718	2,668,960	2,451,957	8.85%
17	909 Inform. & Instruct. Advertising	1,004,139	141,152	862,987	978,485	-11.80%
18	910 Misc. Customer Service & Info.	117,112	117,112	-	-	-
19	**Total Customer Service & Info. Expense**	4,826,930	1,294,983	3,531,947	3,430,442	2.96%
20		-	-	-	-	-
21	**Sales Expenses**	-	-	-	-	
22		-	-	-	-	
23	**Sales-Operation**	-	-	-	-	
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling	-	-	-	-	-
26	913 Advertising	779,851	130,928	648,924	1,052,442	-38.34%
27	916 Miscellaneous Sales	-	-	-	-	-
28	**Total Sales Expenses**	779,851	130,928	648,924	1,052,442	-38.34%
29		-	-	-	-	-
30	**Administrative & General Expenses**	-	-	-	-	
31		-	-	-	-	
32	**Admin. & General-Operation**	-	-	-	-	
33	920 Admin. & General Salaries	31,799,186	3,951,451	27,847,734	27,611,918	0.85%
34	921 Office Supplies & Expenses	15,931,937	2,383,918	13,548,019	12,554,772	7.91%
35	922 Admin. Expense Transferred-Cr.	(8,260,152)	(1,317,261)	(6,942,891)	(6,501,365)	-6.79%
36	923 Outside Services Employed	7,949,210	1,015,118	6,934,092	7,351,747	-5.68%
37	924 Property Insurance	4,826,842	398,193	4,428,650	2,868,436	54.39%
38	925 Injuries & Damages	12,500,705	1,974,553	10,526,152	9,185,182	14.60%
39	926 Employee Pensions & Benefits	25,787,597	3,399,640	22,387,957	19,034,271	17.62%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	3,686,267	(41,555)	3,727,822	3,238,766	15.10%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	15,746,600	763,441	14,983,158	14,164,918	5.78%
44	931 Rents	792,948	151,332	641,617	911,524	-29.61%
45	**Total Operation-Admin. & General**	110,761,140	12,678,830	98,082,310	90,420,169	8.47%
46	**Admin. & General-Maintenance**	-	-	-	-	
47	935 General Plant	4,699,006	644,749	4,054,257	3,846,730	5.39%
48	**Total Maintenance-Admin. & General**	4,699,006	644,749	4,054,257	3,846,730	5.39%
49	**Total Admin. & General Expenses**	115,460,146	13,323,578	102,136,568	94,266,899	8.35%
50	**TOTAL OPER. & MAINT. EXPENSES**	693,461,255	105,609,977	587,851,278	483,717,919	21.53%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	5,521,538	5,228,191	5.61%
3	Property Taxes	109,588,956	139,115,910	-21.22%
4	Electric Energy License Tax	965,734	885,727	9.03%
5	Crow Tribe RR and Utility Tax	84,948	84,948	0.00%
6	Fort Peck	0	-	-
7	City Tax	0	0	-
8	Consumer Counsel Tax	457,957	419,610	9.14%
9	Public Service Commission Tax	2,042,106	1,430,006	42.80%
10	Heavy Highway Use Tax	1,304	11,224	-88.38%
11	Vehicle Use Tax	0	0	-
12	Wholesale Energy Transaction Tax	1,439,774	1,426,403	0.94%
13	Delaware Franchise Tax	152,668	152,668	0.00%
14	Invasive Species	730,508	712,999	2.46%
15				
16				
17				
18	**TOTAL TAXES OTHER THAN INCOME**	$120,985,493	$149,467,686	-19.06%
19				
20				

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	318,297
2	AFFCO INC	Hydro Construction Services	1,698,287
3	AMERICAN INNOVATIONS INC	Software Support Services	102,519
4	ANDRITZ HYDRO CORP	Hydro Upgrade Services	4,245,723
5	ARCADIS US INC	Engineering Services	349,549
6	ARCOS LLC	Call-out Services	163,709
7	ASCEND ANALYTICS LLC	Hydro Expert Analysis	403,149
8	ASPLUNDH TREE EXPERT LLC	Tree Trimming	5,875,054
9	ASSOCIATED UNDERWATER SERVICE	Inspection Services	244,143
10	AUTOMOTIVE RENTALS INC	Fleet Management	4,269,074
11	AVEVA SOFTWARE, LLC	Computer Support Services	221,569
12	BART ENGINEERING COMPANY	Engineering Services	568,520
13	BASELOAD POWER GENERATION PARTS Total	Engineering Services	350,129
14	BEACON COMMUNICATIONS LLC	Software Maintenance	480,851
15	BIG HORN WIRELINE, LLC Total	Storage	180,135
16	BILLINGS FLYING SERVICE, INC.	Powerline Services	87,779
17	BISON ENGINEERING INC	Engineering Services	102,383
18	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	2,779,111
19	BRY ENTERPRISE Total	Road Bore Services	110,816
20	BURK EXCAVATION AND UTILITIES	Construction	2,966,219
21	CATERPILLAR POWER GENERATION	Generation Services	46,387,003
22	CENTRON SERVICES INC	Customer Collection service	90,233
23	CHARLOTTE ST. ADVISORS, LLC Total	Tactical Planning Prof Services	788,153
24	CHAZNLINE, LLC Total	Heavy Haul Services	1,239,313
25	CN UTILITY CONSULTING INC	Utility Consulting Services	634,360
26	CONTINENTAL STEEL WORKS	Fabrication Services	421,892
27	CRIST, KROGH, BUTLER & NORD L	Legal Services	352,616
28	CROWLEY FLECK PLLP	Legal Services	203,778
29	CTA INC.	Energy Conservation Consultants	650,194
30	DAVEY TREE SURGERY COMPANY	Tree Trimming	4,611,717
31	DELOITTE & TOUCHE LLP	Audit Services	449,181
32	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	1,815,351
33	DIETZEL ENTERPRISES INC	Construction	420,288
34	DJ&A P C CONSULTING ENGINEER	Surveying Services	235,949
35	DNV ENERGY SERVICES USA INC Total	Commercial Lighting program	5,002,063
36	DOBLE ENGINEERING CO	Maintenance Service	88,223
37	DORSEY & WHITNEY LLP	Legal Services	796,708
38	DOWL HKM	Geotechnical Services	171,525
39	E SOURCE COMPANIES LLC	Consulting Services	92,228
40	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	4,165,345
41	ENERGY CONTRACT SERVICES LLC	Inspection Services	2,272,846
42	ENERGY SHARE OF MONTANA	USBC Services	677,083
43	EVERGREEN CAISSONS INC	Construction	128,380
44	FAGEN, INC	Construction	2,500,000
45	FITCH RATINGS INC Total	Annual Credit Ratings	114,454
46	FLYNN WRIGHT INC	Advertising Services	1,870,861
47	FOOTHILLS RIG SERVICE	Well Services	87,600
48	GARTNER INC	Information Technology Consulting	192,078
49	GE ENERGY MANAGEMENT SERVICES, LLC Total	E-Terra Source Upgrade Assist	499,427
50	GEI CONSULTANTS INC	Environmental Consultants	560,709
51	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	3,032,717
52	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	179,918
53	GREGG ENGINEERING	Informational Technology Simulation	108,295
54	GUY TABACCO CONSTRUCTION	Construction	166,917
55	H & H ASPHALT & MAINTENANCE L	Asphalt Services	250,268
56	H & H CONTRACTING INC	Concrete and Asphalt Services	397,140
57	H2E INC	Engineering Services	827,639
58	HDR ENGINEERING INC	Engineering Services	5,681,072
59	HEATH CONSULTANTS INC	Gas Leak Surveys	750,837

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	
60	HIGHMARK MEDIA	Safety Training	116,400
61	HITACHI ENERGY USA INC Total	Engineering Consulting	395,671
62	INTEC SERVICES INC	Pole Inspection Services	2,069,372
63	ITRON INC	Meter Installation	16,806,206
64	J D POWER AND ASSOCIATES	Energy Study	92,030
65	J2 BUSINESS PRODUCTS	Copier Maintenance	334,786
66	JARES FENCE COMPANY INC	Fence Materials/Installation	220,133
67	JEFFERY CONTRACTING LLC	Construction	498,514
68	K & K ROOFING AND EXCAVATION INC Total	Roofing and Insulation	108,586
69	KARV LLC	Boring Services	99,551
70	KELLERMEYER BERGENSONS SERVICES LLC Total	Cleaning Services	199,538
71	KM CONSTRUCTION CO INC	Construction	182,512
72	KNIFE RIVER	Construction	84,749
73	LEARJET INC	Repair Services	255,104
74	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	374,669
75	M&D CONSTRUCTION INC	Construction	222,291
76	MCMILLEN LLC	Design Services	7,236,252
77	MERCER HUMAN RESOURCE CONSULT	HR Consulting	171,621
78	MERKEL ENGINEERING INC	Consulting Services	5,612,050
79	MICHAELS FENCE & SUPPLY CO	Installation Services	218,309
80	MICHELS CORPORATION	Construction	16,279,933
81	MIDCON UNDERGROUND CONSTRUCTI	Construction	675,629
82	MINUTEMAN AVIATION INC.	Helicopter Charter Services	296,727
83	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	755,038
84	MOODY'S INVESTORS SERVICE	Debt Rating Services	108,495
85	MORRISON MAIERLE INC	Engineering Services	417,583
86	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	21,991,025
87	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	628,650
88	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	321,800
89	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,896
90	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	764,128
91	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	5,178,084
92	PINNACLE RESEARCH & CONSULTING	Consulting Services	329,414
93	POTEET CONSTRUCTION	Traffic Safety Services	147,721
94	POTELCO INC	Electric Construction and Maintenance	9,889,621
95	POWER SETTLEMENTS CONSULTING &	Consulting Services	206,259
96	POWERS HEATING LLC	Meter Installation	106,407
97	PRO PIPE CORPORATION	Welding Services	467,744
98	QUANTA UTILITY ENGINEERING	Engineering Services	9,263,299
99	RIVER DESIGN GROUP INC	Engineering Services	195,076
100	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	25,311,577
101	ROD TABBERT CONSTRUCTION INC	Construction	248,855
102	ROSEN USA INC	Inspection Services	1,583,183
103	SCENIC CITY ENTERPRISES INC	Construction	143,906
104	SCHNABEL ENGINEERING LLC	Consulting Services	519,369
105	SHAW PIPELINE SERVICES INC Total	Pipeline Service Reroute	1,280,998
106	SIDEWINDERS LLC	Generator Repair Services	2,127,551
107	SOLAR TURBINES INC Total	Commissioning New Controls	506,225
108	SPHERION STAFFING	Temporary Labor	109,299
109	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	128,000
110	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,006,728
111	STINSON LEONARD STREET LLP	Legal Services	449,910
112	SULLIVAN BROS. CONSTRUCTION INC Total	Boring Services	188,809
113	SUPERIOR CONCRETE PRODUCTS INC	Construction	84,904
114	TAYLOR SERVICES INC Total	Excavator Services	108,751
115	TBC CONSTRUCTION LLC Total	Pipeline Service Reroute	1,408,036
116	TERRA REMOTE SENSING (USA) INC	Surveying Services	527,308
117	THE MOSAIC COMPANY	Training	814,217
118	THOMPSON HINE LLP	Benefits Audit Services	139,231
119	TIMBERLINE SECURITY & SERVICES	Security Services	368,099
120	TLC SEPTIC SERVICE	Excavation Contractor	276,731
121	TRADEMARK ELECTRIC INC	Construction	770,987
122	TROUTMAN SANDERS LLP	Legal Services	253,982
123	ULTEIG ENGINEERS INC	Project Manager Services	158,050

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	
124	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	1,066,093
125	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	229,570
126	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	286,566
127	VAISALA INC	Wind Forecasting Services	160,149
128	VERTEX	Billing Services and Programming	2,852,016
129	VERTIV CORPORATION	Maintenance Service	138,038
130	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	518,905
131	WATSON TRUCKING OF HAVRE LLC	Hauling Services	134,510
132	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	118,085
133	WILLIS TOWERS WATSON US LLC	Compensation Services	276,774
134	ZACHA UNDERGROUND CONSTRUCTIO	Construction	444,469
	Total of Payments Set Forth Above		**$ 263,775,130**

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

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2				
3	There are three employee political action committees			
4	(PAC)s:			
5				
6	a. NorthWestern Energy Montana Employee PAC for			
7	Montana employees;			
8				
9	b. Employees of NorthWestern Corporation			
10	(NorthWestern Energy) PAC for South Dakota			
11	employees;			
12				
13	c. NorthWestern Public Service Employees PAC for			
14	Nebraska employees.			
15				
16				
17	All of the money contributed by members is			
18	dedicated to support political candidates, state and			
19	local political party organizations, and ballot issues.			
20	No company funds may be spent in support of a			
21	political candidate. Nominal administrative costs			
22	for such things as duplicating, postage, and			
23	meeting expenses are paid by the company as			
24	provided by law. These costs are charged to			
25	shareholder expense.			
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$ -	$ -	0.00%

Sch. 14	**Pension Costs** 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ________________________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 474,947,258	$ 636,271,675	12.13%
8	Service cost	5,104,682	9,469,971	18.21%
9	Interest cost	23,535,206	17,240,996	-17.47%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	2,235,431	(163,649,996)	-133.52%
13	Settlements	(51,942,557)	-	-
14	Benefits paid	(26,554,142)	(24,385,388)	-4.05%
15	Benefit obligation at end of year	$ 427,325,878	$ 474,947,258	-15.99%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 388,693,381	$ 537,871,174	13.43%
18	Actual return on plan assets	29,936,791	(131,792,405)	-63.52%
19	Settlements	(51,942,557)	-	-
20	Employer contribution	8,000,000	7,000,000	-11.78%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(26,554,142)	(24,385,388)	-4.05%
23	Fair value of plan assets at end of year	$ 348,133,473	$ 388,693,381	-13.12%
24	**Funded Status**	$ (79,192,405)	$ (86,253,877)	28.86%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (79,192,405)	$ (86,253,877)	28.86%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.00%	5.20%	19.57%
32	Expected return on plan assets	6.44%	4.26%	-7.13%
33	Rate of compensation increase	4.00% Union & 4.00% Non-Union	4.00% Union & 4.00% Non-Union	0.00%
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 5,104,682	$ 9,469,971	18.21%
36	Interest cost	23,535,206	17,240,996	-17.47%
37	Expected return on plan assets	(23,448,483)	(22,400,489)	-4.07%
38	Settlement (gain) loss recognized	4,394,595	-	-
39	Recognized net actuarial gain	228,222	382,939	30.00%
40	Net periodic benefit cost (SEC Basis)	$ 9,814,222	$ 4,693,417	81.34%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 8,000,000	$ 7,000,000	-11.78%
43	Pension Costs Capitalized	$ 3,791,146	$ 2,032,818	-11.63%
44	Accumulated Pension Asset (Liability) at Year End	$ (79,192,405)	$ (86,253,877)	28.86%
45	Number of Company Employees:			
46	Covered by the Plan 2/	1,355	1,367	-1.65%
47	Not Covered by the Plan 2/	1,073	1,009	11.39%
48	Active	387	451	-7.37%
49	Retired	685	611	0.85%
50	Deferred Vested Terminated 2/	283	305	-4.44%

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

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

Sch. 14a	Pension Costs **1/**			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			0.00%
8	Service cost			0.00%
9	Interest cost			0.00%
10	Plan participants' contributions	Not Applicable		
11	Amendments			0.00%
12	Actuarial loss			0.00%
13	Acquisition			0.00%
14	Benefits paid			0.00%
15	Benefit obligation at end of year	$ -	$ -	0.00%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year			-
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 2/	$ 13,211,496	$ 12,323,206	7.21%
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 2/			-
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			0.00%
26	Unrecognized prior service cost			0.00%
27	Prepaid (accrued) benefit cost	$ -	$ -	0
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
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 10,351,128	$ 9,564,174	8.23%
44	401(k) Plan Defined Contribution Costs Capitalized	$ 2,626,496	$ 2,784,910	-5.69%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,571	1,529	2.75%
48	Not Covered by the Plan		0	0.00%
49	Active - Participating	1,565	1,516	3.23%
50	Retired		0	0.00%
51	Vested Former Employees, Retirees and Active-	424	397	6.80%
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	475,268	($2,120,027)	122.42%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	4.90%	5.20%	-5.77%
8	Expected return on plan assets	5.62%	4.23%	32.86%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate annually	5.00% fixed rate annually	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	4.00% Union & 4.00% Non-Union	4.00% Union & 4.00% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for			

1/ Obtained from NorthWestern Energy-Montana's 2023 FASB 106 Valuation. Assumptions and data are as of December 31, 2023.

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

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	$12,070,609	$14,290,006	7.72%
10	Service cost	272,534	$307,609	11.93%
11	Interest Cost	553,883	$313,259	-35.92%
12	Plan participants' contributions	1,383,742	$1,372,626	13.40%
13	Amendments	-	$0	-
14	Actuarial loss/(gain)	(820,734)	($656,282)	-77.30%
15	Acquisition	-	$0	-
16	Benefits paid	(2,861,901)	($3,556,609)	-22.57%
17	Benefit obligation at end of year	$10,598,133	$12,070,609	-9.39%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$20,055,071	$25,289,024	7.52%
20	Actual return on plan assets	3,334,030	(4,097,998)	23.00%
21	Acquisition	-	-	-
22	Employer contribution	398,221	1,048,028	50.78%
23	Plan participants' contributions	1,383,742	1,372,626	13.40%
24	Benefits paid	(2,861,901)	(3,556,609)	-22.57%
25	Fair value of plan assets at end of year	$22,309,163	$20,055,071	9.50%
26	**Funded Status**	$11,711,030	$7,984,462	50.19%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$11,711,030	$7,984,462	50.19%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$272,534	$307,609	11.93%
33	Interest cost	553,883	313,259	-35.92%
34	Expected return on plan assets	(1,096,381)	(1,046,911)	6.44%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	116,071	(1,986,418)	2.28%
37	Recognized net actuarial loss/(gain)	79,270	-	-
38	Net periodic benefit cost	($74,623)	($2,412,461)	-0.39%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	398,221	1,048,028	50.78%
43	TOTAL	$398,221	$1,048,028	50.78%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	$ -	-
46	Amount that was tax deductible - Other	475,268	$ (2,120,027)	-11.47%
47	TOTAL	$475,268	($2,120,027)	-11.47%
48	**Montana Intrastate Costs:**	-		
49	Pension Costs	$475,268	($2,120,027)	-11.47%
50	Pension Costs Capitalized	$120,833	($622,388)	-11.66%
51	Accumulated Pension Asset (Liability) at Year End	$11,711,030	$7,984,462	50.19%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,151	1,228	-6.02%
54	Not Covered by the Plan	1,655	1,486	2.89%
55	Active	376	432	-7.71%
56	Retired	718	731	-4.43%
57	Spouses/Dependants covered by the Plan	57	65	-10.34%

4/ There are approximately an additional $3,109,816 and $3,336,830 in other company OPEBS liabilities outstanding at December 31, 2023 and 2022, respectively, for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation /3	Total Compensation Reported Last Year	% Increase Total Compensation 4/
1	Michael R. Cashell Vice President, Transmission	324,917	101,374 A	35,547 B 188,078 C 131,237 D 1,413 E	782,566	694,279	12.7%
2	Jason Merkel VP - Distribution	255,008	78,542 A	33,556 B 102,003 C 127,603 D 11,852 E	608,564	382,077	59.3%
3	Jeanne M. Vold Vice President, Technology	266,909	83,276 A	65,292 B 128,750 C 22,755 D 9,285 E	576,267	573,424	0.5%
4	Jeffrey B. Berzina Controller	253,634	59,782 A	57,913 B 71,888 C 25,000 F	468,217	445,029	5.2%
5	Cynthia S. Fang Vice President, Regulatory	244,151	75,460 A	47,803 B 98,000 C	465,414	316,121	47.2%
6	John Kasperick Director, Financial Planning & Analysis	206,242	32,073 A	35,228 B 50,185 C 120,112 D 17,408 E 613 G	461,861	335,162	37.8%
7	Michael L. Nieman Chief Audit & Compliance Officer	259,450	47,853 A	57,344 B 63,358 C 30,421 D	458,426	428,300	7.0%
8	Bleau J. LaFave Vice President, Asset Management & Business Development	231,687	59,294 A	57,376 B 51,500 C 21,630 D 8,913 E	430,401	350,603	22.8%
9	Travis E. Meyer Director, Corporate Development & Investor Relations Officer	222,033	42,636 A	54,114 B 50,745 C 14,966 D 439 E	384,933	331,293	16.2%
10	Timothy P. Olson Counsel Corporate & Corporate Secretary Sr	209,107	40,205 A	52,918 B 50,434 C 6,110 E	358,774	328,575	9.2%

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/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2023 Annual Incentive Compensation Plan. Amounts were earned in 2023 and paid in the first quarter of 2024. Based on company performance against plan, the incentive plan was funded at 77% of target. Salary and incentive in current rate recovery are based on a 2021 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, 2023.

Actual Change in Pension Value

Mike Cashell	131,237
Jason Merkel	127,603
Jeanne Vold	22,755
Jeff Berzina	—
Cynthia Fang	—
John Kasperick	120,112
Michael Nieman	30,421
Bleau LaFave	21,630
Travis Meyer	14,966
Timothy Olson	—

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

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	Brian B. Bird President & Chief Executive Officer	794,519	616,000	A	62,688 1,600,000 34,619 2,776	B C D F	3,110,602	2,674,787	16.3%
2	Crystal D. Lail Vice President & Chief Financial Officer	457,716	237,425	A	55,078 474,375 23,479 6,396 2,776	B C D E F	1,257,244	1,182,035	6.4%
3	John D. Hines Vice President, Supply & Montana Government Affairs	326,553	101,758	A	35,989 189,694 123,663 6,384	B C D E	784,041	704,356	11.3%
4	Shannon M. Heim General Counsel & Vice President, Federal Government Affairs	347,369	121,275	A	58,277 227,500 13,524 2,165	B C E G	770,110	321,180	139.8%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications, & Human Resources	325,187	101,333	A	65,766 188,900 33,634 20,763	B C D E	735,583	727,633	1.1%

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 2023 Annual Incentive Compensation Plan. Amounts were earned in 2023 and paid in the first quarter of 2024. Based on company performance against plan, the incentive plan was funded at 77% of target. Salary and incentive in current rate recovery are based on a 2021 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, 2023.

Actual Change in Pension Value

Brian Bird	34,619
Crystal Lail	23,479
John Hines	123,663
Shannon Heim	—
Bobbi Schroeppel	33,634

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-taxable tuition reimbursment

3/ Stock-based compensation is paid by shareholders.

Recovery of non-stock-based compensation is based on 2021 ("test year") costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff. There is no specific recovery of these or most other expenses.

Shareholders vote on executive compensation, and have consistently approved at above 96%, most recently 98.8%.

Our Chief Executive Officer's compensation is 75% 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	$7,585,573,447	$7,193,730,425	$391,843,022	5.45%
4	101.1 Property Under Capital Leases	41,127,257	41,504,922	(377,665)	-0.91%
5	103 Experimental Electric Plant Unclassified	4,798,750	4,244,173	554,577	13.07%
6	105 Plant Held for Future Use	4,140,227	4,327,381	(187,154)	-4.32%
7	107 Construction Work in Progress	358,401,452	300,649,215	$57,752,237	19.21%
8	108 Accumulated Depreciation Reserve	(2,675,309,658)	(2,600,452,294)	($74,857,363)	2.88%
9	108.1 Accumulated Depreciation - Capital Leases	(35,183,325)	(33,172,848)	($2,010,477)	6.06%
10	111 Accumulated Amortization & Depletion Reserves	(106,740,672)	(100,549,894)	($6,190,778)	6.16%
11	114 Electric Plant Acquisition Adjustments	481,574,396	481,574,396	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(92,378,300)	(82,128,381)	(10,249,919)	12.48%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	36,212,426	36,209,611	2,815	0.01%
15	**Total Utility Plant**	5,959,801,527	5,603,522,232	356,279,296	6.36%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(67,635)	(65,534)	(2,102)	3.21%
19	123.1 Investments in Assoc Companies and Subsidiaries	(97,949,544)	(109,534,834)	11,585,290	-10.58%
20	124 Other Investments	13,050,811	21,035,719	(7,984,908)	-37.96%
21	128 Miscellaneous Special Funds	-	-	-	-
22	LT Portion of Derivative Assets - Hedges	-	-	-	-
23	**Total Other Property & Investments**	(84,279,563)	(87,877,843)	3,598,280	-4.09%
24	**Current and Accrued Assets**				
25	131 Cash	8,763,190	8,069,935	693,256	8.59%
26	134 Other Special Deposits	14,856,653	12,761,965	2,094,688	16.41%
27	135 Working Funds	22,850	23,450	(600)	-2.56%
28	142 Customer Accounts Receivable	91,004,511	106,890,491	(15,885,979)	-14.86%
29	143 Other Accounts Receivable	17,049,224	26,793,906	(9,744,683)	-36.37%
30	144 Accumulated Provision for Uncollectible Accounts	(2,813,090)	(2,451,237)	(361,854)	14.76%
31	146 Accounts Receivable-Associated Companies	39,498,557	32,854,005	6,644,552	20.22%
32	151 Fuel Stock	9,710,818	7,724,941	1,985,877	25.71%
33	154 Plant Materials and Operating Supplies	85,254,493	71,154,248	14,100,245	19.82%
34	164 Gas Stored - Current	18,814,211	27,722,831	(8,908,620)	-32.13%
35	165 Prepayments	21,740,289	23,739,745	(1,999,456)	-8.42%
36	172 Rents Receivable	73,787	213,473	(139,686)	-65.43%
37	173 Accrued Utility Revenues	105,109,956	117,418,484	(12,308,528)	-10.48%
38	174 Miscellaneous Current & Accrued Assets	876,037	2,372,751	(1,496,714)	-63.08%
39	**Total Current & Accrued Assets**	409,961,486	435,288,987	(25,327,501)	-5.82%
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	11,096,631	9,254,937	1,841,693	19.90%
42	182 Regulatory Assets	746,025,553	729,084,376	16,941,177	2.32%
43	183 Preliminary Survey and Investigation Charges	376,264	-	376,264	100.00%
44	184 Clearing Accounts	(2,521)	37,192	(39,713)	-106.78%
45	186 Miscellaneous Deferred Debits	11,117,717	9,558,916	1,558,801	16.31%
46	189 Unamortized Loss on Reacquired Debt	20,027,942	22,619,741	(2,591,799)	-11.46%
47	190 Accumulated Deferred Income Taxes	289,883,014	163,943,624	125,939,390	76.82%
48	191 Unrecovered Purchased Gas Costs	3,394,843	100,874,939	(97,480,096)	-96.63%
49	**Total Deferred Debits**	1,081,919,443	1,035,373,726	46,545,717	4.50%
50	**TOTAL ASSETS and OTHER DEBITS**	$ 7,367,402,893	$ 6,986,307,102	$ 381,095,792	5.45%

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	$ 1	$ 632,783	$ (632,782)	-100.00%
4	211 Miscellaneous Paid-In Capital	1,981,122,792	1,999,375,991	(18,253,199)	-0.91%
5	216 Unappropriated Retained Earnings	809,312,954	769,270,841	40,042,113	5.21%
6	217 Reacquired Capital Stock	-	(98,392,040)	98,392,040	-100.00%
7	219 Accumulated Other Comprehensive Income	(5,513,000)	(5,705,664)	192,664	-3.38%
8	**Total Proprietary Capital**	2,784,922,747	2,665,181,911	119,740,836	4.49%
9	**Long Term Debt**				
10	221 Bonds	2,479,660,000	2,179,660,000	300,000,000	13.76%
11	224 Other Long Term Debt	318,000,000	450,000,000	(132,000,000)	-29.33%
12	226 (Less) Unamortized Discount on Long Term Debt-Debit	6,538	33,056	(26,517)	-80.22%
13	**Total Long Term Debt**	2,797,653,462	2,629,626,944	168,026,517	6.39%
14	**Other Noncurrent Liabilities**				
15	227 Obligations Under Capital Leases-Noncurrent	5,996,448	9,389,857	(3,393,410)	-36.14%
16	228.2 Accumulated Provision for Injuries and Damages	6,745,658	4,365,711	2,379,947	54.51%
17	228.3 Accumulated Provision for Pensions and Benefits	4,631,028	10,546,632	(5,915,604)	-56.09%
18	228.4 Accumulated Miscellaneous Operating Provisions	50,272,082	72,588,961	(22,316,880)	-30.74%
19	230 Asset Retirement Obligations	41,424,213	40,893,877	530,336	1.30%
20	**Total Other Noncurrent Liabilities**	109,069,428	137,785,039	(28,715,610)	-20.84%
21	**Current and Accrued Liabilities**				
22	231 Notes Payable	-	92,403	(92,403)	-100.00%
23	232 Accounts Payable	131,709,370	214,538,889	(82,829,519)	-38.61%
24	234 Accounts Payable to Associated Companies	2,288,407	(1,884,037)	4,172,444	-221.46%
25	235 Customer Deposits	11,954,099	10,853,645	1,100,455	10.14%
26	236 Taxes Accrued	75,980,842	90,471,745	(14,490,902)	-16.02%
27	237 Interest Accrued	24,775,303	18,349,945	6,425,357	35.02%
28	241 Tax Collections Payable	1,789,013	2,441,695	(652,682)	-26.73%
29	242 Miscellaneous Current and Accrued Liabilities	73,408,628	72,418,219	990,409	1.37%
30	243 Obligations Under Capital Leases-Current	3,720,377	3,802,179	(81,801)	-2.15%
31	**Total Current and Accrued Liabilities**	325,626,039	411,084,682	(85,458,643)	-20.79%
32	**Deferred Credits**				
33	252 Customer Advances for Construction	107,470,505	95,393,208	12,077,297	12.66%
34	253 Other Deferred Credits	147,334,417	158,152,503	(10,818,086)	-6.84%
35	254 Regulatory Liabilities	190,647,029	171,400,902	19,246,126	11.23%
36	255 Accumulated Deferred Investment Tax Credits	258,964	388,447	(129,482)	-33.33%
37	281-283 Accumulated Deferred Income Taxes	904,420,302	717,293,465	187,126,837	26.09%
38	**Total Deferred Credits**	1,350,131,217	1,142,628,525	207,502,692	18.16%
39	**TOTAL LIABILITIES and OTHER CREDITS**	$ 7,367,402,893	$ 6,986,307,101	$ 381,095,792	5.45%
40					
41	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
42	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
43	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
44	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.				
45					
46					
47					
48					
49					Schedule 18A

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, a wholly owned subsidiary of NorthWestern Energy Group, Inc., doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 775,300 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.

Holding Company Reorganization

On October 2, 2023, NorthWestern Corporation and NorthWestern Energy Group, Inc. completed a merger transaction pursuant to which NorthWestern Energy Group, Inc. became the holding company parent of NorthWestern Corporation. In this reorganization, shareholders of NorthWestern Corporation (the predecessor publicly held parent company) became shareholders of NorthWestern Energy Group, Inc., maintaining the same number of shares and ownership percentage as held in NorthWestern Corporation immediately prior to the reorganization. NorthWestern Corporation became a wholly-owned subsidiary of NorthWestern Energy Group. The transaction was effected pursuant to a merger pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the shareholders of the constituent corporation. As a result of the reorganization, NorthWestern Energy Group, Inc. became the successor issuer to NorthWestern Corporation pursuant to Rule 12g-3(a) of the Securities Exchange Act of 1934, and as a result, NorthWestern Energy Group's common stock was deemed registered under Section 12(b) of the Securities Exchange Act of 1934.

Upon the conversion of all issued and outstanding NorthWestern Corporation common stock into common stock of NorthWestern Energy Group, Inc., as described above, the common stock of NorthWestern Corporation ceased to exist. The accounting for this common stock conversion is treated as a retirement of common stock for NorthWestern Corporation as the shares cease to exist. As such, the amounts included in accounts 201 Common stock and 217 Reacquired capital stock were cleared into account 211 Other paid-in capital. Subsequent to the reorganization, NorthWestern Corporation has 100 shares of common stock issued and outstanding, which are held by NorthWestern Energy Group, Inc.

On January 1, 2024, we completed the second and final phase of the holding company reorganization. NorthWestern Corporation contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation, and then distributed its equity interest in NorthWestern Energy Public Service Corporation and certain other subsidiaries to NorthWestern Energy Group, Inc., resulting in NorthWestern Corporation owning and operating the Montana regulated utility and NorthWestern Energy Public Service Corporation owning and operating the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc.

(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 $523.7 million and $502.2 million as of December 31,2023 and December 31,2022, 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 31,2023 and December 31,2022, 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 31,2023 and December 31,2022, 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 $0.9 million and $1.3 million as of December 31,2023 and December 31,2022, 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 $0.9 million and $1.3 million as of December 31,2023 and December 31,2022, 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 $2.8 million and $2.5 million at December 31, 2023 and December 31, 2022, respectively. Unbilled revenues were $105.1 million and $117.4 million at December 31, 2023 and December 31, 2022, respectively.

Inventories

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

	December 31,	
	2023	2022
Fuel stock	$ 9,711	$ 7,725
Plant materials and operating supplies	85,254	71,154
Gas stored underground (including the non-current portion reflected in utility plant)	55,027	63,933
Total Inventories	$ 149,992	$ 142,812

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, 2023, 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 is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. This rate averaged 6.4% for Montana for 2023 and 2022. This rate averaged 6.4% for South Dakota in 2023 and 2022. AFUDC capitalized totaled $24.3 million and $20.2 million for the years ended December 31, 2023 and 2022, 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 127 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 2023 and 2022.

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

Pension and Postretirement Benefits

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

Income Taxes

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

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

Under the Inflation Reduction Act of 2022 our production tax credits may be transferred to an unrelated entity. Our policy is to account for these transferable credits within income tax expense.

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	
	2023	**2022**
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ (827)	$ 4,707
Interest	105,238	95,400
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	42,322	64,758

The following table provides a reconciliation of cash, working 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,	
	2023	**2022**
Cash	$ 8,763	$ 8,069
Working funds	23	23
Special deposits	14,857	12,762
Total shown in the Statement of Cash Flows	$ 23,643	$ 20,854

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

There were no accounting standards adopted in the current year that had a material impact to our financial condition, results of operations, and cash flows. 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 MPSC under Docket 2022.07.78 requesting an annual increase to electric and natural gas utility rates. On October 27, 2023, the MPSC issued a final order approving the settlement agreement filed April 3, 2023. Final rates, adjusting from interim to settled rates, were effective November 1, 2023. The details of our settlement agreement are set forth below:

Returns, Capital Structure & Revenue Increase Resulting From Approved Settlement Agreement ($ in millions)

	Electric	Natural Gas
Return on Equity (ROE)	9.65%	9.55%
Equity Capital Structure	48.02%	48.02%
Base Rates	$67.4	$14.1
PCCAM[1]	$69.7	n/a
Property Tax (tracker base adjustment)[1]	$14.5	$4.2
Total Revenue Increase Through Approved Settlement Agreement	$151.6	$18.3

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

The approved 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 approved 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.

South Dakota Electric Rate Review

On June 15, 2023, we filed a South Dakota electric rate review filing (2022 test year) under Docket EL23-016 for an annual increase to electric rates totaling approximately $30.9 million. Our request was based on a rate of return of 7.54 percent, a capital structure including 50.5 percent equity, and rate base of $787.3 million. On January 10, 2024, the SDPUC issued a final order approving the settlement agreement between NorthWestern and SDPUC Staff for an annual increase in base rates of approximately $21.5 million and an authorized rate of return of 6.81 percent. The approved settlement is based on a capital structure of 50.5 percent equity and a rate base of $791.8 million. Final rates were effective January 10, 2024. In addition, NorthWestern was approved a phase in rate plan rider that allows for the recovery of capital investments not yet included in base rates.

(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,	
	2023	2022
Colstrip Unit 4 Basis Adjustment	$ (126,142)	$ (129,895)
Havre Pipeline Company, LLC	13,163	11,399
NorthWestern Energy Solutions, Inc.	11,797	2,091
NorthWestern Services, LLC	2,135	5,738
Risk Partners Assurance, Ltd.	1,097	1,132
NorthWestern Energy Public Service Corporation	—	—
Total Investments in Subsidiary Companies	**$ (97,950)**	**$ (109,535)**

(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 are the only items earning a rate of return. These 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, 2023	December 31, 2022
			(in thousands)	
Flow-through income taxes	14	Plant Lives	$ 553,452	$ 509,038
Pension	16	See Note 16	79,638	87,965
Excess deferred income taxes	14	Plant Lives	51,404	54,364
Employee related benefits	16	See Note 16	21,926	27,920
State & local taxes & fees		1 Year	2,733	15,643
Environmental clean-up	19	Undetermined	11,131	10,963
Other		Various	25,741	23,191
Total Regulatory Assets			**$ 746,025**	**$ 729,084**
Excess deferred income taxes	14	Plant Lives	136,382	148,989
Unbilled revenue		1 Year	16,004	11,536
Gas storage sales		17 years	6,625	7,046
State & local taxes & fees		1 Year	30,576	2,327
Environmental clean-up and other		1 Year	1,059	1,503
Total Regulatory Liabilities			**$ 190,646**	**$ 171,401**

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 and postretirement benefit 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.

Enhanced Wildfire Mitigation Plan

We have developed an Enhanced Wildfire Mitigation Plan addressing five key areas: situational awareness, operational practices, system preparedness, vegetation management, and public communications outreach. Because of ever-increasing wildfire risk, our plan includes greater focus on situational awareness to monitor changing environmental conditions, operational practices that are more reactive to changing conditions, increased frequency of patrol and repairs, and more robust system hardening programs that target higher risk segments in our transmission and distribution systems. As discussed within Note 3 - Regulatory Matters, the approved Montana rate review settlement provides for the deferral of incremental operating costs related to this Enhanced Wildfire Mitigation Plan. As of December 31, 2023, we have deferred $1.6 million of incremental costs as a regulatory asset related to this plan for future recovery.

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, 2023	December 31, 2022
	(in thousands)	
Electric Plant	5,817,626	5,563,314
Natural Gas Plant	1,443,363	1,307,060
Plant acquisition adjustment	481,574	481,574
Common and Other Plant	374,652	373,433
Construction work in process	358,401	300,649
Total utility plant	8,475,616	8,026,030
Less accumulated depreciation	(2,909,612)	(2,816,303)
Net utility plant	$ 5,566,004	$ 5,209,727

Net utility plant under capital (finance) lease were $5.2 million and $7.2 million as of December 31, 2023 and 2022, respectively, which included $5.0 million and $7.0 million as of December 31, 2023 and 2022, 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.

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 31,2023				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 156,696	$ 64,132	$ 52,630	$ 323,793
Accumulated depreciation	48,537	40,528	42,942	128,484
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

(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,	
	2023	2022
Liability at January 1,	$ 40,894	$ 40,631
Accretion expense	1,899	1,853
Liabilities incurred	—	—
Liabilities settled	(1,244)	(4,004)
Revisions to cash flows	(125)	2,414
Liability at December 31,	$ 41,424	$ 40,894

During the twelve months ended December 31, 2023 our ARO liability decreased $1.2 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, 2023, our ARO liability decreased $0.1 million related to changes in both the timing and amount of retirement cost estimates.

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

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

(8) Utility Plant Adjustments

We completed our annual utility plant adjustment impairment test as of April 1, 2023. We evaluated qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors, and overall financial performance) to determine whether it was more likely than not that the fair value of our reporting units were less than their carrying amounts. Our evaluation of these factors concluded that it was not more likely than not that the fair value of our reporting units was less than their carrying amounts and therefore no further testing was necessary.

(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, 2023 and 2022. 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, 2023	
Interest rate contracts	Interest on long-term debt	$	612

A pre-tax loss of approximately $12.8 million is remaining in AOCI as of December 31, 2023, 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 31,2023	**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	$ 14,857	$ —	$ —	$ —	$ 14,857
Rabbi trust investments	17,093	—	—	—	17,093
Total	**$ 31,950**	**$ —**	**$ —**	**$ —**	**$ 31,950**
December 31,2022					
Special deposits	$ 12,762	$ —	$ —	$ —	$ 12,762
Rabbi trust investments	20,895	—	—	—	20,895
Total	**$ 33,657**	**$ —**	**$ —**	**$ —**	**$ 33,657**

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 31,2023		December 31, 2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,797,660	$ 2,534,105	$ 2,629,660	$ 2,327,478

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 November 29, 2023, NorthWestern Corporation amended its existing $425.0 million revolving credit facility (the Amended Facility) to address the holding company reorganization and extended the maturity date of the facility to November 29, 2028. The Amended 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. After the completion of the holding company reorganization on January 1, 2024, NorthWestern Corporation owns and operates only the Montana regulated utility, and the base capacity of the Amended Facility automatically reduced to $400.0 million.

On October 28, 2022, we entered into a $100.0 million Credit Agreement (the Additional Credit Facility) to supplement our existing $425.0 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. As of December 31, 2023, there were no amounts outstanding under this Additional Credit Facility.

On March 25, 2023, we amended our existing $25.0 million swingline credit facility (the Swingline Facility) to extend the maturity date of the facility from March 27, 2024 to March 27, 2025. 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. As of December 31, 2023, there were no amounts outstanding under this Swingline Facility.

On January 2, 2024, NorthWestern Corporation terminated its $100.0 million Additional Credit Facility. On January 4, 2024, NorthWestern Corporation terminated its $25.0 million Swingline Facility.

Commitment fees for the unsecured revolving lines of credit were $0.6 million and $0.1 million for the years ended December 31, 2023 and 2022.

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

	2023	2022
Unsecured revolving line of credit, expiring May 2027	$ —	$ 425.0
Unsecured revolving line of credit, expiring November 2028[1]	425.0	—
Unsecured revolving line of credit, expiring April 2024[2]	100.0	100.0
Unsecured revolving line of credit, expiring March 2025[2]	25.0	25.0
	550.0	**550.0**
Amounts outstanding at December 31:		
SOFR borrowings	318.0	450.0
Letters of credit	—	—
	318.0	**450.0**
Net availability as of December 31	**$ 232.0**	**$ 100.0**

(1) Upon the completion of the holding company reorganization on January 1, 2024, the base capacity of this facility decreased to $400.0 million.

(2) NorthWestern Corporation terminated the $100.0 million Additional Credit Facility on January 2, 2024, and the $25.0 million Swingline Facility on January 4, 2024.

Our credit facilities include covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facilities also contain 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 Montana First Mortgage Bonds would trigger a cross default on the Amended Facility; however, a default on the Amended Facility would not trigger a default on the Montana First Mortgage Bonds.

(12) Long-Term Debt

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

	Due	December 31, 2023	December 31, 2022
Unsecured Debt:			
Unsecured Revolving Line of Credit	2027	$ —	$ 425,000
Unsecured Revolving Line of Credit	2028	318,000	—
Unsecured Revolving Line of Credit	2024	—	25,000
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
South Dakota—5.57%	2033	31,000	—
South Dakota—5.42%	2033	30,000	—
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
Montana—5.57%	2033	239,000	—
Pollution control obligations—			
Montana—2.00%	2023	—	144,660
Montana—3.88%	2028	144,660	—
Total Long-Term Debt		$ 2,797,660	$ 2,629,660

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 South Dakota indenture was transferred from NorthWestern Corporation to NorthWestern Energy Public Service Corporation upon the completion of the holding company reorganization on January 1, 2024.

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

On March 30, 2023, we issued and sold $239.0 million aggregate principal amount of Montana First Mortgage Bonds (the 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. On May 1, 2023, we issued and sold an additional $30 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.42 percent maturing on May 1, 2033. 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.

On June 29, 2023, the City of Forsyth, Rosebud County, Montana issued $144.7 million principal amount of Pollution Control Revenue Refunding Bonds (2023 Pollution Control Bonds) on our behalf. The 2023 Pollution Control Bonds were issued at a fixed interest rate of 3.88 percent maturing on July 1, 2028. The proceeds of the issuance were loaned to us pursuant to a Loan Agreement and were deposited directly with U.S. Bank Trust Company, National Association, as trustee, for the redemption of the 2.00 percent, $144.7 million City of Forsyth Pollution Control Revenue Refunding Bonds due on August 1, 2023 that had previously been issued on our behalf. Pursuant to the Loan Agreement, we are obligated to make payments in such amounts and at such times as will be sufficient to pay, when due, the principal and interest on the 2023 Pollution Control Bonds. Our obligations under the Loan Agreement are secured by delivery of a like amount of our Montana First Mortgage Bonds, which are secured by our Montana electric and natural gas assets. So long as we are making payments under the Loan Agreement, no payments under these mortgage bonds will be due. The 2023 Pollution Control Bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

On March 28, 2024, NorthWestern Corporation issued and sold $175.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.56 percent maturing on March 28, 2031. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to redeem NorthWestern Corporation's $100.0 million of Montana First Mortgage Bonds due this year and for other general utility purposes. The bonds are secured by NorthWestern Corporation's electric and natural gas assets in Montana.

As of December 31, 2023, we were in compliance with our financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are $100.0 million in 2024, $300.0 million in 2025, $105.0 million in 2026, and $497.7 million in 2028.

(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,	
	2023	2022
Accounts Receivable from Associated Companies:		
Colstrip Unit 4	$ 38,884	$ —
Havre Pipeline Company, LLC	591	$ 3,201
NorthWestern Energy Solutions, Inc.	112	16
Risk Partners Assurance, Ltd.	(88)	(74)
	$ 39,499	$ 3,143
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	2,082	2,045
NorthWestern Energy Group, Inc.	206	—
	$ 2,288	**$ 2,045**

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

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

	December 31,	
	2023	2022
NOL Carryforward	$ 113,310	$ —
Production tax credit	94,283	80,097
Pension / postretirement benefits	15,131	19,291
Customer advances	28,300	25,119
Unbilled revenue	10,604	9,440
Compensation accruals	10,716	10,306
Environmental liability	5,760	6,009
Interest rate hedges	3,280	3,372
Reserves and accruals	3,098	4,015
Other, net	5,401	6,295
Deferred Tax Asset	**289,883**	**163,944**
Excess tax depreciation	(673,172)	(462,895)
Flow through depreciation	(119,458)	(104,976)
Goodwill amortization	(91,803)	(91,746)
Regulatory assets and other	(20,246)	(58,065)
Deferred Tax Liability	**(904,679)**	**(717,682)**
Deferred Tax Liability, net	**$ (614,796)**	**$ (553,738)**

As of December 31, 2023, our total federal NOL carryforward was approximately $447.8 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2023 was approximately $362.1 million. If unused, our state NOL carryforwards will expire in 2033. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

At December 31, 2023, our total production tax credit carryforward was approximately $94.3 million. If unused, our production tax credit carryforwards will expire as follows: $1.8 million in 2035, $10.9 million in 2036, $11.1 million in 2037, $10.9 million in 2038, $11.5 million in 2039, $13.1 million in 2040, $11.5 million in 2041, $13.2 million in 2042, and $10.4 million in 2043. 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):

	2023	2022
Unrecognized Tax Benefits at January 1	$ 30,330	$ 32,049
Gross increases - tax positions in prior period	—	—
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(2,256)	(1,719)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 28,074	$ 30,330

Our unrecognized tax benefits include approximately $24.4 million and $27.9 million related to tax positions as of December 31, 2023 and 2022, that if recognized, would impact our annual effective tax rate. On April 14, 2023, the Internal Revenue Service (IRS) issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting for gas repairs expenditures. During the year ended December 31, 2023, we adopted this method and decreased our total unrecognized tax benefits by $0.5 million and recognized an income tax benefit of approximately $3.2 million for previously unrecognized tax benefits. In the next twelve months we expect the statute of limitations to expire for certain uncertain tax benefits, which would result in a decrease to our total unrecognized tax benefits of approximately $16.9 million.

Our policy is to recognize interest related to uncertain tax positions in interest expense. As of December 31, 2023, we have accrued $4.5 million for the payment of interest in the Balance Sheets. As of December 31, 2022, we had $1.4 million accrued for the payment of interest.

Tax years 2020 and forward remain subject to examination by the IRS and state taxing authorities. During the first quarter of 2023 the IRS commenced and concluded a limited scope examination of our 2019 amended federal income tax return. This examination resulted in a reduction to our previously claimed alternative minimum tax credit refund that is reflected in the table above.

(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,					
	2023			2022		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ 2	$ —	$ 2	$ (8)	$ —	$ (8)
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452
Postretirement medical liability adjustment	(330)	69	(261)	(1,359)	377	(982)
Other comprehensive income (loss)	$ 284	$ (91)	$ 193	$ (755)	$ 217	$ (538)

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

	December 31,	
	2023	2022
Foreign currency translation	$ 1,437	$ 1,435
Derivative instruments designated as cash flow hedges	(7,223)	(7,675)
Postretirement medical plans	273	534
Accumulated other comprehensive loss	$ (5,513)	$ (5,706)

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

	December 31,2023								
	Year Ended								
	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		$	(7,675)	$	534	$	1,435	$	(5,706)
Other comprehensive income before reclassifications							2		2
Amounts reclassified from AOCI	Interest on long-term debt		452						452
Amounts reclassified from AOCI					(261)				(261)
Net current-period other comprehensive income			452		(261)		2		193
Ending Balance		$	(7,223)	$	273	$	1,437	$	(5,513)

	December 31,2022								
	Year Ended								
	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated Cash		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)

(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, 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,	
	2023	2022	2023	2022
Change in benefit obligation:				
Obligation at beginning of period	$ 521,798	$ 696,802	$ 15,407	$ 17,308
Service cost	5,646	10,223	333	351
Interest cost	25,852	18,787	674	358
Actuarial loss	3,127	(176,389)	(1,240)	(99)
Settlements[(1)]	(51,942)	—	—	—
Benefits paid	(30,493)	(27,625)	(1,466)	(2,511)
Benefit Obligation at End of Period	$ 473,988	$ 521,798	$ 13,708	$ 15,407
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 441,539	$ 605,499	$ 20,055	$ 25,289
Return on plan assets	34,367	(144,535)	3,334	(4,098)
Employer contributions	9,200	8,200	386	1,375
Settlements[(1)]	(51,942)	—	—	—
Benefits paid	(30,493)	(27,625)	(1,466)	(2,511)
Fair value of plan assets at end of period	$ 402,671	$ 441,539	$ 22,309	$ 20,055
Funded Status	$ (71,317)	$ (80,259)	$ 8,601	$ 4,648
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	7,875	7,195	12,378	8,831
Total Assets	7,875	7,195	12,378	8,831
Current liability	(11,200)	(11,200)	(1,355)	(1,585)
Noncurrent liability	(67,992)	(76,254)	(2,422)	(2,598)
Total Liabilities	(79,192)	(87,454)	(3,777)	(4,183)
Net amount recognized	$ (71,317)	$ (80,259)	$ 8,601	$ 4,648
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	(116)
Net actuarial loss	(44,453)	(54,383)	15	(3,123)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	—	—
Net actuarial gain	—	—	590	1,046
Total	$ (44,453)	$ (54,383)	$ 605	$ (2,193)

(1) In October 2023, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 285 NorthWestern Energy Pension Plan participants. We purchased the contract with $51.9 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2024. This transaction settled $51.9 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2023, we recorded a non-cash, non-operating settlement charge of $4.4 million. This charge is recorded within operating expense, net on the Statements of Income. As discussed within Note 5 – Regulatory Assets and Liabilities, the MPSC allows recovery of pension costs on a cash funding basis. As such, 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,	
	2023	2022
Projected benefit obligation	$ 427.3	$ 474.9
Accumulated benefit obligation	427.3	474.9
Fair value of plan assets	348.1	388.7

As of December 31, 2023, 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,	
	2023	2022	2023	2022
Components of Net Periodic Benefit Cost				
Service cost	$ 5,646	$ 10,223	$ 333	$ 351
Interest cost	25,852	18,787	674	359
Expected return on plan assets	(25,932)	(24,173)	(1,096)	(1,047)
Amortization of prior service cost (credit)	—	—	116	(1,891)
Recognized actuarial loss (gain)	228	383	(672)	(897)
Settlement loss recognized(1)	4,395	—	—	—
Net Periodic Benefit Cost (Credit)	$ 10,189	$ 5,220	$ (645)	$ (3,125)
Regulatory deferral of net periodic benefit cost(2)	(1,814)	2,307	—	—
Previously deferred costs recognized(2)	210	—	550	292
Amount Recognized in Income	$ 8,585	$ 7,527	$ (95)	$ (2,833)

(1) Settlement losses are related to partial annuitization of NorthWestern Energy Pension Plan effective October 24, 2023 and December 1, 2021, respectively.

(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 the years ended December 31, 2023 and 2022, Service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other income, net on the Statements of Income.

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, 2023 and 2022. 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 decrease in the discount rate during 2023 increased our projected benefit obligation by approximately $10.5 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 6.65 percent and increased our assumption on the NorthWestern Corporation Pension Plan to 5.15 percent for 2024.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2023	2022	2023	2022
Discount rate	4.95-5.00 %	5.20 %	4.85-4.90 %	5.15-5.20 %
Expected rate of return on assets	4.83-6.44	2.66-4.26	5.62	4.23
Long-term rate of increase in compensation levels (non-union)	4.00	4.00	4.00	4.00
Long-term rate of increase in compensation levels (union)	4.00	4.00	4.00	4.00
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 Liability Hedging Fixed Income 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,	
	2023	2022	2023	2022	2023	2022
Fixed income securities	45.0 %	45.0 %	90.0 %	90.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	—	—	1.0	—	—
Opportunistic fixed income	11.0	5.5	3.0	—	—	—
Global equities	38.5	44.0	7.0	9.0	60.0	60.0
Private real estate	5.5	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,	
	2023	2022	2023	2022	2023	2022
Cash and cash equivalents	— %	— %	1.5 %	1.1 %	0.2 %	0.6 %
Fixed income securities	45.3	44.5	88.7	88.6	35.1	36.7
Non-U.S. fixed income securities	—	—	—	0.9	—	—
Opportunistic fixed income	10.6	5.5	2.9	—	—	—
Global equities	37.6	43.4	6.9	9.4	64.7	62.7
Private real estate	6.5 %	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 Energy Group 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 2024 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 2023 and 2022 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2023	2022
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 7,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 9,200	$ 8,200

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

	Pension Benefits	Other Postretirement Benefits
2024	$ 27,553	$ 2,149
2025	28,987	1,813
2026	29,920	1,406
2027	30,545	1,251
2028	31,231	1,210
2029-2032	164,362	5,288

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, 2023 and 2022 were $13.2 million and $12.3 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. These stock-based awards are for the common stock of NorthWestern Energy Group, Inc. As part of effectuating the holding company reorganization, all outstanding and unexercised, unvested and not yet paid or payable stock-based awards were converted into a right to acquire NorthWestern Energy Group, Inc. capital stock of the same class and with the same rights and privileges relative to the stock-based award prior to the merger. See Note 1 - Nature of Operations for further information regarding the holding company effectuation in 2023.

As of December 31, 2023, there were 649,884 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to four 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. Beginning in 2023, these awards contain service-, market-, and performance-based components. The service-based component of these awards, representing 30 percent of the award, vest at the end of the three-year performance period as long as the individual has remained employed with us over that term. The performance goals are independent of each other and equally weighted at 35 percent of the award, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return relative to a peer group. Performance unit awards issued prior to 2023 included both the market- and performance-based components discussed above.

Fair value is determined for each component of the performance unit awards. The fair value of the service-based component is estimated based upon the closing market price of our common stock as of the grant date less the present value of expected dividends. The fair value of the performance-based component is estimated based upon the closing market price of our common stock as of the grant date 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 market-based component 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:

	2023	2022
Risk-free interest rate	4.33 %	1.82 %
Expected life, in years	3	3
Expected volatility	30.4% to 41.0%	28.2% to 38.8%
Dividend yield	4.4 %	4.5 %

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

A summary of nonvested shares as of and changes during the year ended December 31, 2023, are as follows:

	Performance Unit Awards		
	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	194,407	$	51.04
Granted	95,853		54.41
Vested	(87,300)		50.53
Forfeited	(49,176)		51.59
Remaining nonvested grants	153,784	$	53.26

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 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. No retirement/retention restricted shares were granted during the year ended December 31, 2023. 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 grant date less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2023, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	99,285	$	48.62
Granted	—		—
Vested	—		—
Forfeited	(38,506)		49.73
Remaining nonvested grants	60,779	$	47.91

We recognized total stock-based compensation expense of \$3.6 million and \$4.2 million for the years ended December 31, 2023 and 2022, respectively, and related income tax benefit of \$(1.0) million and \$(1.3) million for the years ended December 31, 2023 and 2022, respectively. As of December 31, 2023, we had \$6.5 million of unrecognized compensation cost related to the nonvested portion of our outstanding awards. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was \$4.4 million and \$4.3 million for the years ended December 31, 2023 and 2022, respectively.

(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.

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 4,167 and 16,120 during the years ended December 31, 2023 and 2022, 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, NorthWestern Corporation entered into an Equity Distribution Agreement pursuant to which we could 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. During the twelve months ended December 31, 2023, NorthWestern Corporation issued 1,432,738 shares of our common stock under the ATM program at an average price of $52.02, for net proceeds of $73.6 million, which is net of sales commissions and other fees paid of approximately $0.9 million. We have completed the ATM offering program under this Equity Distribution 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 $67 to $136 per MWH through 2029. As of December 31, 2023, our estimated gross contractual obligation related to these contracts was approximately $303.1 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $266.5 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,	
	2023	2022
Beginning QF liability	$ 49,728	$ 64,943
Settlements[1]	(24,707)	(20,076)
Interest on long-term debt	3,649	4,861
Ending QF liability	$ 28,670	$ 49,728

(1) The primary components of the change in settlement amounts includes (i) a lower periodic adjustment of $4.2 million due to actual price escalation, which was less than previously modeled; and (ii) higher costs of approximately $1.0 million, due to a $0.8 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $1.8 million reduction in costs in the prior period.

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

	Gross Obligation	Recoverable Amounts	Net
2023	$ 74,110	$ 60,706	$ 13,404
2024	60,360	52,950	7,410
2025	55,393	46,274	9,119
2026	56,665	46,668	9,997
2027	42,400	41,664	736
Thereafter	14,134	18,231	(4,097)
Total[(1)]	$ 303,062	$ 266,493	$ 36,569

(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 expense in the Statements of Income and were approximately $340.0 million and $328.0 million for the years ended December 31, 2023 and 2022, respectively. As of December 31, 2023, our commitments under these contracts were $321.9 million in 2024, $244.1 million in 2025, $263.4 million in 2026, $243.6 million in 2027, $225.9 million in 2028, 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 $22.4 million between 2024 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 $21.0 million to $31.4 million. As of December 31, 2023, we had a reserve of approximately $25.3 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,	
	2023	**2022**
Liability at January 1,	$ 26,367	$ 26,866
Deductions	(2,520)	(2,033)
Charged to costs and expense	1,439	1,534
Liability at December 31,	$ 25,285	$ 26,367

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 $19.8 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, 2023, the reserve for remediation costs at this site was approximately $8.0 million, and we estimate that approximately $2.9 million of this amount will be incurred through 2028.

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

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the MDEQ voluntary remediation program for cleanup due to soil and groundwater impacts.

Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and field work was completed in 2022. We submitted a Remedial Investigation Report (RI Report) summarizing the work completed to MDEQ in March 2022 and are awaiting its review and comments as to any additional field work. We now expect the MDEQ review of the RI Report to be concluded in 2024, 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 emissions. Coal-fired plants have come under particular scrutiny due to their level of emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

Proposed EPA Rules **-** Congress has not passed any federal climate change legislation directly regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. However, 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. In May 2023, EPA proposed new GHG emissions standards for coal and natural gas-fired plants. In particular, the proposed rules would (i) strengthen the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establish emission guidelines for states to follow in limiting carbon pollution from existing fossil fuel-fired steam generating electric generating units (including coal, oil and natural gas-fired units); and (iii) establish emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired). In addition, in April 2023, EPA proposed to amend the Mercury Air Toxics Standard (MATS). Among other things, MATS currently sets stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. We are in compliance with existing MATS requirements. The proposed amendment of the MATS would strengthen the MATS requirements, and if adopted as written, both the GHG and MATS proposed rules could have a material negative impact on our coal-fired plants, including requiring potentially expensive upgrades or the early retirement of Colstrip Unit's 3 and 4 due to the rules making the facility uneconomic. On April 25, 2024, the EPA released final rules related to GHG emission standards (GHG Rules) for existing coal-fired facilities and new coal and natural gas-fired facilities as well as final rules strengthening the MATS requirements (MATS Rules). The final MATS and GHG Rules will require compliance as early as 2028 and 2032, respectively. We are evaluating how the final MATS and GHG Rules may impact our coal-fired generation facilities and operations.

Previous efforts by the EPA were met with extensive litigation and we anticipate a similar response if the proposed rules are adopted. As MATS and GHG regulations are implemented, it could result in additional material compliance costs. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any MATS or GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements - federal or state - 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 or hazardous air pollutants may not be available within a timeframe consistent with the implementation of any such 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

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 - Commitments and Contingencies to the financial statements included in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2023. 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. On August 25, 2023, the Federal District Court issued its Findings of Fact, Conclusions of Law and Order (the "Order"), which found all but one of the segments of the riverbeds in dispute not navigable, and thus not owned by the State of Montana. The one segment found navigable, and thus owned by the State, was the segment on which the Black Eagle development was located. The State filed a motion to pursue an interlocutory appeal of the Order, and on January 2, 2024, the Federal District Court certified the Order for appeal to the 9th Circuit Court of Appeals. Briefing in the appeal is underway. Damages were bifurcated by agreement and will be tried separately for the Black Eagle segment, and any other segments found navigable should the State prevail on appeal.

We dispute the State's claims and intend to continue to vigorously defend the lawsuit. If the Federal District Court calculates damages as the State District Court did in 2008, we do not anticipate the resulting annual rent for the Black Eagle segment would have a material impact to our financial position or results of operations. 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 Montana Public Service Commission (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 agreed to stay the Arbitration in an effort to work out a global resolution to the dispute, but that stay has now expired. The parties were not able to agree to continue the stay, and are presently in the process of identifying and retaining an arbitrator (or arbitrators) and are proceeding with the Arbitration.

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 discovery stages, we are unable to predict outcomes. We continue to evaluate 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.

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. NorthWestern and BNSF have settled the majority of the dispute for a non-material sum. Any potential remaining claims are not expected to be material.

Yellowstone County Generating Station Air Permit

On October 21, 2021, the Montana Environmental Information Center and the Sierra Club filed a lawsuit in Montana State District 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. 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 and 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 paused construction. On June 8, 2023, the Montana District Court granted our motion to stay the order vacating the air quality permit pending the outcome of our appeal to the Montana Supreme Court. Oral argument is presently scheduled for May 15, 2024, and a determination of the appeal will follow. We recommenced construction in June 2023 and expect the plant to be operational by the end of the third quarter 2024. The ultimate resolution of the lawsuit challenging the Yellowstone County Generating Station air quality permit could impact our ability to operate the facility and increase costs.

During the litigation of the air permit, Montana House Bill 971 was signed into law, preventing the MDEQ from, except under certain exceptions, evaluating greenhouse gas emissions and corresponding impacts to the climate in environmental reviews of large projects such as coal mines and power plants. On June 1, 2023, the MDEQ issued its draft supplemental environmental assessment that contained the updated exterior lighting analysis, and the MDEQ indicated that no other analysis was necessary. The comment period concerning the MDEQ’s draft supplemental environmental assessment ended on July 3, 2023. On August 4, 2023, the Montana First Judicial District Court in Held v. State of Montana, a separate case by Montana youths alleging climate damages, issued its order finding House Bill 971 unconstitutional delaying the issuance of the revised Yellowstone County Generating Station's air permit. The Montana Supreme Court granted NorthWestern permission to participate as amicus in the Held appeal. The outcome of the Held case could pose additional delays and costs for the Yellowstone County Generating Station.

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 - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	19,995	$ -	$ 19,995	$ 19,995	0.00%
4	302 Franchises and Consents	21,479,709	-	21,479,709	20,247,608	6.09%
5	303 Miscellaneous Intangible Plant	16,607,726	-	16,607,726	12,243,407	35.65%
6	**Total Intangible Plant**	38,107,430	-	38,107,430	32,511,010	17.21%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	-	-			-
12	311 Structures and Improvements	-	-			-
13	312 Boiler Plant Equipment	-	-	-	-	-
14	313 Engines, Engine Driven Generator	-	-	-	-	-
15	314 Turbogenerator Units	-	-	-	-	-
16	315 Accessory Electric Equipment	-	-	-	-	-
17	316 Misc. Power Plant Equipment	453,235,225	-	453,235,225	457,290,401	-0.89%
18	**Total Steam Production Plant**	453,235,225	-	453,235,225	457,290,401	-0.89%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	5,958,417	-	5,958,417	5,941,678	0.28%
26	331 Structures and Improvements	130,050,563	-	130,050,563	126,687,963	2.65%
27	332 Reservoirs, Dams and Waterways	195,161,800	-	195,161,800	195,625,955	-0.24%
28	333 Water Wheel, Turbine, Generators	189,566,171	-	189,566,171	176,785,446	7.23%
29	334 Accessory Electric Equipment	94,867,868	-	94,867,868	94,377,564	0.52%
30	335 Misc. Power Plant Equipment	20,768,388	-	20,768,388	20,725,764	0.21%
31	336 Roads, Railroads and Bridges	3,069,284	-	3,069,284	2,947,096	4.15%
32	**Total Hydraulic Production Plant**	639,442,491	-	639,442,491	623,091,466	2.62%
33						
34	**Other Production**					
35	340 Land and Land Rights	3,819,385		3,819,385	3,819,385	0.00%
36	341 Structures and Improvements	59,449,471	19,232	59,430,239	59,430,239	0.00%
37	342 Fuel Holders & Accessories	21,230,045	112,084	21,117,961	21,117,961	0.00%
38	343 Prime Movers	90,561,056		90,561,056	102,231,898	-11.42%
39	344 Generators	55,657,436	2,177,823	53,479,614	53,479,614	0.00%
40	345 Accessory Electric Equipment	19,164,005	770,151	18,393,854	18,393,854	0.00%
41	346 Misc. Power Plant Equipment	29,091,023	7,268	29,083,754	29,083,755	0.00%
42	**Total Other Production Plant**	278,972,420	3,086,557	275,885,863	287,556,706	-4.06%
43	**Total Production Plant**	1,371,650,136	3,086,557	1,368,563,578	1,367,938,572	0.05%

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	This Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	42,967,324		42,967,324	40,120,055	7.10%
4	352 Structures and Improvements	63,608,479		63,608,479	48,939,329	29.97%
5	353 Station Equipment	365,001,598	-	365,001,598	338,651,187	7.78%
6	354 Towers and Fixtures	30,640,142		30,640,142	30,385,864	0.84%
7	355 Poles and Fixtures	494,311,010	2,381,744	491,929,266	455,842,361	7.92%
8	356 Overhead Conductors & Devices	185,359,012	901,810	184,457,202	178,835,063	3.14%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,961,964	554,036	1,407,928	1,381,313	1.93%
11	359 Roads and Trails	4,043,372	44,906	3,998,466	3,998,466	0.00%
12	**Total Transmission Plant**	1,188,030,779	3,984,782	1,184,045,997	1,098,189,230	7.82%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	14,779,553	601	14,778,952	14,731,356	0.32%
16	361 Structures and Improvements	44,180,370	1,299,812	42,880,558	37,191,792	15.30%
17	362 Station Equipment	262,523,548	5,278,630	257,244,919	241,161,508	6.67%
18	363 Storage Battery Equipment	-				-
19	364 Poles, Towers, and Fixtures	390,091,593	440,763	389,650,830	371,962,802	4.76%
20	365 Overhead Conductors & Devices	156,000,860	495,787	155,505,073	149,977,332	3.69%
21	366 Underground Conduit	182,286,466	740,739	181,545,727	167,443,249	8.42%
22	367 Undergrnd Conductors & Devices	282,060,470	3,882,323	278,178,147	261,301,098	6.46%
23	368 Line Transformers	277,396,147	915,790	276,480,357	257,493,354	7.37%
24	369 Services	186,536,026	479,296	186,056,731	173,421,573	7.29%
25	370 Meters	86,989,797	107,483	86,882,315	76,880,983	13.01%
26	371 Installations on Cust. Premises	-		-		-
27	372 Leased Property on Cust. Premises	-		-		-
28	373 Street Lighting and Signal Systems	83,098,093	31,585.05	83,066,508	81,699,567	1.67%
29	**Total Distribution Plant**	1,965,942,924	13,672,807	1,952,270,117	1,833,264,614	6.49%
30						
31	**General Plant**					
32	389 Land and Land Rights	1,196,602	506,968.71	689,633.48	689,633	0.00%
33	390 Structures and Improvements	10,118,119		10,118,119.20	10,191,519	-0.72%
34	391 Office Furniture and Equipment	2,466,667		2,466,666.69	1,209,368	103.96%
35	392 Transportation Equipment	67,826,401	229,388.89	67,597,011.61	65,523,628	3.16%
36	393 Stores Equipment	1,155,108		1,155,107.55	1,143,158	1.05%
37	394 Tools, Shop & Garage Equipment	11,095,842	-	11,095,841.95	10,567,559	5.00%
38	395 Laboratory Equipment	1,033,178		1,033,178.34	1,033,178	0.00%
39	396 Power Operated Equipment	7,041,214		7,041,213.86	6,542,836	7.62%
40	397 Communication Equipment	58,249,693	2,050,053.67	56,199,638.84	47,650,259	17.94%
41	398 Miscellaneous Equipment	2,122,711		2,122,711.00	2,122,711	0.00%
42	399 Other Tangible Equipment	-			-	-
43	**Total General Plant**	162,305,534	2,786,411	159,519,123	146,673,849	8.76%
44	**Total Plant in Service**	4,726,036,802	23,530,558	4,702,506,244	4,478,577,275	5.00%
45						
46	4101 El Plant Allocated from Common	132,806,825		132,806,825	130,821,540	1.52%
47	103 Experimental Electric Plant Unclassified	4,798,750	1,811,268	2,987,483	3,480,485	-14.16%
48	105 El Plant Held for Future Use	4,110,361		4,110,361	4,297,515	(0.04)
49	107 El Construction Work in Progress	311,442,444	148,699	311,293,745	258,789,141	20.29%
50						
51						
52	**TOTAL ELECTRIC PLANT**	$ 5,179,195,182	$ 25,490,525	$ 5,153,704,657	$ 4,875,965,956	5.70%

Sch. 19 cont. **MONTANA PLANT IN SERVICE - ELECTRIC**

	CONSOLIDATED PLANT IN SERVICE	December 31, 2023	December 31, 2022
1			
2	Montana Electric	$ 4,702,506,244	$ 4,478,577,275
3	Yellowstone National Park	$ 23,530,558	23,181,889
4	Montana Natural Gas (Includes CMP)	$ 1,180,425,818	1,058,136,509
5	Common	$ 193,279,118	191,541,317
6	Townsend Propane	$ 1,547,776	1,528,962
7	South Dakota Electric	$ 1,115,119,868	1,084,736,554
8	South Dakota Natural Gas	$ 262,937,110	248,923,029
9	South Dakota Common	$ 71,074,956	72,289,882
10	Asset Retirement Obligation	$ 35,151,999	34,815,008
11	**TOTAL PLANT**	$ 7,585,573,447	$ 7,193,730,425

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC						
	Functional Plant Class	Montana Plant Cost	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$ 448,011,550	$ 161,723,201		$ 161,723,201	$ 151,077,896	2.94%
4							
5	Nuclear Production	-					-
6							
7	Hydraulic Production	572,274,979	139,268,539	-	139,268,539	145,873,338	2.00%
8							
9	Other Production	291,684,111	78,834,744	2,556,693	76,278,051	97,248,774	3.61%
10							
11	Transmission	1,026,660,481	419,178,376	2,293,682	416,884,694	404,665,749	2.95%
12							
13	Distribution	1,741,538,282	843,074,267	6,132,031	836,942,236	802,378,715	3.12%
14							
15	General and Intangible	172,640,701	109,656,111	1,055,844	108,600,267	100,351,609	7.27%
16							
17	Common	110,535,073	34,952,782	-	34,952,782	32,275,878	5.57%
18							
19							
20	**Total Accum Depreciation**	$ 4,363,345,177	$ 1,786,688,020	$ 12,038,251	$ 1,774,649,769	$ 1,733,871,959	3.11%
21							
22							
23							

24	**Consolidated**	December 31,	
25	**Accumulated Depreciation**	2023	2022
26			
27	Montana Electric	$1,739,696,987	1,701,596,081
28	Yellowstone National Park	12,038,251	11,497,472
29	Montana Natural Gas (Includes CMP)	435,603,710	414,692,232
30	Common	53,580,007	49,925,576
31	Townsend Propane	1,127,274	1,087,518
32	South Dakota Electric	384,514,178	361,933,145
33	South Dakota Natural Gas	113,554,633	108,399,684
34	South Dakota Common	21,556,118	22,856,513
35	Acquisition Writedown	35,163,173	37,867,662
36	Basin Creek Capital Lease	35,183,325	33,172,848
37	FIN 47	2,093,317	1,451,661
38	CWIP-Capital Retirement Clearing	-16,877,317	(10,305,356)
39	**Total Consolidated Accum Depreciation**	$2,817,233,655	$2,734,175,036

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	151 Fuel Stock	$ 2,155,210	$ -	$ 2,155,210	$ 2,283,502	-5.62%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	8,291,005		$ 8,291,005	7,374,847	12.42%
9	Transmission Plant	14,315,451		$ 14,315,451	8,385,999	70.71%
10	Distribution Plant	33,676,475		$ 33,676,475	28,619,724	17.67%
11						
12						
13	**Total MT Materials and Supplies**	$ 58,438,141	$ -	$ 58,438,141	$ 46,664,072	25.23%
14						
15						

16	**Consolidated**	December 31,	
17	**Fuel Stock**	2023	2022
18			
19	Montana Electric	$2,155,210	$2,283,502
20	South Dakota	7,555,608	5,441,439
21			
22	**Total Fuel Stock**	$9,710,818	$7,724,941
23			
24			
25			

26	**Consolidated**	December 31,	
27	**Materials and Supplies**	2023	2022
28			
29	Montana Electric	56,282,931	$44,380,570
30	Montana Natural Gas	9,516,222	8,913,471
31	South Dakota	19,455,340	17,860,206
32			
33	**Total Consolidated Materials and Supplies**	85,254,493	$71,154,247

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
	Regulated Electric Transmission, Distribution and Production Utility			
	Docket Number: D2022.07.078			
	Order Number : 7860y			
	Effective Date: November 1, 2023			
	Common Equity	48.02%	9.65%	4.64%
	Long Term Debt	51.98%	4.01%	2.08%
	TOTAL	100.00%		6.72%
	Colstrip Unit 4			
	Docket Number: 2018.02.012			
	Order Number : 7604u			
	Effective Date: December 20, 2019			
	Common Equity	50.00%	10.00%	5.00%
	Long Term Debt	50.00%	6.50%	3.25%
	TOTAL	100.00%		8.25%

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	$ 194,131,555	$ 183,006,620	6.08%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	179,874,970	167,066,420	7.67%
6	Amortization, Net	36,075,440	33,241,101	8.53%
7	Other Noncash Charges to Net Income, Net	10,610,312	11,976,972	-11.41%
8	Deferred Income Taxes, Net	8,535,605	(8,261,582)	203.32%
9	Investment Tax Credit Adjustments, Net	(129,483)	(129,521)	0.03%
10	Change in Operating Receivables, Net	25,423,506	(36,275,911)	170.08%
11	Change in Materials, Supplies & Inventories, Net	(7,177,502)	(26,725,060)	73.14%
12	Change in Operating Payables & Accrued Liabilities, Net	(68,659,030)	78,691,016	-187.25%
13	Allowance for Funds Used During Construction (AFUDC)	(17,612,998)	(14,189,693)	-24.13%
14	Change in Other Assets & Liabilities, Net	79,866,995	(65,946,235)	221.11%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,275,985)	(2,960,410)	23.12%
17	Change in Regulatory Assets	36,795,341	3,473,736	>300.00%
18	Change in Regulatory Liabilities	19,246,128	(14,255,866)	235.00%
19	**Net Cash Provided by Operating Activities**	494,704,854	308,711,587	60.25%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(566,864,445)	(516,500,191)	-9.75%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(9,105,446)	(1,731,829)	>-300.00%
24	Proceeds from Sale of Assets	-	-	-
25	**Net Cash Used in Investing Activities**	(575,969,891)	(518,232,020)	-11.14%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	300,000,000	-	100.00%
29	Issuance of Notes Payable	-	-	100.00%
30	Line of Credit Borrowings, Net	-	-	100.00%
31	Proceeds From Issuance of Common Stock, Net	73,612,936	276,971,002	-73.42%
32	Payments for Retirement of:			
33	Repayments of Short Term Borrowings, Net	(92,403)	92,403	-200.00%
34	Repayments of Long Term Borrowings, Net	-	-	-
35	Line of Credit Repayments, Net	(132,000,000)	77,000,000	-271.43%
36	Dividends on Common Stock	(154,089,441)	(140,062,161)	-10.02%
37	Other Financing Activities:			
38	Debt Financing Costs	(4,109,961)	(1,286,054)	-219.58%
39	Treasury Stock Activity	731,249	603,028	21.26%
40	**Net Cash Used in Financing Activities**	84,052,380	213,318,218	-60.60%
41	**Net Increase/Decrease in Cash and Cash Equivalents**	2,787,343	3,797,785	-26.61%
42	**Cash and Cash Equivalents at Beginning of Year**	20,855,350	17,057,565	22.26%
43	**Cash and Cash Equivalents at End of Year**	$ 23,642,693	$ 20,855,350	13.37%
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				Schedule 23

Sch. 24	MONTANA LONG TERM DEBT 2023								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
4	5.71% Series ($55M), Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
5	5.01% Series ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
6	4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
7	4.30% Series($40M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
8	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,905,880	15,000,000	4.85%	730,647	4.87%
9	3.99% Series($35M), Due 2028	12/19/13	12/19/28	35,000,000	34,807,797	35,000,000	3.99%	1,409,343	4.03%
10	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,072,899	450,000,000	4.18%	19,570,295	4.35%
11	3.11% Series($75M), Due 2025	06/23/15	07/01/25	75,000,000	74,563,893	75,000,000	3.11%	2,749,526	3.67%
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11%	5,369,022	4.30%
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%
15	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%
16	3.21% Series($100M) Due 2030	05/15/20	05/15/30	100,000,000	99,516,844	100,000,000	3.21%	3,270,011	3.27%
17	1.00% Series($100M) Due 2024	03/26/21	03/26/24	100,000,000	99,442,399	99,993,462	1.00%	1,203,401	1.20%
18	5.57% Series($239M) Due 2033	03/30/23	03/30/33	239,000,000	238,909,984	239,000,000	5.57%	13,400,318	5.61%
19	**Total First Mortgage Bonds**			$ 1,855,000,000	$ 1,843,096,274	$ 1,854,993,462		$ 80,322,803	4.33%
20									
21	**Pollution Control Bonds**								
22	3.875% Series ($144.7M), Due 2028	06/29/23	07/01/28	$ 144,660,000	$ 144,020,056	$ 144,660,000	3.875%	$ 4,217,638	2.92%
23									
24	**Total Pollution Control Bonds**			$ 144,660,000	$ 144,020,056	$ 144,660,000		$ 4,217,638	2.92%
25									
26	**Other Long-Term Debt**								
27									
28									
29	**Total Other Long Term Debt**			$ -	$ -	$ -		$ -	
30									
31	**TOTAL LONG TERM DEBT**			$ 1,999,660,000	$ 1,987,116,330	$ 1,999,653,462		$ 84,540,442	4.23%

34 This schedule does not reflect our obligations under capital lease which total $8,799,105

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										
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29										
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31										
32	**TOTAL**					0		0	0	

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio 2/	Market Price 2/ High	Market Price 2/ Low	Price/ Earnings Ratio 2/
January	59,762,762	45	0.00		-	61	59	
February	59,790,353	45.34	0.00		-	58.99	57.85	
March	59,793,731	45.04	1	0.640	-	58.01	57.20	
April	59,794,937	45.21	0.00		-	61.24	60.16	
May	59,799,253	45.23	-		-	60.29	59.44	
June	59,991,323	44.79	0.32	0.640	-	59.59	58.57	
					-			
July	60,041,849	44.94			-	58.38	57.37	
					-			
August	60,537,126	45.19			-	56.77	55.89	
					-			
September	61,241,819	44.75	0.48	0.640	-	52.52	51.83	
					-			
October 2/	100	27,604.07			-			
					-			
November 2/	100	27,895.46			-			
					-			
December 2/	100	27,853.14	831,422.68	390,416.406	-			
					-			
TOTAL Year End 2/	100	27,853	831,424.53	$390,418.33	-	-	-	

1/ Monthly shares are actual shares outstanding at month-end.

2/ On October 2, 2023, NorthWestern Corporation and NorthWestern Energy Group, Inc. completed the reorganization into a holding company structure. In this reorganization, shareholders of Northwestern Corporation (the predecessor publicly held parent company) became shareholders of Northwestern Energy Group, Inc., maintaining the same number of shares and ownership percentage as held in Northwestern Corporation immediately prior to the reorganization. Northwestern Corporation became a wholly-owned subsidiary of Northwestern Energy Group, Inc. As such, beginning on October 2, 2023, NorthWestern Corporation is not a publically traded entity and the amount of shares outstanding significantly changed. Therefore these amounts for October 2023 through December 2023 will not be comparative to historical amounts. Further, year-to-date amounts may be misleading when compared to historical reports.

Sch. 27		MONTANA EARNED RATE OF RETURN - ELECTRIC			
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$5,173,556,297	$4,927,263,058	5.00%
3	108	Accumulated Depreciation	(1,832,054,980)	(1,763,532,425)	-3.89%
4					
5		**Net Plant in Service**	$3,341,501,317	$3,163,730,632	5.62%
6		Additions:			
7	154, 156	Materials & Supplies	$42,022,457	$32,182,086	30.58%
8	165	Prepayments			
9		Other Additions	15,522,771	16,320,816	-4.89%
10					
11		**Total Additions**	$57,545,228	$48,502,902	18.64%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$160,823,903	$161,124,661	-0.19%
14	252	Customer Advances for Construction	79,519,168	68,260,090	16.49%
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	121,617,272	118,072,407	3.00%
17					
18		**Total Deductions**	$361,960,343	$347,457,158	4.17%
19		**Total Rate Base**	$3,037,086,202	$2,864,776,377	6.01%
20		**Net Earnings**	$ 199,829,304	$ 174,234,680	14.69%
21		**Rate of Return on Average Rate Base**	6.580%	6.082%	8.18%
22		**Rate of Return on Average Equity 1/**	8.945%	7.840%	14.09%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Rate Schedule Revenues 2/	$410,642	($13,739,174)	102.99%
27		Environmental True-up MGP Sites 3/	345,644	844,443	-59.07%
28		FERC Excess Transmission Revenues 6/		(1,031,275)	100.00%
29					
30		Non-Allowables:			
31		Advertising	1,019,825	1,273,126	-19.90%
32		Dues, Contributions, Other	130,016	78,927	64.73%
33					-
34		Associated Income Taxes 4/	(1,180,692)	4,864,289	-124.27%
35					
36		**Total Adjustments**	$725,436	($7,709,664)	109.41%
37		**Revised Net Earnings**	$200,554,740	$166,525,016	20.44%
38		**Rate Base Adjustment**			
39		Stipulation with MCC 5/	($13,876,665)	($14,742,332)	5.87%
40					
41		**Revised Rate Base**	$3,023,209,537	$2,850,034,045	6.08%
42		**Adjusted Rate of Return on Average Rate Base**	6.634%	5.843%	13.54%
43		**Adjusted Rate of Return on Average Equity 1/**	9.080%	7.195%	26.20%
44					
45		1/ Return on Equity calculated using the capital structure approved in Docket No. D2022.7.78.			
46					
47		2/ Rate schedule revenues are adjusted to revenues on a normalized basis by converting actual usage			
48		to normalized usage.			
49					
50		3/ Removal of increase to environmental liability recorded in 2023			
51					
52		4/ Associated income taxes include an interest synchronization adjustment based upon the approved			
53		capital structure in Docket No. D2022.7.78.			
54					
55		5/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting two-thirds of the $38.8 million			
56		allocated to electric as a rate base reduction.			
57					
58		6/ Transmission revenue subject to FERC true-up.			
59					

Sch. 27	cont.	**MONTANA EARNED RATE OF RETURN - ELECTRIC**		
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3				
4	Cost of Refinancing Debt	13,303,415	14,535,400	-8.48%
5	Fuel Stock	2,219,356	1,785,416	24.30%
6				-
7				
8	**Total Other Additions**	$15,522,771	$16,320,816	-4.89%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$3,479,057	$3,511,860	-0.93%
12	Gross Cash Requirements	50,707,505	47,398,184	6.98%
13	Regulatory Liability (TCJA)	69,115,368	68,847,021	0.39%
14	MPSC/MCC Taxes	($2,083,745)	($2,083,745)	0.00%
15	Environmental Reserve	399,087	399,087	0.00%
16	**Total Other Deductions**	$121,617,272	$118,072,407	3.00%
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Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES YNP)		
	Description		Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	4,835,313,068
5	103	Experimental Electric Plant Unclassified	2,987,483
6	105	Plant Held for Future Use	4,110,361
7	107	Construction Work in Progress	311,293,745
8	114	Plant Acquisition Adjustments	481,574,396
9	151-163	Materials & Supplies	46,664,072
10		(Less):	-
11	108, 111, 115	Depreciation & Amortization Reserves	1,774,649,769
12	252	Customer Advances	84,509,399
13	**NET BOOK COSTS**		3,822,783,957
14			-
15		**Revenues & Expenses**	-
16			-
17	400	Operating Revenues	1,094,375,550
18			-
19	**Total Operating Revenues**		1,094,375,550
20			-
21	401-402	Other Operating Expenses (including regulatory amortizations)	614,389,846
22	403-407	Depreciation & Amortization Expenses	144,156,695
23	408.1	Taxes Other than Income Taxes	120,985,493
24	409-411	Federal & State Income Taxes	15,014,212
25	411.8	SO2 Allowances	-
26			-
27	**Total Operating Expenses**		894,546,246
28	**Net Operating Income**		199,829,304
29			-
30	415-421.1	Other Income	12,440,303
31	421.2-426.5	Other Deductions	1,059,395
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 211,210,212
33			-
34		**Average Customers (Intrastate Only)**	-
35		Residential	316,801
36		Commercial & Industrial	74,793
37		Other (including interdepartmental)	3,987
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		395,581
40			0
41		**Other Statistics (Intrastate Only)**	0
42		Average Annual Residential Use (Kwh)	9,046
43		Average Annual Residential Cost per (Kwh)	$0.124
44		Average Residential Monthly Bill	94
45			-
46		Plant in Service (Gross) per Customer	12,223

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,000	478	116	5	599
2	Alberton	452	399	93	15	507
3	Alder	86	235	103	23	361
4	Amsterdam	206	133	42	9	184
5	Anaconda	9,421	4,547	957	63	5,567
6	Armington	-	1	-	-	1
7	Arrow Creek	-	4	3	-	7
8	Augusta	316	273	117	5	395
9	Avon	114	96	65	3	164
10	Barber	-	47	11	1	59
11	Basin	199	170	79	2	251
12	Bearcreek	91	67	26	2	95
13	Belfry	193	174	70	14	258
14	Belgrade	10,460	10,043	2,739	118	12,900
15	Belt	510	651	268	15	934
16	Benchland	-	6	6	-	12
17	Big Sandy	605	333	137	6	476
18	Big Sky	3,591	4,491	1,090	30	5,611
19	Big Timber	1,650	1,286	435	31	1,752
20	Billings	117,116	51,698	9,370	671	61,739
21	Black Eagle	949	456	195	15	666
22	Bonner	1,690	78	66	1	145
23	Boulder	1,201	896	289	26	1,211
24	Box Elder	85	146	70	8	224
25	Bozeman	53,293	36,847	7,722	449	45,018
26	Brady	116	79	35	5	119
27	Bridger	662	464	186	16	666
28	Broadview	139	236	167	2	405
29	Buffalo	-	-	3	5	8
30	Butte	34,494	15,690	2,828	271	18,789
31	Cameron	-	459	139	5	603
32	Canyon Creek	47	197	45	7	249
33	Carter	65	120	76	4	200
34	Cardwell	62	-	1	-	1
35	Cascade	600	1,179	374	29	1,582
36	Centerville	32	13	12	1	26
37	Checkerboard	-	55	9	1	65
38	Chester	847	473	322	15	810
39	Chinook	1,185	811	328	16	1,155
40	Choteau	1,721	1,014	395	26	1,435
41	Churchill	1,030	715	146	30	891
42	Clancy	1,851	941	194	8	1,143
43	Clinton	1,018	106	41	1	148
44	Coffee Creek	22	56	26	1	83
45	Collins	-	1	5	-	6
46	Colstrip	2,096	956	236	37	1,229
47	Columbus	1,857	1,046	364	20	1,430
48	Conrad	2,318	1,254	492	28	1,774
49	Corbin	-	1	3	-	4
50	Corvallis	1,125	925	197	39	1,161
51	Craig	39	96	45	6	147

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Custer	119	2	3	-	5
2	Darby	783	852	283	17	1,152
3	De Borgia	91	162	43	2	207
4	Deer Lodge	2,938	2,160	655	87	2,902
5	Denton	205	174	85	1	260
6	Dillon	3,880	2,159	633	78	2,870
7	Divide	-	73	18	5	96
8	Dodson	125	118	71	5	194
9	Drummond	272	382	238	38	658
10	Dutton	303	242	124	3	369
11	East Helena	1,944	3,544	535	33	4,112
12	Edgar	110	174	62	9	245
13	Elliston	227	219	71	3	293
14	Ennis	917	2,190	663	44	2,897
15	Fairfield	759	410	165	33	608
16	Fishtail	67	51	7	-	58
17	Florence	821	442	162	17	621
18	Floweree	19	106	65	2	173
19	Fort Belknap	1,567	424	105	22	551
20	Fort Benton	1,449	853	391	34	1,278
21	Fort Harrison	-	-	97	3	100
22	Fromberg	392	318	81	10	409
23	Gallatin Gateway	967	970	374	18	1,362
24	Gardiner	833	887	339	12	1,238
25	Garrison	115	137	66	7	210
26	Geraldine	207	284	154	2	440
27	Geyser	78	68	38	3	109
28	Gildford	141	91	69	1	161
29	Glasgow	3,202	1,681	743	59	2,483
30	Glasgow Air Base	-	1	1	-	2
31	Gold Creek	-	87	50	5	142
32	Grantsdale	-	21	3	1	25
33	Great Falls	60,442	30,678	5,709	377	36,764
34	Greycliff	89	51	28	10	89
35	Hall	51	311	97	25	433
36	Hamilton	4,659	5,918	1,560	121	7,599
37	Hardin	3,818	1,411	474	22	1,907
38	Harlem	769	449	209	25	683
39	Harlowton	955	680	295	9	984
40	Harrison	105	203	68	31	302
41	Haugan	58	93	38	2	133
42	Havre	9,362	4,894	1,323	186	6,403
43	Helena	32,091	27,186	5,715	418	33,319
44	Hingham	131	105	75	2	182
45	Hinsdale	193	132	60	5	197
46	Hobson	179	172	69	9	250
47	Huson	256	149	36	2	187
48	Hysham	276	-	1	-	1
49	Inverness	77	43	27	1	71
50	Jardine	47	1	2	-	3
51	Jeffers	25	3	1	-	4

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Jefferson City	597	394	67	4	465
2	Joliet	577	525	161	21	707
3	Joplin	159	101	49	2	152
4	Judith Gap	110	94	56	5	155
5	Kremlin	78	70	39	1	110
6	Laurel	7,222	3,320	563	21	3,904
7	Lavina	136	207	114	15	336
8	Lennep	-	19	14	-	33
9	Lewistown	5,952	3,406	940	62	4,408
10	Lincoln	998	1,116	323	13	1,452
11	Livingston	8,040	5,430	1,268	71	6,769
12	Logan	72	59	27	2	88
13	Lohman	-	30	31	6	67
14	Lolo	4,399	1,690	217	22	1,929
15	Loma	65	70	46	4	120
16	Lothair	-	13	14	-	27
17	Malta	1,860	1,326	528	47	1,901
18	Manhattan	2,086	1,468	431	109	2,008
19	Martinsdale	43	127	89	16	232
20	Marysville	82	77	38	1	116
21	Maxville	138	5	1	-	6
22	McAllister	278	304	66	10	380
23	Melrose	-	2	1	-	3
24	Melstone	126	162	285	20	467
25	Melville	-	68	50	3	121
26	Milltown	-	79	23	4	106
27	Missoula	73,489	40,991	7,032	580	48,603
28	Moccasin	23	47	36	2	85
29	Molt	-	36	38	-	74
30	Monarch	26	336	65	2	403
31	Montana City	2,918	1,231	249	3	1,483
32	Moore	194	110	45	4	159
33	Musselshell	59	67	32	2	101
34	Nashua	301	192	69	3	264
35	Neihart	43	203	46	1	250
36	Nevada City	-	-	8	-	8
37	Norris	46	60	51	4	115
38	Nye	38	17	5	1	23
39	Paradise	166	164	67	9	240
40	Park City	1,023	445	96	5	546
41	Philipsburg	841	2,091	401	26	2,518
42	Plains	1,106	1,867	518	30	2,415
43	Pompey's Pillar	-	1	-	-	1
44	Pony	127	151	38	7	196
45	Power	177	90	46	2	138
46	Pray	790	30	1	1	32
47	Radersburg	61	88	32	1	121
48	Ramsay	-	91	38	1	130
49	Raynesford	31	73	44	2	119
50	Red Lodge	2,257	2,222	445	26	2,693
51	Reedpoint	177	179	61	2	242
52	Ringling	-	42	31	4	77

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Roberts	304	3	-	-	3
2	Rocker	-	68	23	2	93
3	Rockvale	193	2	1	-	3
4	Roscoe	16	98	11	-	109
5	Roundup	1,742	1,129	417	18	1,564
6	Rudyard	270	148	72	2	222
7	Ryegate	223	145	73	7	225
8	Saco	159	169	104	1	274
9	Saint Marie	489	296	54	3	353
10	Saint Regis	313	611	210	12	833
11	Saltese	10	39	23	1	63
12	Sand Coulee	179	160	52	2	214
13	Sapphire Village	-	71	11	-	82
14	Shawmut	42	58	37	2	97
15	Sheridan	694	1,050	291	56	1,397
16	Silesia	103	45	12	-	57
17	Silverbow	-	11	10	-	21
18	Springdale	40	40	12	8	60
19	Square Butte	27	34	19	1	54
20	Stanford	403	348	211	8	567
21	Stevensville	2,002	2,444	673	78	3,195
22	Stockett	157	167	68	1	236
23	Sumatra	-	-	9	-	9
24	Superior	830	975	292	24	1,291
25	Taft	-	-	3	-	3
26	Tampico	-	8	5	-	13
27	Thompson Falls	1,336	1,256	386	32	1,674
28	Three Forks	1,989	1,627	607	78	2,312
29	Toston	100	52	44	24	120
30	Townsend	1,787	1,539	452	23	2,014
31	Tracy	196	89	14	4	107
32	Turah	364	56	2	-	58
33	Twin Bridges	330	323	181	32	536
34	Twodot	26	54	50	6	110
35	Ulm	723	449	141	12	602
36	Utica	23	2	6	1	9
37	Valier	530	377	183	46	606
38	Vaughn	737	244	60	7	311
39	Victor	789	849	321	23	1,193
40	Virginia City	219	218	110	2	330
41	Wagner	-	47	23	2	72
42	Walkerville	639	263	33	3	299
43	Warm Springs	-	-	4	-	4
44	Washoe	-	6	2	-	8
45	West Yellowstone	1,272	2	12	-	14
46	White Sulphur Springs	955	833	412	61	1,306
47	Whitehall	1,006	1,081	347	68	1,496
48	Wickes	-	1	-	-	1
49	Williamsburg	-	1	1	-	2
50	Willow Creek	230	157	69	25	251

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Windham	43	46	32	3	81
2	Winston	169	157	59	3	219
3	Wolf Creek	25	434	176	13	623
4	Yellowstone Club	-	682	15	-	697
5	Zurich	29	-	-	-	-
6		-	-	-	-	-
7		-	-	-	-	-
8		-	-	-	-	-
9		-	-	-	-	-
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49	**Total**	529,292	322,153	74,289	5,755	402,197

1/ Customer populations represent an average of the 12 month period from 01/01/23 through 12/31/23. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	1	0	1
4	Customer Care	150	154	152
5	Finance	57	56	57
6	Information Technology	98	102	100
7	Distribution	404	435	420
8	Asset Management	39	40	40
9	Transmission	312	322	317
10	Supply	129	132	131
11	Legal	23	22	23
12		`	`	
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14				
15				
16				
17				
18				
19	**TOTAL EMPLOYEES**	1,213	1,263	1,238

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2024 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Transmission - Missoula Miller Creek substation rebuild capacity	$19,803,362	$19,803,362
4	MT Distribution - Transformer purchases new connects	8,285,001	8,285,001
5	MT Transmission - Wildfire Mitigation forest mgmt	6,178,969	6,178,969
6	MT Transmission - Capacity upgrades/additions	5,649,299	5,649,299
7	MT Transmission - Pole replacements	5,000,000	5,000,000
8	MT Transmission - Substation auto transformer upgrade	4,865,248	4,865,248
9	MT Transmission - Wildfire Mitigation plan	4,681,257	4,681,257
10	MT Transmission - Substation wildfire mitigation plan	4,500,295	4,500,295
11	MT Distribution - Hamilton North substation capacity	4,277,987	4,277,987
12	MT Transmission - Substation Renova auto rebuild	3,709,329	3,709,329
13	MT Transmission - Bozeman substation Three Rivers Bank 1	3,384,912	3,384,912
14	MT Distribution - Wildfire Mitigation plan	3,145,848	3,145,848
15	MT Transmission - Crooked Falls-Great Falls ES capacity	2,999,999	2,999,999
16	MT Transmission - Great Falls 230 - Eastside capacity	2,999,997	2,999,997
17	SD Distribution - LED Streetlight program	2,973,341	-
18	MT Transmission - Substation capacity Harlem	2,720,532	2,720,532
19	MT Transmission - Bozeman Bradley Creek substation 161 PCB	2,677,430	2,677,430
20	MT Distribution - Great Falls pole replacements	2,440,853	2,440,853
21	MT Distribution - Bozeman westside substation bank 1 capacity	2,094,896	2,094,896
22	MT Transmission - Bridger-Red Lodge B reliability	1,927,134	1,927,134
23	MT Distribution - Billings eastside bank 4 substation upgrade	1,887,835	1,887,835
24	MT Transmission - Substation Gardiner capacity	1,819,256	1,819,256
25	MT Transmission - Billings Baseline substation relays and comms	1,709,262	1,709,262
26	MT Distribution - Wildfire Mitigation Missoula forest mgmt	1,576,226	1,576,226
27	MT Distribution - Helena westside bank 2 substation capacity	1,560,919	1,560,919
28	MT Distribution - Helena pole replacements	1,543,833	1,543,833
29	MT Distribution - Rural Reliability Geraldine resiliency	1,527,253	1,527,253
30	MT Distribution - Butte pole replacements	1,524,768	1,524,768
31	MT Transmission - Clyde Park substation rebuild	1,450,921	1,450,921
32	MT Distribution - Helena Spokane Bench bank 1 substation capacity	1,405,498	1,405,498
33	MT Distribution - Wildfire Mitigation Helena forest mgmt	1,394,545	1,394,545
34	MT Distribution - Bozeman pole replacements	1,318,706	1,318,706
35	MT Distribution - New Manhattan substation	1,304,752	1,304,752
36	MT Transmission - Bitterroot Area Initiative capacity	1,274,521	1,274,521
37	MT Distribution - Billings eastside bank 3 subsation upgrade	1,235,643	1,235,643
38	MT Distribution - Skalkaho cutover	1,225,030	1,225,030
39	MT Transmission - Butte Substation maintenance Mill Creek	1,211,630	1,211,630
40	SD Distribution - Aberdeen A5200 reconductor	1,192,720	-
41	MT Distribution - Butte McQueen substation booster	1,089,807	1,089,807
42	SD Distribution - North Division pole replacements	1,079,210	-
43	MT Distribution - Harrison Pony substation transformer capacity	1,074,770	1,074,770
44	MT Distribution - Deer Lodge 4.16kv cutover	1,073,106	1,073,106
45	MT Distribution - Loweth substation transformer upgrade	1,050,758	1,050,758
46	SD Transmission - Substation upgrade Redfield	1,050,477	-
47	MT Distribution - Livingston cutover	1,045,339	1,045,339
48	MT Distribution - Rockvale substation transformer capacity	1,043,102	1,043,102
49	MT Distribution - Boseman westside sub bank 1 new feeder capacity	1,037,874	1,037,874
50			
51	All Other Projects < $1 Million Each and blankets	83,999,609	63,191,724
52	**Total Electric Utility Construction Budget**	**214,023,059**	**186,919,426**
53			
54	**Natural Gas Operations**		
55	MT Transmission - Mainline 3 South Loop	$22,257,771	$22,257,771
56	MT Transmission - Kalispell capacity upgrade	10,270,090	10,270,090
57	MT Transmission - Telstad reroute	5,680,022	5,680,022
58	MT Transmission - Butte city gate 1 to city gate 3 replace	5,675,645	5,675,645
59	MT Transmission - Vaughn to Sun Prarie MAOP compliance	4,589,602	4,589,602
60	MT Distribution - Butte Base gas one upgrades	3,499,090	$3,499,090
61	MT Transmission - Dry Creek Storage additional cushion gas	2,067,585	2,067,585
62	MT Transmission - New Dry Creek well	1,715,052	1,715,052
63	MT Transmission - Helena tie to Boulder tap	1,622,616	1,622,616
64	MT Transmission - Helena - Three Forks pipeline	1,489,760	1,489,760
65	SD Distribution - Huron relocate town border station flooding/layout	1,281,461	-
66	MT Distribution - Gas meters and regulators new connect	1,257,252	1,257,252
67	MT Transmission - Three Forks compressor	1,203,217	1,203,217
68	MT Transmission - Great Falls city gate 1 and valve set compliance	1,111,832	1,111,832
69	MT Distribution - Bozeman Base gas one upgrades	1,042,150	1,042,150
70	MT Transmission - Belgrade city gate 1 and 2 MAOP compliance	1,013,185	1,013,185
71			
72	All Other Projects < $1 Million Each and blankets	$35,048,563.04	$22,181,588
73	**Total Natural Gas Utility Construction Budget**	**$100,824,893**	**$86,676,457**
74			
75	**Common**		
76	MT Common - Distribution AMI Metering and Infrastructure	$26,319,902	$26,319,902
77	MT Common - Livingston Facility design and construct	4,787,019	4,787,019
78	MT Common - Fleet vehicles and equipment	4,266,996	4,266,996
79	MT Common - Business Technology Enterprise GIS - ESRI	1,663,246	1,663,246
80	SD Common - Fleet Vehicles and equipment	1,075,992	-
81			
82	All Other Projects < $1 Million Each and blankets	$16,823,668.72	$12,832,062
83	(Includes BT, Communications, Facilities, Land, Customer Service)		
84	**Total Common Utility Construction Budget**	**54,936,824**	**49,869,225**
85			
86	**MT/SD Generation**		
87	MT Generation - Yellowstone generation station	$71,867,782	$71,867,782
88	SD Generation - Aberdeen new generation	25,000,000	-
89	MT Generation - CU4 plant upgrades	6,964,389	6,964,389
90	MT Generation - DGGS GG 743179 50k hour overhaul	6,085,061	6,085,061
91	MT Generation - DGGS GG 743177 50k hour overhaul	6,082,978	6,082,978
92	MT Generation - Hydro Cochrane radial hoist upgrade	4,273,603	4,273,603
93	MT Generation - Hydro Holter U2 turbine upgrade	3,497,403	3,497,403
94	MT Generation - Hydro Cochrane U2 turbine upgrade	3,378,758	3,378,758
95	MT Generation - Hydro Hauser U1 turbine upgrade	3,356,125	3,356,125
96	MT Generation - DGGS PT 804400 50k Overhaul	3,221,257	3,221,257
97	MT Generation - DGGS PT 804401 50k Overhaul	3,221,257	3,221,257
98	SD Generation - Mobile Fleet Expansion	2,732,718	-
99	SD Generation - NEAL 4 partner generation	2,255,517	-
100	MT Generation - Hydro Ryan headgate operator upgrade	1,833,835	1,833,835
101	MT Generation - Hydro Holter U2 generator rewind	1,596,259	1,596,259
102	SD Generation - Big Stone partner generation	1,563,012	-
103	MT Generation - Hydro Black Eagle spillway upgrade for ice	1,337,987	1,337,987
104	MT Generation - Thompson Falls relicensing	1,070,282	1,070,282
105			
106	All Other Projects < $1 Million Each and blankets	$9,907,627	$9,242,561
107	**Total MT/SD Generation**	**159,245,849**	**127,029,537**
108	**TOTAL CONSTRUCTION BUDGET**	**$529,030,626**	**$450,494,646**

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	5	19:00	2,214	719,195	71,778
2	February	23	19:00	2,330	743,652	68,180
3	March	10	8:00	2,065	718,921	107,168
4	April	14	9:00	1,906	727,529	66,596
5	May	20	17:00	1,799	565,981	112,259
6	June	28	17:00	1,942	567,285	59,924
7	July	29	19:00	2,295	651,935	94,666
8	August	1	17:00	2,252	686,081	123,059
9	September	7	18:00	1,895	651,188	98,980
10	October	28	10:00	1,978	632,768	132,185
11	November	18	18:00	2,010	754,577	129,598
12	December	22	19:00	2,336	767,186	148,995
13	**TOTALS**				8,186,298	1,213,387
14		**Montana Peak and Energy**				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			SAME AS ABOVE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)	-		
2	Steam	1,648,505		
3	Nuclear	-	**Sales to Ultimate Consumers**	6,321,895
4	Hydro - Conventional	2,483,047	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	620,295	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	4,751,847	Non-Requirement Sales	1,213,387
9	**Purchases**	3,434,127	**Sales for Resale**	1,213,387
10	Power Exchanges	-		
11	Received	28,874		
12	Delivered	28,550	Energy Furnished w/o Charge	
13	**Net Power Exchanges**	324	**Energy Furnished**	-
14	Transmission Wheeling for Others	-	Energy Used Within Utility	
15	Received	13,602,809	Electric Department	
16	Delivered	13,602,809	(Less) Station Use	
17	**Net Transmission Wheeling**	-	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	651,016
19	**TOTAL SOURCES**	8,186,298	**TOTAL DISPOSITIONS**	8,186,298

1/ The megawatts hours listed above do not include sales to billed choice customers, consistent with the presentation used in the corresponding schedule on FERC Form 1. It also includes unbilled consumption of 439,420 megawatt hours.

Sch. 34	SOURCES OF MONTANA ELECTRIC SUPPLY				
	Type	Plant Name	Location	Nameplate Capacity (MW)	Net Generation (Mwh)
1	Steam Generation	Colstrip Unit 4	Colstrip, MT	222.0	1,648,505
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	474,945
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	112,224
4	Wind Generation	Two Dot	Two Dot, MT	11.3	33,126
5	Hydro Generation	Black Eagle	Great Falls, MT	23.9	121,505
6	Hydro Generation	Cochrane	Great Falls, MT	48.9	244,710
7	Hydro Generation	Hauser	Helena, MT	18.7	142,769
8	Hydro Generation	Holter	Helena, MT	53.6	281,585
9	Hydro Generation	Madison	Ennis, MT	12.7	57,714
10	Hydro Generation	Morony	Great Falls, MT	46.5	295,018
11	Hydro Generation	Mystic	Columbus, MT	12.0	62,334
12	Hydro Generation	Rainbow	Great Falls, MT	59.0	394,875
13	Hydro Generation	Ryan	Great Falls, MT	55.2	486,256
14	Hydro Generation	Thompson Falls	Thompson Falls, MT	92.4	396,281
	Total Generation			846.1	4,751,847
		Source of capacity	Seller	Billing Demand (MW)	Annual Energy (Mwh)
15	Qualifying Facility Purchases	Wind	71 Ranch		10,010
16	Qualifying Facility Purchases	Solar	Apex Solar LLC (commercial energy)		53,437
17	Qualifying Facility Purchases	Solar	Apex Solar LLC (test energy)		24,555
18	Qualifying Facility Purchases	Wind	Big Timber Wind		76,384
19	Qualifying Facility Purchases	Thermal	Billings Generation Inc		490,738
20	Qualifying Facility Purchases	Solar	Black Eagle Solar		5,285
21	Qualifying Facility Purchases	Hydro	Boulder Hydro		1,181
22	Qualifying Facility Purchases	Hydro	Broadview East/Two Dot		4,198
23	Qualifying Facility Purchases	Hydro	Cascade Creek		0
24	Qualifying Facility Purchases	Thermal	Colstrip Energy Ltd/Montana One		306,168
25	Qualifying Facility Purchases	Wind	Cycle Horseshoe Bend		4,265
26	Qualifying Facility Purchases	Wind	DA Wind		9,407
27	Qualifying Facility Purchases	Wind	Fairfield Wind		25,760
28	Qualifying Facility Purchases	Hydro	Flint Creek Hydro		10,960
29	Qualifying Facility Purchases	Wind	Gordon Butte Wind		37,246
30	Qualifying Facility Purchases	Solar	Great Divide Solar LLC		5,894
31	Qualifying Facility Purchases	Solar	Green Meadow Solar		5,498
32	Qualifying Facility Purchases	Solar	Greenfield		83,749
33	Qualifying Facility Purchases	Hydro	Hanover Hydro		242
34	Qualifying Facility Purchases	Hydro	Hydrodynamics - Strawberry Creek		376
35	Qualifying Facility Purchases	Hydro	Lower South Fork		647
36	Qualifying Facility Purchases	Solar	Magpie Solar LLC		5,774
37	Qualifying Facility Purchases	Solar	Montana Sun, LLC		152,731
38	Qualifying Facility Purchases	Wind	Musselshell Wind 1		19,483
39	Qualifying Facility Purchases	Wind	Musselshell Wind 2		23,624
40	Qualifying Facility Purchases	Wind	Oversight Resources		9,807
41	Qualifying Facility Purchases	Hydro	Pine Creek		1,232
42	Qualifying Facility Purchases	Hydro	Pony Hydro		458
43	Qualifying Facility Purchases	Solar	River Bend Solar		3,641
44	Qualifying Facility Purchases	Hydro	Ross Creek Hydro		1,696
45	Qualifying Facility Purchases	Hydro	South Dry Creek		2,908
46	Qualifying Facility Purchases	Solar	South Mills Solar 1		5,941
47	Qualifying Facility Purchases	Wind	South Peak Wind		248,245
48	Qualifying Facility Purchases	Hydro	State of Montana-DNRC / Broadwater Dam		39,318
49	Qualifying Facility Purchases	Wind	Stillwater Wind		256,339
50	Qualifying Facility Purchases	Hydro	Strawberry Creek		419
51	Qualifying Facility Purchases	Hydro	Wisconsin Creek		618
52					
53					
54					
55					
56					
57					
58					
59					
60					
	Subtotal			0.0	1,928,234

Sch. 34A	SOURCES OF MONTANA ELECTRIC SUPPLY (continued)				
		see descriptions below	Seller	Annual Peak (MW) 1/	Annual Energy (Mwh)
1	Purchased Power	SF	Avangrid Renewables, LLC		13,398
2	Purchased Power	SF	Avista Corporation		18,538
3	Purchased Power	SF	Basin Electric Power Cooperative		1,200
4	Purchased Power	LU	Basin Creek Energy Partners	52.0	8,760
5	Purchased Power	SF	Black Hills Power Inc		0
6	Purchased Power	SF	Bonneville Power Administration		26,770
7	Purchased Power	SF	Clatskanie Peoples Utility District - Electric		1,613
8	Purchased Power	SF	ConocoPhillips Company		2,546
9	Purchased Power	SF	Constellation Energy Generation, LLC		1,509
10	Purchased Power	SF	Dynasty Power, Inc.		2,576
11	Purchased Power	SF	EDF Trading North America, LLC		23,626
12	Purchased Power	SF	Energy Keepers, Inc.		25,382
13	Purchased Power	SF	Eugene Water & Electric Board		3,921
14	Purchased Power	SF	Guzman Energy, LLC		4,879
15	Purchased Power	SF	Heartland Generation LTD		19,797
16	Purchased Power	SF	Idaho Power Company		1,670
17	Purchased Power	SF	Invenergy Energy Marketing LLC-Electric		417,335
18	Purchased Power	SF	Macquarie Energy LLC		8,674
19	Purchased Power	SF	Morgan Stanley Capital Group, Inc.		417,465
20	Purchased Power	SF	PacifiCorp		2,030
21	Purchased Power	SF	Portland General Electric		48,241
22	Purchased Power	SF	Powerex Corp.		242,110
23	Purchased Power	SF	Puget Sound Energy		28,610
24	Purchased Power	SF	Rainbow Energy Marketing Corporation		6,010
25	Purchased Power	SF	Seattle City Light		7,487
26	Purchased Power	SF	Shell Energy North America (US), L.P.		10,267
27	Purchased Power	LF	Tacoma Power		5,931
	Purchased Power	SF	Talen Energy Marketing, LLC		0
28	Purchased Power	SF	Tenaska Power		635
29	Purchased Power	SF	The Energy Authority, Inc.		70,967
30	Purchased Power	LU	Tiber Montana, LLC	not available	40,714
31	Purchased Power	SF	TransAlta Energy Marketing (US), Inc.		19,017
32	Purchased Power	LU	Turnbull Hydro, LLC	13.0	22,909
33	Purchased Power	SF	Vitol Inc- Electric		80
	Purchased Power	SF	Western Area Power Administation		653
34	Subtotal			65.0	1,505,320
35	Reserve Sharing				574
36	Total Purchases				3,434,127

LF - for long-term firm service

LU - for long-term service from a designated generating unit

SF - for short-term service

Sch. 34B **THERMAL GENERATION OUTAGE REPORT**

This schedule intentionally omitted.

Schedule 34B contains operations data for Colstrip Unit 3 and Colstrip Unit 4 that is considered trade secret and confidential by Talen Montana, LLC (“Talen”).

NorthWestern will provide this schedule upon request, subject to a Commission order in response to Talen’s request to maintain the confidentiality of the data.

THERMAL GENERATION OUTAGE REPORT

Sch. 34C	Unit	Outage Start Date	Description	Outage Duration (hours)
1	**DGGS Unit 1**	1/10/2023	fuel nozzle work	56
3		9/26/2023	borescope inspections	61
13	**DGGS Unit 2**	9/22/2023	borescope inspection	77
15		11/28/2023	Bushing Replacement	28
21	**DGGS Unit 3**	9/21/2023	Replacing U3B Servo	18
23		3/5/2023	engines and Power Turbine"s removed for rebuild	4803

Only outages greater than 12 hours are reported. Does not reflect partial outages of a unit.

Sch. 34D	HYDRO GENERATION OUTAGE REPORT				
	Plant	**Unit Name**	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**Black Eagle**	BE 1	1/1/2023	Unit Overhaul	8,296
2		BE 1	3/13/2023	Turbine inspection	30
3		BE 1	5/10/2023	Replaced bearing staves; worn due to ineffective WFU - plugged & bl	31
4		BE 1	5/30/2023	Marine Bearing Staves	32
5		BE 1	6/1/2023	Poor WFU performance; marine bearing staves	24
6		BE 1	6/11/2023	Poor WFU performance; High Vibrations, Check Marine Bearing	50
7		BE 2	6/14/2023	Poor WFU performance; vib levels sheared bolts around marine bear	36
8		BE 2	6/17/2023	Poor WFU performance; re-stave marine bearing.	54
9		BE 2	6/24/2023	Poor WFU performance; Vibration issues	50
10		BE 3	9/05/2023	Annual Maintenance	531
11		BE 3	12/12/2023	Unit Overhaul/ Testing	19
12		BE 3	12/13/2023	Unit overhaul/ testing	17
13		BE 3	12/20/2023	Exciter ground fault detected	17
14		BE 3	12/21/2023	Exciter ground fault detected	252
15					
16	**Cochrane**	CCH 1	1/01/2023	Divers remove debris from screens	199
17		CCH 2	2/12/2023	Unit upgrades	52
18					
19	**Hauser**	HAU 1	5/24/2023	Failed pressure switch on governor shutdown circuit	22
20		HAU 1	9/13/2023	Transformer work	33
21		HAU 1	9/14/2023	Generator Overhaul	2,601
22		HAU 2	1/5/2023	Bearing oil leak	146
23		HAU 2	1/11/2023	Bearing oil leak	643
24		HAU 2	2/07/2023	Governor issues: hydraulic hoses swapped during reassembly	150
25		HAU 2	8/07/2023	Annual Maintenance	50
26		HAU 2	9/13/2023	Transformer work	35
27		HAU 3	8/21/2023	Annual Maintenance	197
28		HAU 3	9/13/2023	Transformer work	35
29		HAU 3	9/14/2023	Bearing issues	15
30		HAU 4	4/03/2023	Annual Maintenance	103
31		HAU 4	9/12/2023	Transformer work	35
32		HAU 4	9/14/2023	PLC/ Com issues	28
33		HAU 5	2/20/2023	repair hydraulic oil leak	415
34		HAU 5	9/12/2023	Transformer work	35
35		HAU 5	9/14/2023	Cooling water filtration issues	15
36		HAU 5	10/30/2023	Headgate work	54
37		HAU 6	4/17/2023	Annual Maintenance	76
38		HAU 6	4/20/2023	Upstream end of shaft broke at previous repair location (Sep 2020)	2,350
39		HAU 6	9/12/2023	Transformer work	34
40					
41	**Holter**	HLT 1	1/1/2023	Major generator and turbine overhaul	8,149
42		HLT 2	12/8/2023	Overhaul	562
43		HLT 3	1/1/2023	High temp on upper guide bearing	425
44		HLT 3	4/13/2023	Servo seal blew out	174
45		HLT 3	12/7/2023	Annual Inspection outage	30
46		HLT 4	5/1/2023	annual maintenance	242
47					
48	**Madison**	MAD 1	5/23/2023	Headgate Work	31
49		MAD 1	5/24/2023	Flowline Headgate wouldn't open	65
50		MAD 1	9/12/2023	Spillgate upgrade	1,031
51		MAD 1	10/25/2023	Spillgate upgrade	1,625
52		MAD 2	05/23/2023	Headgate Work	31
53		MAD 2	05/24/2023	Flowline Headgate wouldn't open	65
54		MAD 2	9/12/2023	Spillgate upgrade	1,031
55		MAD 2	10/25/2023	Spillgate upgrade	1,625
56		MAD 3	05/23/2023	Headgate Work	31
57		MAD 3	5/24/2023	Flowline Headgate wouldn't open	65
58		MAD 3	9/12/2023	Spillgate work	1,031
59		MAD 3	10/25/2023	Spillgate upgrade	1,625
60		MAD 4	05/23/2023	Headgate Work	31
61		MAD 4	5/24/2023	Flowline Headgate wouldn't open	65
62		MAD 4	9/12/2023	Spillgate work	1,031
63		MAD 4	10/25/2023	Spillgate upgrade	1,625

Sch. 34E	HYDRO GENERATION OUTAGE REPORT			
Plant	**Unit Name**	**Outage Start Date**	**Description**	**Outage Duration (hours)**
Morony				
	MOR 1	1/9/2023	Annual inspection and maintenance	171
	MOR 1	5/24/2023	NERC Testing	32
	MOR 1	11/1/2023	relay replacement/ battery work	32
	MOR 2	1/23/2023	Annual Maintenance and Inspection	171
	MOR 2	5/24/2023	NERC Testing	32
	MOR 2	11/1/2023	relay replacement/ battery work	32
Mystic	MYS 1	4/24/2023	Annual Maintenance	174
	MYS 2	5/01/2023	Headgate Inspection	80
Rainbow	RNB 9	3/22/2023	Annual Maintenance and Inspection	199
	RNB 9	9/09/2023	Governor problems	23
	RNB 9	9/10/2023	Governor Problems	18
	RNB 9	9/12/2023	Governor problems	15
	RNB 9	10/08/2023	Governor Issues	25
	RNB 9	12/05/2023	Governor Trouble	15
	RNB 9	12/06/2023	Governor Trouble	19
Ryan	RYN 2	3/21/2023	Divers doing headgate inspection	29
	RYN 2	3/22/2023	Thrust bearing oil pot level indication	21
	RYN 2	7/31/2023	Annual Maintenance	105
	RYN 3	12/04/2023	Annual maintenance	77
	RYN 4	8/24/2023	Annual Maintenance	150
	RYN 4	8/30/2023	Wiped thrust bearing due to low oil level during startup	1369
	RYN 5	7/24/2023	Annual Maintenance	75
	RYN 6	8/14/2023	Annual maintenance	82
Thompson Falls	THF 1	4/05/2023	Divers doing intake inspection	309
	THF 1	7/20/2023	Annual Maintenance	703
	THF 1	11/13/2023	Transformer and relay work	96
	THF 2	4/05/2023	Divers doing intake inspection	24
	THF 2	4/11/2023	Annual Inspection and Maintenance	487
	THF 2	11/13/2023	Transformer and relay work	1168
	THF 3	3/21/2023	Annual Maintenance and Inspection	363
	THF 3	4/05/2023	Divers doing intake inspection	48
	THF 3	11/13/2023	transformer and relay work	339
	THF 4	2/28/2023	Annual Maintenance and Inspection	870
	THF 4	4/05/2023	Divers doing intake inspection	309
	THF 4	11/27/2023	GSU/ Transformer testing	825
	THF 5	4/05/2023	Divers doing intake inspections	309
	THF 5	11/27/2023	GSU/ Transformer testing	825
	THF 6	2/06/2023	Annual inspection and maintenance	744
	THF 6	4/05/2023	Divers doing intake inspection	24
	THF 6	8/01/2023	Lack of water/ breaker test	19
	THF 6	11/27/2023	GSU/Transformer testing	71
	THF 7	2/24/2023	Needle Ice blocking inlet to bearing cooling water.	13
	THF 7	9/11/2023	Annual Maintenance	536
	THF 7	10/12/2023	Cooling water issues	452

Only outages greater than 12 hours are reported. Low water events are excluded.

Sch. 35	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS					
Program Description (These are Electric DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (MW & MWh)	Achieved Savings (MW & MWh)	Difference (MW & MWh)
2023 Residential Lighting Program*	$ 1,391,537	$ 2,070,981	-33%	-	-	-
- Initiated 2005, 2023 weighted average program life = 10 years, 4 participants.				3,977	6,467	2,490
2023 Residential Electric Existing Program	$ 115,055	$ 46,482	148%	-	-	-
- Reinitiated 2021, 202 weighted average program life = 16 years, 473 participants.				648	1,054	406
2023 Residential Electric New Construction Program	$ 12,994	$ 3,945	229%	-	-	-
- Reinitiated 2021, 2023 weighted average program life = 18 years, 9 participants.				44	71	27
2023 Commercial Lighting Program	$ 3,521,789	$ 4,605,990	-24%	-	-	-
- Initiated 2005, 2023 weighted average program life = 14 years, 749 participants.				17,643	28,688	11,045
2023 Electric Business Partners Program	$ 204,219	$ 593,839	-66%	-	-	-
- Initiated 2005, 2023 weighted average program life = 17 years, 3 participants.				374	607	234
2023 Northwest Energy Efficiency Alliance (NEEA)**	$ 1,284,200	$ 1,605,973	-20%	-	-	-
- Initiated electric savings in 2006, program life is 15 years				6,904	11,225	4,322
2023 Commercial Electric New Construction Program	$ 285,008	$ 610,609	-53%	-	-	-
- Initiated 2005, 2023 weighted average program life = 14 years, 24 participants.				2,521	4,099	1,578
2023 Commercial Electric Savings Program	$ 202,466	$ 992,906	-80%	-	-	-
- Initiated 2005, 2022 weighted average program life = 14 years, 30 participants.				915	1,488	573
2023 General Expenses All Electric DSM Programs	$ 189,340	$28,125	573%	-	-	-
- N/A				-	-	-
TOTAL	$ 7,206,608	$ 10,558,850	-31.75%	-	-	-
				33,025	53,699	20,674

A program participant is a Montana residential and/or commercial electric customer who installs eligible energy conservation measures and receives financial incentives/rebates either directly or indirectly.

* Number of participants cannot be counted for the Manufacturer Buydown portion of the E+ Residential Lighting Program.

**Note: 2023 NEEA expeditures are allocated to electric DSM but there are gas savings as a result of some NEEA initiatives. Participant has not been defined or counted for NEEA.

Units reported are in megawatts ("MW") and megawatt-hours ("MWh")

Sch. 35a	Electric Universal System Benefits Programs						
	Program Description	Actual	Contracted or	Total	Expected savings		Most recent
1	Local Conservation				MWh	MW	
2	Energy Audit Program	$ 435,865	$ 736,213	$ 1,172,078	179	0.02	2012
3	Irrigation Projects	$ 26,637	$ 3,960	$ 30,597	203		2012
4	NWE Promotion	$ 2,383	$ -	$ 2,383			
5	NWE Labor	$ 17,957	$ -	$ 17,957			
6	NWE Admin. Non-labor	$ 1,408	$ -	$ 1,408			
7	USB Interest & Svc Chg	$ (11,140)	$ -	$ (11,140)			
8	Market Transformation						
9	Motor Management Training	$ -	$ -	$ -			
10	Energy Star Homes	$ 45,465	$ 59,728	$ 105,193			
11	Building Operator Certification	$ 71,912	$ 71,200	$ 143,112	794		2012
12	Regional Mkt Transformation	$ 33,000	$ 155,610	$ 188,610			
13	Cold Climate Ductless Heat Pump (Pilot)	$ 24,178	$ 346,900	$ 371,078			
14	Heat Pump Water Heater (Pilot)	$ 85,390	$ 523,450	$ 608,840	2		
15	Lighting Controls (Pilot)	$ 150,289	$ 393,193	$ 543,482			
16	NWE Promotion	$ 7,528	$ -	$ 7,528			
17	NWE Labor	$ 63,338	$ -	$ 63,338			
18	NWE Admin. Non-labor	$ 3,919	$ -	$ 3,919			
19	USB Interest & Svc Chg	$ (7,113)	$ -	$ (7,113)			
20	Renewable Resources						
21	Generation/Education	$ 706,200	$ 1,165,452	$ 1,871,652	0.5		2012
22	Green Power Product Offering	$ (16,389)	$ 94,019	$ 77,629			
23	NWE Promotion	$ -	$ -	$ -			
24	NWE Labor	$ 59,706	$ -	$ 59,706			
25	NWE Admin. Non-labor	$ 55	$ -	$ 55			
26	USB Interest & Svc Chg	$ (11,961)	$ -	$ (11,961)			
27	Research & Development						
28	R&D/ Infrastructure	$ 151,227	$ 154,470	$ 305,697			
29	NWE Promotion	$ 250	$ -	$ 250			
30	NWE Labor	$ 18,243	$ -	$ 18,243			
31	NWE Admin. Non-labor	$ 17	$ -	$ 17			
32	USB Interest & Svc Chg	$ (3,721)	$ -	$ (3,721)			
33	Low Income						
34	Bill Discount	$ 2,974,391	$ -	$ 2,974,391			
35	Free Weatherization	$ 1,908,688	$ 3,112,608	$ 5,021,296	121		2012
36	Elec Wx Incentives	$ 18,196	$ -	$ 18,196			
37	Fuel Switch Analyses	$ -	$ -	$ -			
38	Energy Share	$ 289,000	$ -	$ 289,000			
39	Low Income	$ -	$ 1,938,948	$ 1,938,948			
40	NWE Promotion	$ 54,939	$ -	$ 54,939			
41	NWE Labor	$ 23,965	$ -	$ 23,965			
42	NWE Admin. Non-labor	$ 1,130	$ -	$ 1,130			
43	USB Interest & Svc Chg	$ (107,865)	$ -	$ (107,865)			
44	Large Customer						
45	Self-Directed Energy Reduction	$ 2,854,872	$ 1,050,526	3,905,398			
46	Self-Directed to Low Income	$ 626,235	$ -	626,235			
47	NWE Reallocate to Free Weatherization	$ 24,902	$ 41	24,943			
48	NWE Reallocate to Low Income	$ -	$ 65,841	65,841			
49	NWE Labor	$ 8,240	$ -	8,240			
50	Admin. Non-labor	$ -	$ -	0			
51	USB Interest & Svc Chg	$ (73,931)	$ -	(73,931)			
52	Total	$ 10,457,408	$ 9,872,159	$ 20,329,567	1,298	0.02	
53	Number of customers that received low income rate discounts				11,364		
54	Average monthly bill discount amount ($/mo)				$ 21.81		
55	Average LIEAP-eligible household income				n/a		
56	Number of customers that received weatherization assistance				162		
57	Expected average annual bill savings from weatherization				744	Kwh	
58	Number of residential audits performed				341		
59	Number of residential audits performed (mail in survey)				-		
60	Number of residential virtual assessments performed				484		
61	[a] Total expenditures are reported for the combination of 2020 - 2023 electric USB funds spent in 2023. Total allocations are reported for the combination						
62	Funds carried forward to 2024 as allowed by statute and with extensions of time granted by the Department of Revenue as allowed by Administrative Rules						

Sch. 35b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Electric USB Programs)	Actual Current Year Expenditures	Contracted or Committed to Spend	Total Allocations & Expenditures [a]	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2 3	E+ Energy Audit for the Home or Business	$ 435,865	$ 736,213	$ 1,172,078	0.02 179	2012
4 5	E+ Electric Business Partners Program / Irrigation	$ 26,637	$ 3,960	$ 30,597	- 203	2012
6	Market Transformation					
7 8	Motor Management Training	$ -	$ -	$ -	- -	2012
9 10	Energy Star Homes	$ 45,465	$ 59,728	$ 105,193	- -	2012
11 12	Building Operator Certification	$ 71,912	$ 71,200	$ 143,112	- 794	2012
13 14	Regional Market Transformation	$ 33,000	$ 155,610	$ 188,610	- -	2012
15 16	Cold Climate Ductless Heat Pump (Pilot)	$ 24,178	$ 346,900	$ 371,078	- -	
17 18	Heat Pump Water Heater (Pilot)	$ 85,390	$ 523,450	$ 608,840	- 1.78	
19 20	Lighting Controls (Pilot)	$ 150,289	$ 393,193	$ 543,482	- -	
21	Renewables					
22 23	Generation/Education	$ 706,200	$ 1,165,452	$ 1,871,652	- 0.47	2012
24 25	Green Power Product	$ (16,389)	$ 94,019	$ 77,629	- -	2012
26	Research & Development					
27 28	R&D / Infrastructure	$ 151,227	$ 154,470	$ 305,697	- -	2012
29	Low Income					
30 31	Free Weatherization	$ 1,908,688	$ 3,112,608	$ 5,021,296	- 121	2012
32 33	Elec Wx Incentives	$ 18,196	$ -	$ 18,196	- -	2012
34 35	Fuel Switch	$ -	$ -	$ -	- -	2012
36 37	Total	$ 3,640,658	$ 6,816,803	$ 10,457,461	0.02 1,296	2012
38	[a] Total expenditures are reported for the combination of 2020 - 2023 electric USB funds spent in 2023. Total allocations are reported for the combination of 2020 - 2023 electric USB funds expected to be spent in 2024.					
39	Funds carried forward to 2024 as allowed by statute and with extensions of time granted by the Department of Revenue as allowed by Administrative Rules (ARM) of Montana.					

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES YNP)						
		Operating Revenues 1/		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$ 408,083,607	$356,192,072	2,793,132	2,865,835	322,153	316,801
4	Commercial & Industrial	483,741,102	415,702,911	6,521,962	6,468,366	76,092	74,793
5	Public Street & Highway Lighting	17,093,930	14,388,533	28,190	30,777	3,608	3,624
6	Sales to Other Utilities	86,727,064	51,420,884	1,213,387	1,058,843	24	21
7	Interdepartmental	1,031,286	879,131	7,562	7,442	344	342
8							
9	**TOTAL SALES**	$996,676,989	$838,583,531	10,564,233	10,431,263	402,221	395,581
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							