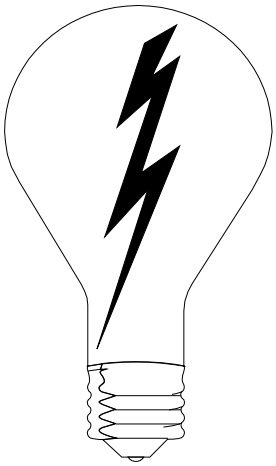
YEAR ENDING 2024

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY

Docket 2025.01.001



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

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

Respondent is a wholly-owned, direct subsidiary of NorthWestern Energy Group, Inc. At December 31, 2024, 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 No. 1 page	
3	105 for our Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1			
2	President and Chief Operating Officer	Executive	Brian Bird
3			
4	Vice President,	Legal Services	Shannon Heim
5	General Counsel and Federal Government Affairs	Corporate Secretary	
6		Risk Management	
7		Contracts	
8		Federal Governmental Affairs	
9			
10	Vice President,	Asset and Project Management	Bleau LaFave
11	Asset Management & Business Development	Business Development and Strategic Support	
12			
13	Vice President, Distribution	Distribution Operations - MT/SD/NE	Jason Merkel
14		Construction	
15		Substation Operations	
16		Wildfire Operations	
17			
18	Vice President, Transmission	Transmission Planning, Engineering, Construction,	Michael Cashell
19		and Operations	
20		Gas Transmission & Storage	
21		Transmission Policy, Services, and Operations	
22		Transmission Market Strategy	
23		Grid Real Time and Scada Operations	
24		FERC and NERC Compliance	
25		Support Services	
26			
27	Vice President,	Thermal and Wind Generation	John Hines
28	Supply and Montana Government Affairs	Hydro Operations	
29		Environmental and Lands Permitting & Compliance	
30		Long Term Resources	
31		Energy Supply Marketing Operations	
32		Montana Government Affairs	
33			
34	Vice President,	Brand, Advertising, and	Bobbi Schroeppel
35	Customer Care, Communications and	Customer Communications	
36	Human Resources	Customer Experience and Support	
37		Customer Interaction	
38		Community Connections	
39		Revenue Cycle Management	
40		Human Resources	
41		Safety/Health/Environmental Services	
42		DSM and Energy Efficiency	
43		Sustainability	
44			
45	Vice President & Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
46		Financial Planning & Analysis	
47		Controller and Treasury Functions	
48		Investor Relations and Corporate Finance	
49		Flight Services	
50		Regulatory Affairs	
51		Governmental Affairs - Nebraska and South Dakota	
52		Enterprise Risk and Business Continuity	
53			
54	Vice President, Technology	Business Technology	Jeanne Vold
55		Customer Systems & Solutions	
56		Data & Analytics	
57		Operation Technology	
58		Security	
59			

Reflects active officers as of December 31, 2024

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 180,078**	**100.00 %**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipeline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
Unregulated Operations		**$ —**	**— %**
Direct Subsidiaries:			
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Total Corporation		**$ 180,078**	**100.00 %**

Sch. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1						
2						
3						
4	Executive Department	Includes the following departments:	Overhead costs not charged directly are	$4,885,116	78.10 %	$1,369,656
5		CEO and Board of Directors	typically allocated based on a 3-factor formula			
6			consisting of gross plant, labor, and margin.			
7						
8	Legal Department	Includes the following departments:	Overhead costs not charged directly are	27,628,155	83.94 %	5,285,028
9		Chief Legal and Risk Management	typically allocated based on a 3-factor formula			
10			consisting of gross plant, labor, and margin.			
11						
12	Regulatory Affairs	Includes the following departments:	Overhead costs not charged directly are	1,526,618	65.08 %	819,042
13		Regulatory Affairs MT, SD & NE Public and Regulatory Affairs	typically allocated based on a 3-factor formula			
14			consisting of gross plant, labor, and margin.			
15						
16	Finance	Includes the following departments: CFO, Treasury, FP&A	Overhead costs not charged directly are	20,747,534	80.35 %	5,073,321
17		Tax , Investor Relations, Corporate Aircraft,	typically allocated based on a 3-factor formula			
18		and Compensation & Benefits	consisting of gross plant, labor, and margin.			
17						
18	Controller	Includes the following departments: Controller, Accounting	Overhead costs not charged directly are	5,805,939	80.07 %	1,445,158
17		Accounts Payable, Payroll, Financial Reporting & Regulatory Affairs Finance	typically allocated based on a 3-factor formula			
18			consisting of gross plant, labor, and margin.			
19						
20	Audit & Controls	Includes the following departments:	Overhead costs not charged directly are	1,016,574	79.00 %	270,229
21		Internal Audit and Enterprise Risk Management	typically allocated based on a 3-factor formula			
22			consisting of gross plant, labor, and margin.			
23						
24	Business Technology	Includes the following departments:	Overhead costs not charged directly are	22,500,547	79.32 %	5,864,517
25		Applications, Architecture, Governance	typically allocated based on a 3-factor formula			
26			consisting of gross plant, labor, and margin.			
27						
28	Corporate Facilities	Includes the following departments:	Overhead costs not charged directly are	82,179	31.27 %	180,603
29		Sioux Falls Facilities and Helena Building	typically allocated based on a 3-factor formula			
30			consisting of gross plant, labor, and margin.			
31						
32	Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE	Overhead costs not charged directly are	25,464,061	75.57 %	8,231,999
33		CC MT, CC - Assoc & Dispatch, Business Develop and Regulatory Support	typically allocated based on a 3-factor formula			
34		Human Resources, Print Services and Charitable Contributions	consisting of gross plant, labor, and margin.			
35						
36						
37						
38						
39						
40	**TOTAL**			$ 109,656,723	79.35 %	$ 28,539,553

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 Affiliates**					
3	NorthWestern Energy Group, Inc.	Board of Director Fees	Actual Expense	$ 1,400,076		$ 1,400,076
4	**Total Nonutility Affiliates**			$1,400,076		$1,400,076
6						
7						
8						
9	**Utility Affiliates**					
10	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,158,465		
11		transmission, & compression	transmission & compression			
12			are at tariffed rates			
13	**Total Utility Affiliates**			$2,158,465		$0
14	**TOTAL AFFILIATE TRANSACTIONS**			$3,558,541		$1,400,076

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 Affiliates**					
3	NorthWestern Energy Group, Inc.	Labor and Benefits	Actual Expense	$ 49,800	4.40 %	$ 49,800
4						
5						
6	**Total Nonutility Affiliates**			$49,800		$49,800
8						
9						
10						
11	**Utility Affiliates**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	511,733	15.20 %	511,733
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,293,304	38.40 %	1,293,304
15	NorthWestern Energy Public Service Corporation	Labor Cost	Actual Expense	39,301,336	56.50 %	$ 39,301,336
16	**Total Utility Affiliates**			41,106,373		$ 41,106,373
17						
18	**TOTAL AFFILIATE TRANSACTIONS**			41,156,173		$ 41,156,173

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	$ 1,027,480,707	$ 31,913,086	995,567,621	$ 1,094,375,550	(9.03)%
3						
4	**Total Operating Revenues**	1,027,480,707	31,913,086	995,567,621	1,094,375,550	(9.03)%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	498,891,272	29,023,717	469,867,555	550,978,118	(14.72)%
9	402 Maintenance Expense	40,796,831	498,262	40,298,569	36,873,160	9.29 %
10	403 Depreciation Expense	135,832,344	(1,291,774)	137,124,118	126,931,631	8.03 %
11	404-405 Amort. of Electric Plant	8,776,685	10	8,776,675	8,175,538	7.35 %
12	406 Amort. of Plant Acquisition Adj.	9,049,525	—	9,049,525	9,049,525	0.00 %
13	407.3 Regulatory Amortizations - Debit	27,630,970	188,918	27,442,052	51,008,737	(46.20)%
14	407.4 Regulatory Amortizations - Credit	(57,321,723)	—	(57,321,723)	(24,470,168)	(134.25)%
15	408.1 Taxes Other Than Income Taxes	127,004,398	22,718	126,981,680	120,985,493	4.96 %
16	409.1 Income Taxes - Federal	(1,193,788)	(173,012)	(1,020,776)	(182,193)	>-300.00%
17	- Other	(659,390)	(59,637)	(599,753)	(600,182)	0.07 %
18	410.1 Deferred Income Taxes-Dr.	239,654,591	1,857,820	237,796,771	178,010,098	33.59 %
19	411.1 Deferred Income Taxes-Cr.	(220,938,758)	(1,344,567)	(219,594,191)	(162,084,029)	(35.48)%
20	411.4 Investment Tax Credit Adj.	1,970,244	—	1,970,244	(129,482)	>300.00%
21	411.6 Gain from Disposition of Property	—	—	—	—	0.00 %
22	411.7 Loss from Disposition of Property	—	—	—	—	0.00 %
23	411.8 SO2 Allowances	—	—	—	—	0.00 %
24						
25	**Total Operating Expenses**	809,493,201	28,722,455	780,770,746	894,546,246	(12.72)%
26	**NET OPERATING INCOME**	$ 217,987,506	$ 3,190,631	$ 214,796,875	$ 199,829,304	7.49 %

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	$ 398,789,874	$ 9,197,370	$ 389,592,504	$ 408,083,607	(4.53)%
5	442 Commercial	408,976,796	15,516,419	393,460,377	425,884,148	(7.61)%
6	Industrial	60,430,764	7,025,926	53,404,838	57,856,955	(7.70)%
7	444 Public Street, Highway Lighting	—	—	—	—	-
8	& Other Sales to Public Authorities	14,857,439	88,819	14,768,620	17,093,930	(13.60)%
9	448 Interdepartmental Sales	886,039	21,158	864,881	1,031,286	(16.14)%
10						
11	**Total Sales to Ultimate Consumers**	883,940,912	31,849,692	852,091,220	909,949,926	(6.36)%
12	447 Sales for Resale	36,084,608	—	36,084,608	86,727,064	(58.39)%
13						
14	**Total Sales of Electricity**	920,025,520	31,849,692	888,175,828	996,676,989	(10.89)%
15	449.1 Provision for Rate Refunds	—	—	—	—	-
16						
17	**Total Revenue Net of Rate Refunds**	920,025,520	31,849,692	888,175,828	996,676,989	(10.89)%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	—	—	—	—	-
21	451 Miscellaneous Service Revenue	93,984	475	93,509	(8,165)	>300.00%
22	453 Sales of Water & Water Power	—	—	—	—	-
23	454 Rent From Electric Property	4,255,667	—	4,255,667	4,528,992	(6.04)%
24	456 Other Electric Revenues	103,105,536	62,919	$ 103,042,617	93,177,734	10.59 %
25						
26	**Total Other Operating Revenue**	107,455,187	63,394	107,391,793	97,698,561	9.92 %
27	**TOTAL OPERATING REVENUE**	$ 1,027,480,707	$ 31,913,086	$ 995,567,621	$ 1,094,375,550	(9.03)%

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	53,571	—	53,571	53,473	0.18 %
5	501 Fuel	32,828,350	—	32,828,350	36,168,095	(9.23)%
6	502 Steam Expenses	1,447,837	—	1,447,837	1,394,076	3.86 %
7	503 Steam from Other Sources	—	—	—	—	-
8	505 Electric Plant	274,631	—	274,631	403,193	(31.89)%
9	506 Miscellaneous Steam Power	2,718,070	—	2,718,070	2,839,102	(4.26)%
10	507 Rents	—	—	—	—	-
11	**Total Operation-Steam Power Gen.**	37,322,459	—	37,322,459	40,857,939	(8.65)%
12	**Steam Power Generation-Maintenance**					
13	510 Supervision & Engineering	409,166	—	409,166	270,438	51.30 %
14	511 Structures	841,135	—	841,135	734,202	14.56 %
15	512 Steam Boiler Plant	7,173,388	—	7,173,388	4,974,170	44.21 %
16	513 Electric Plant	1,387,575	—	1,387,575	531,996	160.82 %
17	514 Miscellaneous Steam Plant	493,370	—	493,370	478,815	3.04 %
18	**Total Maintenance-Steam Power Gen.**	10,304,634	—	10,304,634	6,989,621	47.43 %
19	**Total Steam Power Generation**	47,627,093	—	47,627,093	47,847,560	(0.46)%
20	**Hydro Power Generation-Operation**					
21	535 Supervision & Engineering	1,064,069	—	1,064,069	773,199	37.62 %
22	536 Water for Power	1,004,649	—	1,004,649	1,010,210	(0.55)%
23	537 Hydraulic Expenses	4,131,752	—	4,131,752	3,726,277	10.88 %
24	538 Electric Expenses	3,528,125	—	3,528,125	3,430,921	2.83 %
25	539 Miscellaneous Hydraulic Power	2,361,963	—	2,361,963	3,025,811	(21.94)%
26	540 Rents	842,469	—	842,469	824,957	2.12 %
27	**Total Operation-Hydro Power Gen.**	12,933,027	—	12,933,027	12,791,375	1.11 %
28	**Hydro Power Generation-Maintenance**					
29	541 Supervision & Engineering	921,622	—	921,622	650,985	41.57 %
30	542 Structures	342,314	—	342,314	507,445	(32.54)%
31	543 Reservoirs, Dams & Waterways	148,326	—	148,326	151,023	(1.79)%
32	544 Electric Plant	821,098	—	821,098	1,036,087	(20.75)%
33	545 Miscellaneous Hydro Plant	88,700	—	88,700	211,995	(58.16)%
34	**Total Maintenance-Hydro Power Gen.**	2,322,060	—	2,322,060	2,557,535	(9.21)%
35	**Total Hydraulic Power Generation**	15,255,087	—	15,255,087	15,348,910	(0.61)%
36	**Other Power Generation-Operation**					
37	546 Supervision & Engineering	512,657	—	512,657	485,709	5.55 %
38	547 Fuel	16,452,550	383,682	16,068,868	20,451,291	(21.43)%
39	548 Generation Expenses	4,395,712	60,020	4,335,692	3,894,750	11.32 %
40	549 Miscellaneous Other Power	857,099	9,022	848,077	790,697	7.26 %
41	550 Rents	—	—	—	—	-
42	**Total Operation-Other Power Gen.**	22,218,018	452,724	21,765,294	25,622,447	(15.05)%
43	**Other Power Generation-Maintenance**					
44	551 Supervision & Engineering	—	—	—	—	-
45	552 Structures	—	—	—	—	-
46	553 Generating & Electric Plant	1,719,640	111,955	1,607,685	1,300,873	23.59 %
47	554 Miscellaneous Other Power Plant	34,147	200	33,947	93,563	(63.72)%
48	**Total Maintenance-Other Power Gen.**	1,753,787	112,155	1,641,632	1,394,436	17.73 %
49	**Total Other Power Generation**	23,971,805	564,879	23,406,926	27,016,883	(13.36)%
50	**Other Power Supply Expenses**					
51	555 Purchased Power	256,772,116	35,413,300	221,358,816	264,332,114	(16.26)%
52	556 System Control & Load Dispatch	—	—	—	—	-
53	557 Other Expenses	15,042,672	(7,606,454)	22,649,126	62,910,866	(64.00)%
54	**Total Other Power Supply Expenses**	271,814,788	27,806,846	244,007,942	327,242,980	(25.44)%
55	**Total Power Production Expenses**	358,668,773	28,371,725	330,297,048	417,456,333	(20.88)%

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						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	3,082,102	—	3,082,102	2,877,263	7.12 %
6	561 Load Dispatching	—	—	—	—	-
7	561.1 Load Dispatch - Reliability	953,566	—	953,566	920,115	3.64 %
8	561.2 Load Disp-Monitor/Op	883,163	—	883,163	878,169	0.57 %
9	561.3 Load Disp-Srv/Schedu	1,088,750	—	1,088,750	1,146,993	(5.08)%
10	561.4 Relia Pln/StdDev-RTO	—	—	—	—	-
11	561.5 Reliab, Plan, Stds	—	—	—	—	-
12	561.6 Transmission Service Studies	—	—	—	—	-
13	561.8 Sch,Sys&Ctrl Srv-RTO	—	—	—	—	-
14	562 Station Expenses	1,694,747	—	1,694,747	1,893,265	(10.49)%
15	563 Overhead Lines	1,113,452	90,641	1,022,811	705,716	44.93 %
16	564 Underground Lines	—	—	—	—	-
17	565 Transmission of Elec. by Others	6,395,363	—	6,395,363	6,685,938	(4.35)%
18	566 Miscellaneous Transmission	117,177	—	117,177	161,951	(27.65)%
19	567 Rents	1,285,765	—	1,285,765	1,032,912	24.48 %
20	**Total Operation-Transmission**	16,614,085	90,641	16,523,444	16,302,323	1.36 %
21	**Transmission-Maintenance**					-
22	568 Supervision & Engineering	594,405	—	594,405	478,209	24.30 %
23	569 Structures	22,308	4,025	18,283	20,709	(11.71)%
24	569.1 Maintenance of Computer Hardware	1,381,160	—	1,381,160	1,312,307	5.25 %
25	569.2 Maintenance of Computer Software	3,125	—	3,125	13,110	(76.16)%
26	569.3 Maint-Comm Equip	—	—	—	—	-
27	570 Station Equipment	677,570	6,390	671,180	673,956	(0.41)%
28	571 Overhead Lines	2,096,311	173,233	1,923,078	2,545,748	(24.46)%
29	572 Underground Lines	—	—	—	—	-
30	573 Miscellaneous Transmission Plant	—	—	—	—	-
31	**Total Maintenance-Transmission**	4,774,879	183,648	4,591,231	5,044,039	(8.98)%
32	**Total Transmission Expenses**	21,388,964	274,289	21,114,675	21,346,362	(1.09)%
33						-
34	**Regional Market Operation**					-
35	575.1 Operation Supervision	—	—	—	—	-
36	575.2 Day-Ahead & Real-time Admin	—	—	—	—	-
37	575.3 Transmission Rights Mkt Admin	—	—	—	—	-
38	575.5 Ancillary Services Mkt Admin	—	—	—	—	-
39	575.6 Market Monitoring & Compliance	—	—	—	—	-
40	**Total Operation-Regional Market**	—	—	—	—	-
41						-
42	**Distribution Expenses**					-
43						-
44	**Distribution-Operation**					-
45	580 Supervision & Engineering	3,449,092	34,954	3,414,138	3,338,726	2.26 %
46	581 Load Dispatching	—	—	—	—	-
47	582 Station Expenses	1,614,284	2,422	1,611,862	1,368,864	17.75 %
48	583 Overhead Lines	2,017,558	20,358	1,997,200	1,818,991	9.80 %
49	584 Underground Lines	2,687,440	38,126	2,649,314	2,344,555	13.00 %
50	585 Street Lighting & Signal Systems	87,712	—	87,712	68,421	28.19 %
51	586 Meters	1,369,015	2,457	1,366,558	1,834,572	(25.51)%
52	587 Customer Installations	1,691,467	1,596	1,689,871	1,633,252	3.47 %
53	588 Miscellaneous Distribution	2,719,335	102,940	2,616,395	2,491,431	5.02 %
54	589 Rents	104,717	—	104,717	72,610	44.22 %
55	**Total Operation-Distribution**	15,740,620	202,853	15,537,767	14,971,423	3.78 %
56	**Distribution-Maintenance**					-
57	590 Supervision & Engineering	1,388,562	26,037	1,362,525	1,263,181	7.86 %
58	591 Structures	23,996	—	23,996	19,450	23.37 %
59	592 Station Equipment	507,786	11,740	496,046	462,508	7.25 %
60	593 Overhead Lines	12,441,889	73,225	12,368,664	12,098,786	2.23 %
61	594 Underground Lines	1,262,015	11,544	1,250,471	1,356,305	(7.80)%
62	595 Line Transformers	63,818	—	63,818	40,867	56.16 %
63	596 Street Lighting, Signal Systems	434,662	109	434,553	395,628	9.84 %
64	597 Meters	1,113,031	369	1,112,662	1,196,545	(7.01)%
65	598 Miscellaneous Distribution Plant	—	—	—	—	-
66	**Total Maintenance-Distribution**	17,235,759	123,024	17,112,735	16,833,271	1.66 %
67	**Total Distribution Expenses**	32,976,379	325,877	32,650,502	31,804,695	2.66 %

MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC							
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	—	—	—	—	-
6	902 Meter Reading	1,008,194	1,260	1,006,934	1,224,981	(17.80)%
7	903 Customer Records & Collection	8,412,790	267	8,412,523	7,461,259	12.75 %
8	904 Uncollectible Accounts	1,383,537	—	1,383,537	2,240,210	(38.24)%
9	905 Miscellaneous Customer Accts.	—	—	—	—	-
10	**Total Customer Accounts Expenses**	10,804,521	1,527	10,802,994	10,926,450	(1.13)%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	—	—	—	—	-
16	908 Customer Assistance	1,348,887	—	1,348,887	2,668,960	(49.46)%
17	909 Inform. & Instruct. Advertising	1,691,380	—	1,691,380	862,987	95.99 %
18	910 Misc. Customer Service & Info.	—	—	—	—	-
19	**Total Customer Service & Info. Expense**	3,040,267	—	3,040,267	3,531,947	(13.92)%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	—	—	—	—	-
25	912 Demonstrating & Selling	—	—	—	—	-
26	913 Advertising	543,461	—	543,461	648,924	(16.25)%
27	916 Miscellaneous Sales	—	—	—	—	-
28	**Total Sales Expenses**	543,461	—	543,461	648,924	(16.25)%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	31,454,597	123,043	31,331,554	27,847,734	12.51 %
34	921 Office Supplies & Expenses	15,002,954	60,396	14,942,558	13,548,019	10.29 %
35	922 Admin. Expense Transferred-Cr.	(7,599,517)	(31,069)	(7,568,448)	(6,942,891)	(9.01)%
36	923 Outside Services Employed	6,796,380	25,473	6,770,907	6,934,092	(2.35)%
37	924 Property Insurance	4,835,181	16,990	4,818,191	4,428,650	8.80 %
38	925 Injuries & Damages	15,507,192	63,379	15,443,813	10,526,152	46.72 %
39	926 Employee Pensions & Benefits	22,844,846	154,274	22,690,572	22,387,957	1.35 %
40	927 Franchise Requirements	—	—	—	—	-
41	928 Regulatory Commission Expenses	3,875,995	—	3,875,995	3,727,822	3.97 %
42	929 Duplicate Charges-Cr.	—	—	—	—	-
43	930 Miscellaneous General Expenses	14,647,389	54,612	14,592,777	14,983,158	(2.61)%
44	931 Rents	495,009	2,028	492,981	641,617	(23.17)%
45	**Total Operation-Admin. & General**	107,860,026	469,126	107,390,900	98,082,310	9.49 %
46	**Admin. & General-Maintenance**					
47	935 General Plant	4,405,712	79,435	4,326,277	4,054,257	6.71 %
48	**Total Maintenance-Admin. & General**	4,405,712	79,435	4,326,277	4,054,257	6.71 %
49	**Total Admin. & General Expenses**	112,265,738	548,561	111,717,177	102,136,568	9.38 %
50	**TOTAL OPER. & MAINT. EXPENSES**	539,688,103	29,521,979	510,166,124	587,851,278	(13.22)%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	5,827,382	5,521,538	5.54 %
3	Property Taxes	114,594,043	109,588,956	4.57 %
4	Electric Energy License Tax	867,658	965,734	(10.16)%
5	Crow Tribe RR and Utility Tax	74,880	84,948	(11.85)%
7	Consumer Counsel Tax	450,380	457,957	(1.65)%
8	Public Service Commission Tax	2,784,076	2,042,106	36.33 %
9	Heavy Highway Use Tax	759	1,304	(41.79)%
11	Wholesale Energy Transaction Tax	1,418,857	1,439,774	(1.45)%
12	Delaware Franchise Tax	225,179	152,668	47.50 %
13	Invasive Species	738,466	730,508	1.09 %
14				
15				
16				
17				
18	**TOTAL TAXES OTHER THAN INCOME**	$ 126,981,680	$ 120,985,493	4.96 %
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	261,701
2	ABSOLUTAIRE, INC	HVAC Consulting	125,135
3	ACRT, INC	Consulting Services	336,354
4	AFFCO INC	Hydro Construction Services	2,830,609
5	ALERTWEST INC	Security Services	108,878
6	AMERICAN INNOVATIONS INC	Software Support Services	120,135
7	ANDRITZ HYDRO CORP	Hydro Upgrade Services	2,899,165
8	ARCADIS US INC	Engineering Services	1,675,886
9	ARCOS LLC	Call-out Services	163,709
10	ASCEND ANALYTICS LLC	Hydro Expert Analysis	378,526
11	ASPLUNDH TREE EXPERT LLC	Tree Trimming	7,629,399
12	ASSOCIATED UNDERWATER SERVICE	Inspection Services	143,767
13	AVEVA SOFTWARE, LLC	Computer Support Services	285,729
14	BART ENGINEERING COMPANY	Engineering Services	664,833
15	BASELOAD POWER GENERATION PARTS Total	Engineering Services	475,606
16	BEACON COMMUNICATIONS LLC	Software Maintenance	902,828
17	BIG HORN WIRELINE, LLC Total	Storage	534,597
18	BILLINGS FLYING SERVICE, INC.	Powerline Services	81,950
19	BISON ENGINEERING INC	Engineering Services	482,608
20	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	1,750,357
21	BRY ENTERPRISE Total	Road Bore Services	476,671
22	BURK EXCAVATION AND UTILITIES	Construction	1,773,504
23	CATERPILLAR POWER GENERATION	Generation Services	11,452,834
24	CENTRON SERVICES INC	Customer Collection service	78,467
25	CHARLOTTE ST. ADVISORS, LLC Total	Tactical Planning Prof Services	622,725
26	CHAZNLINE, LLC Total	Heavy Haul Services	1,479,980
27	CN UTILITY CONSULTING INC	Utility Consulting Services	312,382
28	CONTINENTAL STEEL WORKS	Fabrication Services	3,601,852
29	CRIST, KROGH, BUTLER & NORD L	Legal Services	367,635
30	CROWLEY FLECK PLLP	Legal Services	218,196
31	CTA INC.	Energy Conservation Consultants	1,326,989
32	DAVEY RESOURCE GROUP, INC	Surveying Services	158,610
33	DAVEY TREE SURGERY COMPANY	Tree Trimming	5,880,940
34	DELOITTE & TOUCHE LLP	Audit Services	1,790,953
35	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	2,018,371
36	DIETZEL ENTERPRISES INC	Construction	518,225
37	DJ&A P C CONSULTING ENGINEER	Surveying Services	183,117
38	DNV ENERGY SERVICES USA INC Total	Commercial Lighting program	6,169,892
39	DOBLE ENGINEERING CO	Maintenance Service	122,499
40	DORSEY & WHITNEY LLP	Legal Services	961,107
41	DOWL HKM	Geotechnical Services	136,916
42	E SOURCE COMPANIES LLC	Consulting Services	168,680
43	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	6,153,175
44	ENERGY CONTRACT SERVICES LLC	Inspection Services	2,936,634
45	ENERGY SHARE OF MONTANA	USBC Services	485,307
46	EOCENE ENVIROMENTAL GROUP	Environmental Services	888,698
47	FAGEN, INC	Construction	28,333,410
48	FLYNN WRIGHT INC	Advertising Services	2,756,110
49	FOOTHILLS RIG SERVICE	Well Services	81,061
50	GARTNER INC	Information Technology Consulting	659,611
51	GE ENERGY MANAGEMENT SERVICES, LLC Total	E-Terra Source Upgrade Assist	833,420
52	GEI CONSULTANTS INC	Environmental Consultants	438,758
53	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	4,769,233
54	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	322,088
55	GREGG ENGINEERING	Informational Technology Simulation	107,345
56	GUY TABACCO CONSTRUCTION	Construction	198,991
57	H2E INC	Engineering Services	642,756
58	HARDY CONSTRUCTION CO	Construction	2,467,729

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	HDR ENGINEERING INC	Engineering Services	6,413,893
62	HEATH CONSULTANTS INC	Gas Leak Surveys	1,009,409
63	HIGHMARK MEDIA	Safety Training	107,265
64	HITACHI ENERGY USA INC Total	Engineering Consulting	871,100
65	INTEC SERVICES INC	Pole Inspection Services	3,015,168
66	ITRON INC	Meter Installation	27,189,449
67	J D POWER AND ASSOCIATES	Energy Study	136,030
68	J2 BUSINESS PRODUCTS	Copier Maintenance	219,056
69	JACKSON CONTRACTOR GROUP	Construction	151,022
70	JACKSON HOMES LLC	Construction	624,054
71	JARES FENCE COMPANY INC	Fence Materials/Installation	160,552
72	JEFFERY CONTRACTING LLC	Construction	879,895
73	KARV LLC	Boring Services	186,421
74	KELLERMEYER BERGENSONS SERVICES LLC Total	Cleaning Services	487,300
75	LEARJET INC	Repair Services	415,618
76	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	233,098
77	M&D CONSTRUCTION INC	Construction	1,031,281
78	MERCER HUMAN RESOURCE CONSULT	HR Consulting	162,225
79	MERKEL ENGINEERING INC	Consulting Services	703,463
80	MICHAELS FENCE & SUPPLY CO	Installation Services	81,539
81	MICHELS CORPORATION	Construction	7,471,160
82	MINUTEMAN AVIATION INC.	Helicopter Charter Services	528,353
83	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	788,184
84	MOODY'S INVESTORS SERVICE	Debt Rating Services	302,000
85	MORRISON MAIERLE INC	Engineering Services	809,035
86	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	21,935,062
87	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	511,641
88	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	872,857
89	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,896
90	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	750,764
91	PINNACLE RESEARCH & CONSULTING	Consulting Services	323,974
92	PL-ENERSERV, LLC	Construction	260,908
93	POTEET CONSTRUCTION	Traffic Safety Services	202,291
94	POTELCO INC	Electric Construction and Maintenance	20,898,233
95	POWER SETTLEMENTS CONSULTING &	Consulting Services	213,271
96	POWERS HEATING LLC	Meter Installation	95,706
97	PRO PIPE CORPORATION	Welding Services	485,871
98	QUANTA UTILITY ENGINEERING	Engineering Services	7,765,723
99	RIVER DESIGN GROUP INC	Engineering Services	103,903
100	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	25,575,881
101	ROD TABBERT CONSTRUCTION INC	Construction	209,810
102	SCENIC CITY ENTERPRISES INC	Construction	97,393
103	SCHNABEL ENGINEERING LLC	Consulting Services	248,095
104	SHAW PIPELINE SERVICES INC Total	Pipeline Service Reroute	592,702
105	SIDEWINDERS LLC	Generator Repair Services	2,025,172
106	SOLAR TURBINES INC Total	Commissioning New Controls	1,083,808
107	SPHERION STAFFING	Temporary Labor	164,548
108	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	143,370
109	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	850,784
110	STINSON LEONARD STREET LLP	Legal Services	898,373
111	SULLIVAN BROS. CONSTRUCTION INC Total	Boring Services	276,521
112	TBC CONSTRUCTION LLC Total	Pipeline Service Reroute	1,447,439
113	TERRA REMOTE SENSING (USA) INC	Surveying Services	1,100,534
114	THE MOSAIC COMPANY	Training	728,521
115	THOMPSON HINE LLP	Benefits Audit Services	109,782
116	TIMBERLINE SECURITY & SERVICES	Security Services	487,630
117	TLC SEPTIC SERVICE	Excavation Contractor	397,401

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
121	TRADEMARK ELECTRIC INC	Construction	743,825
122	TROUTMAN SANDERS LLP	Legal Services	156,385
123	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	799,273
124	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	235,800
125	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	321,501
126	VAISALA INC	Wind Forecasting Services	163,944
127	VERTEX	Billing Services and Programming	2,862,854
128	VERTIV CORPORATION	Maintenance Service	272,931
129	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	447,405
130	WATSON TRUCKING OF HAVRE LLC	Hauling Services	154,120
131	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	273,083
132	WILLIS TOWERS WATSON US LLC	Compensation Services	328,960
133	ZACHA UNDERGROUND CONSTRUCTIO	Construction	138,780
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172			
	Total of Payments Set Forth Above		**$ 266,762,938**

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 is one employee political action committee			
4	(PAC):			
5				
6	a. NorthWestern Energy Montana Employee PAC for			
7	Montana employees;			
8				
9				
10				
11				
12				
13				
14				
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				
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33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$ —	$ —	— %

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: _____		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 427,325,878	$ 474,947,258	(10.03)%
8	Service cost	5,099,037	5,104,682	(0.11)%
9	Interest cost	20,725,219	23,535,206	(11.94)%
10	Plan participants' contributions	—	—	-
11	Amendments	—	—	-
12	Actuarial (gain) loss	(26,780,061)	2,235,431	>-300.00%
13	Settlements	(848,500)	(51,942,557)	98.37 %
14	Benefits paid	(20,718,964)	(26,554,142)	21.97 %
15	Benefit obligation at end of year	$ 404,802,609	$ 427,325,878	(5.27)%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 348,133,473	$ 388,693,381	(10.43)%
18	Actual return on plan assets	8,025,978	29,936,791	(73.19)%
19	Settlements	(848,500)	(51,942,557)	98.37 %
20	Employer contribution	8,122,500	8,000,000	1.53 %
21	Plan participants' contributions	—	—	-
22	Benefits paid	(20,718,964)	(26,554,142)	21.97 %
23	Fair value of plan assets at end of year	$ 342,714,487	$ 348,133,473	(1.56)%
24	**Funded Status**	$ (62,088,122)	$ (79,192,405)	21.60 %
26	Unrecognized net actuarial gain (loss)	—	—	-
27	Unrecognized prior service cost	—	—	-
29	Prepaid (accrued) benefit cost	$ (62,088,122)	$ (79,192,405)	21.60 %
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.60 %	5.00 %	12.00 %
32	Expected return on plan assets	6.65 %	6.44 %	3.26 %
33	Rate of compensation increase	4.00% Union & 4.00% Non-Union	4.00% Union & 4.00% Non-Union	— %
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 5,099,037	$ 5,104,682	(0.11)%
36	Interest cost	20,725,219	23,535,206	(11.94)%
37	Expected return on plan assets	(22,585,531)	(23,448,483)	3.68 %
38	Settlement (gain) loss recognized	—	4,394,595	(100.00)%
39	Recognized net actuarial gain	33,810	228,222	(85.19)%
40	Net periodic benefit cost (SEC Basis)	$ 3,272,535	$ 9,814,222	(66.66)%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 8,122,500	$ 8,000,000	1.53 %
43	Pension Costs Capitalized	2,317,926	3,791,146	(38.86)%
44	Accumulated Pension Asset (Liability) at Year End	$ (62,088,122)	$ (79,192,405)	21.60 %
45	**Number of Company Employees:**			
46	Covered by the Plan 1/	1,058	1,355	(21.92)%
47	Not Covered by the Plan 1/	1,124	1,073	4.75 %
48	Active 1/	349	387	(9.82)%
49	Retired	455	685	(33.58)%
50	Deferred Vested Terminated 1/	254	283	(10.25)%

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

Sch. 14A	**Pension Costs 1/**			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			0.00%
8	Service cost			0.00%
9	Interest cost			0.00%
10	Plan participants' contributions	Not Applicable		
11	Amendments			0.00%
12	Actuarial loss			0.00%
13	Acquisition			0.00%
14	Benefits paid			0.00%
15	Benefit obligation at end of year	$ —	$ —	0.00%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year			0.00%
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 1/	$ 14,659,033	$ 13,211,496	10.96 %
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 1/			0.00%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss		0	0.00%
26	Unrecognized prior service cost		0	0.00%
27	Prepaid (accrued) benefit cost	$ —	$ —	0.00%
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate		— %	0.00%
31	Expected return on plan assets		— %	0.00%
32	Rate of compensation increase		— %	0.00%
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			0.00%
36	Interest cost			0.00%
37	Expected return on plan assets			0.00%
38	Amortization of prior service cost			0.00%
39	Recognized net actuarial loss			0.00%
40	Net periodic benefit cost (SEC Basis)	$ —	$ —	0.00%
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 11,611,162	$ 10,351,128	12.17 %
44	401(k) Plan Defined Contribution Costs Capitalized	2,936,990	2,626,496	11.82 %
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	2/	2/	
47	Covered by the Plan - Eligible	1,590	1,571	1.21 %
48	Not Covered by the Plan			0.00%
49	Active - Participating	1,579	1,565	0.89 %
50	Retired			0.00%
51	Vested Former Employees, Retirees and Active-	431	424	1.65 %
52	Noncontributing			

1/ This plan covers all NorthWestern Corporation employees.
2/ 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: 2022.07.078			
4	Order number: 7860y			
5	Amount recovered through rates	$ (390,861)	$ 475,268	(182.24)%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.45 %	4.90 %	11.22 %
8	Expected return on plan assets	5.84 %	5.62 %	3.91 %
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				

1/ Obtained from NorthWestern Energy-Montana's 2024 FASB 106 Valuation. Assumptions and data are as of December 31, 2024.

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

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/Dependents covered by the Plan			0.00%
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$ 10,598,133	$ 12,070,609	(12.20)%
10	Service cost	251,843	272,534	(7.59)%
11	Interest Cost	456,347	553,883	(17.61)%
12	Plan participants' contributions	1,109,234	1,383,742	(19.84)%
13	Amendments			-
14	Actuarial loss/(gain)	(1,803,657)	(820,734)	(119.76)%
15	Acquisition			-
16	Benefits paid	(2,272,247)	(2,861,901)	20.60 %
17	Benefit obligation at end of year	$ 8,339,653	$ 10,598,133	(21.31)%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$ 22,309,163	$ 20,055,071	11.24 %
20	Actual return on plan assets	3,177,129	3,334,030	(4.71)%
21	Acquisition			-
22	Employer contribution	448,847	398,221	12.71 %
23	Plan participants' contributions	1,109,234	1,383,742	(19.84)%
24	Benefits paid	(2,272,247)	(2,861,901)	20.60 %
25	Fair value of plan assets at end of year	$ 24,772,126	$ 22,309,163	11.04 %
26	**Funded Status**	$ 16,432,473	$ 11,711,030	40.32 %
27	Unrecognized net transition (asset)/obligation	—	—	-
28	Unrecognized net actuarial loss/(gain)	—	—	-
29	Unrecognized prior service cost	—	—	-
30	Prepaid (accrued) benefit cost	$ 16,432,473	$ 11,711,030	40.32 %
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$ 251,843	$ 272,534	(7.59)%
33	Interest cost	456,347	553,883	(17.61)%
34	Expected return on plan assets	(1,279,870)	(1,096,381)	(16.74)%
35	Amortization of transitional (asset)/obligation	—	—	-
36	Amortization of prior service cost	—	116,071	(100.00)%
37	Recognized net actuarial loss/(gain)	—	79,270	(100.00)%
38	Net periodic benefit cost	$ (571,680)	$ (74,623)	>-300.00%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ —	$ —	-
41	Amount Funded through 401(h)	—	—	-
42	Amount Funded through other - Company funds	448,847	398,221	12.71 %
43	TOTAL	$ 448,847	$ 398,221	12.71 %
44	Amount that was tax deductible - VEBA	$ —	$ —	-
45	Amount that was tax deductible - 401(h)	—	—	-
46	Amount that was tax deductible - Other	(390,861)	475,268	(182.24)%
47	TOTAL	$ (390,861)	$ 475,268	(182.24)%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$ (390,861)	$ 475,268	(182.24)%
50	Pension Costs Capitalized	(111,770)	120,833	(192.50)%
51	Accumulated Pension Asset (Liability) at Year End	16,432,473	11,711,030	40.32 %
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,030	1,151	(10.51)%
54	Not Covered by the Plan	1,664	1,655	0.54 %
55	Active	341	376	(9.31)%
56	Retired	633	718	(11.84)%
57	Spouses/Dependents covered by the Plan	56	57	(1.75)%

4/ There are approximately $2,386,168 and $3,109,816 of additional OPEB liabilities outstanding at December 31, 2024 and 2023, respectively, for other company supplemental retirement agreements, in addition to what is reflected for Montana above.

SCHEDULE 16
TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Michael R. Cashell Vice President, Transmission	340,729	193,597 A	36,777 B 65,827 C 213,966 D — E	850,896	782,566	8.7 %
2	Jeanne M. Vold Vice President, Technology	277,409	146,160 A	68,159 B 54,075 C 148,689 D 14,999 E 10,529 F	720,020	576,267	24.9 %
3	Bleau J. LaFave Vice President, Asset Management & Business Development	264,620	140,940 A	64,077 B 50,003 C 125,014 D 9,142 E 10,097 F 2,776 G 132 H	666,801	430,401	54.9 %
4	Jason Merkel Vice President, Distribution	273,656	166,518 A	35,188 B 51,002 C 127,518 D 7,169 E 3,213 G 183 H	664,447	608,564	9.2 %
5	Jeffrey Berzina Controller	266,360	124,884 A	59,843 B 103,557 D	554,644	468,217	18.5 %
6	Cynthia Fang Vice President, Regulatory	177,077	— A	43,420 B 2,935 G 21,338 I 6,927 J 241,000 K	492,697	465,414	5.9 %
7	Michael L. Nieman Chief Audit & Compliance Officer	266,926	77,971 A	59,452 B 65,440 D 11,299 E	481,088	458,426	4.9 %
8	Travis E. Meyer Director, Corporate Development & Investor Relations Officer	244,167	80,014 A	57,247 B 69,009 D 5,318 E 7,921 F	463,676	384,933	20.5 %
9	Emilie Ng Treasurer	224,448	52,878 A	58,597 B 53,748 D 9,044 E	398,715	346,041	15.2 %
10	Timothy P. Olson Counsel Corporate & Corporate Secretary Sr	218,324	64,009 A	54,519 B 52,969 D 264 H	390,085	358,774	8.7 %

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2024 Annual Incentive Compensation Plan. Amounts were earned in 2024 and paid in the first quarter of 2025. Based on company performance against plan, the incentive plan was funded at 116% of target. Salary and incentive in current rate recovery are based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

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> Defined Contribution Supplemental Executive Retirement Program

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

E> 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, 2024.

Actual Change in Pension Value	
Mike Cashell	(13,466)
Jeanne Vold	14,999
Bleau LaFave	9,142
Jason Merkel	7,169
Jeff Berzina	—
Cynthia Fang	—
Michael Nieman	11,299
Travis Meyer	5,318
Emilie Ng	9,044
Timothy Olson	—

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

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

H> Value of non-cash taxable award and associated tax gross-up.

I> Value of PTO payout

J> Value of COBRA reimbursements

K> Severance Agreement

3/ Recovery of non-stock-based compensation is based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

Shareholders vote on executive compensation, and have consistently approved above 96%, most recently 98.9%.

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	Total Compensation Reported Last Year	% Increase Total Compensation
1	Brian B. Bird President & Chief Executive Officer	873,077	1,044,000 A	64,661 B 480,000 C 2,320,016 D 29,203 E 132 H	4,811,089	3,110,602	54.7 %
2	Crystal D. Lail Vice President, Chief Financial Officer	493,101	435,000 A	57,247 B 142,313 C 592,947 D 6,161 E 13,367 F	1,740,136	1,257,244	38.4 %
3	Shannon M. Heim General Counsel & Vice President, Federal Government Affairs	364,615	171,680 A	59,312 B 70,000 C 332,498 D — E 2,972 G	1,001,077	770,110	30.0 %
4	John D. Hines Vice President, Supply & Montana Government Affairs	341,065	193,597	37,311 B 66,077 C 214,745 D 71,969 E 5,123 F	929,887	784,041	18.6 %
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications, & Human Resources	344,347	182,700 A	68,131 B 65,800 C 213,843 D 16,836 E 800 I	892,457	735,583	21.3 %

TOP FIVE 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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2024 Annual Incentive Compensation Plan. Amounts were earned in 2024 and paid in the first quarter of 2025. Based on company

on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

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> Defined Contribution Supplemental Executive Retirement Program

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

E> 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, 2024.

Actual Change in Pension Value

Brian B. Bird	29,203
Crystal D. Lail	6,161
Shannon M. Heim	—
John D. Hines	71,969
Bobbi L. Schroeppel	16,836

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

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

H> Value of non-cash taxable award and associated tax gross-up.

I> Imputed income for facilities

3/ Stock-based compensation is paid by shareholders.
Recovery of non-stock-based compensation is based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

Shareholders vote on proposed executive compensation on an annual basis during our shareholder meeting, and have consistently approved at above 96%, most recently 98.9%.
Our Chief Executive Officer's compensation is 80% 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	$ 6,769,324,100	$ 7,585,573,446	$ (816,249,346)	(10.76)%
4	101.1 Property Under Capital Leases	40,943,217	41,127,257	(184,040)	(0.45)%
5	103 Experimental Electric Plant Unclassified	4,798,750	4,798,750	—	— %
6	105 Plant Held for Future Use	4,191,929	4,140,227	51,702	1.25 %
7	107 Construction Work in Progress	125,080,799	358,401,452	$ (233,320,653)	(65.10)%
8	108 Accumulated Depreciation Reserve	(2,244,952,173)	(2,675,309,658)	$ 430,357,485	(16.09)%
9	108.1 Accumulated Depreciation - Capital Leases	(37,193,803)	(35,183,325)	$ (2,010,478)	5.71 %
10	111 Accumulated Amortization & Depletion Reserves	(116,083,491)	(106,740,672)	$ (9,342,819)	8.75 %
11	114 Electric Plant Acquisition Adjustments	451,564,554	481,574,396	(30,009,842)	(6.23)%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(91,524,576)	(92,378,300)	853,724	(0.92)%
13	116 Utility Plant Adjustments	263,806,234	357,585,527	(93,779,293)	(26.23)%
14	117 Gas Stored Underground-Noncurrent	38,192,545	36,212,426	1,980,119	5.47 %
15	**Total Utility Plant**	5,208,148,085	5,959,801,526	(751,653,441)	(12.61)%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	—	— %
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(68,042)	(67,635)	(407)	0.60 %
19	123.1 Investments in Assoc Companies and Subsidiaries	(110,826,649)	(97,949,544)	(12,877,105)	13.15 %
20	124 Other Investments	14,135,821	13,050,811	1,085,010	8.31 %
21	128 Miscellaneous Special Funds	—	—	—	-
22	LT Portion of Derivative Assets - Hedges	—	—	—	-
23	**Total Other Property & Investments**	(96,072,065)	(84,279,563)	(11,792,502)	13.99 %
24	**Current and Accrued Assets**				
25	131 Cash	911,923	8,763,190	(7,851,267)	(89.59)%
26	134 Other Special Deposits	13,894,365	14,856,653	(962,288)	(6.48)%
27	135 Working Funds	17,500	22,850	(5,350)	(23.41)%
28	142 Customer Accounts Receivable	66,518,761	91,004,511	(24,485,750)	(26.91)%
29	143 Other Accounts Receivable	12,617,310	17,049,224	(4,431,914)	(25.99)%
30	144 Accumulated Provision for Uncollectible Accounts	(2,160,945)	(2,813,090)	652,145	(23.18)%
31	146 Accounts Receivable-Associated Companies	44,900,286	39,498,557	5,401,729	13.68 %
32	151 Fuel Stock	2,248,613	9,710,818	(7,462,205)	(76.84)%
33	154 Plant Materials and Operating Supplies	79,780,714	85,254,493	(5,473,779)	(6.42)%
34	164 Gas Stored - Current	6,743,589	18,814,211	(12,070,622)	(64.16)%
35	165 Prepayments	18,978,350	21,740,289	(2,761,939)	(12.70)%
36	172 Rents Receivable	64,160	73,787	(9,627)	(13.05)%
37	173 Accrued Utility Revenues	74,104,042	105,109,956	(31,005,914)	(29.50)%
38	174 Miscellaneous Current & Accrued Assets	1,025,532	876,037	149,495	17.06 %
39	**Total Current & Accrued Assets**	319,644,200	409,961,486	(90,317,286)	(22.03)%
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	9,376,139	11,096,631	(1,720,492)	(15.50)%
42	182 Regulatory Assets	676,869,364	746,025,553	(69,156,189)	(9.27)%
43	183 Preliminary Survey and Investigation Charges	—	376,264	(376,264)	(100.00)%
44	184 Clearing Accounts	—	(2,520)	2,520	(100.00)%
45	186 Miscellaneous Deferred Debits	949,677	11,117,717	(10,168,040)	(91.46)%
46	189 Unamortized Loss on Reacquired Debt	16,960,804	20,027,942	(3,067,138)	(15.31)%
47	190 Accumulated Deferred Income Taxes	194,013,891	289,883,014	(95,869,123)	(33.07)%
48	191 Unrecovered Purchased Gas Costs	253,352	3,394,843	(3,141,491)	(92.54)%
49	**Total Deferred Debits**	898,423,227	1,081,919,444	(183,496,217)	(16.96)%
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,330,143,447	$ 7,367,402,893	$ (1,037,259,446)	(14.08)%

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	$ 1	$ —	— %
4	211	Miscellaneous Paid-In Capital	2,044,999,693	1,981,122,792	63,876,901	3.22 %
5	216	Unappropriated Retained Earnings	349,075,632	809,312,954	(460,237,322)	(56.87)%
6	217	Reacquired Capital Stock	—	—	—	-
7	219	Accumulated Other Comprehensive Income	(5,383,393)	(5,513,000)	129,607	(2.35)%
8	**Total Proprietary Capital**		2,388,691,933	2,784,922,747	(396,230,814)	(14.23)%
9		**Long Term Debt**				
10	221	Bonds	2,074,660,000	2,479,660,000	(405,000,000)	(16.33)%
11	224	Other Long Term Debt	342,000,000	318,000,000	24,000,000	7.55 %
12	226	(Less) Unamortized Discount on Long Term Debt-Debit	—	6,538	(6,538)	(100.00)%
13	**Total Long Term Debt**		2,416,660,000	2,797,653,462	(380,993,462)	(13.62)%
14		**Other Noncurrent Liabilities**				
15	227	Obligations Under Capital Leases-Noncurrent	2,292,287	5,996,448	(3,704,161)	(61.77)%
16	228.2	Accumulated Provision for Injuries and Damages	5,427,888	6,745,658	(1,317,770)	(19.54)%
17	228.3	Accumulated Provision for Pensions and Benefits	(4,015,920)	4,631,028	(8,646,948)	(186.72)%
18	228.4	Accumulated Miscellaneous Operating Provisions	30,772,443	50,272,082	(19,499,639)	(38.79)%
19	229	Accumulated Provision for Rate Refunds	—	—	—	-
20	230	Asset Retirement Obligations	33,987,819	41,424,213	(7,436,394)	(17.95)%
21	**Total Other Noncurrent Liabilities**		68,464,517	109,069,429	(40,604,912)	(37.23)%
22		**Current and Accrued Liabilities**				
23	231	Notes Payable	—	—	—	-
24	232	Accounts Payable	90,053,114	131,709,370	(41,656,256)	(31.63)%
25	234	Accounts Payable to Associated Companies	212,852	2,288,407	(2,075,555)	(90.70)%
26	235	Customer Deposits	17,640,442	11,954,099	5,686,343	47.57 %
27	236	Taxes Accrued	76,941,004	75,980,842	960,162	1.26 %
28	237	Interest Accrued	24,578,517	24,775,303	(196,786)	(0.79)%
29	241	Tax Collections Payable	298,173	1,789,013	(1,490,840)	(83.33)%
30	242	Miscellaneous Current and Accrued Liabilities	57,585,069	73,408,627	(15,823,558)	(21.56)%
31	243	Obligations Under Capital Leases-Current	3,902,892	3,720,377	182,515	4.91 %
32	**Total Current and Accrued Liabilities**		271,212,063	325,626,038	(54,413,975)	(16.71)%
33		**Deferred Credits**				
34	252	Customer Advances for Construction	123,249,058	107,470,505	15,778,553	14.68 %
35	253	Other Deferred Credits	93,579,661	147,334,417	(53,754,756)	(36.48)%
36	254	Regulatory Liabilities	119,721,846	190,647,029	(70,925,183)	(37.20)%
37	255	Accumulated Deferred Investment Tax Credits	2,229,208	258,964	1,970,244	>300.00%
38	281-283	Accumulated Deferred Income Taxes	846,335,161	904,420,302	(58,085,141)	(6.42)%
39	**Total Deferred Credits**		1,185,114,934	1,350,131,217	(165,016,283)	(12.22)%
40	**TOTAL LIABILITIES and OTHER CREDITS**		$ 6,330,143,447	$ 7,367,402,893	$ (1,037,259,446)	(14.08)%
41						
42	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory					
43	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the					
44	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian					
45	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.					
46						
47	2/ On January 1, 2024, we completed the second and final phase of the holding company reorganization. NorthWestern Corporation (NW Corp) contributed the assets and liabilities of its					
48	South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation, (NWE Public Service), and then distributed its equity interest in NWE Public Service					
49	and certain other subsidiaries to NorthWestern Energy Group, Inc., resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating					
50	the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc. Due to this reorganization, the prior period information included in these					
51	statements may not be comparable to the current period.					

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation (NW Corp), a direct wholly-owned subsidiary of NorthWestern Energy Group, Inc., doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 627,900 customers in Montana and Yellowstone National Park. We 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.

The following notes to the financials statements appear in Northwestern Corporation's annual report to the stockholders and are prepared in conformity with 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:

- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $444.1 million and $523.7 million as of December 31,2024 and December 31,2023, 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 $263.8 million as of December 31,2024 and $357.6 million as of December 31,2023, 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 31,2024 and December 31,2023, 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 $0.7 million and $0.9 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 $0.7 million and $0.9 million as of December 31,2024 and December 31,2023, 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.

Events occurring subsequent to December 31, 2023, have been evaluated as to their potential impact to the Financial Statements through the date of this report.

Holding Company Reorganization

On October 2, 2023, NW Corp and NorthWestern Energy Group, Inc. completed a merger transaction pursuant to which NorthWestern Energy Group, Inc. became the holding company parent of NW Corp. In this reorganization, shareholders of NW Corp (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 NW Corp immediately prior to the reorganization. NW Corp became a wholly-owned subsidiary of NorthWestern Energy Group, Inc. 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 NW Corp pursuant to Rule 12g-3(a) of the Securities Exchange Act of 1934, and as a result, NorthWestern Energy Group, Inc.'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 NW Corp common stock into common stock in NorthWestern Energy Group, Inc., as described above, the common stock of NW Corp ceased to exist. The accounting for this common stock conversion is treated as a retirement of common stock for NW Corp as the shares cease to exist. As such, the amounts included in Common stock and Treasury stock were cleared into Paid-in capital. Subsequent to the reorganization, NW Corp 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. NW Corp contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation (NWE Public Service), and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, Inc., resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc.

(2) Discontinued Operations

On January 1, 2024, we completed the previously announced second and final phase of our holding company reorganization resulting in the distribution of our ownership in NWE Public Service, our former South Dakota electric and natural gas and Nebraska natural gas operating segments, and certain non-regulated subsidiaries, our former other operating segment, to NorthWestern Energy Group, Inc. As a result of this distribution, the historical assets and liabilities for these operating segments have been classified as assets and liabilities of discontinued operations and the historical results of operations are shown in discontinued operations, net of tax. Our Financial Statements for prior periods reflect this reclassification. The notes to our financial statements present information from continuing operations.

The carrying amounts of the major classes of assets and liabilities of discontinued operations included in our Consolidated Balance Sheet at December 31, 2023, were as follows:

	As of December 31, 2023
ASSETS	
Current Assets:	
Cash and cash equivalents	$ 253
Restricted cash	1,166
Accounts receivable, net	37,547
Inventories	31,717
Regulatory assets	5,681
Prepaid expenses and other	10,910
Total current assets	**87,274**
Property, plant, and equipment, net	1,067,606
Goodwill	93,779
Regulatory assets	93,933
Other noncurrent assets	21,555
Total Assets	**$ 1,364,147**
LIABILITIES	
Current Liabilities:	
Accounts payable	28,766
Accrued expenses	27,949
Regulatory liabilities	20,767
Total current liabilities	**77,482**
Long-term debt	532,148
Deferred income taxes	20,307
Noncurrent regulatory liabilities	106,307
Other noncurrent liabilities	57,206
Total Liabilities	**$ 793,450**

The reconciliation of the major classes of income and expense constituting pretax income from discontinued operations to the after-tax income from discontinued operations on the Condensed Consolidated Statements of Income were as follows:

	Year Ended December 31, 2023
Operating revenues	$ 285,942
Operating expenses	249,024
Operating Income	36,918
Interest expense, net	(22,221)
Other income, net	1,805
Income from discontinued operations before income tax	16,502
Income tax expense	11,880
Discontinued operations, net of tax	$ 28,382

(3) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP 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 Consolidated 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, AROs, regulatory assets and liabilities, allowances for uncollectible accounts, our QF liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

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

Cash Equivalents

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

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.2 million and $2.5 million at December 31, 2024 and December 31, 2023, respectively. Receivables include unbilled revenues of $74.1 million and $84.1 million at December 31, 2024 and December 31, 2023, respectively.

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 Consolidated 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 (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), 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 Consolidated 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 AOCL 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 Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items. As of December 31, 2024, 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.

Property, Plant and Equipment

Property, plant and equipment are 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 property, plant and equipment 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 interest expense, while the equity component is included in other income. This rate averaged 7.0% and 6.4% for 2024 and 2023, respectively. AFUDC capitalized totaled $25.5 million and $23.1 million for the years ended December 31, 2024 and 2023, respectively.

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 5 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 2024 and 2023.

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 noncurrent regulatory liabilities.

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 Consolidated Income Statements 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. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

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

Supplemental Cash Flow Information

	Year Ended December 31,	
	2024	2023
		(in thousands)
Cash paid (received) for:		
Income taxes [1]	$ (4,769)	$ (827)
Interest [2]	100,853	105,238
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable [3]	18,537	42,322

(1) Includes income tax refunds from discontinued operations of $845 as of December 31, 2023.

(1) Includes interest payments from discontinued operations of $20,778 as of December 31, 2023.

(2) Includes capital expenditures included in trade accounts payable of discontinued operations of $3,867 as of December 31, 2023.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Consolidated Statements of Cash Flows (in thousands):

	December 31,	
	2024	2023
Cash and cash equivalents	$ 1,934	$ 8,851
Restricted cash	13,894	14,857
Discontinued operations (Note 2)	—	1,419
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 15,828	$ 25,127

Restricted cash consists 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.

(4) Regulatory Matters

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the Montana Public Service Commission (MPSC). In November 2024, the MPSC partially approved our requested interim rates effective December 1, 2024, subject to refund. Subsequently, we modified our request through rebuttal testimony. In March 2025, we filed a natural gas settlement with certain parties and a motion for revised interim natural gas rates. In April 2025, we filed a partial electric settlement with certain other parties and a motion for revised interim electric rates. Both settlements and motions for revised interim rates are subject to approval by the MPSC.

The partial electric settlement includes, among other things, agreement on base revenue increases (excluding base revenues associated with Yellowstone County Generating Station (YCGS)), allocated cost of service, rate design, updates to the amount of revenues associated with property taxes (excluding property taxes associated with YCGS), regulatory policy issues related to requested changes in regulatory mechanisms, and agreement to support a separate motion for revised electric interim rates. The partial electric settlement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The natural gas settlement includes, among other things, agreement on base revenues, allocated cost of service, rate design, updates to the amount of revenues associated with property taxes, and agreement to support a separate motion for revised natural gas interim rates.

The details of our rebuttal request are set forth below:

Requested Revenue Increase (Decrease) Through Rebuttal Testimony (in millions)

	Electric	Natural Gas
Base Rates	$ 153.8	27.9
Power Cost & Credit Mechanism (PCCAM)[1]	(94.5)	n/a
Property Tax (tracker base adjustment)[1]	(1.3)	0.1
Total Revenue Increase Requested through Rebuttal Testimony	$ 58.0	$ 28.0

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

The details of our interim rates granted are set forth below:

Interim Revenue Increase (Decrease) Granted (in millions)

	Electric	Natural Gas
Base Rates	$ 18.4	$ 17.4
PCCAM[1]	(88.0)	n/a
Property Tax (tracker base adjustment)[1][2]	7.4	0.2
Total Interim Revenue Granted	$ (62.2)	$ 17.6

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(2) Our requested interim property tax base increase went into effect on January 1, 2025, as part of our 2024 property tax tracker filing.

The details of our settlement agreement and requested revised interim rates are set forth below:

Requested Revenue Increase (Decrease) through Settlement Agreements and Revised Interim Filing (in millions)

	Electric	Natural Gas
Base Rates:		
Base Rates (Settled)	$ 66.4	$ 18.0
Base Rates - YCGS (Non-settled)[1][2]	43.9	n/a
Requested Base Rates for Revised Interim Filing	110.3	18.0
Pass-through items:		
Property Tax (tracker base adjustment) (Settled)[3]	(5.2)	0.1
Property Tax (tracker base adjustment) - YCGS (Non-settled)[1][3]	4.0	n/a
PCCAM (Non-settled)[1][2][3]	(94.5)	n/a
Requested Pass-Through Rates for Revised Interim Filing	(95.7)	0.1
Total Requested Revenue Increase through Revised Interim Filing[4]	$ 14.6	$ 18.1

(1) These items were not included within the partial electric settlement and will be contested items that are expected to be determined in the MPSC's final order.
(2) Intervenor positions propose up to an $11.6 million reduction to this base rate revenue request and an additional $38.4 million decrease to the PCCAM base.
(3) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(4) Revised interim filing rates are requested to be effective May 1, 2025. If the revised interim rates are not approved, and a final order is not received by May 23, 2025, which is 270 days from acceptance of our filing, we intend to implement, as permitted by Montana statute, our rebuttal rates, which will be subject to refund, until a final order is received.

A hearing on the electric and natural gas rate review is scheduled for June 9, 2025. Interim rates will remain in effect on a refundable basis until the MPSC issues a final order.

(5) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 3 - 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. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2024	December 31, 2023
			(in thousands)	
Flow-through income taxes	13	Plant Lives	$ 522,015	$ 483,949
Pension	15	See Note 15	56,719	73,823
Excess deferred income taxes	13	Plant Lives	39,040	44,657
Employee related benefits	15	See Note 15	17,877	21,926
Wildfire Mitigation		Undetermined	17,368	1,623
Deferred financing costs	12	See Note 12	16,961	18,540
State & local taxes & fees		1 Year	8,863	2,733
Supply costs		1 Year	1,132	3,895
Other		Various	15,098	22,811
Total Regulatory Assets			**$ 695,073**	**$ 673,957**
Removal cost	7	Plant Lives	$ 444,058	$ 435,470
Excess deferred income taxes	13	Plant Lives	108,154	117,870
State & local taxes & fees		1 Year	46	29,686
Supply costs		1 Year	5,093	924
Gas storage sales		16 years	6,205	6,625
Other		Various	1,977	905
Total Regulatory Liabilities			**$ 565,533**	**$ 591,480**

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 13 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated 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 MPSC allows recovery of postretirement benefit costs on an accrual basis.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

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. The MPSC has approved the deferral of incremental operating costs related to this Enhanced Wildfire Mitigation Plan.

Supply Costs

The MPSC has authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 6.7 percent. For our electric supply tracker, the PCCAM, the interest rate we earn on supply costs under collected, or the interest rate we apply to an over collection, is based on the monthly interest rate for three month commercial paper as published by the Federal Reserve.

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, or refund the decrease, in rates, less the amount allocated to Federal Energy Regulatory Commission jurisdictional customers and net of the related income tax benefit.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 7 - Asset Retirement Obligations, for further information regarding this item.

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.

(6) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	December 31, 2024	December 31, 2023
	(in thousands)	
Electric Plant	$ 4,888,326	$ 4,343,235
Natural Gas Plant	1,328,386	1,244,451
Plant acquisition adjustment[1]	656,319	656,319
Common and Other Plant	204,663	197,783
Construction work in process	133,740	352,377
Total property, plant and equipment	7,211,434	6,794,165
Less accumulated depreciation	(1,561,647)	(1,502,887)
Less accumulated amortization	(344,785)	(315,082)
Net property, plant and equipment	$ 5,305,002	$ 4,976,196

(1) The plant acquisition adjustment balance above includes our hydro generating assets acquired in 2014 and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Net plant and equipment under finance lease were $3.0 million and $5.2 million as of December 31, 2024 and 2023, respectively, which is primarily comprised of 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 a 30% ownership interest in Colstrip Unit 4, a base-load electric generating plant, which is coal fired and operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. We have a reciprocating sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party if responsible for its own fuel-related costs. Our interest in this plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

In January 2023 and July 2024, we entered into definitive agreements, the first with Avista and the second with Puget, to acquire their respective interests in Colstrip Units 3 & 4. In particular, we agreed to acquire a 15% (222 megawatts) interest from Avista and a 25% (370 megawatts) interest from Puget. Both agreements provide that the purchase price will be $0. These agreements are substantially similar and are both scheduled to close December 31, 2025, subject to the satisfaction of customary closing conditions and approvals contained within the agreements. Under the terms of the agreements, we will be responsible for operating costs starting on January 1, 2026; while Puget and Avista will remain responsible for their respective 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 their interests.

Acquisition of Avista and Puget's interests would result in our ownership of 55 percent of the facility with the ability to guide operating and maintenance investments. This would provide capacity to help us meet our obligation to provide reliable and cost effective power to our customers in Montana, while allowing opportunity for us to identify and plan for newer lower or no-carbon technologies in the future.

Either party may terminate the respective separate 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 this facility is as follows (in thousands):

	Colstrip Unit 4
December 31, 2024	
Ownership percentages	30.0 %
Plant in service	$ 330,888
Accumulated depreciation	137,153
December 31, 2023	
Ownership percentages	30.0 %
Plant in service	$ 323,793
Accumulated depreciation	127,381

(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 property, plant and equipment and other noncurrent liabilities. 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 asset retirement obligation (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 facility, 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,	
	2024	2023
Liability at January 1,	$ 34,808	$ 33,861
Accretion expense	1,626	1,575
Liabilities incurred	—	—
Liabilities settled	(1,923)	(1,151)
Revisions to cash flows	(299)	523
Liability at December 31,	$ 34,212	$ 34,808

During the twelve months ended December 31, 2024 our ARO liability decreased $1.9 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facility and natural gas pipeline segments. Additionally, during the twelve months ended December 31, 2024, our ARO liability decreased $0.3 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 Consolidated 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. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 5 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2024 and 2023.

(8) Goodwill

We completed our annual goodwill impairment test as of April 1, 2024, and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2024	2023
Electric	$ 179,900	$ 179,900
Natural gas	83,900	83,900
Total Goodwill	$ 263,800	$ 263,800

(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 Consolidated Financial Statements at December 31, 2024 and 2023. 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 AOCL. We reclassify these gains from AOCL into interest expense 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 Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2024
Interest rate contracts	Interest Expense	$ 612

A pre-tax loss of approximately $12.1 million is remaining in AOCL as of December 31, 2024, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL 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, accounts payable, and short-term borrowings, 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, 2024	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Rabbi trust investments	14,136	—	—	—	14,136
Total	**$ 14,136**	**$ —**	**$ —**	**$ —**	**$ 14,136**
December 31, 2023					
Restricted cash equivalents	$ 14,857	$ —	$ —	$ —	$ 14,857
Rabbi trust investments	13,030	—	—	—	13,030
Total	**$ 27,887**	**$ —**	**$ —**	**$ —**	**$ 27,887**

Restricted cash equivalents represents 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, 2024		December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,406,206	$ 2,104,381	$ 2,223,561	$ 2,000,767

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

On November 29, 2023 we amended our 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, we own and operate only the Montana regulated utility, and the base capacity of the Amended Facility automatically reduced to $400.0 million. The Amended Facility has uncommitted features that allow us to request one-year extensions to the maturity date and increase the size of the Amended Facility by an additional $100.0 million.

On January 24, 2025, we amended our existing $400.0 million Amended Facility to increase the capacity to $425.0 million. This amendment did not affect the maturity date or borrowing rates.

On January 2, 2024, we terminated our $100.0 million Additional Credit Facility. On January 4, 2024, we terminated our $25.0 Swingline Facility.

Commitment fees for the unsecured revolving lines of credit were $0.4 million and $0.5 million for the years ended December 31, 2024 and 2023.

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

	2024	2023
Unsecured revolving line of credit, expiring November 2028	400.0	425.0
Unsecured revolving line of credit, expiring November 2024	—	100.0
Unsecured revolving line of credit, expiring November 2025	—	25.0
	400.0	**550.0**
Amounts outstanding at December 31:		
SOFR borrowings	342.0	264.0
Letters of credit	—	—
	342.0	**264.0**
Net availability as of December 31[1]	**$ 58.0**	**$ 286.0**

(1) As discussed above, upon the completion of the holding company reorganization and termination of the Additional Credit Facility and Swingline facility in January 2024, our total consolidated capacity decreased to $400.0 million.

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 and Finance Leases

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

	Due	December 31, 2024	December 31, 2023
Unsecured Debt:			
Unsecured Revolving Line of Credit	2028	$ 342,000	$ 264,000
Secured Debt:			
Mortgage bonds—			
Montana—1.00%	2024	—	100,000
Montana—5.01%	2025	161,000	161,000
Montana—3.11%	2025	75,000	75,000
Montana—3.99%	2028	35,000	35,000
Montana—3.21%	2030	100,000	100,000
Montana—5.57%	2031	175,000	—
Montana—5.57%	2033	239,000	239,000
Montana—5.71%	2039	55,000	55,000
Montana—4.15%	2042	60,000	60,000
Montana—4.85%	2043	15,000	15,000
Montana—4.176%	2044	450,000	450,000
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—4.30%	2052	40,000	40,000
Pollution control obligations—			
Montana—3.88%	2028	144,660	144,660
Other Long Term Debt:			
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(10,454)	(11,099)
Total Long-Term Debt		$ 2,406,206	$ 2,252,561
Less current maturities (including associated debt issuance costs)		(235,959)	(99,950)
Total Long-Term Debt, Net of Current Maturities		$ 2,170,247	$ 2,152,611
Finance Leases:			
Total Finance Leases	2026	$ 5,461	$ 8,799
Less current maturities		(3,596)	(3,338)
Total Long-Term Finance Leases		$ 1,865	$ 5,461

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

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. 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 May 28, 2024, we 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 the $100.0 million of Montana First Mortgage Bonds due this year and for other general utility purposes. The bonds are secured by our electric and natural gas assets associated with its Montana utility operations.

On March 21, 2025, NW Corp issued and sold $400.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.07 percent maturing on March 21, 2030. These bonds were issued and sold to certain initial purchasers without being registered under the Securities Act of 1933, as amended (Securities Act), in reliance upon exemptions therefrom in compliance with Rule 144A under the Securities Act, or under Regulation S under the Securities Act for sales to non-U.S. persons. Proceeds will be used to repay outstanding borrowings under our NW Corp revolving credit facility, repay maturing Montana First Mortgage Bonds, and for general utility purposes.

On April 11, 2025, we redeemed all $161.0 million of NW Corp's 5.01 percent Montana First Mortgage Bonds due May 1, 2025.

As of December 31, 2024, we were in compliance with our financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and finance leases, during the next five years are $239.6 million in 2025, $1.9 million in 2026, and $521.7 million in 2028.

(13) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31,	
	2024	2023
Federal		
Current	$ 1,667	$ (1,016)
Deferred	13,602	17,581
Investment tax credits	1,970	(129)
State		
Current	61	(864)
Deferred	2,365	3,847
Income Tax Expense	$ 19,665	$ 19,419

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 following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,	
	2024	2023
Federal statutory rate	21.0 %	21.0 %
State income tax, net of federal provisions	0.9	1.3
Flow-through repairs deductions	(9.6)	(11.5)
Gas repairs safe harbor method change	(2.2)	—
Amortization of excess deferred income taxes	(1.2)	(0.8)
Production tax credits	(1.1)	(1.4)
Prior year permanent return to accrual adjustments	(0.3)	—
Plant and depreciation of flow through items	3.3	2.8
Release of unrecognized tax benefits	—	(1.4)
Other, net	(1.0)	0.5
Effective tax rate	9.8 %	10.5 %

The table below summarizes the significant differences in income tax expense (benefit) based on the differences between our effective tax rate and the federal statutory rate (in thousands). All of our income from continuing operations is primarily from domestic operations.

	Year Ended December 31,	
	2024	2023
Income Before Income Taxes	$ 199,744	$ 185,168
Income tax calculated at federal statutory rate	41,946	38,885
Permanent or flow through adjustments:		
State income, net of federal provisions	1,719	2,367
Flow-through repairs deductions	(19,274)	(21,379)
Gas repairs safe harbor method change	(4,366)	—
Amortization of excess deferred income taxes	(2,465)	(1,479)
Production tax credits	(2,288)	(2,582)
Prior year permanent return to accrual adjustments	(567)	—
Plant and depreciation of flow through items	6,690	5,167
Release of unrecognized tax benefits	—	(2,680)
Other, net	(1,730)	1,120
	(22,281)	(19,466)
Income Tax Expense	$ 19,665	$ 19,419

We and our subsidiaries are included in NorthWestern Energy Group, Inc.'s consolidated federal and state income tax returns. In accordance with our tax sharing agreement with NorthWestern Energy Group, Inc., we compute our income taxes based upon the separate return method, where we are assumed to file a separate return with the taxing authority, thereby reporting our taxable income and paying the applicable tax to or receiving the appropriate refund from NorthWestern Energy Group, Inc.

In 2023, the Internal Revenue Service (IRS) issued a safe harbor method of accounting for the repair and maintenance of natural gas transmission and distribution property. For the year ending December 31, 2024, after completion of our impact analysis of the gas repairs safe harbor method change, we recorded an income tax benefit of approximately $4.4 million related to tax deductions for repair costs that were previously capitalized in the 2022 and prior tax years.

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

	December 31,	
	2024	2023
NOL carryforward	$ 89,816	82,351
Production tax credit	35,602	$ 33,279
Customer advances	32,455	28,300
Pension / postretirement benefits	10,369	16,352
Compensation accruals	9,857	8,319
Interest rate hedges	3,205	3,367
Unbilled revenue	3,126	7,222
Reserves and accruals	2,133	2,952
Environmental liability	2,131	2,222
Other, net	4,334	3,407
Deferred Tax Asset	**193,028**	**187,771**
Excess tax depreciation	(599,893)	(552,815)
Flow through depreciation	(119,674)	(108,413)
Goodwill amortization	(89,687)	(88,183)
Regulatory assets and other	(23,721)	(18,572)
Deferred Tax Liability	**(832,975)**	**(767,983)**
Deferred Tax Liability, net	**$ (639,947)**	**$ (580,212)**

As of December 31, 2024, our total federal net operation loss (NOL) carryforward was approximately $342.6 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2024 was approximately $335.3 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, 2024, our total production tax credit carryforward was approximately $35.6 million. If unused, our production tax credit carryforwards will expire as follows: $1.2 million in 2035, $3.4 million in 2036, $3.5 million in 2037, $3.9 million in 2038, $4.4 million in 2039, $5.4 million in 2040, $4.4 million in 2041, $4.5 million in 2042, $2.6 million in 2043, and $2.3 million in 2044 . 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):

	2024	2023
Unrecognized Tax Benefits at January 1	$ 5,179	$ 7,310
Gross increases - tax positions in prior period	—	—
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,569)	(2,131)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 3,610	$ 5,179

Our unrecognized tax benefits include approximately $1.4 million related to tax positions as of December 31, 2024 and 2023, 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 $0.4 million and

recognized an income tax benefit of approximately $2.7 million for previously unrecognized tax benefits. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2024, we have accrued $1.7 million for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2023, we had $1.0 million accrued for the payment of interest and penalties.

Tax years 2021 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.

(14) 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,					
	2024			2023		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (4)	$ —	$ (4)	$ 2	$ —	$ 2
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452
Postretirement medical liability adjustment	—	—	—	(331)	69	(262)
Other comprehensive (loss) income	$ 608	$ (160)	$ 448	$ 283	$ (91)	$ 192

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

	December 31,	
	2024	2023
Foreign currency translation	$ 1,433	$ 1,437
Derivative instruments designated as cash flow hedges	(8,921)	(9,373)
Postretirement medical plans	(45)	280
Accumulated other comprehensive loss	$ (7,533)	$ (7,656)

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

		December 31, 2024			
		Year Ended			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)
Other comprehensive income before reclassifications		—	—	(4)	(4)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	—	—	—
Net current-period other comprehensive income (loss)		452	—	(4)	448
Distribution to Parent		$ —	$ (325)	$ —	$ (325)
Ending Balance		$ (8,921)	$ (45)	$ 1,433	$ (7,533)

		December 31, 2023			
		Year Ended			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,825)	$ 542	$ 1,435	$ (7,848)
Other comprehensive loss before reclassifications		—	—	2	2
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(262)	—	(262)
Net current-period other comprehensive income (loss)		452	(262)	2	192
Ending Balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)

(15) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our Montana employees is referred to as the NorthWestern Energy MT Plan (formerly known as the NorthWestern Energy Plan). 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 a liability in our Consolidated 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,	
	2024	2023	2024	2023
Change in benefit obligation:				
Obligation at beginning of period	$ 427,326	$ 474,947	$ 10,598	$ 12,070
Service cost	5,099	5,105	252	272
Interest cost	20,725	23,535	456	554
Actuarial (gain) loss	(26,780)	2,235	(1,804)	(820)
Settlements[1]	(848)	(51,942)	—	—
Benefits paid	(20,719)	(26,554)	(1,163)	(1,478)
Benefit Obligation at End of Period	$ 404,803	$ 427,326	$ 8,339	$ 10,598
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 348,134	$ 388,693	$ 22,309	$ 20,055
Return on plan assets	8,026	29,937	3,177	3,334
Employer contributions	8,122	8,000	449	398
Settlements[1]	(848)	(51,942)	—	—
Benefits paid	(20,719)	(26,554)	(1,163)	(1,478)
Fair value of plan assets at end of period	$ 342,715	$ 348,134	$ 24,772	$ 22,309
Funded Status	$ (62,088)	$ (79,192)	$ 16,433	$ 11,711
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	—	—	16,943	12,378
Total Assets	—	—	16,943	12,378
Current liability	(10,000)	(10,000)	(510)	(667)
Noncurrent liability	(52,088)	(69,192)	—	—
Total Liabilities	(62,088)	(79,192)	(510)	(667)
Net amount recognized	$ (62,088)	$ (79,192)	$ 16,433	$ 11,711
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	—
Net actuarial (loss) gain	(30,843)	(43,097)	3,716	15
Total	$ (30,843)	$ (43,097)	$ 3,716	$ 15

(1) In October 2023, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to select NorthWestern Energy MT Pension Plan participants. We purchased the contract with $51.9 million of plan assets in 2023. A trailing premium of $0.8 million related to final data reconciliation was paid from plan assets in 2024, reflecting a final annuitized participant count of 276. The insurance company took over the payments of these benefits starting January 1, 2024. This transaction settled $51.9 million of our NorthWestern Energy MT 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 other income, net on the Consolidated 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 Consolidated Balance Sheets, with a corresponding decrease to operating and maintenance expense on the Consolidated 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.

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 December 31,		Other Postretirement Benefits December 31,	
	2024	2023	2024	2023
Components of Net Periodic Benefit Cost				
Service cost	$ 5,099	$ 5,105	$ 252	$ 272
Interest cost	20,725	23,535	456	554
Expected return on plan assets	(22,585)	(23,448)	(1,280)	(1,096)
Amortization of prior service cost (credit)	—	—	—	116
Recognized actuarial loss (gain)	33	228	—	79
Settlement loss recognized[1]	—	4,395	—	—
Net Periodic Benefit Cost (Credit)	$ 3,272	$ 9,815	$ (572)	$ (75)
Regulatory deferral of net periodic benefit cost[2]	4,850	(1,814)	—	—
Previously deferred costs recognized[2]	—	—	181	550
Net Periodic Benefit Cost Recognized	$ 8,122	$ 8,001	$ (391)	$ 475

(1) Settlement losses are related to partial annuitization of the NorthWestern Energy MT Pension Plan effective October 24, 2023.
(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 Consolidated Statements of Income as those costs are recovered through customer rates.

For the years ended December 31, 2024 and 2023 Service costs were recorded in Operating, general, and administrative expense while non-service costs were recorded in Other income, net on the Consolidated 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, 2024 and 2023. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets. During 2022, the plan's actuary conducted an experience study to review five years of plan experience and update these assumptions.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in the discount rate during 2024 decreased our projected benefit obligation by approximately $27.6 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we decreased our long term rate of return on assets assumption for NorthWestern Energy MT Pension Plan to 6.17 percent for 2025.

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

	Pension Benefits December 31,		Other Postretirement December 31,	
	2024	2023	2024	2023
Discount rate	5.60	5.00	5.45	4.90
Expected rate of return on assets	6.65	6.44	5.84	5.62
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	6.00	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 Energy Health and Welfare	
	December 31,		December 31,	
	2024	2023	2024	2023
Fixed income securities	45.0 %	45.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	—	—	—
Opportunistic fixed income	11.0	11.0	—	—
Global equities	38.5	38.5	60.0	60.0
Private real estate	5.5	5.5	—	—

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,	
	2024	2023	2024	2023
Cash and cash equivalents	— %	— %	0.3 %	0.2 %
Fixed income securities[(1)]	43.7	45.3	32.2	35.1
Non-U.S. fixed income securities	—	—	—	—
Opportunistic fixed income	11.1	10.6	—	—
Global equities[(1)]	39.0	37.6	67.5	64.7
Private real estate	6.2	6.5	—	—
	100.0 %	100.0 %	100.0 %	100.0 %

(1) While the NorthWestern Energy Health and Welfare plan allocation of assets as of December 31, 2024, between Fixed income securities and Global equities is greater than 5 percent different from the target allocation, the plan Investment Manager has 60 days to correct this deviation from the plan.

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 SEC. Investments in a collective investment vehicle are valued by multiplying the investee company’s net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT’s investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT’s investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation or any affiliate's 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 2024 and 2023 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2024	2023
NorthWestern Energy Pension Plan	$ 8,122	$ 8,000

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

	Pension Benefits	Other Postretirement Benefits
2025	24,575	1,680
2026	25,611	986
2027	26,608	845
2028	27,326	841
2029	28,027	755
2030-2034	147,401	3,400

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 the plan. We also contribute various percentages of employees' gross compensation to the plan. Company contributions for the years ended December 31, 2024 and 2023 were $11.6 million, $10.3 million, respectively.

(16) Stock-Based Compensation

Our employees participate in the NorthWestern Energy Group, Inc. Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. The remaining vesting period for awards previously granted ranges from one to three 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.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. 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 certain performance goals are achieved 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 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 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 NorthWestern Energy Group, Inc. 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 NorthWestern Energy Group, Inc. 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:

	2024	2023
Risk-free interest rate	4.38 %	4.33 %
Expected life, in years	3	3
Expected volatility	12.5% to 29.0%	30.4% to 41.0%
Dividend yield	5.6 %	4.4 %

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 NorthWestern Energy Group, Inc.'s nonvested shares as of and changes during the year ended December 31, 2024, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	153,784	$ 53.26
Granted	150,704	41.13
Vested	(60,830)	51.61
Forfeited	(11,732)	48.12
Remaining nonvested grants	231,926	$ 46.07

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 NorthWestern Energy Group, Inc. 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 NorthWestern Energy Group, Inc. 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 NorthWestern Energy Group, Inc.'s common stock as of the grant date less the present value of expected dividends.

A summary of NorthWestern Energy Group, Inc.'s nonvested shares as of and changes during the year ended December 31, 2024, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	60,779	$ 47.91
Granted	—	—
Vested	—	—
Forfeited	(9,983)	60.73
Remaining nonvested grants	50,796	$ 45.40

We recognized total stock-based compensation expense of $2.8 million and $3.0 million for the years ended December 31, 2024 and 2023, respectively, and related income tax benefit of $(0.6) million, $(0.8) million for the years ended December 31, 2024 and 2023, respectively. As of December 31, 2024, there was $6.6 million of unrecognized compensation cost related to the nonvested portion of the outstanding awards at Northwestern Energy Group, Inc. A portion of these cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of NorthWestern Energy Group, Inc. shares vested was $3.1 million and $4.4 million, for the years ended December 31, 2024 and 2023 respectively.

(17) 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. We have 100 shares of common stock issued and outstanding.

Dividend Restrictions

Under various state regulatory agreements, debt agreements and the Federal Power Act, we have restrictions, including minimum equity ratios, that limit the amount of dividend distributions that can be made.

Pursuant to the MPSC regulatory agreement, if our secured credit ratings are above BBB- for S&P Global Ratings and Baa3 for Moody's Investor Services, we may declare or pay dividends as long as our common equity ratio is 40 percent or above. If our secured credit ratings are BBB- for S&P Global Ratings or Baa3 for Moody's Investor Services, we may declare or pay dividends as long as our common equity ratio is 43 percent or above. If our secured credit ratings fall below BBB- with S&P Global Ratings or Baa3 with Moody's Investor Services, we may not declare or pay dividends.

Our ability to pay dividends is also limited by the terms of various debt agreements, pursuant to which, we are required to maintain a debt to capitalization ratio of no more than 0.65 to 1.00.

As of December 31, 2024, approximately $784.6 million of our net assets were available for the payment of dividends under our most restrictive dividend restriction.

(18) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $118 to $130 per MWH through 2029. As of December 31, 2024, our estimated gross contractual obligation related to these contracts was approximately $229.0 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $205.8 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Fuel, purchased power and direct transmission expense and Electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in Other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2024	2023
Beginning QF liability	$ 28,670	$ 49,728
Settlements[1]	(7,606)	(24,707)
Interest expense	2,434	3,649
Ending QF liability	$ 23,498	$ 28,670

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

	Gross Obligation	Recoverable Amounts	Net
2025	$ 60,360	$ 52,950	$ 7,410
2026	55,393	46,274	9,119
2027	56,665	46,668	9,997
2028	42,400	41,664	736
2029	14,134	18,231	(4,097)
Total[(1)]	$ 228,952	$ 205,787	$ 23,165

(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 Fuel, purchased power and direct transmission expense in the Consolidated Statements of Income and were approximately $189.5 million and $217.9 million for the years ended December 31, 2024 and 2023, respectively. As of December 31, 2024, our commitments under these contracts were $264.3 million in 2025, $312.2 million in 2026, $300.2 million in 2027, $298.9 million in 2028, $302.6 million in 2029, and $2.3 billion thereafter. These commitments are not reflected in our Consolidated 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 $19.1 million between 2024 and 2040. These commitments are not reflected in our Consolidated 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 is estimated to range between $6.2 million to $10.8 million. As of December 31, 2024, we had a reserve of approximately $8.1 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,	
	2024	2023
Liability at January 1,	$ 8,438	$ 8,858
Deductions	(416)	(1,084)
Charged to costs and expense	71	664
Liability at December 31,	$ 8,093	$ 8,438

We are permitted to recover the remediation costs related to certain environmental liabilities within rates. 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 for all remediation costs, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide (CO_2) 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 one coal-fired electric generating plants, which is operated by Talen. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

EPA Rules - Congress has not passed any federal climate change legislation regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. 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 April 2024, the EPA released final rules related to greenhouse gas (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). In particular, the GHG Rules will (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). The MATS Rules will strengthen emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. Compliance with the rules will require expensive upgrades at Colstrip Units 3 and 4 with proposed compliance dates that may not be achievable and / or require technology that is unproven, resulting in significant impacts to costs of the facilities. The final MATS and GHG Rules require compliance as early as 2027 and 2032, respectively.

Previous efforts by the EPA were met with extensive litigation, and this time is no different. We, along with many other utilities, electric cooperatives, organizations, and states, have petitioned for judicial review of the GHG and MATS Rules with the U.S. Court of Appeals for the D.C. Circuit. The United States Supreme Court denied the multiple stay requests related to the MATS Rule and the GHG Rule. The litigation on the merits continues for both the MATS and GHG rules in the D.C. Circuit Court of Appeals, and decisions are expected in 2025. On April 8, 2025, President Trump issued a proclamation, "Regulatory Relief for Certain Stationary Sources to Promote American Energy," exempting certain coal plants, including Colstrip Units 3 and 4, Big Stone Plant, and Coyote Plant, from compliance with the MATS Rule through July 8, 2029. If the MATS Rules and GHG Rules are fully implemented, it would result in additional material compliance costs. We will continue working with

federal and state regulatory authorities, other utilities, and stakeholders to seek relief from the MATS and GHG regulations that, in our view, disproportionately impact customers in our region.

These GHG Rules and MATS Rules as well as 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 state of Montana has developed and submitted to the EPA, for its approval, their respective State Implementation Plan (SIP) for Regional Haze compliance. While the state of Montana did not meet the EPA's July 31, 2021 submission deadline, it was 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. Until the SIP is finalized and approved by EPA, the potential remains that installation of additional emissions controls might be required at the Colstrip facility

Jointly Owned Plants - We have joint ownership in a generation plant located in Montana that is 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 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). 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.. Upon the State's motion, the Federal District Court certified the Order for interlocutory appeal to the 9th Circuit Court of Appeals. After briefing and oral argument, the 9th Circuit affirmed the Federal District Court's Order in full on March 4, 2025.

Following the mandate and remand, the District Court will resume jurisdiction to determine damages for the Sun River to Black Eagle Falls Segment of the Missouri River. 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 MPSC would approve any such recovery.

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 MDEQ and NorthWestern, alleging that the environmental analysis conducted by MDEQ prior to issuance of the YCGS 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 YCGS 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. We recommenced YCGS construction in June 2023 and placed the plant in service in October 2024. On January 3, 2025, the Montana Supreme Court ordered that the YCGS air quality permit be reinstated. The Court remanded the matter back to MDEQ for supplemental analysis regarding lighting and greenhouse gas emissions in Montana. YCGS is commercially operable with the reinstated air quality permit.

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.

(19) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and do not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

We currently provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which include single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to our customers. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to our customers. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue for the twelve months ended by major source and customer class (in millions):

December 31, 2024	Electric	Natural Gas	Total
Residential	$ 398.8	$ 110.2	$ 509.0
Commercial	409.0	59.9	468.9
Industrial	46.6	1.0	47.6
Lighting, governmental, irrigation, and interdepartmental	30.0	1.3	31.3
Total Retail Revenues	**884.4**	**172.4**	**1,056.8**
Regulatory Amortization	21.2	14.9	36.1
Transmission	97.1	—	97.1
Wholesale and other	7.5	36.9	44.4
Total Revenues	**$ 1,010.2**	**$ 224.2**	**$ 1,234.4**

December 31, 2023	Electric	Natural Gas	Total
Residential	$ 408.3	$ 136.1	$ 544.4
Commercial	431.4	73.7	505.1
Industrial	46.0	—	46.0
Lighting, governmental, irrigation, and interdepartmental	30.0	1.7	31.7
Total Retail Revenues	**915.7**	**211.5**	**1,127.2**
Regulatory Amortization	(103.8)	(15.2)	(119.0)
Transmission	78.4	—	78.4
Wholesale and other	8.0	41.6	49.6
Total Revenues	**$ 898.3**	**$ 237.9**	**$ 1,136.2**

(20) Related Party Transactions and Shared Services

Our parent, NorthWestern Energy Group, Inc., is organized as a holding company. As part of a holding company we receive services and share costs with Northwestern Energy Group, Inc., and its other subsidiaries pursuant to an Intercompany Services Agreement (ISA) that became effective in 2023. The ISA was approved by the MPSC. We employ all or substantially all of the employees of NorthWestern Energy Group, Inc. and its subsidiaries and, in accordance with the ISA, will provide all employment related services to the parties to the ISA. Pursuant to the ISA, all rendered services are at cost. For the year ended December 31, 2024, the total amount of payroll related services provided to NorthWestern Energy Public Service Corporation, a direct wholly-owned subsidiary of NorthWestern Energy Group, Inc., was $39.3 million.

Additionally, pursuant to the ISA, when utility-related operating, administrative, and general costs are attributable to more than one entity within the holding company structure and are unable to be direct charged (Shared OA&G Costs), these costs will be allocated amongst the entities pursuant to a Cost Allocation Manual. The nature of these Shared OA&G Costs includes operations supervision and engineering, energy supply marketing, networking communications, information technology, human resources, accounting, legal, and other such administrative costs.

The services provided under the ISA are settled in cash amongst the parties each month.

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	— %
4	302 Franchises and Consents	22,457,191	—	22,457,191	21,479,709	4.55 %
5	303 Miscellaneous Intangible Plant	16,896,106	—	16,896,106	16,607,726	1.74 %
6	**Total Intangible Plant**	39,373,292	—	39,373,292	38,107,430	3.32 %
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	459,088,547	—	459,088,547	453,235,225	1.29 %
18	**Total Steam Production Plant**	459,088,547	—	459,088,547	453,235,225	1.29 %
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	—	—	—	—	-
22	**Total Nuclear Production Plant**	—	—	—	—	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	6,339,294	—	6,339,294	5,958,417	6.39 %
26	331 Structures and Improvements	130,635,819	—	130,635,819	130,050,563	0.45 %
27	332 Reservoirs, Dams and Waterways	206,122,833	—	206,122,833	195,161,800	5.62 %
28	333 Water Wheel, Turbine, Generators	201,672,413	—	201,672,413	189,566,171	6.39 %
29	334 Accessory Electric Equipment	95,546,019	—	95,546,019	94,867,868	0.71 %
30	335 Misc. Power Plant Equipment	20,879,880	—	20,879,880	20,768,388	0.54 %
31	336 Roads, Railroads and Bridges	3,908,013	—	3,908,013	3,069,284	27.33 %
32	**Total Hydraulic Production Plant**	665,104,271	—	665,104,271	639,442,491	4.01 %
33						
34	**Other Production**					
35	340 Land and Land Rights	3,819,385		3,819,385	3,819,385	— %
36	341 Structures and Improvements	123,846,271	19,232	123,827,039	59,430,239	108.36 %
37	342 Fuel Holders & Accessories	34,699,345	112,084	34,587,261	21,117,961	63.78 %
38	343 Prime Movers	178,282,348		178,282,348	90,561,056	96.86 %
39	344 Generators	116,365,367	2,177,823	114,187,544	53,479,614	113.52 %
40	345 Accessory Electric Equipment	52,121,970	770,151	51,351,819	18,393,854	179.18 %
41	346 Misc. Power Plant Equipment	61,774,033	7,268	61,766,765	29,083,754	112.38 %
42	**Total Other Production Plant**	570,908,719	3,086,558	567,822,161	275,885,863	105.82 %
43	**Total Production Plant**	1,695,101,537	3,086,558	1,692,014,979	1,368,563,579	23.63 %

Sch. 19 cont.	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	**Transmission Plant**					
3	350 Land and Land Rights	43,467,408	—	43,467,408	42,967,324	1.16 %
4	352 Structures and Improvements	86,576,778	—	86,576,778	63,608,479	36.11 %
5	353 Station Equipment	384,949,916	—	384,949,916	365,001,598	5.47 %
6	354 Towers and Fixtures	30,640,142	—	30,640,142	30,640,142	— %
7	355 Poles and Fixtures	519,430,683	4,363,389	515,067,294	491,929,266	4.70 %
8	356 Overhead Conductors & Devices	189,374,070	941,700	188,432,370	184,457,202	2.16 %
9	357 Underground Conduit	137,878	102,286	35,592	35,592	— %
10	358 Undergrnd Conductors & Devices	1,961,964	554,036	1,407,928	1,407,928	— %
11	359 Roads and Trails	4,056,594	44,906	4,011,688	3,998,466	0.33 %
12	**Total Transmission Plant**	1,260,595,433	6,006,317	1,254,589,116	1,184,045,997	5.96 %
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	14,732,728	601	14,732,127	14,778,952	(0.32)%
16	361 Structures and Improvements	52,764,767	1,299,812	51,464,955	42,880,558	20.02 %
17	362 Station Equipment	276,646,321	5,278,630	271,367,691	257,244,919	5.49 %
18	363 Storage Battery Equipment	8,867,100	—	8,867,100	—	-
19	364 Poles, Towers, and Fixtures	415,390,059	442,774	414,947,285	389,650,830	6.49 %
20	365 Overhead Conductors & Devices	166,151,862	497,801	165,654,061	155,505,073	6.53 %
21	366 Underground Conduit	195,766,544	744,352	195,022,192	181,545,727	7.42 %
22	367 Undergrnd Conductors & Devices	298,985,174	3,881,838	295,103,336	278,178,147	6.08 %
23	368 Line Transformers	293,830,738	966,547	292,864,191	276,480,357	5.93 %
24	369 Services	200,535,016	482,315	200,052,701	186,056,731	7.52 %
25	370 Meters	92,679,948	107,483	92,572,465	86,882,315	6.55 %
26	371 Installations on Cust. Premises	—	—	—	—	-
27	372 Leased Property on Cust. Premises	—	—	—	—	-
28	373 Street Lighting and Signal Systems	83,788,346	31,585	83,756,761	83,066,508	0.83 %
29	**Total Distribution Plant**	2,100,138,603	13,733,738	2,086,404,865	1,952,270,117	6.87 %
30						
31	**General Plant**					
32	389 Land and Land Rights	689,633	—	689,633	689,633	— %
33	390 Structures and Improvements	10,602,203	506,969	10,095,234	10,118,119	(0.23)%
34	391 Office Furniture and Equipment	3,221,765	—	3,221,765	2,466,667	30.61 %
35	392 Transportation Equipment	69,838,782	275,970	69,562,812	67,597,012	2.91 %
36	393 Stores Equipment	1,179,099	—	1,179,099	1,155,108	2.08 %
37	394 Tools, Shop & Garage Equipment	11,549,407	—	11,549,407	11,095,842	4.09 %
38	395 Laboratory Equipment	1,027,426	—	1,027,426	1,033,178	(0.56)%
39	396 Power Operated Equipment	6,949,253	—	6,949,253	7,041,214	(1.31)%
40	397 Communication Equipment	63,025,160	2,050,054	60,975,106	56,199,639	8.50 %
41	398 Miscellaneous Equipment	2,253,008	—	2,253,008	2,122,709	6.14 %
42	399 Other Tangible Equipment	—	—	—	—	-
43	**Total General Plant**	170,335,736	2,832,993	167,502,743	159,519,121	5.00 %
44	**Total Plant in Service**	5,265,544,601	25,659,606	5,239,884,995	4,702,506,244	11.43 %
45						
46	4101 El Plant Allocated from Common	145,516,099	—	145,516,099	132,806,825	9.57 %
47	103 Experimental Electric Plant Unclassified	4,798,750	1,811,268	2,987,482	2,987,483	(0.00)%
48	105 El Plant Held for Future Use	4,162,063	—	4,162,063	4,110,361	1.26 %
49	107 El Construction Work in Progress	99,321,755	52,427	99,269,328	311,293,745	(68.11)%
50						
51						
52	**TOTAL ELECTRIC PLANT**	$5,519,343,268	$ 27,523,301	$5,491,819,967	$5,153,704,658	6.56 %

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

	CONSOLIDATED PLANT IN SERVICE	December 31, 2024	December 31, 2023
1			
2	Montana Electric	$ 5,239,884,995	$ 4,702,506,244
3	Yellowstone National Park	25,659,606	23,530,558
4	Montana Natural Gas (Includes CMP)	1,261,777,577	1,180,425,818
5	Common	210,314,290	193,279,118
6	Townsend Propane	1,730,243	1,547,775
7	South Dakota Electric	—	1,115,119,868
8	South Dakota Natural Gas	—	262,937,110
9	South Dakota Common	—	71,074,956
10	Asset Retirement Obligation	29,957,389	35,151,999
11	**TOTAL PLANT**	$ 6,769,324,100	$ 7,585,573,446

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	$ 459,088,547	$ 176,590,473	$ —	$ 176,590,473	$ 161,723,201	3.78 %
4							
5	Nuclear Production	—	—	—	—		— %
6							
7	Hydraulic Production	665,104,271	138,627,959	—	138,627,959	139,268,539	3.25 %
8							
9	Other Production	570,908,719	85,541,907	2,622,109	82,919,798	76,278,051	4.00 %
10							
11	Transmission	1,260,595,433	436,084,670	2,302,198	433,782,472	416,884,694	2.49 %
12							
13	Distribution	2,100,138,603	872,955,697	6,450,986	866,504,711	836,942,236	3.36 %
14							
15	General and Intangible	209,709,028	116,865,638	1,743,027	115,122,611	108,600,267	7.81 %
16							
17	Common	145,516,099	42,235,666	—	42,235,666	34,952,782	6.48 %
18							
19							
20	**Total Accum Depreciation**	$ 5,411,060,700	$ 1,868,902,010	$ 13,118,320	$ 1,855,783,690	$ 1,774,649,770	3.48 %
21							
22							
23							

24	**Consolidated**	December 31,	
25	**Accumulated Depreciation**	2024	2023
26			
27	Montana Electric	$ 1,813,548,024	$ 1,739,696,988
28	Yellowstone National Park	13,118,320	12,038,251
29	Montana Natural Gas (Includes CMP)	451,826,784	435,603,710
30	Common	63,662,277	53,580,007
31	Townsend Propane	1,164,154	1,127,273
32	South Dakota Electric	—	384,514,178
33	South Dakota Natural Gas	—	113,554,633
34	South Dakota Common	—	21,556,117
35	Acquisition Writedown	32,458,684	35,163,173
36	Basin Creek Capital Lease	37,193,802	35,183,325
37	FIN 47	(3,217,616)	2,093,317
38	CWIP-Capital Retirement Clearing	(11,524,962)	(16,877,317)
39	**Total Consolidated Accum Depreciation**	$ 2,398,229,467	$ 2,817,233,655

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	$ 2,248,613	$ —	$ 2,248,613	$ 2,155,210	4.33 %
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	—		$ —	$ —	-
7	Construction	64,258,964		$ 64,258,964	$ 52,720,347	21.89 %
8	Production Plant	402,267		$ 402,267	$ 524,803	(23.35)%
9	Transmission Plant	582,720		$ 582,720	$ 906,136	(35.69)%
10	Distribution Plant	2,067,174		$ 2,067,174	$ 2,131,645	(3.02)%
11						
12						
13	**Total MT Materials and Supplies**	$ 69,559,738	$ —	$ 69,559,738	$ 58,438,141	19.03 %
14						
15						

	Consolidated	December 31,	
	Fuel Stock	2024	2023
18			
19	Montana Electric	$ 2,248,613	$ 2,155,210
20	South Dakota	—	7,555,608
21			
22	**Total Fuel Stock**	$ 2,248,613	$ 9,710,818
23			
24			
25			

	Consolidated	December 31,	
	Materials and Supplies	2024	2023
28			
29	Montana Electric	$ 67,311,125	$ 56,282,931
30	Montana Natural Gas	12,469,589	9,516,222
31	South Dakota	—	19,455,340
32			
33	**Total Consolidated Materials and Supplies**	$ 79,780,714	$ 85,254,493

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
1				
2	**Regulated Electric Transmission, Distribution and Generation Utility**			
3				
4	Docket Number: D2022.07.078			
5	Order Number : 7860y			
6	Effective Date: November 1, 2023			
7				
8	Common Equity	48.02 %	9.65 %	4.64 %
9	Long Term Debt	51.98 %	4.01 %	2.08 %
10				
11	**TOTAL**	100.00 %		6.72 %
12				
13	**Colstrip Unit 4**			
14				
15	Docket Number: 2018.02.012			
16	Order Number : 7604u			
17	Effective Date: December 20, 2019			
18				
19	Common Equity	50.00 %	10.00 %	5.00 %
20	Long Term Debt	50.00 %	6.50 %	3.25 %
21				
22	**TOTAL**	100.00 %		8.25 %
23				
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Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(Decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 180,078,441	$ 194,131,555	(7.24)%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	147,975,406	179,874,970	(17.73)%
6	Amortization, Net	35,587,522	36,075,440	(1.35)%
7	Other Noncash Charges to Net Income, Net	7,046,126	10,610,312	(33.59)%
8	Deferred Income Taxes, Net	15,695,900	8,535,605	83.89 %
9	Investment Tax Credit Adjustments, Net	1,970,244	(129,483)	>300.00%
10	Change in Operating Receivables, Net	4,548,357	25,423,506	(82.11)%
11	Change in Materials, Supplies & Inventories, Net	(6,710,218)	(7,177,502)	6.51 %
12	Change in Operating Payables & Accrued Liabilities, Net	23,887,716	(68,659,030)	134.79 %
13	Allowance for Funds Used During Construction (AFUDC)	(17,537,612)	(17,612,998)	0.43 %
14	Change in Other Assets & Liabilities, Net	(30,228,854)	79,866,995	(137.85)%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,152,888)	(2,275,985)	5.41 %
17	Change in Regulatory Assets	9,340,746	36,795,341	(74.61)%
18	Change in Regulatory Liabilities	(35,364,509)	19,246,128	(283.75)%
19	**Net Cash Provided by Operating Activities**	334,136,377	494,704,854	(32.46)%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(484,972,274)	(566,864,445)	14.45 %
22	(Net of AFUDC)			
23	Investment in Equity Securities	(253,166)	(9,105,446)	97.22 %
24	Proceeds from Sale of Assets	—	—	-
25	**Net Cash Used in Investing Activities**	(485,225,440)	(575,969,891)	15.76 %
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	175,000,000	300,000,000	(41.67)%
29	Issuance of Notes Payable	—	—	-
30	Line of Credit Borrowings, Net	—	—	-
31	Proceeds From Issuance of Common Stock, Net	—	73,612,936	(100.00)%
32	Payments for Retirement of:			-
33	Repayments of Short Term Borrowings, Net	—	(92,403)	100.00 %
34	Repayments of Long Term Borrowings, Net	(100,000,000)	—	-
35	Line of Credit Borrowings (Repayments), Net	78,000,000	(132,000,000)	159.09 %
36	Dividends on Common Stock	(69,936,850)	(154,089,441)	54.61 %
37	Other Financing Activities:			
38	Distribution of Cash From NorthWestern Energy Group, Inc.	60,000,000	—	-
39	Debt Financing Costs	(792,992)	(4,109,961)	80.71 %
40	Treasury Stock Activity	—	731,249	(100.00)%
41	**Net Cash Used in Financing Activities**	142,270,158	84,052,380	69.26 %
42	**Net Increase/Decrease in Cash and Cash Equivalents**	(8,818,905)	2,787,343	>-300.00%
43	**Cash and Cash Equivalents at Beginning of Year**	23,642,693	20,855,350	13.37 %
44	**Cash and Cash Equivalents at End of Year**	$ 14,823,788	$ 23,642,693	(37.30)%
45				
46	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
47	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
48	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
49	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
50				
51	On January 1, 2024, we completed the second and final phase of the holding company reorganization. NorthWestern Corporation (NW Corp)			
52	contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation, (NWE			
53	Public Service), and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, Inc.,			
54	resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota			
55	utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc. Due to this reorganization, the prior period information included in these			
56	statements may not be comparable to the current period.			

Sch. 24	MONTANA LONG TERM DEBT 2024								
	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	4.18% Series($450M), Due 2044	11/14/14	11/15/44	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 %	2,581,777	3.44 %
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11 %	5,530,890	4.42 %
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	5.57% Series($239M) Due 2033	03/30/23	03/30/33	239,000,000	238,912,135	239,000,000	5.57 %	13,429,877	5.62 %
18	5.56% Series($175M) Due 2031	03/28/24	03/28/31	175,000,000	174,207,008	175,000,000	5.56 %	9,813,279	5.61 %
19	**Total First Mortgage Bonds**			$ 1,930,000,000	$ 1,917,863,034	$ 1,930,000,000		$ 88,956,357	4.61 %
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 %	$ 5,918,622	4.09 %
23									
24	**Total Pollution Control Bonds**			$ 144,660,000	$ 144,020,056	$ 144,660,000		$ 5,918,622	4.09 %
25									
26	**Other Long-Term Debt**								
27									
28									
29	**Total Other Long Term Debt**			$ —	$ —	$ —		$ —	
30									
31	**TOTAL LONG TERM DEBT**			$ 2,074,660,000	$ 2,061,883,090	$ 2,074,660,000		$ 94,874,979	4.57 %
32									
33									
34	This schedule does not reflect our obligations under capital lease which total $5,461,499								
35									
36									
37									
38									
39									
40									
41									
42									
43									
44									
45									
46									
47									
48									

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not Applicable									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
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26										
27										
28										
29										
30										
31										
32	**TOTAL**					0		0	0	

Sch. 26	COMMON STOCK								
		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
							High	Low	
1									
2									
3	January	100	$ 0.01				N/A	N/A	
4									
5	February	100	0.01				N/A	N/A	
6									
7	March	100	0.01	N/A	N/A		N/A	N/A	
8									
9	April	100	0.01				N/A	N/A	
10									
11	May	100	0.01				N/A	N/A	
12									
13	June	100	0.01	N/A	N/A		N/A	N/A	
14									
15	July	100	0.01				N/A	N/A	
16									
17	August	100	0.01				N/A	N/A	
18									
19	September	100	0.01	N/A	N/A		N/A	N/A	
20									
21	October	100	0.01				N/A	N/A	
22									
23	November	100	0.01				N/A	N/A	
24									
25	December	100	0.01	N/A	N/A		N/A	N/A	
26									
27	**TOTAL Year End**	100	$ 0.01	N/A	N/A	N/A	N/A	N/A	N/A
28									
29									
30	1/ Monthly shares are actual shares outstanding at month-end.								
31									
32									
33									
34									
35									
36									

Sch. 27		MONTANA EARNED RATE OF RETURN - ELECTRIC			
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$ 5,730,770,769	$ 5,173,556,297	10.77 %
3	108	Accumulated Depreciation	(1,906,971,686)	(1,832,054,980)	(4.09)%
4	**Net Plant in Service**		$ 3,823,799,083	$ 3,341,501,317	14.43 %
5		Additions:			
6	154, 156	Materials & Supplies	$ 61,296,558	$ 42,022,457	45.87 %
7	165	Prepayments			
8		Other Additions	14,325,339	15,522,771	(7.71)%
9	**Total Additions**		$ 75,621,897	$ 57,545,228	31.41 %
10		Deductions:			
11	190	Accumulated Deferred Income Taxes	$ 161,382,354	$ 160,823,903	0.35 %
12	252	Customer Advances for Construction	90,856,836	79,519,168	14.26 %
13	255	Accumulated Def. Investment Tax Credits			
14		Other Deductions	134,218,064	121,617,272	10.36 %
15	**Total Deductions**		$ 386,457,254	$ 361,960,343	6.77 %
16	**Total Rate Base**		$ 3,512,963,726	$ 3,037,086,202	15.67 %
17	**Net Earnings**		$ 214,796,875	$ 199,829,304	7.49 %
18	**Rate of Return on Average Rate Base**		6.114 %	6.580 %	(7.07)%
19	**Rate of Return on Average Equity 1/**		8.127 %	8.945 %	(9.14)%
20					
21		**Major Normalizing and**			
22		**Commission Ratemaking Adjustments**			
23		Rate Schedule Revenues 2/	$ 2,054,531	$ 410,642	>300.00%
24		Environmental True-up MGP Sites 3/	(16,414)	345,644	(104.75)%
25					-
26		Non-Allowables:			-
27		Advertising	817,125	1,019,825	(19.88)%
28		Dues, Contributions, Other	80,769	130,016	(37.88)%
29					-
30		Associated Income Taxes 4/	(1,710,552)	(1,180,692)	(44.88)%
31					
32					
33					
34					
35					
36	**Total Adjustments**		$ 1,225,459	$ 725,435	68.93 %
37	**Revised Net Earnings**		$ 216,022,334	$ 200,554,739	7.71 %
38	**Adjusted Rate of Return on Average Rate Base**		6.149 %	6.604 %	(6.88)%
39	**Adjusted Rate of Return on Average Equity 1/**		8.255 %	9.039 %	(8.67)%
40					

41 1/ Return on Equity calculated using the capital structure approved in Docket No. D2022.7.78

42 2/ Rate schedule revenues are adjusted to revenues on a normalized basis by converting to volumes based on normal
43 weather. The impact to our adjusted rate of returns due to interim rates, which are subject to refund, going into
44 into effect on December 1, 2024, as approved in docket no. 2024.05.053, interim order no. 7968e, was $2,813,914.
45 Absent these interim rates, our adjusted rate of return on average rate base and average equity would have been
46 6.069% and 8.089%, respectively.

47 3/ Removal of expenses recorded in 2024 related to environmental costs not recovered from customers.

48 4/ Associated income taxes include an interest synchronization adjustment based upon the approved
49 capital structure in Docket No. D2022.7.78.

50

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	12,123,427	13,303,415	(8.87)%
5	Fuel Stock	2,201,912	2,219,356	(0.79)%
6				-
7				
8	**Total Other Additions**	$ 14,325,339	$ 15,522,771	(7.71)%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$ 4,006,027	$ 3,479,057	15.15 %
12	Gross Cash Requirements	62,595,118	50,707,505	23.44 %
13	Regulatory Liability (TCJA)	68,480,379	69,115,368	(0.92)%
14	MPSC/MCC Taxes	(1,346,750)	(2,083,745)	35.37 %
15	Environmental Reserve	483,290	399,087	21.10 %
16	**Total Other Deductions**	$ 134,218,064	$ 121,617,272	10.36 %
17				
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42				

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)	$ 5,385,401,094
5	103	Experimental Electric Plant Unclassified	2,987,482
6	105	Plant Held for Future Use	4,162,063
7	107	Construction Work in Progress	99,269,328
8	114	Plant Acquisition Adjustments	451,564,554
9	151-163	Materials & Supplies	69,559,738
10		(Less):	
11	108, 111, 115	Depreciation & Amortization Reserves	1,855,783,688
12	252	Customer Advances	97,204,273
13	**NET BOOK COSTS**		4,059,956,298
14			
15		**Revenues & Expenses**	
16			
17	400	Operating Revenues	995,567,621
18			
19	**Total Operating Revenues**		995,567,621
20			
21	401-402	Other Operating Expenses (including regulatory amortizations)	480,286,453
22	403-407	Depreciation & Amortization Expenses	154,950,318
23	408.1	Taxes Other than Income Taxes	126,981,680
24	409-411	Federal & State Income Taxes	18,552,295
25	411.8	SO2 Allowances	—
26			
27	**Total Operating Expenses**		780,770,746
28	**Net Operating Income**		214,796,875
29			
30	415-421.1	Other Income	13,025,915
31	421.2-426.5	Other Deductions	1,098,155
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 226,724,635
33			
34		**Average Customers (Intrastate Only)**	
35		Residential	328,401
36		Commercial & Industrial	79,500
37		Other (including interdepartmental)	2,569
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		410,470
40			
41		**Other Statistics (Intrastate Only)**	
42		Average Annual Residential Use (Kwh)	8,536
43		Average Annual Residential Cost per (Kwh)	$ 0.139
44		Average Residential Monthly Bill	$ 98.86
45			
46		Plant in Service (Gross) per Customer	$ 13,120

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,000	480	118	5	603
2	Alberton	452	423	93	15	531
3	Alder	86	239	106	24	369
4	Amsterdam	206	134	43	9	186
5	Anaconda	9,421	4,581	974	63	5,618
6	Armington	—	1	—	—	1
7	Arrow Creek	—	4	3	—	7
8	Augusta	316	275	117	5	397
9	Avon	114	97	68	3	168
10	Barber	—	46	10	1	57
11	Basin	199	172	80	2	254
12	Bearcreek	91	68	27	2	97
13	Belfry	193	176	70	16	262
14	Belgrade	10,460	10,409	2,872	126	13,407
15	Belt	510	653	274	15	942
16	Benchland	—	6	7	—	13
17	Big Sandy	605	330	139	6	475
18	Big Sky	3,591	4,636	1,122	29	5,787
19	Big Timber	1,650	1,293	443	36	1,772
20	Billings	117,116	52,745	9,594	685	63,024
21	Black Eagle	949	461	200	14	675
22	Bonner	1,690	78	69	1	148
23	Boulder	1,201	921	298	27	1,246
24	Box Elder	85	146	70	8	224
25	Bozeman	53,293	38,396	7,974	463	46,833
26	Brady	116	79	35	5	119
27	Bridge Bay	—	—	1	—	1
28	Bridger	662	466	187	17	670
29	Broadview	139	239	167	3	409
30	Buffalo	—	—	3	5	8
31	Butte	34,494	15,832	2,860	269	18,961
32	Cameron	—	467	142	5	614
33	Canyon	—	4	28	—	32
34	Canyon Creek	47	199	44	7	250
35	Carter	65	120	76	4	200
36	Cardwell	62	1	—	—	1
37	Cascade	600	1,193	382	30	1,605
38	Centerville	32	12	12	1	25
39	Checkerboard	—	54	9	1	64
40	Chester	847	474	314	15	803
41	Chinook	1,185	811	328	16	1,155
42	Choteau	1,721	1,022	401	27	1,450
43	Churchill	1,030	712	152	32	896
44	Clancy	1,851	948	202	8	1,158
45	Clinton	1,018	106	41	1	148
46	Coffee Creek	22	56	26	1	83
47	Collins	—	1	6	—	7
48	Colstrip	2,096	965	239	35	1,239
49	Columbus	1,857	1,049	369	21	1,439
50	Conrad	2,318	1,261	492	28	1,781
51	Corbin	—	1	3	—	4
52	Corvallis	1,125	924	197	38	1,159
53	Craig	39	98	47	7	152

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	856	288	17	1,161
3	De Borgia	91	162	40	2	204
4	Deer Lodge	2,938	2,181	663	88	2,932
5	Denton	205	175	85	2	262
6	Dillon	3,880	2,179	642	80	2,901
7	Divide	—	74	18	4	96
8	Dodson	125	118	69	5	192
9	Drummond	272	383	243	38	664
10	Dutton	303	242	124	3	369
11	East Helena	1,944	3,667	562	33	4,262
12	Edgar	110	169	65	10	244
13	Elliston	227	222	74	3	299
14	Ennis	917	2,266	671	43	2,980
15	Fairfield	759	411	166	34	611
16	Fishing Bridge		—	8	—	8
17	Fishtail	67	51	7	—	58
18	Florence	821	441	163	16	620
19	Floweree	19	105	67	2	174
20	Fort Belknap	1,567	429	105	22	556
21	Fort Benton	1,449	852	390	36	1,278
22	Fort Harrison	—	—	99	3	102
23	Fromberg	392	321	85	11	417
24	Gallatin Gateway	967	1,084	384	19	1,487
25	Gardiner	833	913	340	12	1,265
26	Garrison	115	141	67	6	214
27	Geraldine	207	283	152	2	437
28	Geyser	78	69	39	4	112
29	Gildford	141	92	69	1	162
30	Glasgow	3,202	1,677	742	59	2,478
31	Glasgow Air Base	—	1	1	—	2
32	Gold Creek	—	88	53	5	146
33	Grant Village	—	6	50	—	56
34	Grantsdale	—	21	3	1	25
35	Great Falls	60,442	31,013	5,789	379	37,181
36	Greycliff	89	51	28	12	91
37	Hall	51	313	106	26	445
38	Hamilton	4,659	5,990	1,579	121	7,690
39	Hardin	3,818	1,405	472	23	1,900
40	Harlem	769	443	211	25	679
41	Harlowton	955	685	295	10	990
42	Harrison	105	204	74	31	309
43	Haugan	58	94	37	2	133
44	Havre	9,362	4,885	1,334	186	6,405
45	Helena	32,091	27,479	5,814	426	33,719
46	Hingham	131	106	75	2	183
47	Hinsdale	193	132	61	5	198
48	Hobson	179	174	71	9	254
49	Huson	256	150	36	2	188
50	Hysham	276	—	1	—	1
51	Inverness	77	43	28	1	72
52	Jardine	47	1	2	—	3
53	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	412	72	4	488
2	Joliet	577	529	168	24	721
3	Joplin	159	101	51	2	154
4	Judith Gap	110	97	57	5	159
5	Kremlin	78	70	41	1	112
6	Lake	—	41	62	—	103
7	Laurel	7,222	3,371	573	21	3,965
8	Lavina	136	209	117	15	341
9	Lennep	—	19	13	—	32
10	Lewistown	5,952	3,419	939	64	4,422
11	Lincoln	998	1,127	330	13	1,470
12	Livingston	8,040	5,520	1,288	73	6,881
13	Logan	72	59	29	2	90
14	Lohman	—	30	33	4	67
15	Lolo	4,399	1,709	219	23	1,951
16	Loma	65	69	46	4	119
17	Lothair	—	13	15	—	28
18	Madison Junction	1	—	22	—	22
19	Malta	1,860	1,326	534	47	1,907
20	Mammoth	—	171	77	1	249
21	Manhattan	2,086	1,498	464	111	2,073
22	Martinsdale	43	127	93	17	237
23	Marysville	82	75	40	—	115
24	Maxville	138	5	1	—	6
25	McAllister	278	323	70	10	403
26	Melrose	—	2	1	—	3
27	Melstone	126	166	280	23	469
28	Melville	—	68	51	4	123
29	Milltown	—	79	23	4	106
30	Missoula	73,489	41,708	7,108	572	49,388
31	Moccasin	23	46	37	2	85
32	Molt	—	36	40	—	76
33	Monarch	26	335	67	1	403
34	Montana City	2,918	1,247	258	3	1,508
35	Moore	194	111	45	3	159
36	Musselshell	59	65	33	2	100
37	Nashua	301	191	70	4	265
38	Neihart	43	205	47	1	253
39	Nevada City	—	—	10	—	10
40	Norris	46	62	52	4	118
41	Norris Junction	—	12	12	—	24
42	Nye	38	19	5	1	25
43	Old Faithful	—	35	57	—	92
44	Paradise	166	161	68	11	240
45	Park City	1,023	447	101	5	553
46	Philipsburg	841	2,141	420	25	2,586
47	Plains	1,106	1,902	533	29	2,464
48	Pompey's Pillar	—	1	—	—	1
49	Pony	127	153	37	7	197
50	Power	177	91	48	2	141
51	Pray	790	30	1	1	32
52	Radersburg	61	89	31	2	122
53	Ramsay	—	96	39	1	136
54	Raynesford	31	74	46	2	122
55	Red Lodge	2,257	2,269	451	27	2,747
56	Reedpoint	177	180	63	3	246
57	Ringling	—	45	32	3	80

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Roberts	304	3	—	—	3
2	Rocker	—	69	24	2	95
3	Rockvale	193	2	1	—	3
4	Roscoe	16	99	11	—	110
5	Roundup	1,742	1,144	423	17	1,584
6	Rudyard	270	147	74	2	223
7	Ryegate	223	146	73	8	227
8	Saco	159	168	104	1	273
9	Saint Marie	489	292	53	3	348
10	Saint Regis	313	613	217	11	841
11	Saltese	10	39	23	1	63
12	Sand Coulee	179	162	57	2	221
13	Sapphire Village	—	79	11	—	90
14	Shawmut	42	61	37	2	100
15	Sheridan	694	1,065	299	61	1,425
16	Silesia	103	45	13	1	59
17	Silverbow	—	11	12	—	23
18	Springdale	40	40	15	9	64
19	Square Butte	27	34	18	1	53
20	Stanford	403	348	212	8	568
21	Stevensville	2,002	2,473	687	80	3,240
22	Stockett	157	168	69	1	238
23	Sumatra	—	—	9	—	9
24	Sun River	—	1	—	—	1
25	Superior	830	998	299	23	1,320
26	Taft	—	—	5	—	5
27	Tampico	—	8	5	—	13
28	Thompson Falls	1,336	1,279	386	33	1,698
29	Three Forks	1,989	1,649	626	82	2,357
30	Toston	100	53	44	23	120
31	Tower Junction	—	2	26	—	28
32	Townsend	1,787	1,560	465	22	2,047
33	Tracy	196	87	14	4	105
34	Turah	364	59	2	—	61
35	Twin Bridges	330	326	186	34	546
36	Twodot	26	57	50	7	114
37	Ulm	723	449	145	12	606
38	Utica	23	2	6	1	9
39	Valier	530	384	187	47	618
40	Vaughn	737	247	63	7	317
41	Victor	789	854	328	22	1,204
42	Virginia City	219	221	112	2	335
43	Wagner	—	45	23	2	70
44	Walkerville	639	262	33	4	299
45	Warm Springs	—	—	4	—	4
46	Washoe	—	6	2	—	8
47	West Thumb	—	—	1	—	1
48	West Yellowstone	1,272	2	12	—	14
49	White Sulphur Springs	955	838	423	62	1,323
50	Whitehall	1,006	1,087	349	73	1,509
51	Wickes	—	1	—	—	1
52	Williamsburg	—	1	1	—	2
53	Willow Creek	230	158	73	26	257

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Windham	43	45	32	3	80
2	Winston	169	156	60	3	219
3	Wolf Creek	25	441	177	11	629
4	Yellowstone Club	—	709	15	—	724
5	Zurich	29	104	86	10	200
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49	Total	529,293	328,401	76,187	5,858	410,446

1/ Customer populations represent an average of the 12 month period from 01/01/24 through 12/31/24. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
4	Customer Care	154	151	153
5	Finance	56	64	60
6	Information Technology	102	95	99
7	Distribution	435	521	478
8	Asset Management	40	49	45
9	Transmission	322	261	292
10	Supply	132	126	129
11	Legal	22	10	16
12				
13				
14				
15				
16				
	TOTAL EMPLOYEES	1,263	1,277	1,270

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2025 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Distribution - Transformer Purchase New Connects	$ 13,722,000	$ 13,722,000
4	MT Distribution - Wildfire Line Device Upgrades	8,053,055	8,053,055
5	MT Transmission - Sub Maint. Autotransformer Upgrade	6,975,123	6,975,123
6	MT Transmission - Capacity Miller-Stevensville A Line	6,232,913	6,232,913
7	MT Transmission - TSR Wind Alkali Creek 161kv	5,405,763	5,405,763
8	MT Distribution - New Manhattan Substation	5,244,900	5,244,900
9	MT Distribution - Sub Capacity Hamilton North Sub	4,958,348	4,958,348
10	MT Transmission - Sub Broadview Cap Replace 500kv	4,450,763	4,450,763
11	MT Transmission - TSR WAPA Belt-Monarch 100kv	4,394,819	4,394,819
12	MT Transmission - Sub Maint. Clyde Park Sub Rebuild	4,271,764	4,271,764
13	MT Transmission - Capacity Great Falls Eastside-SE-Southside	3,327,340	3,327,340
14	MT Distribution - Sub Capacity GTF SW Sub Bank #2	3,110,146	3,110,146
15	MT Transmission - Sub Maint. Broadview	3,091,256	3,091,256
16	MT Distribution - Sub Capacity Belgrade West Bank #2	2,707,914	2,707,914
17	MT Distribution - Pole Replacements Helena	2,516,639	2,516,639
18	MT Transmission - Sub Capacity Broadview Bus	2,505,077	2,505,077
19	MT Transmission - Billings Wildfire Hardening	2,504,192	2,504,192
20	MT Transmission - Missoula Wildfire Hardening	2,490,789	2,490,789
21	MT Transmission - Butte Wildfire Hardening	2,457,449	2,457,449
22	MT Transmission - Sub Maint. Richardson Coulee	2,369,340	2,369,340
23	MT Distribution - Missoula Wildfire Hardening	2,343,439	2,343,439
24	MT Transmission - Sub Maint. Glengarry	2,183,455	2,183,455
25	MT Distribution - Helena Wildfire Hardening	2,168,607	2,168,607
26	MT Distribution - Sub Maint. Bozeman-E Gallatin Bank 3	2,165,409	2,165,409
27	MT Transmission - Sub Maint. Malta	2,077,306	2,077,306
28	MT Transmission - Sub Capacity TSR Three Rivers 230/161	2,075,387	2,075,387
29	MT Transmission - Sub Capacity GTF 230 Switchyard Expansion	2,072,200	2,072,200
30	MT Transmission - Capacity Great Falls Southside-MT Refining	2,049,519	2,049,519
31	MT Transmission - Great Falls Wildfire Hardening	1,998,748	1,998,748
32	MT Transmission - Havre Wildfire Hardening	1,996,132	1,996,132
33	MT Transmission - Bozeman Wildfire Hardening	1,995,911	1,995,911
34	MT Distribution - Wildfire PSPS Mobile Generators	1,853,084	1,853,084
35	MT Distribution - New Manhattan Substation Feeders	1,803,659	1,803,659
36	MT Distribution - Sub Capacity Missoula Russel St Transformer	1,781,525	1,781,525
37	MT Distribution - Pole Replacements Great Falls	1,747,496	1,747,496
38	MT Distribution - Sub Capacity Lolo Bank Upgrade	1,683,239	1,683,239
39	MT Transmission - Capacity Billings Broadview-Shorey	1,556,105	1,556,105
40	MT Transmission - Lewistown Wildfire Hardening	1,499,430	1,499,430
41	MT Transmission - Hamilton Wildfire Hardening	1,498,651	1,498,651
42	MT Transmission - Helena Wildfire Hardening	1,496,274	1,496,274
43	MT Distribution - Sub Capacity Ennis City Transf. Upgrade	1,481,164	1,481,164
44	MT Distribution - Pole Replacements Lewistown	1,393,334	1,393,334
45	MT Distribution - Bozeman Wildfire Hardening	1,381,997	1,381,997
46	MT Transmission - Sub Maint. SBRU Lewistown	1,240,893	1,240,893
47	MT Transmission - Pole Replacements Lewistown	1,227,967	1,227,967
48	MT Distribution - Wildfire Cutout Replacements	1,190,362	1,190,362
49	MT Distribution - Pole Replacements Butte	1,009,975	1,009,975
50	MT Transmission - Wildfire Reclosures Hamilton	1,000,000	1,000,000
51	MT Transmission - Wildfire Reclosures Livingston	1,000,000	1,000,000
52	MT Transmission - Wildfire Reclosures Havre	1,000,000	1,000,000
53			
54	All Other Projects < $1 Million Each and blankets	89,466,287	89,466,287
55	**Total Electric Utility Construction Budget**	**$ 230,227,145**	**$ 230,227,145**
56			
57	**Natural Gas Operations**		
58	MT Transmission - Capacity Helena Junction - Helena City Gate 1	$ 19,211,640	$ 19,211,640
59	MT Transmission - Butte City Gate 1 to City Gate 3 Replace	13,794,047	13,794,047
60	MT Transmission - Capacity North Helena Tie - Boulder Tap	9,356,089	9,356,089
61	MT Gas Storage - Dry Creek Compressors	6,087,038	6,087,038
62	MT Gas Storage - Dry Creek Additional Wells	5,202,628	5,202,628
63	MT Transmission - RIGTL Vaughn to Sun Prairie	4,355,397	4,355,397
64	MT Distribution - Butte Base Gas One Upgrades	3,411,019	3,411,019
65	MT Distribution - Gas Meters and Regulators New Connects	1,254,000	1,254,000
66	MT Transmission - Frenchtown City Gate 1 Upgrade	1,029,234	1,029,234
67	MT Gas Transmission - Missoula Landfill RNG	1,027,166	1,027,166
68			
69	All Other Projects < $1 Million Each and blankets	$ 30,006,074	$ 30,006,074
70	**Total Natural Gas Utility Construction Budget**	**$ 94,734,332**	**$ 94,734,332**
71			
72	**Common**		
73	MT Common - Distribution AMI Metering and Infrastructure	$ 11,278,506	$ 11,278,506
74	MT Common - Fleet Replacements	5,000,072	5,000,072
75	MT Common - Facilities Livingston Design and Construct	4,879,101	4,879,101
76	MT Common - Business Technology HRIS Solution	3,896,032	3,896,032
77	MT Common - Billings Mechanics Garage	2,382,800	2,382,800
78	MT Common - Business Technology Enterprise GIS	1,921,370	1,921,370
79	MT Common - Business Technology Microsoft Enterprise Platform	1,352,354	1,352,354
80	MT Common - Business Technology Digital Workforce Mgmt	1,012,449	1,012,449
81			
82	All Other Projects < $1 Million Each and blankets	11,647,024	11,647,024
83	(Includes BT, Communications, Facilities, Land, Customer Service)		
84	**Total Common Utility Construction Budget**	**$ 43,369,708**	**$ 43,369,708**
85			
86	**MT Generation**		
87	MT Generation - Hydro Black Eagle Spillway Upgrade for Ice	$ 9,156,445	$ 9,156,445
88	MT Generation - CU4 Plant Upgrades	8,796,195	8,796,195
89	MT Generation - DGGS Gas Gen 50k hour overhaul	6,859,039	6,859,039
90	MT Generation - DGGS Gas Gen 50k hour overhaul	6,821,530	6,821,530
91	MT Generation - DGGS PT 50k hour overhaul	4,174,313	4,174,313
92	MT Generation - DGGS PT 50k hour overhaul	4,099,545	4,099,545
93	MT Generation - Colstrip Land	3,004,390	3,004,390
94	MT Generation - Hydro Holter Unit 4 Turbine Upgrade	2,497,189	2,497,189
95	MT Generation - Hydro Hauser Unit 6 Turbine Upgrade	1,905,362	1,905,362
96	MT Generation - Hydro Thompson Falls Unit 6 Turbine Upgrade	1,857,131	1,857,131
97	MT Generation - Holter Unit 4 Generator Rewind	1,832,763	1,832,763
98	MT Generation - Hydro Hauser Unit 1 Turbine Upgrade	1,701,389	1,701,389
99	MT Generation - Hydro Holter Headgate Upgrade	1,451,408	1,451,408
100	MT Generation - Hydro Thompson Falls Unit 6 Generator Rewind	1,393,567	1,393,567
101	MT Generation - Hydro Thompson Falls Relicensing	1,266,989	1,266,989
102	MT Generation - Hydro Spare 20 MVA GSU	1,155,145	1,155,145
103			
104	All Other Projects < $1 Million Each and blankets	$ 7,797,126	$ 7,797,126
105	**Total MT Generation**	**65,769,526**	**65,769,526**
106	**TOTAL CONSTRUCTION BUDGET**	**$ 434,100,711**	**$ 434,100,711**

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	13	18:00	2,758	731,487	124,874
2	February	15	19:00	2,407	741,662	90,781
3	March	21	21:00	2,306	660,719	101,743
4	April	19	9:00	2,086	615,357	88,866
5	May	8	10:00	2,038	577,100	68,679
6	June	23	19:00	2,331	621,735	88,484
7	July	23	17:00	2,623	637,423	80,868
8	August	2	18:00	2,594	742,573	71,484
9	September	9	17:00	2,363	694,245	64,683
10	October	31	10:00	2,148	595,063	97,169
11	November	25	9:00	2,312	631,015	70,535
12	December	16	18:00	2,357	745,467	68,725
13	**TOTALS**				7,993,846	1,016,891
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**				0	0

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,374,085		
3	Nuclear	—	**Sales to Ultimate Consumers**	6,339,707
4	Hydro - Conventional	2,340,616	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	—		
6	Other	684,078	Sales for Resale	
7	(Less) Energy for Pumping	—	Requirement Sales	
8	**Net Generation**	4,398,779	Non-Requirement Sales	1,016,891
9	**Purchases**	3,595,503	**Sales for Resale**	1,016,891
10	Power Exchanges			
11	Received	41,796		
12	Delivered	42,232	Energy Furnished w/o Charge	—
13	**Net Power Exchanges**	(436)	**Energy Furnished**	—
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	14,942,950	Electric Department	
16	Delivered	14,942,950	(Less) Station Use	—
17	**Net Transmission Wheeling**	—	**Net Energy Used Within Util.**	—
18	**Transmission by Others Losses**	—	**Energy Losses**	637,248
19	**TOTAL SOURCES**	7,993,846	**TOTAL DISPOSITIONS**	7,993,846

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 425,163 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	1,374,085
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	480,325
3	Gas Turbine Generation	Station	Laurel, MT	175.0	60,564
4	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	109,248
5	Wind Generation	Two Dot	Two Dot, MT	11.3	33,941
6	Hydro Generation	Black Eagle	Great Falls, MT	23.9	127,466
7	Hydro Generation	Cochrane	Great Falls, MT	48.9	228,009
8	Hydro Generation	Hauser	Helena, MT	19.3	134,425
9	Hydro Generation	Holter	Helena, MT	53.6	265,780
10	Hydro Generation	Madison	Ennis, MT	12.7	76,209
11	Hydro Generation	Morony	Great Falls, MT	46.5	255,027
12	Hydro Generation	Mystic	Columbus, MT	12.0	53,734
13	Hydro Generation	Rainbow	Great Falls, MT	59.0	328,967
14	Hydro Generation	Ryan	Great Falls, MT	55.2	434,562
15	Hydro Generation	Thompson Falls	Thompson Falls, MT	92.4	436,437
16	Total Generation			1,021.8	4,398,779
		Source of capacity	Seller	Avg Monthly Billing Demand (MW)	Annual Energy (Mwh)
17	Qualifying Facility Purchases	Wind	71 Ranch		11,355
18	Qualifying Facility Purchases	Solar	Apex Solar LLC (commercial energy)		158,247
19	Qualifying Facility Purchases	Wind	Big Timber Wind		80,013
20	Qualifying Facility Purchases	Thermal	Billings Generation Inc		381,833
21	Qualifying Facility Purchases	Solar	Black Eagle Solar		5,177
22	Qualifying Facility Purchases	Hydro	Boulder Hydro		1,218
23	Qualifying Facility Purchases	Hydro	Broadview East/Two Dot		4,085
24	Qualifying Facility Purchases	Thermal	Colstrip Energy Ltd/Montana One		287,520
25	Qualifying Facility Purchases	Wind	Cycle Horseshoe Bend		4,447
26	Qualifying Facility Purchases	Wind	DA Wind		11,748
27	Qualifying Facility Purchases	Wind	Fairfield Wind		26,042
28	Qualifying Facility Purchases	Hydro	Flint Creek Hydro		11,029
29	Qualifying Facility Purchases	Wind	Gordon Butte Wind		39,077
30	Qualifying Facility Purchases	Solar	Great Divide Solar LLC		6,239
31	Qualifying Facility Purchases	Solar	Green Meadow Solar		5,637
32	Qualifying Facility Purchases	Wind	Greenfield Wind		82,458
33	Qualifying Facility Purchases	Hydro	Hanover Hydro		267
34	Qualifying Facility Purchases	Hydro	Lower South Fork		681
35	Qualifying Facility Purchases	Solar	Magpie Solar LLC		5,650
36	Qualifying Facility Purchases	Solar	Montana Sun, LLC		173,865
37	Qualifying Facility Purchases	Wind	Musselshell Wind 1		23,394
38	Qualifying Facility Purchases	Wind	Musselshell Wind 2		26,207
39	Qualifying Facility Purchases	Wind	Oversight Resources		10,571
40	Qualifying Facility Purchases	Hydro	Pine Creek		1,031
41	Qualifying Facility Purchases	Hydro	Pony Hydro		869
42	Qualifying Facility Purchases	Solar	River Bend Solar		3,599
43	Qualifying Facility Purchases	Hydro	Ross Creek Hydro		1,364
44	Qualifying Facility Purchases	Hydro	South Dry Creek		3,789
45	Qualifying Facility Purchases	Solar	South Mills Solar 1		5,707
46	Qualifying Facility Purchases	Wind	South Peak Wind		258,911
47	Qualifying Facility Purchases	Hydro	State of Montana-DNRC / Broadwater Dam		47,260
48	Qualifying Facility Purchases	Wind	Stillwater Wind		274,716
49	Qualifying Facility Purchases	Hydro	Strawberry Creek		1,069
50	Qualifying Facility Purchases	Hydro	Wisconsin Creek		616
51					
52					
53					
54					
55					
56	Subtotal			0.0	1,955,691

Sch. 34A	SOURCES OF MONTANA ELECTRIC SUPPLY				
		see descriptions below	Seller	Annual Peak (MW) 1/	Annual Energy (Mwh)
1	Purchased Power	SF	Avangrid Renewables, LLC		13,965
2	Purchased Power	SF	Altop Energy Trading		550
3	Purchased Power	SF	Avista Corporation		27,920
4	Purchased Power	SF	Basin Electric Power Cooperative		—
5	Purchased Power	LU	Basin Creek Energy Partners	52.0	68,271
6	Purchased Power	SF	Black Hills Power Inc		195
7	Purchased Power	SF	Bonneville Power Administration		24,035
8	Purchased Power	LU	Replacement Purchases CELP		154,594
9	Purchased Power	SF	Clatskanie Peoples Utility District - Electric		5,037
10	Purchased Power	SF	ConocoPhillips Company		5,408
11	Purchased Power	SF	Constellation Energy Generation, LLC		—
12	Purchased Power	SF	Dynasty Power, Inc.		11,865
13	Purchased Power	SF	EDF Trading North America, LLC		85,672
14	Purchased Power	SF	Exelon Generation Company, LLC		1,345
15	Purchased Power	SF	Energy Keepers, Inc.		69,818
16	Purchased Power	SF	Eugene Water & Electric Board		5,428
17	Purchased Power	SF	Guzman Energy, LLC		2,855
18	Purchased Power	SF	Heartland Generation LTD		50,169
19	Purchased Power	SF	Idaho Power Company		1,576
20	Purchased Power	SF	Invenergy Energy Marketing LLC-Electric		408,119
21	Purchased Power	SF	Macquarie Energy LLC		47,156
22	Purchased Power	SF	Mercuria Energy America, Inc.		354
23	Purchased Power	SF	Morgan Stanley Capital Group, Inc.		167,479
24	Purchased Power	SF	PacifiCorp		3,396
25	Purchased Power	SF	Portland General Electric		17,542
26	Purchased Power	SF	Powerex Corp.		303,106
27	Purchased Power	SF	Pud No. 1 of Snohomish County		1,370
28	Purchased Power	SF	Puget Sound Energy		22,768
29	Purchased Power	SF	Rainbow Energy Marketing Corporation		4,961
30	Purchased Power	SF	Seattle City Light		11,645
31	Purchased Power	SF	Shell Energy North America (US), L.P.		12,076
32	Purchased Power	LF	Tacoma Power		5,975
33	Purchased Power	SF	Talen Energy Marketing, LLC		—
34	Purchased Power	SF	Tenaska Power		1,728
35	Purchased Power	SF	The Energy Authority, Inc.		50,267
36	Purchased Power	LU	Tiber Montana, LLC	not available	17,146
37	Purchased Power	SF	TransAlta Energy Marketing (US), Inc.		15,914
38	Purchased Power	LU	Turnbull Hydro, LLC	13.0	19,150
39	Purchased Power	SF	Vitol Inc- Electric		25
40	Purchased Power	SF	Western Area Power Administation		450
41					
42					
43	Subtotal			65.0	1,639,330
44	Reserve Sharing				482
45	Total Purchases				3,595,503

1/ Annual peak information is provided, where available, for sellers from whom we purchase all of their output.

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
1	
2	This schedule intentionally omitted.
3	
4	
5	
6	Schedule 34B contains operations data for Colstrip Unit 3 and Colstrip Unit 4 that is considered trade secret and
7	confidential by Talen Montana, LLC (“Talen”).
8	
9	
10	NorthWestern will provide this schedule upon request, subject to a Commission order in response to Talen’s request to
11	maintain the confidentiality of the data.
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Sch. 34C	THERMAL GENERATION OUTAGE REPORT			
	Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**DGGS Unit 1**	6/09/2024	Borescope inspections	60
2				
3		3/6/2024	U1A GG removed for 50k rebuild. U2A GG moved to U1A.	61
4				
5				
6	**DGGS Unit 2**	3/03/2024	U2B PT being sent to Depot for 50k rebuild	17
7				
8		07/11/2024	Hose leak	27
9				
10		07/31/2024	Generator issues	30
11				
12		6/3/2024	Borescope and alignment	65
13				
14		7/12/2024	U2 Generator NEE and EE vibrations	69
15				
16		7/8/2024	Unit 2B install GG	78
17				
18		7/18/2024	Scavenge oil system not working on U2B	236
19				
20		5/14/2024	U2 maintenance outage for fire system testing	321
21				
22		6/5/2024	Engine sent back to depot for inspection	390
23				
24		3/4/2024	U2A back in service. Blanking plate is on 2B side.	922
25				
26	**DGGS Unit 3**	7/26/2024	Fuel Valve faulted	13
27				
28		6/26/2024	Shut U3 down because of high bearing temperature again.	15
29				
30		9/24/2024	Gen Rotor Ground Fault 64F	17
31				
32		3/29/2024	Oil cooler replacement	18
33				
34		9/23/2024	U3 Rotor Ground Fault Trip	21
35				
36		6/23/2024	U3 Dilution air fan F5302A pillow block	24
37				
38		6/25/2024	U3 Dilution fan F5302A pillow block	30
39				
40		6/27/2024	Ammonia fan bearing temps	36
41				
42		9/21/2024	Generator Rotor Ground fault 64F trip	46
43				
44		7/12/2024	Belly Band Install in engine	63
45				
46		6/6/2024	Maintenance Outage and Inspections	65
47				
48				

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

Sch. 34D	THERMAL GENERATION OUTAGE REPORT			
	Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**YCGS Unit 16**	10/27/2024	High Temperature Coolant Pump Failure	30
2				
3	**YCGS Unit 5**	11/8/2024	Engine to Genset Coupling Failure	264
4				
5	**YCGS Unit 2**	11/11/2024	Engine to Genset Coupling Failure	522
6				
7	**YCGS Unit 4**	11/13/2024	Generator Protection Relay Trip	37
8				
9	**YCGS Unit 7**	11/13/2024	Generator Protection Relay Trip	51
10				
11	**YCGS Unit 14**	11/13/2024	Generator Protection Relay Trip	51
12				
13	**YCGS Unit 18**	11/13/2024	Generator Protection Relay Trip	532
14				
15	**YCGS Unit 13**	11/13/2024	Generator Protection Relay Trip	165
16				
17	**YCGS Unit 16**	12/1/2024	Gas Regulation Trip	13
18				
19	**YCGS Unit 13**	12/4/2024	Engine to Genset Coupling Failure	136
20				
21	**YCGS Unit 4**	12/4/2024	ICPM Failure	18
22				
23	**YCGS Unit 5**	12/5/2024	Engine to Genset Coupling Failure	628
24				
25	**YCGS Unit 4**	12/6/2024	Engine ECM Communication Failure	16
26				
27	**YCGS Unit 8**	12/14/2024	Reverse Power-Engine Overspeed	48
28				
29	**YCGS Unit 16**	12/14/2024	Low Temperature Cooling Water Pump Failure	42
30				
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Only outages greater than 12 hours are reported. Does not reflect partial outages of a unit.

Sch. 34E

HYDRO GENERATION OUTAGE REPORT

	Plant	Unit Name	Outage Start Date	Description	Outage Duration (hours)
1	**Black Eagle**	BE 3	1/16/2024	Thrust bearing oil pot level installed	14
2		BE 2	6/17/2024	Governor issue	18
3		BE 2	1/13/2024	Water in guide bearing	21
4		BE 3	8/13/2024	Relay crct issue	24
5		BE 2	6/11/2024	Governor issue	25
6		BE 2	10/15/2024	Broken screw headgate	29
7		BE 2	5/21/2024	Bearing work	48
8		BE 2	5/16/2024	Cooling issues	109
9		BE 2	6/12/2024	Governor issue	118
10		BE 2	6/06/2024	Governor issue	127
11		BE 2	5/23/2024	Cooling issues	142
12		BE 2	10/07/2024	Annual Maintenance	188
13		BE 2	1/01/2024	Annual Maintenance	232
14		BE 3	12/10/2024	Annual Maintenance	520
15					
16	**Cochrane**	CCH 1	4/25/2024	Switch yard line work	15
17		CCH 2	9/25/2024	NERC/WECC MOD testing	21
18		CCH 1	8/08/2024	Cap bank tie in	28
19		CCH 1	8/09/2024	Excessive cavitation	67
20		CCH 2	09/20/2024	NERC/WECC MOD testing	117
21		CCH 2	08/21/2024	Unit upgrade	704
22		CCH 2	9/26/2024	Oil head vibration	1,097
23		CCH 2	1/1/2024	Unit upgrade	5,599
24					
25	**Hauser**	HAU 3	6/17/2024	Annual Maintenance	50
26		HAU 5	4/15/2024	Switch gear stab replacement	51
27		HAU 6	4/15/2024	Switch gear stab replacement	51
28		HAU 4	3/25/2024	Annual Maintenance	51
29		HAU 4	4/15/2024	Switch gear stab replacement	55
30		HAU 2	11/18/2024	Annual Maintenance	79
31		HAU 4	3/18/2024	Annual Maintenance	80
32		HAU 6	4/17/2024	Annual outage	193
33		HAU 5	11/21/2024	Draft tube inspection	286
34		HAU 3	9/10/2024	Wicket Gate maintenance	312
35		HAU 6	8/04/2024	Speed sensor fail	738
36		HAU 6	4/25/2024	Mitigate cracked shaft	986
37		HAU 1	1/01/2024	Unit upgrade	8,784
38					
39	**Holter**	HLT 1	6/3/2024	Generator inspection	33
40		HLT 3	7/27/2024	Shaft packing issues	45
41		HLT 3	5/13/2024	Annual maintenance	69
42		HLT 3	7/23/2024	Cooling issues	103
43		HLT 1	9/16/2024	Annual maintenance	245
44		HLT 4	4/4/2024	Annual maintenance	288
45		HLT 3	4/29/2024	Headgate upgrade	343
46		HLT 4	4/16/2024	Headgate upgrade	582
47		HLT 2	1/1/2024	Unit upgrade	8,784
48					
49	**Madison**	MAD 1	1/11/2024	Frozen pressure alarm line	18
50		MAD 3	2/20/2024	Spillgate testing	27
51		MAD 1	1/12/2024	Frozen spillgate	69
52		MAD 2	01/30/2024	Replacement of headgate	74
53		MAD 2	01/11/2024	Frozen spillgate	87
54		MAD 2	1/19/2024	Headgate work	92
55		MAD 4	11/04/2024	Transmission relay cutover	96
56		MAD 1	11/04/2024	Transmission relay cutover	96
57		MAD 3	11/04/2024	Transmission relay cutover	96
58		MAD 2	11/04/2024	Transmission relay cutover	96
59		MAD 1	3/19/2024	Change out lube oil line	170
60		MAD 1	1/1/2024	Spillgate upgrade	260
61		MAD 2	1/1/2024	Spillgate upgrade	260
62		MAD 3	01/01/2024	Spillgate upgrade	260
63		MAD 4	01/01/2024	Spillgate upgrade	260

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

Sch. 34F

HYDRO GENERATION OUTAGE REPORT

	Plant	Unit Name	Outage Start Date	Description	Outage Duration (hours)
1	**Morony**	MOR 1	6/01/2024	Cleaning speed sensor	52
2		MOR 1	1/08/2024	Annual maintenance	53
3		MOR 1	5/27/2024	A phase fault	109
4		MOR 2	1/22/2024	Annual maintenance	168
5					
6	**Mystic**	MYS 2	4/30/2024	Annual maintenance	80
7		MYS 1	4/22/2024	Annual maintenance	192
8					
9	**Rainbow**	RNB 9	07/3/2024	Governor Maintenance	18
10		RNB 9	5/9/2024	Governor Maintenance	22
11		RNB 9	5/10/2024	Governor Maintenance	92
12		RNB 9	7/4/2024	Governor Maintenance	128
13		RNB 9	4/1/2024	Annual maintenance	344
12					
13	**Ryan**	RYN 4	6/23/2024	Failed power supply for VAR Control Module	17
14		RYN 5	9/09/2024	Annual Maintenance	195
15		RYN 3	10/28/2024	Annual Maintenance	201
16		RYN 6	9/30/2024	Annual Maintenance	211
17		RYN 2	9/17/2024	Annual Maintenance	315
18		RYN 6	11/25/2024	Headgate controls upgrade	329
19		RYN 5	11/26/2024	Headgate controls upgrade	333
20		RYN 2	11/11/2024	Headgate control upgrade	368
21		RYN 3	12/10/2024	Headgate control project	515
22		RYN 4	12/9/2024	Headgate controls upgrade	542
23					
24	**Thompson Falls**	THF 6	01/22/2024	Annual Maintenance	243
25		THF 2	3/19/2024	Annual Maintenance	366
26		THF 1	4/09/2024	Annual Maintenance	391
27		THF 4	2/06/2024	Annual Maintenance	502
28		THF 5	7/23/2024	Annual Maintenance	557
29		THF 7	9/10/2024	Annual Maintenance	559
30		THF 3	2/27/2024	Annual Maintenance	676
31					
32					
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37					

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)
1							
2	2024 Residential Lighting Program	$ 7,415	$ 1,391,537	(99.47)%	—	—	—
3	- Initiated 2005, 2024 weighted average program life = 10 years, 6 participants.				0.68	1.18	0.50
4							
5	2024 Residential Electric Existing Program	$ 187,088	$ 115,055	62.61 %	—	—	—
6	- Reinitiated 2021, 2024 weighted average program life = 15 years, 639 participants.				625	1,087	462
7							
8	2024 Residential Electric New Construction Program	$ 47,342	$ 12,994	264.34 %	—	—	—
9	- Reinitiated 2021, 2024 weighted average program life = 19 years, 67 participants.				148	257	109
10							
11	2024 Commercial Lighting Program	$ 5,018,467	$ 3,521,789	42.50 %	—	—	—
12	- Initiated 2005, 2024 weighted average program life = 14 years, 703 participants.				17,716	30,802	13,086
13							
14	2024 Electric Business Partners Program	$ 349,925	$ 204,219	71.35 %	—	—	—
15	- Initiated 2005, 2024 weighted average program life = 15 years, 1 participants.				510	887	377
16							
17	2024 Northwest Energy Efficiency Alliance (NEEA)**	$ 962,760	$ 1,284,200	(25.03)%	—	—	—
18	- Initiated electric savings in 2006, program life is 15 years				8,439	14,672	6,233
19							
20	2024 Commercial Electric New Construction Program	$ 1,246,583	$ 285,008	>300.00%	—	—	—
21	- Initiated 2005, 2024 weighted average program life = 16 years, 44 participants.				3,679	6,396	2,717
22							
23	2024 Commercial Electric Savings Program	$ 598,008	$ 202,466	195.36 %	—	—	—
24	- Initiated 2005, 2024 weighted average program life = 14 years, 60 participants.				1,907	3,316	1,409
25							
26	2024 General Expenses All Electric DSM Programs	$ 434,785	$ 189,340	129.63 %	—	—	—
27	- N/A				—	—	—
28							
29	A program participant is a Montana residential and/or commercial electric						
30	customer who installs eligible energy conservation measures and receives						
31	financial incentives/rebates either directly or indirectly.						
32							
33	**Note: 2024 NEEA expenditures are allocated to electric DSM						
34	but there are gas savings as a result of some NEEA initiatives.						
35	Participant has not been defined or counted for NEEA.						
36							
37	Units reported are in megawatts ("MW") and megawatt-hours ("MWh")						
38							
39							
40							
41							
42							
43							
44							
45	**TOTAL**	$ 8,852,373	$ 7,206,608	22.84 %	—	—	—
46					33,025	57,418	24,394

Sch. 35A	Electric Universal System Benefits Programs						
	Program Description	Actual Expenditures	Contracted or Committed to Spend	Total Allocations & Expenditures (a)	Expected savings (b)		Most recent program evaluation
1	Local Conservation				MWh	MW	
2	Energy Audit Program	$ 736,833	$ 865,044	$ 1,601,877	270	0.057	2012
3	Irrigation Projects	$ 32,003	$ 35,752	$ 67,755	122	0	2012
4	NWE Promotion	$ 43,501	$ —	$ 43,501			
5	NWE Labor	$ 14,880	$ —	$ 14,880			
6	NWE Admin. Non-labor	$ 1,027	$ —	$ 1,027			
7	USB Interest & Svc Chg	$ (17,189)	$ —	$ (17,189)			
8							
9	Market Transformation						
10	Motor Management Training	$ —	$ —	$ —	0	0	
11	Energy Star Homes	$ 40,543	$ —	$ 40,543	0	0	
12	Building Operator Certification	$ 54,450	$ 71,200	$ 125,650	647	0	2012
13	Regional Mkt Transformation	$ 33,800	$ —	$ 33,800	0	0	
14	Cold Climate Ductless Heat Pump (Pilot)	$ 97,228	$ 240,000	$ 337,228	29	0	
15	Heat Pump Water Heater (Pilot)	$ 207,047	$ 453,722	$ 660,769	28	0	
16	Lighting Controls (Pilot)	$ 177,883	$ 200,000	$ 377,883	0	0	
17	NWE Promotion	$ 100	$ —	$ 100			
18	NWE Labor	$ 45,601	$ —	$ 45,601			
19	NWE Admin. Non-labor	$ 3,214	$ —	$ 3,214			
20	USB Interest & Svc Chg	$ (11,005)	$ —	$ (11,005)			
21							
22	Renewable Resources						
23	Generation/Education	$ 401,850	$ 1,694,996	$ 2,096,846	202	0	2012
24	Green Power Product Offering	$ 4,313	$ 98,332	$ 102,645			
25	NWE Promotion	$ —	$ —	$ —			
26	NWE Labor	$ 12,710	$ —	$ 12,710			
27	NWE Admin. Non-labor	$ 39	$ —	$ 39			
28	USB Interest & Svc Chg	$ (19,652)	$ —	$ (19,652)			
29							
30	Research & Development						
31	R&D/ Infrastructure	$ 115,750	$ 110,990	$ 226,740			
32	NWE Promotion	$ —	$ —	$ —			
33	NWE Labor	$ 4,032	$ —	$ 4,032			
34	NWE Admin. Non-labor	$ 9	$ —	$ 9			
35	USB Interest & Svc Chg	$ (4,559)	$ —	$ (4,559)			
36							
37	Low Income						
38	Bill Discount	$ 2,826,777	$ —	$ 2,826,777	0	0	
39	Free Weatherization	$ 1,556,990	$ 3,368,618	$ 4,925,608	154	0	2012
40	Elec Wx Incentives	$ 9,613	$ —	$ 9,613	0	0	
41	Fuel Switch Analyses	$ —	$ —	$ —			
42	Energy Share	$ 223,159	$ 294,000	$ 517,159			
43	Low Income	$ —	$ 2,055,561	$ 2,055,561			
44	NWE Promotion	$ 62,761	$ —	$ 62,761			
45	NWE Labor	$ 26,199	$ —	$ 26,199			
46	NWE Admin. Non-labor	$ 26,551	$ —	$ 26,551			
47	USB Interest & Svc Chg	$ (164,777)	$ —	$ (164,777)			
48	Large Customer Self Directed						
49	Self-Directed Energy Reduction	$ 2,797,892		$ 2,797,892			
50	Self-Directed to Low Income	$ 431,462		$ 431,462			
51	NWE Reallocate to Free Weatherization	$ 41	$ 695	$ 736			
52	NWE Reallocate to Low Income	$ —	$ —	$ —			
53	NWE Reallocate to Energy Share	$ 65,841	$ —	$ 65,841			
54	NWE Labor			$ —			
55	Admin. Non-labor		$ —	$ —			
56	USB Interest & Svc Chg		$ —	$ —			
57	Total	$ 9,836,917	$ 9,488,910	$ 19,325,827	1,452	0.057	
58	Number of customers that received low income rate discounts				11,177		
59	Average monthly bill discount amount ($/mo)				$ 21.08		
60	Average LIEAP-eligible household income				n/a		
61	Number of customers that received weatherization assistance				154		
62	Expected average annual bill savings from weatherization				1,002	Kwh	
63	Number of residential HomeEnergy Checks and/or Surveys performed				902		
64	(a) Total expenditures are reported for the combination of 2020 - 2024 electric USB funds spent in 2024. Total allocations are reported for the combination of 2020 - 2024 electric USB funds expected to be spent in 2024						
65	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.						
66							

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	Energy Audit	$ 736,833	$ 865,044	$ 1,601,877	0.06	2012
3					269.65	
4	Irrigation Projects	$ 32,003	$ 35,752	$ 67,755	0	2012
5					122	
6	Market Transformation					
7	Motor Management Training	$ —	$ —	$ —	0	2012
8					0	
9	Energy Star Homes	$ 40,543	$ —	$ 40,543	0	2012
10					0	
11	Building Operator Certification	$ 54,450	$ 71,200	$ 125,650	0	2012
12					647	
13	Regional Market Transformation	$ 33,800	$ —	$ 33,800	0	2012
14					0	
15	Cold Climate Ductless Heat Pump (Pilot)	$ 97,228	$ 240,000	$ 337,228	0	
16					0	
17	Heat Pump Water Heater (Pilot)	$ 207,047	$ 453,722	$ 660,769	0	
18					28	
19	Lighting Controls (Pilot)	$ 177,883	$ 200,000	$ 377,883	0	
20					0	
21	Renewables					
22	Generation/Education	$ 401,850	$ 1,694,996	$ 2,096,846	0	2012
23					202	
24	Green Power Product	$ 4,313	$ 98,332	$ 102,644	0	2012
25					0	
26	Research & Development					
27	R&D / Infrastructure	$ 115,750	$ 110,990	$ 226,740	0	2012
28					0	
29	Low Income					
30	Free Weatherization	$ 1,556,990	$ 3,368,618	$ 4,925,608	0	2012
31					154	
32	Elec Wx Incentives	$ 9,613	$ —	$ 9,613	0	2012
33					0	
34	Fuel Switch	$ —	$ —	$ —		2012
35					0	
36	Total	$ 3,468,303	$ 7,138,654	$ 10,606,957	0.06	2012
37					1394	
38	(a) Total expenditures are reported for the combination of 2020 - 2024 electric USB funds spent in 2024. Total allocations are reported for the combination of 2020 - 2024 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 2/		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$ 389,592,504	$ 408,083,607	2,803,096	2,795,247	328,401	322,153
4	Commercial & Industrial	446,865,215	483,741,102	3,504,479	3,492,841	79,500	76,092
5	Public Street & Highway Lighting	14,768,620	17,093,930	25,479	26,245	2,197	3,608
6	Sales to Other Utilities	36,084,608	86,727,064	1,016,891	1,213,387	24	24
7	Interdepartmental	864,881	1,031,286	6,653	7,562	348	344
8							
9	**TOTAL SALES**	$ 888,175,828	$ 996,676,989	7,356,598	7,535,282	410,470	402,221
10							
11	1/ Revenue and MWHs include unbilled.						
12	2/ The megawatt hours listed above do not include sales billed to choice customers, consistent with the presentation used in the corresponding schedule on the FERC Form 1.						
13							
14							
15							
16							