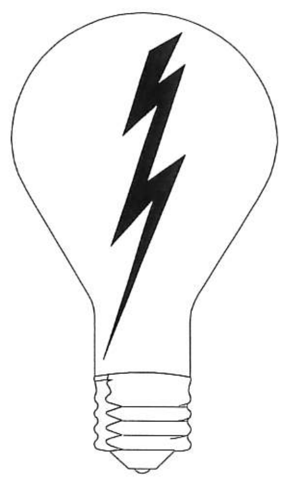
YEAR ENDING 2019

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY

Docket 2020.02.017



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

Electric Annual Report

Table of Contents

continued on next page

Sch. 1

IDENTIFICATION

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

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

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
	See NorthWestern Corporation's Annual Report on Form 10-K to the SEC for the Corporate Board of Directors.	

Sch. 3

OFFICERS

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

Reflects active officers as of December 31, 2019.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 198,403	98.16%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ 3,717	1.84%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
NorthWestern Energy Solutions, Inc.	Non-regulated customer services		
Total Corporation		$ 202,120	100.00%

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting, Accounts Payable, Payroll, Financial Reporting, and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$21,898,813	74.31%	$7,569,298
Customer Care	Includes the following departments: Customer Care, Contributions, Human Resources, Creative Services, Business Development, and Regulatory Support Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	23,314,652	72.79%	8,714,154
Legal Department	Includes the following departments: Chief Legal, Contracts Administration, Regulatory Affairs MT, SD & NE Public and Regulatory Affairs, Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	15,141,301	78.27%	4,202,809
Finance	Includes the following departments: CFO, Treasury, FP&A, Tax, Investor Relations, Corporate Aircraft, Business Technology Applications, Capital Related Expenses, Data Center, Project Management & Asset Control, Records Management Systems, and Security	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor,	22,395,736	79.05%	5,937,043
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,500,005	76.07%	1,101,018
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	843,318	78.00%	237,859
Distribution	Includes the following departments: Sioux Falls Facilities and Helena Building	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	43,171	78.00%	12,177
TOTAL			$87,136,996	75.83%	$27,774,358

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$258,848		
13						
14	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,675,720		
15		transmission, & compression	transmission & compression			
16			are at tariffed rates			
17	**Total Utility Subsidiaries Revenues**			$2,934,568		
18	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	500,400.00	14.4%	500,400.00
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,327,592.06	38.1%	$1,327,592
15						
16	**Total Utility Subsidiaries**			1,827,992.06		$1,827,992
17	**Total Utility Subsidiaries Expenses**			$3,534,248		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,827,992		$1,827,992

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	$ 992,916,182	$ 175,382,114	$ 817,534,068	$ 770,172,790	6.15%
3						
4	**Total Operating Revenues**	992,916,182	175,382,114	817,534,068	770,172,790	6.15%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	434,794,293	81,661,890	353,132,403	335,491,746	5.26%
9	402 Maintenance Expense	51,126,999	10,851,845	40,275,154	40,238,409	0.09%
10	403 Depreciation Expense	130,949,784	27,146,811	103,802,973	103,166,246	0.62%
11	404-405 Amort. of Electric Plant	7,182,404	1,175,475	6,006,929	5,142,101	16.82%
12	406 Amort. of Plant Acquisition Adj.	10,249,919	1,200,394	9,049,525	13,195,131	-31.42%
13	407.3 Regulatory Amortizations - Debit	9,406,504	(359,876)	9,766,380	5,321,619	83.52%
14	407.4 Regulatory Amortizations - Credit	(13,559,098)	-	(13,559,098)	(20,201,203)	32.88%
15	408.1 Taxes Other Than Income Taxes	140,937,710	6,187,847	134,749,863	135,066,703	-0.23%
16	409.1 Income Taxes - Federal	(11,483,213)	(6,906,506)	(4,576,707)	(4,063,533)	-12.63%
17	- Other			-	-	
18	410.1 Deferred Income Taxes-Dr.	132,127,636	8,262,498	123,865,138	103,860,941	19.26%
19	411.1 Deferred Income Taxes-Cr.	(115,566,646)	(9,108,941)	(106,457,705)	(99,928,631)	-6.53%
20	411.4 Investment Tax Credit Adj.	(9,617)	(9,617)	-	-	-
21	411.6 Gain from Disposition of Property	-	-	-	-	-
22	411.7 Loss from Disposition of Property	-	-	-	-	-
23	411.8 SO2 Allowances	(6)	(5)	(1)	(1)	0.00%
24						
25	**Total Operating Expenses**	776,156,669	120,101,815	656,054,854	617,289,528	6.28%
26	**NET OPERATING INCOME**	$ 216,759,513	$ 55,280,299	$ 161,479,214	$ 152,883,262	5.62%

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	$ 372,507,635	$ 62,621,840	$ 309,885,795	$ 295,264,873	4.95%
5	442 Commercial	446,506,497	102,144,595	344,361,902	332,870,805	3.45%
6	Industrial	53,622,094	-	53,622,094	52,495,273	2.15%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	19,891,579	2,576,625	17,314,954	16,466,431	5.15%
9	448 Interdepartmental Sales	996,057	-	996,057	1,009,279	-1.31%
10						
11	**Total Sales to Ultimate Consumers**	893,523,862	167,343,060	726,180,802	698,106,661	4.02%
12	447 Sales for Resale	36,001,205	-	36,001,205	24,878,366	44.71%
13						
14	**Total Sales of Electricity**	929,525,067	167,343,060	762,182,007	722,985,027	5.42%
15	449.1 Provision for Rate Refunds	(13,953,559)	-	(13,953,559)	(17,707,763)	21.20%
16						
17	**Total Revenue Net of Rate Refunds**	915,571,508	167,343,060	748,228,448	705,277,264	6.09%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	484,456	484,456	-	-	-
21	451 Miscellaneous Service Revenue	226,545	226,545	-	-	-
22	453 Sales of Water & Water Power	-	-	-	-	-
23	454 Rent From Electric Property	3,868,981	150,897	3,718,084	3,499,829	6.24%
24	456 Other Electric Revenues	72,764,692	7,177,156	65,587,536	61,395,697	6.83%
25						
26	**Total Other Operating Revenue**	77,344,674	8,039,054	69,305,620	64,895,526	6.80%
27	**TOTAL OPERATING REVENUE**	$ 992,916,182	$ 175,382,114	$ 817,534,068	$ 770,172,790	6.15%

MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
Power Production Expenses					
Steam Power Generation-Operation					
500 Supervision & Engineering	856,361	805,407	50,954	$ 61,399	-17.01%
501 Fuel	43,158,606	19,788,219	23,370,387	20,598,485	13.46%
502 Steam Expenses	3,477,016	1,982,987	1,494,029	1,621,637	-7.87%
503 Steam from Other Sources	-	-	-	-	-
505 Electric Plant	878,113	596,441	281,672	258,169	9.10%
506 Miscellaneous Steam Power	3,409,011	1,562,129	1,846,882	2,354,270	-21.55%
507 Rents	48,114	33,280	14,834	33,922	-56.27%
Total Operation-Steam Power Gen.	51,827,221	24,768,463	27,058,758	24,927,882	8.55%
Steam Power Generation-Maintenance					
510 Supervision & Engineering	1,225,120	833,203	391,917	340,941	14.95%
511 Structures	1,036,775	431,601	605,174	444,230	36.23%
512 Steam Boiler Plant	6,966,120	2,956,761	4,009,359	3,637,779	10.21%
513 Electric Plant	1,124,441	932,354	192,087	323,401	-40.60%
514 Miscellaneous Steam Plant	922,739	460,855	461,884	600,368	-23.07%
Total Maintenance-Steam Power Gen.	11,275,195	5,614,774	5,660,421	5,346,719	5.87%
Total Steam Power Generation	63,102,416	30,383,237	32,719,179	30,274,601	8.07%
Hydro Power Generation-Operation					
535 Supervision & Engineering	673,533	-	673,533	853,966	-21.13%
536 Water for Power	943,437	-	943,437	881,053	7.08%
537 Hydraulic Expenses	4,045,571	-	4,045,571	4,163,893	-2.84%
538 Electric Expenses	3,368,350	-	3,368,350	4,228,819	-20.35%
539 Miscellaneous Hydraulic Power	2,497,884	-	2,497,884	2,271,804	9.95%
540 Rents	770,064	-	770,064	754,193	2.10%
Total Operation-Hydro Power Gen.	12,298,839	-	12,298,839	13,153,728	-6.50%
Hydro Power Generation-Maintenance					
541 Supervision & Engineering	649,954	-	649,954	816,219	-20.37%
542 Structures	651,539	-	651,539	456,106	42.85%
543 Reservoirs, Dams & Waterways	886,246	-	886,246	1,628,692	-45.59%
544 Electric Plant	1,381,196	-	1,381,196	1,700,262	-18.77%
545 Miscellaneous Hydro Plant	996,767	-	996,767	468,756	112.64%
Total Maintenance-Hydro Power Gen.	4,565,702	-	4,565,702	5,070,035	-9.95%
Total Hydraulic Power Generation	16,864,541	-	16,864,541	18,223,763	-7.46%
Other Power Generation-Operation					
546 Supervision & Engineering	725,312	281,921	443,391	584,897	-24.19%
547 Fuel	10,175,257	888,650	9,286,607	7,143,637	30.00%
548 Generation Expenses	6,286,198	3,254,341	3,031,857	2,788,217	8.74%
549 Miscellaneous Other Power	1,575,201	468,227	1,106,974	827,589	33.76%
550 Rents	-	-	-	-	-
Total Operation-Other Power Gen.	18,761,968	4,893,140	13,868,829	11,344,340	22.25%
Other Power Generation-Maintenance					
551 Supervision & Engineering	69,128	69,128	-	-	-
552 Structures	73,279	72,798	481	49	>300.00%
553 Generating & Electric Plant	2,885,049	798,286	2,086,763	1,381,367	51.07%
554 Miscellaneous Other Power Plant	144,643	49,327	95,316	102,849	-7.32%
Total Maintenance-Other Power Gen.	3,172,099	989,539	2,182,560	1,484,265	47.05%
Total Other Power Generation	21,934,067	5,882,679	16,051,389	12,828,605	25.12%
Other Power Supply Expenses					
555 Purchased Power	211,219,583	17,587,420	193,632,163	194,896,576	-0.65%
556 System Control & Load Dispatch	310,887	310,887	-	-	-
557 Other Expenses	(30,324,583)	(4,358,810)	(25,965,773)	(25,285,347)	-2.69%
Total Other Power Supply Expenses	181,205,887	13,539,497	167,666,390	169,611,229	-1.15%
Total Power Production Expenses	283,106,911	49,805,413	233,301,499	230,938,198	1.02%

MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
Transmission Expenses					
Transmission-Operation					
560 Supervision & Engineering	3,217,366	268,639	2,948,727	3,289,659	-10.36%
561 Load Dispatching	53,678	53,678	-	-	-
561.1 Load Dispatch - Reliability	685,084	-	685,084	943,785	-27.41%
561.2 Load Disp-Monitor/Op	711,016	104,009	607,007	771,988	-21.37%
561.3 Load Disp-Srv/Schedu	1,065,111	3,000	1,062,111	1,280,294	-17.04%
561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
561.5 Reliab, Plan, Stds	77,048	77,048	-	-	-
561.6 Transmission Service Studies	-	-	-	-	-
561.8 Sch,Sys&Ctrl Srv-RTO			-	-	-
562 Station Expenses	1,338,140	148,069	1,190,071	1,697,198	-29.88%
563 Overhead Lines	979,166	291,921	687,245	667,650	2.93%
564 Underground Lines	-	-	-	-	-
565 Transmission of Elec. by Others	22,309,139	17,096,840	5,212,299	5,416,786	-3.78%
566 Miscellaneous Transmission	211,542	90,405	121,137	114,677	5.63%
567 Rents	862,623	6,879	855,744	968,838	-11.67%
Total Operation-Transmission	31,509,913	18,140,488	13,369,425	15,150,875	-11.76%
Transmission-Maintenance					
568 Supervision & Engineering	747,863	91,674	656,189	1,014,752	-35.34%
569 Structures	32,916	8,937	23,979	45,742	-47.58%
569.1 Maintenance of Computer Hardware	875,563	-	875,563	854,858	2.42%
569.2 Maintenance of Computer Software	(2,577)	-	(2,577)	2,459	-204.80%
569.3 Maint-Comm Equip	101,460	101,460	-	-	-
570 Station Equipment	677,798	64,039	613,759	846,204	-27.47%
571 Overhead Lines	5,410,708	1,016,848	4,393,860	3,080,086	42.65%
572 Underground Lines	306	306	-	-	-
573 Miscellaneous Transmission Plant	-	-	-	-	-
Total Maintenance-Transmission	7,844,037	1,283,264	6,560,773	5,844,101	12.26%
Total Transmission Expenses	39,353,950	19,423,752	19,930,198	20,994,976	-5.07%
Regional Market Operation					
575.1 Operation Supervision	35	35	-	-	-
575.2 Day-Ahead & Real-time Admin	399,706	399,706	-	-	-
575.3 Transmision Rights Mkt Admin	18	18	-	-	-
575.5 Ancillary Services Mkt Admin	114,192	114,192	-	-	-
575.6 Market Monitoring & Complaince	57,096	57,096	-	-	-
Total Operation-Regional Market	571,047	571,047	-	-	-
Distribution Expenses					
Distribution-Operation					
580 Supervision & Engineering	3,533,090	549,349	2,983,741	3,371,308	-11.50%
581 Load Dispatching	-	-	-	-	-
582 Station Expenses	1,517,193	252,531	1,264,662	1,646,571	-23.19%
583 Overhead Lines	2,047,619	465,079	1,582,540	1,701,608	-7.00%
584 Underground Lines	2,637,881	820,183	1,817,698	1,747,510	4.02%
585 Street Lighting & Signal Systems	408,698	35,339	373,359	532,101	-29.83%
586 Meters	2,503,285	473,858	2,029,427	2,739,223	-25.91%
587 Customer Installations	1,534,316	206,057	1,328,259	2,325,585	-42.88%
588 Miscellaneous Distribution	2,588,008	429,232	2,158,776	1,755,281	22.99%
589 Rents	65,558	-	65,558	80,242	-18.30%
Total Operation-Distribution	16,835,648	3,231,628	13,604,020	15,899,429	-14.44%
Distribution-Maintenance					
590 Supervision & Engineering	1,420,492	216,141	1,204,351	1,434,749	-16.06%
591 Structures	29,277	-	29,277	21,091	38.81%
592 Station Equipment	583,346	162,305	421,041	701,078	-39.94%
593 Overhead Lines	16,382,091	1,719,610	14,662,481	13,199,893	11.08%
594 Underground Lines	1,302,110	283,259	1,018,851	1,452,216	-29.84%
595 Line Transformers	123,386	10,067	113,319	182,945	-38.06%
596 Street Lighting, Signal Systems	958,505	176,072	782,433	1,039,841	-24.75%
597 Meters	1,374,241	100,908	1,273,333	1,487,479	-14.40%
598 Miscellaneous Distribution Plant	43,517	43,517	-	-	-
Total Maintenance-Distribution	22,216,965	2,711,879	19,505,086	19,519,292	-0.07%
Total Distribution Expenses	39,052,613	5,943,507	33,109,106	35,418,721	-6.52%

MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
Customer Accounts Expenses					
Customer Accounts-Operation					
901 Supervision	-	-	-	-	-
902 Meter Reading	2,125,634	764,676	1,360,958	1,809,745	-24.80%
903 Customer Records & Collection	7,439,238	1,134,637	6,304,601	7,242,508	-12.95%
904 Uncollectible Accounts	1,609,011	280,346	1,328,665	2,142,606	-37.99%
905 Miscellaneous Customer Accts.	48,624	50,071	(1,447)	(1,480)	2.23%
Total Customer Accounts Expenses	11,222,507	2,229,730	8,992,777	11,193,379	-19.66%
Customer Service & Information					
Customer Service-Operation					
907 Supervision	-	-	-	-	-
908 Customer Assistance	3,405,503	1,039,156	2,366,347	2,913,070	-18.77%
909 Inform. & Instruct. Advertising	1,065,089	131,266	933,823	921,953	1.29%
910 Misc. Customer Service & Info.	611,467	-	611,467	873,492	-30.00%
Total Customer Service & Info. Expense	5,082,059	1,170,422	3,911,637	4,708,515	-16.92%
Sales Expenses					
Sales-Operation					
911 Supervision	-	-	-	-	-
912 Demonstrating & Selling			-	-	-
913 Advertising	1,656,129	79,199	1,576,930	415,727	279.32%
916 Miscellaneous Sales	-	-	-	-	-
Total Sales Expenses	1,656,129	79,199	1,576,930	415,727	279.32%
Administrative & General Expenses					
Admin. & General-Operation					
920 Admin. & General Salaries	33,470,170	4,723,856	28,746,314	33,170,847	-13.34%
921 Office Supplies & Expenses	11,044,418	2,068,978	8,975,440	8,686,355	3.33%
922 Admin. Expense Transferred-Cr.	(6,213,563)	(1,061,273)	(5,152,290)	(4,918,091)	-4.76%
923 Outside Services Employed	7,694,930	728,723	6,966,207	4,343,802	60.37%
924 Property Insurance	2,459,633	490,198	1,969,435	2,392,917	-17.70%
925 Injuries & Damages	9,299,009	759,975	8,539,034	6,513,923	31.09%
926 Employee Pensions & Benefits	27,279,328	4,268,078	23,011,250	1,773,481	>300.00%
927 Franchise Requirements	-	-	-	-	-
928 Regulatory Commission Expenses	3,002,339	4,298	2,998,041	2,966,129	1.08%
929 Duplicate Charges-Cr.	-	-	-	-	-
930 Miscellaneous General Expenses	13,947,542	684,298	13,263,244	12,680,248	4.60%
931 Rents	1,839,269	371,144	1,468,125	1,477,031	-0.60%
Total Operation-Admin. & General	103,823,075	13,038,275	90,784,800	69,086,642	31.41%
Admin. & General-Maintenance					
935 General Plant	2,053,001	252,388	1,800,613	2,973,997	-39.45%
Total Maintenance-Admin. & General	2,053,001	252,388	1,800,613	2,973,997	-39.45%
Total Admin. & General Expenses	105,876,076	13,290,663	92,585,413	72,060,639	28.48%
TOTAL OPER. & MAINT. EXPENSES	485,921,292	92,513,735	393,407,557	$ 375,730,155	4.70%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	4,968,069	5,028,818	-1.21%
3	Property Taxes	124,205,307	123,457,936	0.61%
4	Electric Energy License Tax	910,743	876,074	3.96%
5	Crow Tribe RR and Utility Tax	84,948	84,728	0.26%
6	Fort Peck	288	(11)	>300.00%
7	City Tax	4,177	4,629	-9.76%
8	Consumer Counsel Tax	357,803	489,681	-26.93%
9	Public Service Commission Tax	1,215,421	1,907,872	-36.29%
10	Heavy Highway Use Tax	14,876	17,556	-15.27%
11	Vehicle Use Tax	198,988	205,521	-3.18%
12	Wholesale Energy Transaction Tax	1,474,945	1,403,007	5.13%
13	Delaware Franchise Tax	150,029	183,989	-18.46%
14	Invasive Species	1,164,269	1,406,903	-17.25%
15				
16				
17				
18	**TOTAL TAXES OTHER THAN INCOME**	$134,749,863	$135,066,703	-0.23%
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	222,787
2	A&E ARCHITECTS P C	Architectural Services	95,444
3	ACE ELECTRIC INC	Electric Construction Service	95,102
4	ACUREN INSPECTION INC	Inspection Services	126,579
5	AECOM TECHNICAL SERVICES INC	Inspection Services	164,357
6	AFFCO INC	Hydro Construction Services	2,811,279
7	ALME CONSTRUCTION, INC.	Construction	864,769
8	ALSTOM GRID INC	Software Support Services	914,714
9	AMERESCO INC	Design and Testing	78,623
10	AMERICAN INNOVATIONS INC	Software Support Services	228,180
11	AMPED I LLC	Engineering Services	524,200
12	ARCADIS US INC	Engineering Services	1,557,319
13	ARCADIS US INC	Engineering Services	365,255
14	ASCEND ANALYTICS LLC	Hydro Expert Analysis	1,609,202
15	ASPLUNDH TREE EXPERT LLC	Tree Trimming	8,615,500
16	ASSOCIATED UNDERWATER SERVICE	Inspection Services	187,348
17	AUTOMOTIVE RENTALS INC	Fleet Management	8,454,143
18	BART ENGINEERING COMPANY	Engineering Services	491,320
19	BASELOAD POWER GENERATION PAR	Inspection Services	415,535
20	BENTLY NEVADA INC	System Monitoring	143,465
21	BEVERIDGE INCORPORATED	Drilling Services	270,149
22	BIG SKY COMMUNICATION & CABLE	Communications Construction	114,190
23	BILL FIELD TRUCKING INC	Hauling Services	573,786
24	BILLINGS FLYING SERVICE, INC.	Powerline Services	123,400
25	BISON ENGINEERING INC	Engineering Services	116,442
26	BISON ENGINEERING INC	Engineering Services	97,965
27	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	769,430
28	BRITT IDE	Board of Director Fees	75,251
29	BURK EXCAVATION AND UTILITIES	Construction	1,607,721
30	CCI INC	Inspection Services	108,299
31	CEB INC	HR Consulting	90,523
32	CENTERPOINT ENERGY SERVICES	Energy	3,361,433
33	CENTRAL AIR SERVICE INC	Aerial Pilot Services	139,745
34	CENTRON SERVICES INC	Customer Collection service	104,631
35	CLARK ENGINEERING CORPORATION	Engineering Services	114,196
36	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	742,898
37	CMC EXCAVATION INC	Construction	83,442
38	CN UTILITY CONSULTING INC	Utility Consulting Services	556,463
39	COMPLETE CAREER CENTER INC	Meter Reader Services	269,897
40	CONTINENTAL STEEL WORKS	Fabrication Services	2,241,199
41	COPPER CREEK LLC	Construction	496,287
42	CORE CONTROL INC	Installation	102,254
43	CRANE SERVICES & INSPECTIONS	DOT Inspections	89,348
44	CRUX SUBSURFACE INC	Construction	1,316,839
45	CTA INC.	Energy Conservation Consultants	1,602,173
46	CUDA DIRECTIONAL LLC	Boring Services	262,920
47	DANA J DYKHOUSE	Board of Director Fees	75,000
48	DAVEY TREE SURGERY COMPANY	Tree Trimming	4,467,046
49	DDC ADVOCACY LLC	Consulting Services	303,766
50	DELOITTE & TOUCHE LLP	Audit Services	1,672,414
51	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	4,055,571
52	DGR ENGINEERING	Engineering Services	567,770
53	DICK ANDERSON CONSTRUCTION INC	Construction	4,394,895
54	DIETZEL ENTERPRISES INC	Construction	454,962
55	DITCH WITCH UNDERCON	Consulting Services	101,997
56	DNV GL ENERGY INSIGHTS USA INC	Software Support Services	152,235
57	DONOVAN CONSTRUCTION	Electric Construction Service	1,272,877
58	DORSEY & WHITNEY LLP	Legal Services	794,096
59	DOWL HKM	Geotechnical Services	419,887
60	E SOURCE COMPANIES LLC	Consulting Services	87,180

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	EDM INTERNATIONAL INC	Repair & Pole Services	76,917
62	EIDE BAILLY LLP	Audit Services	98,166
63	ELECTRICAL RELIABILITY SERVICES	Consulting Services	84,000
64	ELLIOT CONSTRUCTION INC	Boring Services	1,311,469
65	ELM LOCATING & UTILITY SERVICES	Locating Services and Excavation Notifications	3,391,725
66	ENERGY AND ENVIRONMENTAL ECONOMICS	Consulting Services	152,867
67	ENERGY CONTRACT SERVICES LLC	Inspection Services	957,916
68	ENERGY LABORATORIES INC	Environmental Consultants	90,416
69	ENERGY SHARE OF MONTANA	USBC Services	934,499
70	EVERGREEN CAISSONS INC	Construction	2,781,866
71	FENCECRAFTERS HELENA INC	Repair Services	98,818
72	FINANCIAL CONCEPTS & APPLICATIONS	Consulting Services	84,106
73	FIRE EYE INC	Incident Response	92,053
74	FLYNN WRIGHT INC	Advertising Services	2,179,814
75	FLYNN WRIGHT INC	Advertising Services	183,397
76	FOOTHILLS RIG SERVICE	Well Services	91,115
77	G & L WATER	Hauling & Other Services	113,908
78	G2 INTEGRATED SOLUTIONS LLC	Computer System Implementation	275,932
79	GARTNER INC	Information Technology Consulting	432,068
80	GE ELECTRIC INTERNATIONAL INC	Road Improvements	385,371
81	GEI CONSULTANTS INC	Environmental Consultants	387,237
82	GENERAL ELECTRIC INTERNATIONAL	Plant Operator Services	4,461,866
83	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	471,580
84	GREGG ENGINEERING	Informational Technology Simulation	91,770
85	GTS WELL SERVICE, LLC	Well Services	116,325
86	GUY TABACCO CONSTRUCTION	Construction	455,352
87	H & H ASPHALT & MAINTENANCE	Asphalt Services	132,813
88	H & H CONTRACTING INC	Concrete and Asphalt Services	458,821
89	H2E INC	Engineering Services	509,067
90	HAIDER CONSTRUCTION INC	Boring Services	586,959
91	HDR ENGINEERING INC	Engineering Services	1,735,034
92	HEATH CONSULTANTS INC	Gas Leak Surveys	583,837
93	HELI DUNN	Helicopter Charter Services	374,849
94	HIGHMARK MEDIA	Safety Training	104,595
95	HUNTER BROTHERS CONSTRUCTION	Construction	212,765
96	HYDRO CONSULTING & MAINTENANCE	Repair Services	155,525
97	HYDROINSIGHT LLC	Rewind & Restack Services	95,109
98	IES COMMERCIAL INC	Construction	614,529
99	IMCO GENERAL CONSTRUCTION INC	Construction	816,200
100	INTEC SERVICES INC	Pole Inspection Services	2,583,621
101	ITRON INC	Meter Installation	13,132,413
102	IVANS BORING	Boring Services	384,846
103	J D POWER AND ASSOCIATES	Energy Study	81,470
104	J2 BUSINESS PRODUCTS	Copier Maintenance	217,378
105	JACKSON UTILITIES LLC	Construction	290,419
106	JACOBSEN TREE EXPERTS	Tree Trimming	977,043
107	JAN HORSFALL	Board of Director Fees	87,256
108	JAY FORTUNE CONSTRUCTION INC	Construction	287,898
109	JEFFERY CONTRACTING LLC	Construction	618,709
110	JOHNSON CONTROLS FIRE PROTECTION	Fire Protection Services	121,752
111	JONES DAY	Legal Services	123,183
112	JULIA L JOHNSON	Board of Director Fees	81,490
113	KARV LLC	Boring Services	160,088
114	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	333,789
115	KENNEBEC TELEPHONE CO., INC	Boring Services	199,224
116	KM CONSTRUCTION CO INC	Construction	198,114
117	KNIFE RIVER	Construction	146,960
118	LACY CONSTRUCTION	Construction	369,105
119	LEARJET INC	Repair Services	232,837
120	LIMITLESS WIRING SOLUTIONS	Electrical Services	219,115
121	LOCKMER PLUMBING HEATING & UTILITIES	Gas Meter Relocations	542,070
122	LODGEPOLE LAND SERVICES LLC	Real Estate Services	186,795
123	M & P EXCAVATING	Excavation Services	278,530
124	M&D CONSTRUCTION INC	Construction	485,250

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
125	MANAGEMENT APPLICATIONS CONSULTING	Regulatory Consulting	115,226
126	MAP MECHANCIAL CONTRACTORS	Demolition Services	120,500
127	MARTEL CONSTRUCTION, INC.	Construction	6,352,235
128	MERCER HUMAN RESOURCE CONSULTING	HR Consulting	184,380
129	MERIDIAN IT INC	Information Technology Services	193,224
130	MERKEL ENGINEERING INC	Consulting Services	117,096
131	MEYERS SAND & GRAVEL	Snow Removal Service	78,264
132	MICHELS CANADA CO	Construction	855,372
133	MICHELS CORPORATION	Construction	10,656,198
134	MIDCON UNDERGROUND CONSTRUCTION	Construction	661,060
135	MINUTEMAN AVIATION INC.	Helicopter Charter Services	128,798
136	MISSOULA CONCRETE CONSTRUCTION	Construction	129,770
137	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	873,352
138	MOODY'S INVESTORS SERVICE	Debt Rating Services	349,598
139	MORGAN, LEWIS & BOCKIUS LLP	Legal Services	710,712
140	MORRISON MAIERLE INC	Engineering Services	362,509
141	MOUNTAIN POWER CONSTRUCTION	Electric Construction and Maintenance	24,680,553
142	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	683,351
143	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	364,723
144	MUTH ELECTRIC INC	Construction	182,099
145	NATIONAL CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	506,788
146	NAVIGANT CONSULTING INC	Renewables Consulting Service	143,129
147	NEAL STRUCTURAL REPAIR	Site Preparation Services	144,000
148	NEELY ELECTRIC INC	Electric Services	180,510
149	NEI ELECTRIC POWER ENGINEERING	Engineering Services	100,000
150	NORTHERN HYDRAULICS INC	Construction	149,812
151	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,218,340
152	OLSSON ASSOCIATES	Surveying Services	94,533
153	OLTROGGE CONSTRUCTION INC	Construction	119,494
154	ONSTREAM PIPELINE INSPECTION	Inspection Services	101,750
155	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	394,785
156	OUTBACK POWER COMPANY	Construction	505,733
157	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	9,205,889
158	PINNACLE RESEARCH & CONSULTING	Consulting Services	400,509
159	PIONEER TECHNICAL SERVICES INC	Environmental Services	80,656
160	PIONEER WIRELINE SERVICES	Rig Services	104,933
161	POTEET CONSTRUCTION	Traffic Safety Services	205,432
162	POWERPLAN INC	Software Support Services	1,441,080
163	PTW FACILITY SERVICES LTD	Installation Service	76,481
164	QUANTA UTILITY ENGINEERING	Engineering Services	6,152,996
165	RAWHIDE LEASING COMPANY LLC	Gas Services	193,350
166	RAY PETERSON ELECTRIC INC	Electrical Services	76,493
167	REPUBLIC SERVICES OF MONTANA	Garbage Service	85,521
168	RIVER DESIGN GROUP INC	Engineering Services	362,269
169	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	27,996,453
170	ROD TABBERT CONSTRUCTION INC	Construction	307,895
171	ROSEN USA INC	Inspection Services	136,320
172	ROUNDS BROTHERS TRENCHING	Boring Services	656,584
173	SANDERSON STEWART	Engineering Services	171,804
174	SBS SOLAR	Installation Service	659,428
175	SCENIC CITY ENTERPRISES INC	Construction	174,661
176	SCHNABEL ENGINEERING LLC	Consulting Services	279,349
177	SCHNEIDER ELECTRIC SOFTWARE CANADA	Computer Support Services	165,042
178	SCHROCK COMMERCIAL ROOFING INC	Construction	190,658
179	SERRALA SOLUTIONS US CORPORATION	Implementation Services	466,456
180	SHAW PIPELINE SERVICES INC	Pipeline Services	286,453
181	SHUMAKER TRUCKING & EXCAVATING	M&S	289,056
182	SIDEWINDERS LLC	Generator Repair Services	1,945,463
183	SPENCER STUART	Consulting Services	102,331
184	SPHERION STAFFING	Temporary Labor	102,223
185	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	172,500
186	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,167,575
187	STEPHEN P ADIK	Board of Director Fees	132,324
188	STINSON LEONARD STREET LLP	Legal Services	1,012,804

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
189	STREAM WORKS INC	Construction	78,469
190	SUPERIOR CONCRETE PRODUCTS INC	Construction	1,143,230
191	SYNACTIVE INC	Consulting Services	101,915
192	TDW SERVICES INC	Inspection Services	248,374
193	TERRA REMOTE SENSING (USA) INC	Surveying Services	360,018
194	TERRACON CONSULTANTS INC	Geotechnical Services	189,995
195	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	1,044,870
196	THE MOSAIC COMPANY	Training	476,455
197	THOMPSON HINE LLP	Benefits Audit Services	156,580
198	TLC SEPTIC SERVICE	Excavation Contractor	227,196
199	TODD O BRUESKE CONSTRUCTION	Construction	348,371
200	TRADEMARK ELECTRIC INC	Construction	600,892
201	TRI-COUNTY MECHANICAL & ELECTRICAL	Construction	477,451
202	ULTEIG ENGINEERS INC	Project Manager Services	292,543
203	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	356,362
204	UNDERGROUND CONSTRUCTION	Construction	113,828
205	UNITED STATES GEOLOGICAL SURVEY	Environmental Consulting	208,470
206	UTEGRATION LLC	Consulting Services	124,415
207	UTILICAST LLC	Consulting Services	724,814
208	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	167,483
209	VAISALA INC	Wind Forecasting Services	110,040
210	VARSITY CONTRACTORS INC	Janitorial Services	336,280
211	VEOLIA ES TECNICAL SOLUTIONS	Oil Recycling	84,253
212	VERTEX	Billing Services and Programming	3,227,509
213	VERTIV CORPORATION	Maintenance Service	119,840
214	VESTA PARTNERS LLC	Information Technology Consulting	367,879
215	VIKOR	Construction	83,071
216	WATER & ENVIRONMENTAL TECHNOLOGIES	Engineering Services	479,567
217	WATSON TRUCKING OF HAVRE LLC	Hauling Services	100,546
218	WILLIAMSON FENCING & SPR.,INC	Fence Materials/Installation	578,033
219	WILLIS TOWERS WATSON US LLC	Compensation Services	101,139
220	WOOD GROUP PRATT & WHITNEY LLC	Inspection Services	250,731
221	ZACHA UNDERGROUND CONSTRUCTION	Construction	123,438
222			
223			
224			
225			
226			
227			
228			
229			
230			
231			
232			
233			
234			
235			
236			
237			
238			
239			
240			
241			
242			
243			
244			
245			
246			
247			
248			
249			
250			
251			
	Total of Payments Set Forth Above		$ 230,398,639

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

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
3	There are three employee political action committees			
4	(PAC)s:			
6	a. NorthWestern Energy Montana Employee PAC for			
7	Montana employees;			
9	b. Employees of NorthWestern Corporation			
10	(NorthWestern Energy) PAC for South Dakota			
11	employees;			
13	c. NorthWestern Public Service Employees PAC for			
14	Nebraska employees.			
17	All of the money contributed by members is			
18	dedicated to support political candidates and ballot			
19	issues. No company funds may be spent in support			
20	of a political candidate. Nominal administrative			
21	costs for such things as duplicating, postage, and			
22	meeting expenses are paid by the company as			
23	provided by law. These costs are charged to			
24	shareholder expense.			
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	$ 592,485,431	$ 634,362,119	-6.60%
8	Service cost	8,796,395	10,798,164	-18.54%
9	Interest cost	24,205,284	22,325,211	8.42%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	76,705,761	(48,907,131)	256.84%
13	Acquisition	-	-	-
14	Benefits paid	(26,699,284)	(26,092,932)	-2.32%
15	Benefit obligation at end of year	$ 675,493,587	$ 592,485,431	14.01%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 466,697,791	$ 522,739,468	-10.72%
18	Actual return on plan assets	96,797,687	(37,948,745)	>300.00%
19	Acquisition	-	-	-
20	Employer contribution	9,000,000	8,000,000	12.50%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(26,699,284)	(26,092,932)	-2.32%
23	Fair value of plan assets at end of year	$ 545,796,194	$ 466,697,791	16.95%
24	**Funded Status**	$ (129,697,393)	$ (125,787,640)	-3.11%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (129,697,393)	$ (125,787,640)	-3.11%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	3.20%	4.20%	-23.81%
32	Expected return on plan assets	5.06%	4.97%	1.81%
33	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.05% Union & 2.67% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 8,796,395	$ 10,798,164	-18.54%
36	Interest cost	24,205,284	22,325,211	8.42%
37	Expected return on plan assets	(23,034,532)	(25,430,379)	9.42%
38	Amortization of prior service cost	-	4,453	-100.00%
39	Recognized net actuarial gain	6,544,238	4,359,524	50.11%
40	Net periodic benefit cost (SEC Basis)	$ 16,511,385	$ 12,056,973	36.94%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 9,000,144	$ 8,000,000	12.50%
43	Pension Costs Capitalized	2,081,747	1,730,858	20.27%
44	Accumulated Pension Asset (Liability) at Year End	$ (129,697,393)	$ (125,787,640)	-3.11%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,588	2,628	-1.52%
47	Not Covered by the Plan 2/	735	675	8.89%
48	Active	633	686	-7.73%
49	Retired	1,647	1,629	1.10%
50	Deferred Vested Terminated 2/	308	313	-1.60%

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

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

Sch. 14a	Pension Costs 1/			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions		Not Applicable	
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 356,074,413	$ 395,411,056	11.05%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 10,958,378	$ 10,613,868	3.25%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 413,343,235	$ 356,074,413	16.08%
24	**Funded Status**		Not Applicable	
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**		Not Applicable	
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**		Not Applicable	
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 8,317,152	$ 8,005,766	3.89%
44	401(k) Plan Defined Contribution Costs Capitalized	1,923,770	1,732,106	11.07%
45	Accumulated Pension Asset (Liability) at Year End		Not Applicable	
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,530	1,523	0.46%
48	Not Covered by the Plan			
49	Active - Participating	1,520	1,512	0.53%
50	Retired			
51	Vested Former Employees, Retirees and Active-	310	306	1.31%
52	Noncontributing			
	2/ This plan covers all NorthWestern Corporation employees.			
	3/ Represents total company 401(k) plan participants.			

Sch. 15	**Other Post Employment Benefits (OPEBS)**			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	($1,150,620)	($1,218,014)	5.53%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	2.80%	3.90%	-28.21%
8	Expected return on plan assets	4.79%	4.82%	-0.62%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate anually	5.00% fixed rate anually	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.05% Union & 2.67% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for the fiscal year ending December 31, 2018.			

1/ Obtained from NorthWestern Energy-Montana's 2019 FASB 106 Valuation. Assumptions and data are as of December 31, 2019.

2/ Obtained from NorthWestern Energy-Montana's 2018 FASB 106 Valuation. Assumptions and data are as of December 31, 2018.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$15,201,801	$17,466,152	-12.96%
10	Service cost	283,867	342,560	-17.13%
11	Interest Cost	536,543	514,079	4.37%
12	Plan participants' contributions	942,033	956,828	-1.55%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	766,140	(1,643,464)	146.62%
15	Acquisition	-	-	-
16	Benefits paid	(3,088,522)	(2,434,354)	-26.87%
17	Benefit obligation at end of year	$14,641,862	$15,201,801	-3.68%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$18,671,114	$20,380,579	-8.39%
20	Actual return on plan assets	3,804,534	(865,545)	>300.00%
21	Acquisition	-	-	-
22	Employer contribution	1,150,020	633,606	81.50%
23	Plan participants' contributions	942,033	956,828	-1.55%
24	Benefits paid	(3,088,522)	(2,434,354)	-26.87%
25	Fair value of plan assets at end of year	$21,479,179	$18,671,114	15.04%
26	**Funded Status**	$6,837,317	$3,469,313	97.08%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$6,837,317	$3,469,313	97.08%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$283,867	$342,560	-17.13%
33	Interest cost	536,543	514,079	4.37%
34	Expected return on plan assets	(869,332)	(953,892)	8.86%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,032,848)	(2,032,848)	
37	Recognized net actuarial loss/(gain)	-	-	-
38	Net periodic benefit cost	($2,081,770)	($2,130,101)	2.27%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	1,150,020	633,606	81.50%
43	TOTAL	$1,150,020	$633,606	81.50%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(1,150,620)	(1,218,014)	5.53%
47	TOTAL	($1,150,620)	($1,218,014)	5.53%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($1,150,620)	($1,218,014)	5.53%
50	Pension Costs Capitalized	(266,140)	(263,526)	-0.99%
51	Accumulated Pension Asset (Liability) at Year End	6,837,317	3,469,313	97.08%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,551	1,630	-4.85%
54	Not Covered by the Plan	1,808	1,707	5.92%
55	Active	612	666	-8.11%
56	Retired	843	861	-2.09%
57	Spouses/Dependants covered by the Plan	96	103	-6.80%

4/ There is approximately an additional $5,630,347 and $5,410,095 in other company OPEBS liabilities outstanding at December 31, 2019 and 2018, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation 3/
1	Michael R. Cashell Vice President, Transmission	282,291	144,256 A	30,182 B 151,970 C 363,461 D 6,831 E 5,276 F	984,267	602,081	63.5%
2	John D. Hines Vice President, Supply & Montana Government Affairs	282,291	144,256 A	29,125 B 151,970 C 171,043 D 3,637 E 2,943 F	785,265	621,959	26.3%
3	Jason Merkel General Manager, Operations	196,972	50,085 A	34,798 B 38,517 C 262,066 D 139 E	582,577	313,008	86.1%
4	Crystal D. Lail Vice President & Controller	256,069	113,883 A	34,488 B 139,023 C 30,266 D 816 E	574,545	539,242	6.5%
5	Michael L. Nieman Chief Audit and Compliance Officer	234,507	76,358 A	56,724 B 57,402 C 39,513 D	464,504	413,227	12.4%
6	Daniel L. Rausch Treasurer	222,877	69,031 A	51,299 B 54,555 C 29,151 D 7,868 E	434,781	394,104	10.3%
7	Jeanne M. Vold Business Technology Officer	202,250	64,249 A	29,701 B 49,506 C 21,878 D	367,584	337,885	8.8%
8	Bleau J. LaFave Director, Long-Term Resources	176,715	48,502 A	47,581 B 34,604 C 26,795 D 6,249 E	340,446	0	N/A
9	Travis E. Meyer Director, Corporate Finance & Investor Relations Officer	182,774	48,802 A	47,462 B 35,299 C 19,144 D	333,481	0	N/A
10	Timothy P. Olson Corporate Counsel & Corporate Secretary	186,442	47,349 A	47,423 B 36,573 C	317,787	310,847	2.2%

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2019 Annual Incentive Compensation Plan. Amounts were earned in 2019 and paid in the first quarter of 2020. Based on company performance against plan, the incentive plan was funded at 126% of target. Salary and incentive in current rate recovery are based on a 2017 test period.

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

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

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

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019. Pension values increased due to the decrease in discount rate, which results in an overall increase in liability. The overall change in the cash balance amount year over year also factored into the degree of change.

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

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

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

Cashell	3.1%	Rausch	2.9%
Hines	3.2%	Vold	2.8%
Merkel	2.4%	LaFave	N/A
Lail	1.0%	Meyer	N/A
Nieman	2.8%	Olson	2.2%

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	Bonuses 1/	Other 2/	Total Compensation 3/	Total Compensation Reported Last Year	% Increase Total Compensation 4/
1	Robert C. Rowe President & Chief Executive Officer	643,770	818,022 A	39,120 B 1,650,164 C 144,501 D 2,727 E	3,298,304	3,165,931	4.2%
2	Brian B. Bird Chief Financial Officer	445,284	339,487 A	54,677 B 548,242 C 31,861 D 2,710 F	1,422,261	1,349,357	5.4%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	416,601	293,497 A	51,505 B 444,292 C	1,205,895	1,131,564	6.6%
4	Curtis T. Pohl Vice President, Distribution	302,572	153,789 A	53,608 B 238,776 C 59,131 D	807,876	739,646	9.2%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	285,059	144,887 A	54,205 B 182,672 C 39,441 D 2,710 F	708,974	654,067	8.4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the Northwestern Energy 2019 Annual Incentive Compensation Plan. Amounts were earned in 2019 and paid in the first quarter of 2020. Based on company performance against plan, the incentive plan was funded at 126% of target. Salary and incentive in current rate recovery are based on a 2017 test period.

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

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

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

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019. Pension values increased due to the decrease in discount rate, which results in an overall increase in liability. The overall change in the cash balance amount year over year also factored into the degree of change.

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

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

3/ Stock-based compensation is paid by shareholders.

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

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

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

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

Rowe	0.7%
Bird	3.5%
Grahame	6.6%
Pohl	1.2%
Schroeppel	2.4%

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$6,120,077,623	$5,840,335,682	$279,741,941	4.79%
4	101.1 Property Under Capital Leases	43,891,413	40,209,537	3,681,876	9.16%
5	103 Experimental Electric Plant Unclassified	1,631,264	1,631,264	-	0.00%
6	105 Plant Held for Future Use	4,903,851	4,922,322	(18,471)	-0.38%
7	107 Construction Work in Progress	88,677,933	99,808,223	($11,130,290)	-11.15%
8	108 Accumulated Depreciation Reserve	(2,254,708,460)	(2,071,616,130)	($183,092,330)	8.84%
9	108.1 Accumulated Depreciation - Capital Leases	(27,141,417)	(25,130,941)	($2,010,476)	8.00%
10	111 Accumulated Amortization & Depletion Reserves	(82,964,465)	(76,813,025)	($6,151,440)	8.01%
11	114 Electric Plant Acquisition Adjustments	481,574,396	381,625,879	99,948,517	26.19%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(51,378,623)	(32,882,953)	(18,495,670)	56.25%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	35,192,358	33,038,099	2,154,259	6.52%
15	**Total Utility Plant**	4,717,341,400	4,552,713,484	164,627,916	3.62%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(29,180)	(47,652)	18,472	-38.76%
19	123.1 Investments in Assoc Companies and Subsidiaries	(122,612,624)	(125,437,362)	2,824,738	-2.25%
20	124 Other Investments	47,501,223	40,469,134	7,032,089	17.38%
21	128 Miscellaneous Special Funds	250,000	250,000	-	0.00%
23	**Total Other Property & Investments**	(74,203,776)	(84,079,075)	9,875,299	-11.75%
24	**Current and Accrued Assets**				
25	131 Cash	4,673,108	7,522,207	(2,849,099)	-37.88%
26	134 Other Special Deposits	5,202,171	5,705,336	(503,165)	-8.82%
27	135 Working Funds	23,150	23,050	100	0.43%
30	142 Customer Accounts Receivable	76,136,135	73,325,455	2,810,680	3.83%
31	143 Other Accounts Receivable	11,411,798	14,369,677	(2,957,879)	-20.58%
32	144 Accumulated Provision for Uncollectible Accounts	(2,346,427)	(2,280,211)	(66,216)	2.90%
34	146 Accounts Receivable-Associated Companies	1,307,288	359,020	948,268	264.13%
35	151 Fuel Stock	6,354,506	6,933,578	(579,072)	-8.35%
36	154 Plant Materials and Operating Supplies	42,194,053	36,494,449	5,699,604	15.62%
37	164 Gas Stored - Current	4,607,138	6,692,917	(2,085,779)	-31.16%
38	165 Prepayments	13,354,236	10,330,909	3,023,327	29.26%
41	172 Rents Receivable	100,788	136,641	(35,853)	-26.24%
42	173 Accrued Utility Revenues	83,344,000	78,204,239	5,139,761	6.57%
43	174 Miscellaneous Current & Accrued Assets	203,131	100,176	102,955	102.77%
48	**Total Current & Accrued Assets**	246,565,075	237,917,443	8,647,632	3.63%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	12,355,991	12,291,542	64,449	0.52%
51	182 Regulatory Assets	651,438,813	599,139,637	52,299,176	8.73%
53	184 Clearing Accounts	2,634	2,044	590	28.86%
55	186 Miscellaneous Deferred Debits	5,095,671	3,033,001	2,062,670	68.01%
56	189 Unamortized Loss on Reacquired Debt	31,089,217	34,079,779	(2,990,562)	-8.78%
57	190 Accumulated Deferred Income Taxes	158,673,379	140,591,723	18,081,656	12.86%
58	191 Unrecovered Purchased Gas Costs	34,065,519	6,566,452	27,499,067	>300.00%
59	**Total Deferred Debits**	892,721,224	795,704,178	97,017,046	12.19%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 5,782,423,923	$ 5,502,256,030	$ 280,167,893	5.09%

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	$ 539,992	$ 538,894	$ 1,098	0.20%
6	211 Miscellaneous Paid-In Capital	1,508,968,799	1,499,069,743	9,899,056	0.66%
10	216 Unappropriated Retained Earnings	633,103,630	546,110,299	86,993,331	15.93%
12	217 Reacquired Capital Stock	(96,014,713)	(95,545,989)	(468,724)	0.49%
13	219 Accumulated Other Comprehensive Income	(7,505,099)	(7,791,798)	286,699	-3.68%
14	**Total Proprietary Capital**	2,039,092,609	1,942,381,149	96,711,460	4.98%
15	**Long Term Debt**				
16	221 Bonds	1,929,660,000	1,779,660,000	150,000,000	8.43%
18	224 Other Long Term Debt	315,976,900	334,976,900	(19,000,000)	-5.67%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit		-	-	-
20	**Total Long Term Debt**	2,245,636,900	2,114,636,900	131,000,000	6.19%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	19,742,260	19,915,440	(173,180)	-0.87%
24	228.2 Accumulated Provision for Injuries and Damages	7,650,043	6,475,282	1,174,761	18.14%
25	228.3 Accumulated Provision for Pensions and Benefits	10,393,155	12,131,093	(1,737,938)	-14.33%
26	228.4 Accumulated Miscellaneous Operating Provisions	121,180,549	131,495,876	(10,315,327)	-7.84%
27	229 Accumulated Provision for Rate Refunds	17,019,084	2,567,455	14,451,629	>300.00%
28	230 Asset Retirement Obligations	42,449,270	40,659,427	1,789,843	4.40%
29	**Total Other Noncurrent Liabilities**	218,434,361	213,244,573	5,189,788	2.43%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	-	-	-	-
32	232 Accounts Payable	105,556,234	95,824,027	9,732,207	10.16%
34	234 Accounts Payable to Associated Companies	1,715,201	1,678,806	36,395	2.17%
35	235 Customer Deposits	4,372,087	7,134,336	(2,762,249)	-38.72%
36	236 Taxes Accrued	60,825,677	55,658,065	5,167,612	9.28%
37	237 Interest Accrued	17,537,539	16,953,728	583,811	3.44%
40	241 Tax Collections Payable	1,696,553	1,577,187	119,366	7.57%
41	242 Miscellaneous Current and Accrued Liabilities	52,128,884	76,229,323	(24,100,439)	-31.62%
42	243 Obligations Under Capital Leases-Current	3,855,092	2,298,029	1,557,063	67.76%
45	**Total Current and Accrued Liabilities**	247,687,267	257,353,501	(9,666,234)	-3.76%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	56,869,680	50,088,672	6,781,008	13.54%
48	253 Other Deferred Credits	170,566,702	182,429,084	(11,862,382)	-6.50%
49	254 Regulatory Liabilities	197,585,036	185,559,637	12,025,399	6.48%
50	255 Accumulated Deferred Investment Tax Credits	281,903	293,407	(11,504)	-3.92%
52	281-283 Accumulated Deferred Income Taxes	606,269,464	556,269,107	50,000,357	8.99%
53	**Total Deferred Credits**	1,031,572,785	974,639,907	56,932,878	5.84%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 5,782,423,922	$ 5,502,256,030	$ 280,167,892	5.09%
55					
56	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
57	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
58	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
59	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.				
60					
61					
62					
63					
64					Schedule 18A

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 734,800 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

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

(2) Significant Accounting Policies

Financial Statement Presentation

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

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

- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $442.1 million and $428.5 million as of December 31, 2019 and December 31, 2018, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;

- Goodwill is reflected in the Balance Sheets as a utility plant adjustments of $357.6 million as of December 31, 2019 and December 31, 2018, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 6);

- 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, 2019 and December 31, 2018, 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 classified in the Balance Sheets as capital leases in accordance with regulatory treatment, as compared to non-current assets for GAAP purposes;

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

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

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

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

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

- Deficient and excess accumulated deferred tax assets and liabilities associated with the Tax Cuts and Jobs Act are classified in the Balance Sheets as gross regulatory assets and liabilities, respectively, while GAAP presentation reflects a net non-current regulatory deferred tax asset;

- 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 postretirement 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; and

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

Use of Estimates

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

Revenue Recognition

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

Cash Equivalents

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

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.3 million at December 31, 2019 and December 31, 2018. Unbilled revenues were $83.3 million and $78.2 million at December 31, 2019 and December 31, 2018, respectively.

Inventories

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

	December 31,	
	2019	2018
Fuel stock	$ 6,355	$ 6,934
Plant materials and operating supplies	42,194	36,494
Gas stored underground (including the non-current portion reflected in utility plant)	39,799	39,731
Total Inventory	$ 88,348	$ 83,159

Regulation of Utility Operations

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

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

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

Derivative Financial Instruments

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

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

Utility Plant

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

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. This rate averaged 6.9% and 7.1% for Montana for 2019 and 2018, respectively. This rate averaged 6.6% and 6.7% for South Dakota for 2019 and 2018, respectively. AFUDC capitalized totaled $8.2 million and $5.9 million for the years ended December 31, 2019 and 2018, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 2 years to 96 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.8% and 3.0% for 2019 and 2018, respectively.

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

Pension and Postretirement Benefits

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

Income Taxes

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

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

Environmental Costs

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

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

Supplemental Cash Flow Information

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Cash (received) paid for:		
Income taxes	$ (6,737)	$ 55
Interest	83,776	76,499
Significant non-cash transactions:		
Capital expenditures included in accounts payable	33,473	21,625

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

	December 31,	
	2019	2018
Cash	$ 4,673	$ 7,522
Working funds	23	23
Other special funds	250	250
Special deposits	5,202	5,705
Total shown in the Statements of Cash Flows	$ 10,148	$ 13,500

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

Accounting Standards Adopted

Leases - In February 2016, revised guidance was issued requiring substantially all leases to be recognized on the balance sheet as right-of-use assets and lease liabilities. Leases with a term of 12 months or less may be excluded from the balance sheet and continue to be reflected in the income statement. Recognition, measurement and presentation of expenses depends on classification as a finance or operating lease.

We adopted this standard on January 1, 2019, using the modified retrospective method of adoption. Adoption of this standard had minimal impact on our Financial Statements and disclosures. We elected a package of practical expedients that allow us to carry forward historical conclusions related to (1) whether any expired or existing contract is a lease or contains a lease, (2) the lease classification of any expired or existing leases and easements, and (3) the initial direct costs for any existing leases. In addition, as our easements are entered into in perpetuity, they do not meet the definition of a lease in accordance with this guidance. We did not restate comparative periods upon adoption. We had one finance lease that was already included on our balance sheets prior to adoption of the lease standard, consistent with previous guidance for capital leases. We also lease office equipment and facilities under various long-term operating leases. As of December 31, 2019, the recognition of right-of-use assets and lease liabilities for operating leases increased our property under capital leases and obligations under capital leases in the Balance Sheets as follows (in thousands):

	Affected Line Item in the Balance Sheets	December 31, 2019
Operating lease assets	Utility plant	$ 3,682
Operating lease liabilities, current	Obligations under capital leases-current	1,379
Operating lease liabilities, noncurrent	Obligations under capital leases-noncurrent	2,303
Total operating lease liabilities		$ 3,682

(3) Regulatory Matters

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the Montana Public Service Commission (MPSC) requesting an annual increase to electric rates of approximately $34.9 million. The MPSC issued an order approving an interim increase in revenue of approximately $10.5 million effective April 1, 2019. In May 2019, we reached a settlement with all parties who filed comprehensive revenue requirement, cost allocation, and rate design testimony in our Montana electric rate case. The MPSC issued a Final Order in December 2019, accepting the settlement, resulting in an annual increase to electric revenue of approximately $6.5 million (based upon a 9.65% return on equity (ROE) and rate base and capital structure as filed) and an annual decrease in depreciation expense of approximately $9.3 million. In addition to approving the settlement, the MPSC approved a pilot decoupling mechanism with no adjustment to ROE.

The Montana Consumer Counsel (MCC) filed a motion for reconsideration of several aspects of the Final Order. In particular, the MCC opposed the pilot decoupling mechanism and our methodology for determining the amount of revenue credited to Montana retail customers from our Federal Energy Regulatory Commission (FERC) transmission service rates.

The MCC argued in the alternative that, if the MPSC does not eliminate the pilot decoupling mechanism, the MPSC should reduce ROE by 0.25%. We expect the MPSC to issue an Order on Reconsideration during the second quarter of 2020.

We implemented final rates, consistent with the Final Order, and began refunding interim rate revenue collected in excess of the stipulated revenue requirement effective March 1, 2020. As of March 31, 2020, and December 31, 2019, we had deferred revenue of approximately $6.5 million and $2.9 million, respectively, in the Condensed Consolidated Balance Sheets.

FERC Filing - Montana Transmission Service Rates

In May 2019, we submitted a filing with the FERC for our Montana transmission assets. The revenue requirement associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. We expect to submit a compliance filing with the MPSC upon resolution of our Montana FERC case adjusting the proposed credit in our Montana retail rates. In June 2019, the FERC issued an order accepting our filing, granting interim rates (subject to refund) effective July 1, 2019, establishing settlement procedures and terminating our related Tax Cuts and Jobs Act filing. A settlement judge has been appointed and settlement negotiations are ongoing.

Cost Recovery Mechanisms - Montana

Montana Electric and Natural Gas Supply Cost Trackers - Each year we submit an electric and natural gas tracker filing for recovery of supply costs for the 12-month period ended June 30. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our supply procurement activities were prudent.

The MPSC approved a new design for our electric tracker effective July 1, 2017. The revised electric tracker, or Power Costs and Credits Adjustment Mechanism (PCCAM), established a baseline of power supply costs and tracks the differences between the actual costs and revenues. Variances above or below the baseline are allocated 90% to customers and 10% to shareholders, with an annual adjustment. The initial design of the PCCAM also included a "deadband" which required us to absorb the variances within +/- $4.1 million from the base, with 90% of the variance above or below the deadband collected from or refunded to customers. In 2019, the Montana legislature revised the statute effective May 7, 2019, prohibiting a deadband, allowing 100% recovery of QF purchases, and maintaining the 90% / 10% sharing ratio for other purchases.

We submitted our annual PCCAM filing in September 2019, requesting recovery of approximately $23.8 million in costs for the period July 1, 2018 to June 30, 2019, with the under recovery being collected over the 12-month period October 1, 2019 through September 30, 2020. The MCC and the Montana Environmental Information Center (MEIC) submitted testimony advocating for a disallowance of approximately $6.0 million of replacement power costs incurred during a 2018 third quarter intermittent outage at our Colstrip generating facility due to an exceedance of air permit limits. In addition, the MCC advocated for a prorated application of the May 2019 statutory change eliminating the deadband and removing QF costs from the sharing calculation, which would result in an additional under recovery of costs of approximately $4.0 million. The MPSC scheduled a hearing in this matter for June 2020. We began collecting costs for the July 2018 - June 2019 PCCAM period on October 1, 2019. As of March 31, 2020, the remaining under collection of approximately $13.2 million was reflected in regulatory assets in the Condensed Consolidated Balance Sheets.

Montana Property Tax Tracker - Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in taxes and fees, net of the associated income tax benefit. We submit an annual property tax tracker filing with the MPSC for an automatic rate adjustment, with rates typically effective January 1st of each year. In February 2020, we amended our December 2019 filing in order to make corrections. We and the MCC agreed to a briefing schedule in this docket concluding in May 2020. We expect the MPSC to issue an order on the rate adjustment in the second quarter of 2020.

Montana QF Power Purchase Cases

Under the Public Utility Regulatory Policies Act (PURPA), electric utilities are required, with certain exceptions, to purchase energy and capacity from independent power producers that are QFs. We track the costs of these purchases through our PCCAM. These purchases are also the subject of proceedings before the MPSC, whose orders are subject to judicial review by Montana state courts.

In May 2016, we filed our biennial update of standard rates for small QFs (3 MW or less). In November 2017, the MPSC approved new, lower rates, reduced the maximum contract term from 25 to 15 years, and ordered that it would apply the same 15-year contract term to our future owned and contracted electric supply resources (Symmetry Finding). We sought judicial review with the Montana State District Court (District Court) of the Symmetry Finding. Cypress Creek Renewables, LLC, Vote Solar, and MEIC, sought judicial review with the District Court of the rates and contract term.

The District Court reversed and modified the MPSC's decisions on rates, contract term, and the Symmetry Finding. We appealed the District Court's order regarding rates and contract term to the Montana Supreme Court. The MPSC did not appeal the District Court's Symmetry Finding. The Montana Supreme Court granted our motion to stay the District Court's decisions regarding rates and contract term. The matter is fully briefed and the Montana Supreme Court held oral argument in the case on February 26, 2020. We are awaiting the Montana Supreme Court's decision.

The MPSC also issued the same Symmetry Finding in another docket when setting the rates and contract term for a large QF - MT Sun, LLC (MTSun). We, as well as MTSun, sought judicial review of the MPSC's order. The District Court reversed and modified the MPSC's order regarding rates, contract length, and the Symmetry Finding. We appealed the District Court's order to the Montana Supreme Court on the issues of rates and contract length, and the MPSC did not appeal the District Court's reversal of the Symmetry Finding. Briefing on the matter is complete and we are awaiting a decision from the Montana Supreme Court.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2019, approximately 66 MW of CREPs. While we have made progress towards meeting this obligation by acquiring approximately 36 MW of CREPs, we have been unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC's action as it related to waivers granted for 2015 and 2016 has been challenged legally and briefing is currently taking place before the Montana Supreme Court. We expect to file waiver requests for 2017, 2018, and 2019 as well, after resolution of that litigation. If the Court rules that the 2015 and 2016 waivers were invalid or if the requested waivers for 2017 through 2019 are not granted, we may be liable for penalties, although we believe the statutory penalty for failure to acquire sufficient energy does not apply to the acquisition of CREP resources. If the MPSC imposes a penalty, the amount of the penalty would depend on how the MPSC calculated the energy that a CREP would have produced.

(4) Equity Investments

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

	December 31,	
	2019	2018
Colstrip Unit 4 Basis Adjustment	$ (141,154)	$ (147,543)
Havre Pipeline Company, LLC	12,672	13,700
NorthWestern Services, LLC	1,972	1,946
NorthWestern Energy Solutions, Inc.	1,302	2,474
Risk Partners Assurance, Ltd.	2,595	1,349
Total Investments in Subsidiary Companies	**$ (122,613)**	**$ (125,437)**

(5) Regulatory Assets and Liabilities

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

	Note Reference	Remaining Amortization Period	December 31, 2019	December 31, 2018
			(in thousands)	
Income taxes	14	Plant Lives	$ 376,548	$ 335,289
Pension	16	Undetermined	132,000	130,193
Tax Cuts and Jobs Act		Various	73,670	56,768
Employee related benefits	16	Undetermined	18,622	19,458
State & local taxes & fees		Various	7,141	15,527
Environmental clean-up	19	Various	11,179	11,221
Other		Various	32,279	30,684
Total Regulatory Assets			**$ 651,439**	**$ 599,140**
Tax Cut and Jobs Act		1 Year	172,784	161,623
Unbilled revenue		1 Year	13,467	12,215
Gas storage sales		20 Years	8,307	8,728
State & local taxes & fees		1 Year	1,846	1,747
Environmental clean-up		Various	1,181	1,247
Total Regulatory Liabilities			**$ 197,585**	**$ 185,560**

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. See Note 14 - Income Taxes for further discussion.

Pension and Employee Related Benefits

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

Rates Subject to Refund

In June 2019, in response to a filing associated with our Montana transmission assets, FERC granted an interim rate increase, effective July 1, 2019. Also, in our Montana general electric rate case, the MPSC granted an interim rate increase, effective April 1, 2019. See Note 3 - Regulatory Matters, for further information regarding these dockets.

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

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

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Tax Cut and Jobs Act

The Tax Cuts and Jobs Act provided a customer benefit as a result of the lower statutory rate. This amount reflects amounts credited to customers in our Montana jurisdiction in the first quarter of 2019.

Gas Storage Sales

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

Unbilled Revenue

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

(6) Utility Plant

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

	Estimated Useful Life	December 31, 2019	December 31, 2018
	(years)	(in thousands)	
Land and improvements	50 – 96	$ 164,293	$ 157,708
Building and improvements	23 – 73	482,911	467,628
Storage, distribution, and transmission	15 – 85	3,669,658	3,440,524
Generation	23 – 71	1,983,756	1,870,027
Construction work in process	25 – 50	88,678	99,808
Other equipment	2 – 45	351,460	332,838
Total utility plant		6,740,756	6,368,533
Less accumulated depreciation		(2,416,192)	(2,206,443)
Net utility plant		$ 4,324,564	$ 4,162,090

Net utility plant under capital (finance) lease was $13.3 million and $15.4 million as of December 31, 2019 and 2018, respectively, which included $13.1 million and $15.1 million as of December 31, 2019 and 2018, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

Jointly Owned Electric Generating Plant

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

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

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2019				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,662	$ 62,565	$ 52,448	$ 311,399
Accumulated depreciation	44,695	35,823	41,765	98,415
December 31, 2018				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,359	$ 60,758	$ 50,325	$ 309,163
Accumulated depreciation	45,894	34,394	41,379	89,734

(7) Asset Retirement Obligations

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

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

	December 31,	
	2019	2018
Liability at January 1,	$ 40,659	$ 39,286
Accretion expense	2,051	2,031
Liabilities incurred	—	773
Liabilities settled	(46)	(63)
Revisions to cash flows	(215)	(1,368)
Liability at December 31,	$ 42,449	$ 40,659

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

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

(8) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2019 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

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

Objectives and Strategies for Using Derivatives

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

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

Accounting for Derivative Instruments

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

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Financial Statements at December 31, 2019 and 2018. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

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

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

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

Interest Rate Swaps Designated as Cash Flow Hedges

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

Cash Flow Hedges	Location of Amount Reclassified from AOCI to Income	Amount Reclassified from AOCI into Income during the Year Ended December 31, 2019
Interest rate contracts	Interest on long-term debt	$ 613

A pre-tax loss of approximately $15.2 million is remaining in AOCI as of December 31, 2019, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCI into interest on long-term debt during the next twelve months. These amounts relate to terminated swaps.

(10) Fair Value Measurements

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

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

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

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

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

December 31, 2019	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Special deposits	$ 5,202	$ —	$ —	$ —	$ 5,202
Rabbi trust investments	29,288	—	—	—	29,288
Total	**$ 34,490**	**$ —**	**$ —**	**$ —**	**$ 34,490**
December 31, 2018					
Special deposits	$ 5,705	$ —	$ —	$ —	$ 5,705
Rabbi trust investments	$ 22,270	—	—	—	22,270
Total	**$ 27,975**	**$ —**	**$ —**	**$ —**	**$ 27,975**

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

Financial Instruments

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

	December 31, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,245,637	$ 2,429,170	$ 2,114,637	$ 2,130,204

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 Revolving Line of Credit

Unsecured Revolving Line of Credit

We have a $400 million revolving credit facility, which matures December 12, 2021. The facility includes an accordion feature that allows us to increase the size to $450 million with the consent of the lenders. The facility does not amortize and is unsecured. The facility bears interest at the lower of prime plus a credit spread, ranging from 0% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2021, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13%, or available rates tied to the Eurodollar rate plus a credit spread of 0.65%. Commitment fees for the unsecured revolving lines of credit were $0.3 million and $0.4 million for the years ended December 31, 2019 and 2018.

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

	2019	2018
Unsecured revolving line of credit, expiring December 2021	$ 400.0	$ 400.0
Unsecured revolving line of credit, expiring March 2021	25.0	25.0
	425.0	**425.0**
Amounts outstanding at December 31:		
Eurodollar borrowings	289.0	308.0
Letters of credit	—	0.2
	289.0	**308.2**
Net availability as of December 31	**$ 136.0**	**$ 116.8**

Our covenants require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. In addition, there are covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facilities would not trigger a default on any other obligations.

(12) Long-Term Debt

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

	Due	December 31, 2019	December 31, 2018
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ 289,000	$ 290,000
Unsecured Revolving Line of Credit	2021	—	18,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	—
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Total Long-Term Debt		$ 2,245,637	$ 2,114,637

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

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

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

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

As of December 31, 2019, we were in compliance with our financial debt covenants.

Other Long-Term Debt

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

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are \$289.0 million in 2021 and \$144.7 million in 2023.

(13) Related Party Transactions

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

	December 31,			
	2019		2018	
Accounts Receivable from Associated Companies:				
Havre Pipeline Company, LLC	$	1,238	$	308
NorthWestern Energy Solutions, Inc.		51		33
Risk Partners Assurance, Ltd.		18		18
	$	1,307	$	359
Accounts Payable to Associated Companies:				
NorthWestern Services, LLC	$	1,715	$	1,679

(14) Income Taxes

Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The lower federal statutory tax rate in 2019 and 2018 reduces the impact of these deductions as compared with 2017. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The income tax benefit during the twelve months ended December 31, 2019, reflects the release of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, net of tax, due to the lapse of statutes of limitation in the second quarter of 2019. The income tax benefit during the twelve months ended December 31, 2018, includes finalization of the remeasurement of deferred income taxes associated with the Tax Cuts and Jobs Act following the conclusion of the associated regulatory dockets.

Deficient and excess accumulated deferred tax assets and liabilities associated with the Tax Cuts and Jobs Act are classified as follows in the Balance Sheets (in thousands):

	December 31, 2019					
	Protected		Unprotected		Total	
	Montana	South Dakota/ Nebraska	Montana	South Dakota/ Nebraska	Montana	South Dakota/ Nebraska
Other Regulatory Assets	$ 33,984	$ 5,199	$ 32,267	$ 2,220	$ 66,251	$ 7,419
Other Regulatory Liabilities	$ 126,966	$ 23,486	$ 22,031	$ 300	$ 148,997	$ 23,787

	December 31, 2018					
	Protected		Unprotected		Total	
	Montana	South Dakota/ Nebraska	Montana	South Dakota/ Nebraska	Montana	South Dakota/ Nebraska
Other Regulatory Assets	$ 25,834	$ 4,240	$ 24,941	$ 1,754	$ 50,775	$ 5,994
Other Regulatory Liabilities	$ 120,682	$ 23,795	$ 16,909	$ 237	$ 137,591	$ 24,031

Protected excess and deficient accumulated deferred income taxes (ADITs) in 2019 were amortized in the Statement of Income as follows (in thousands):

	Montana		South Dakota/ Nebraska	
	December 31,		December 31,	
	2019	2018	2019	2018
Provision for Deferred Income Taxes	$ 2,711	$ 799	$ 133	$ 133
Provision for Deferred Income Taxes-Cr.	$ 3,397	$ 3,343	$ 1,134	$ 1,319

Protected ADITs, which are required by IRS normalization rules to be provided to customers, are typically amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. In the event that remaining book lives are undeterminable, an average book life of assets in the same asset class will be used under the Reverse South Georgia Method. Unprotected non-plant excess ADITs for Montana electric operations are being amortized over five years. Montana and Nebraska gas operations unprotected non-plant excess ADITs will be amortized based on the results of the next rate case filing in those jurisdictions. South Dakota unprotected non-plant excess ADITs were written off as shareholder expense in 2018.

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

	December 31,	
	2019	2018
Production tax credit	$ 50,440	$ 38,957
Pension / postretirement benefits	30,041	30,634
Customer advances	14,975	13,190
Compensation accruals	13,163	11,885
NOL carryforward	16,054	12,205
Unbilled revenue	9,820	12,305
Reserves and accruals	7,069	1,099
Environmental liability	5,938	5,810
Interest rate hedges	3,956	4,074
AMT credit carryforward	3,400	6,799
Other, net	3,817	3,634
Deferred Tax Asset	**158,673**	**140,592**
Excess tax depreciation	(400,918)	(378,435)
Utility plant adjustments amortization (1)	(82,595)	(81,104)
Flow through depreciation	(71,679)	(57,456)
Regulatory assets and other (1)	(51,359)	(39,568)
Deferred Tax Liability	**$ (606,551)**	**$ (556,563)**

---

(1) The presentation of the December 31, 2018, deferred tax liabilities has been corrected to reflect a decrease of $38.3 million in deferred tax liabilities from utility plant adjustments amortization and a corresponding increase in deferred tax liabilities from regulatory assets and other related to amortization of intangible assets. This correction in presentation had no effect on income tax expense (benefit), or net income, or the presentation of deferred taxes on the balance sheets.

At December 31, 2019 our total federal NOL carryforward was approximately $181.9 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $103.7 million in 2036 and $78.2 million in 2037. Our state NOL carryforward as of December 31, 2019 was approximately $121.4 million. If unused, our state NOL carryforwards will expire as follows: $60.3 million in 2023 and $61.1 million in 2024. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

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

	2019	2018
Unrecognized Tax Benefits at January 1	$ 56,150	$ 57,473
Gross increases - tax positions in prior period	539	—
Gross decreases - tax positions in prior period	—	—
Gross increases - tax positions in current period	—	338
Gross decreases - tax positions in current period	(1,489)	(1,661)
Lapse of statute of limitations	(20,115)	—
Unrecognized Tax Benefits at December 31	$ 35,085	$ 56,150

Our unrecognized tax benefits include approximately $28.0 million and $47.5 million related to tax positions as of December 31, 2019 and 2018, respectively that, if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest related to uncertain tax positions in interest expense. As discussed above, during the twelve months ended December 31, 2019, we released $2.7 million of accrued interest in the Statements of Income. As of December 31, 2019, we did not have any amounts accrued for the payment of interest. During the year ended December 31, 2018, we recognized $1.2 million of expense for interest in the Statements of Income. As of December 31, 2018, we had $2.7 million of interest accrued in the Balance Sheets.

Tax years 2016 and forward remain subject to examination by the IRS and state taxing authorities. In addition, the available federal net operating loss carryforward may be reduced by the IRS for losses originating in certain tax years from 2002 forward.

(15) Comprehensive Income (Loss)

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

	2019			2018		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (35)	$ —	$ (35)	$ 270	$ —	$ 270
Reclassification of net income (loss) on derivative instruments	613	(160)	453	613	(116)	497
Postretirement medical liability adjustment	(175)	44	(131)	346	(133)	213
Other comprehensive income (loss)	$ 403	$ (116)	$ 287	$ 1,229	$ (249)	$ 980

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

	December 31, 2019	December 31, 2018
Foreign currency translation	$ 1,413	$ 1,448
Derivative instruments designated as cash flow hedges	(9,031)	(9,484)
Postretirement medical plans	113	244
Accumulated other comprehensive loss	$ (7,505)	$ (7,792)

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

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

	Affected Line Item in the Statements of Income	December 31, 2018 Year Ended Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)
Other comprehensive income before reclassifications		—	—	270	270
Amounts reclassified from AOCI	Interest on long-term debt	497	—	—	497
Amounts reclassified from AOCI		—	213	—	213
Net current-period other comprehensive income		497	213	270	980
Ending Balance		$ (9,484)	$ 244	$ 1,448	$ (7,792)

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

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

Benefit Obligation and Funded Status

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2019	2018	2019	2018
Change in benefit obligation:				
Obligation at beginning of period	$ 649,626	$ 696,796	$ 20,611	$ 22,921
Service cost	9,637	11,776	331	398
Interest cost	26,488	24,420	609	578
Actuarial loss (gain)	83,364	(53,496)	997	(1,903)
Settlements	(4,065)	—	390	390
Benefits paid	(29,486)	(29,870)	(2,666)	(1,773)
Benefit Obligation at End of Period	$ 735,564	$ 649,626	$ 20,272	$ 20,611
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 525,310	$ 586,508	$ 18,670	$ 20,380
Return on plan assets	107,041	(40,528)	3,805	(866)
Employer contributions	10,200	9,200	1,670	929
Settlements	(4,065)	—	—	—
Benefits paid	(29,486)	(29,870)	(2,666)	(1,773)
Fair value of plan assets at end of period	$ 609,000	$ 525,310	$ 21,479	$ 18,670
Funded Status	$ (126,564)	$ (124,316)	$ 1,207	$ (1,941)
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	4,333	2,672	7,783	4,565
Total Assets	4,333	2,672	7,783	4,565
Current liability	(11,401)	—	(2,113)	(2,271)
Noncurrent liability	(119,496)	(126,988)	(4,463)	(4,235)
Total Liabilities	(130,897)	(126,988)	(6,576)	(6,506)
Net amount recognized	$ (126,564)	$ (124,316)	$ 1,207	$ (1,941)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	5,890	7,922
Net actuarial (loss) gain	(111,449)	(116,425)	259	(1,910)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(397)	(548)
Net actuarial gain	—	—	934	1,260
Total	$ (111,449)	$ (116,425)	$ 6,686	$ 6,724

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

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

	NorthWestern Energy Pension Plan December 31,	
	2019	2018
Projected benefit obligation	$ 675.5	$ 592.5
Accumulated benefit obligation	675.5	592.5
Fair value of plan assets	545.8	466.7

As of December 31, 2019, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

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

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2019	2018	2019	2018
Components of Net Periodic Benefit Cost				
Service cost	$ 9,637	$ 11,776	$ 331	$ 398
Interest cost	26,488	24,420	609	578
Expected return on plan assets	(25,443)	(28,207)	(869)	(954)
Amortization of prior service cost (credit)	—	4	(1,882)	(1,882)
Recognized actuarial loss (gain)	6,544	4,360	(96)	(79)
Settlement loss recognized	198	—	390	390
Net Periodic Benefit Cost (Credit)	$ 17,424	$ 12,353	$ (1,517)	$ (1,549)
Regulatory deferral of net periodic benefit cost (1)	(7,510)	(4,057)	—	—
Previously deferred costs recognized (1)	728	243	931	913
Amount Recognized in Income	$ 10,642	$ 8,539	$ (586)	$ (636)

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

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

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2019 and 2018. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The decrease in discount rate during 2019 increased our projected benefit obligation by approximately $87.6 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 Pension Plan to 4.49% and decreased our assumption on the NorthWestern Corporation Pension Plan to 3.45% for 2020.

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

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2019	2018	2019	2018
Discount rate	3.10-3.20 %	4.15-4.20 %	2.80 %	3.90-3.95 %
Expected rate of return on assets	4.23-5.06	4.47-4.97	4.79	4.82
Long-term rate of increase in compensation levels (non-union)	2.84	2.84	2.84	2.84
Long-term rate of increase in compensation levels (union)	2.00	2.03	2.00	2.03
Interest crediting rate	3.60-6.00	4.00-6.00	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00% 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, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. 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;
- 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 overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

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

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

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2019	2018	2019	2018	2019	2018
Domestic debt securities	55.0%	55.0%	80.0%	75.0%	40.0%	40.0%
International debt securities	4.0	4.0	2.0	2.5	—	—
Domestic equity securities	16.5	16.5	7.2	9.0	50.0	50.0
International equity securities	24.5	24.5	10.8	13.5	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2019	2018	2019	2018	2019	2018
Cash and cash equivalents	—%	0.1%	0.9%	—%	1.0%	1.0%
Domestic debt securities	53.8	57.5	77.0	81.3	37.8	40.8
International debt securities	4.0	4.4	2.6	2.6	—	—
Domestic equity securities	16.8	15.0	8.1	6.3	52.4	49.1
International equity securities	25.4	23.0	11.4	9.8	8.8	9.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

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

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. We expect to continue to make contributions to the pension plans in 2019 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2019 and 2018 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2019	2018
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 8,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 10,200	$ 9,200

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

	Pension Benefits	Other Postretirement Benefits
2020	$ 33,310	$ 3,025
2021	34,823	2,934
2022	36,154	2,501
2023	37,605	2,337
2024	39,084	1,843
2025-2029	207,765	5,851

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2019 and 2018 were $11.0 million and $10.6 million, respectively.

(17) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2019, there were 750,205 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

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

Performance Unit Awards

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

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

	2019	2018
Risk-free interest rate	2.47%	2.30%
Expected life, in years	3	3
Expected volatility	16.4% to 20.9%	16.5% to 21.9%
Dividend yield	3.5%	4.2%

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

A summary of nonvested shares as of and changes during the year ended December 31, 2019, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	197,703	$ 47.99
Granted	73,366	60.41
Vested	(86,712)	47.99
Forfeited	(6,112)	51.12
Remaining nonvested grants	178,245	$ 53.00

We recognized compensation expense of $6.5 million and $6.3 million for the years ended December 31, 2019 and 2018, respectively, and related income tax expense of $0.2 million and $0.3 million for the years ended December 31, 2019 and 2018, respectively. As of December 31, 2019, we had $4.9 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.2 million and $4.2 million for the years ended December 31, 2019 and 2018, respectively.

Retirement/Retention Restricted Share Awards

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

A summary of nonvested shares as of and changes during the year ended December 31, 2019, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	73,391	$ 48.19
Granted	13,425	60.73
Vested	(13,958)	43.79
Forfeited	—	—
Remaining nonvested grants	72,858	$ 51.35

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2019 and 2018, DSUs issued to members of our Board totaled 19,027 and 29,870, respectively. During 2019, DSUs withdrawn by our Board totaled 3,708. Total compensation expense attributable to the DSUs during the years ended December 31, 2019 and 2018 was approximately $3.7 million and $1.9 million, respectively. During 2019, DSUs of $0.3 million were withdrawn.

(18) Common Stock

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

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 25,329 and 12,193 during the years ended December 31, 2019 and 2018, respectively, and are reflected in reacquired capital stock. These shares were credited to reacquired capital stock based on their fair market value on the vesting date.

(19) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act (PURPA). These contracts require us to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. As of December 31, 2019, our estimated gross contractual obligation related to these contracts was approximately $630.8 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $508.2 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within operation expenses and operating revenues in our Statements of Income. The present value of the remaining liability is recorded in accumulated miscellaneous operating provisions in our Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2019	2018
Beginning QF liability	$ 102,260	$ 132,786
Unrecovered amount (1)	(17,257)	(39,827)
Interest on long-term debt	7,934	9,301
Ending QF liability	$ 92,937	$ 102,260

(1) The change in the unrecovered amount includes (i) a lower periodic adjustment of $14.2 million due to price escalation, which was less than previously modeled, and (ii) a lower impact of the annual reset to actual output and pricing resulting in approximately $6.7 million in higher supply costs for these QF contracts due primarily to outages at two facilities in 2018.

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

	Gross Obligation	Recoverable Amounts	Net
2020	$ 76,533	$ 59,647	$ 16,886
2021	78,356	60,136	18,220
2022	80,226	60,639	19,587
2023	82,320	61,280	21,040
2024	79,726	60,706	19,020
Thereafter	233,632	205,787	27,845
Total	$ 630,793	$ 508,195	$ 122,598

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in operating expenses in the Statements of Income and were approximately $222.5 million, and $209.3 million for the years ended December 31, 2019 and 2018, respectively. As of December 31, 2019, our commitments under these contracts were $186.5 million in 2020, $146.5 million in 2021, $150.4 million in 2022, $150.3 million in 2023, $146.0 million in 2024, and $1.1 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $17.4 million between 2020 and 2040. These commitments are not reflected in our Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

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

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us, is estimated to range between $29.2 million to $31.9 million. As of December 31, 2019, we had a reserve of approximately $30.3 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

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

Manufactured Gas Plants - Approximately \$24.5 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2019, the reserve for remediation costs at this site was approximately \$8.2 million, and we estimate that approximately \$2.9 million of this amount will be incurred during the next five years.

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

In addition, we own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site. In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments on previously submitted drafts of the RIWP. The RIWP requires additional investigation including vapor intrusion and investigation of potential contamination from transformers and treated poles. Conditional approval for investigation work outlined in the RIWP was given by MDEQ in November, and work was completed during the first two weeks of December 2019. MDEQ completed its review of the RIWP in the first part of December 2019 and returned additional comments to us, which were addressed in January 2020.

An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells were installed and groundwater is monitored semiannually. At the request of Missoula Valley Water Quality District (MVWQD), a draft risk assessment was prepared for the Missoula site and presented to the MVWQD. We and the MVWQD agreed additional site investigation work is appropriate. Analytical results from an October 2016 sampling exceeded the Montana Maximum Contaminant Level for benzene and/or total cyanide in certain monitoring wells. These results were forwarded to MVWQD which shared the same with the MDEQ. MDEQ requested that MVWQD file a formal complaint with MDEQ's Enforcement Division, which MVWQD filed in July 2017. On April 2, 2019, MDEQ requested our participation at a stakeholders' meeting for the Missoula site. At the meeting, MDEQ indicated that it expects to proceed in listing the site as a Montana superfund site. After researching historical ownership we identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

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

While numerous bills have been introduced that address climate change from different perspectives, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. On June 19, 2019, EPA finalized the Affordable Clean Energy Rule (ACE), which repeals the 2015 Clean Power Plan (CPP). Numerous parties, including us, filed petitions for review and reconsideration of the CPP. Those CPP proceedings were dismissed as moot by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in September 2019. The ACE became effective on September 6, 2019, and various challenges to it are pending in the D.C. Circuit.

Generally, ACE provides more regulatory flexibility to individual states than the CPP and likely will not reduce CO_2 emissions as much as the CPP. Under the ACE, states must establish unit-specific standards that reflect emissions achievable through heat rate improvements, which EPA designated as the best system of emissions reduction, and if the state chooses, take into account the remaining useful life of the unit and other source specific factors. States generally have three years to submit the standards to EPA and coal-fired plants will have two additional years to comply with the standards.

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

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

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been issued or proposed. Regarding the ACE, as discussed above, we cannot predict the impact of the ACE on us until the state plans are adopted and any judicial reviews are completed. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures - The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership.

Regional Haze Rules - On January 10, 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

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

In North Dakota, the Coyote facility was assessed in 2010 and did not require additional emissions controls. The facility is expected to be reassessed in 2020 by the North Dakota Department of Environmental Quality (ND DEQ). Once the ND DEQ establishes a strategy for regional haze compliance, the joint owners will assess the requirements, if any, and determine whether to move forward with the installation of additional emissions controls.

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

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

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

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

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

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

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

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

In August 2017, pursuant to a non-monetary, partial settlement with us, PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the amount of damages sought by the plaintiff was reduced to approximately $8 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and there have been no settlement negotiations since then. A jury trial is scheduled to begin on June 2, 2020.

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

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our 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, which culminated with a 2012 decision by the United States Supreme Court holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). The State filed a motion to remand. Following briefing and argument, on October 10, 2017, the Federal District Court entered an order denying the State's motion.

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed between Black Eagle Falls and the Great Falls. In particular, the dismissal pertains to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. This leaves a portion of the Black Eagle reservoir and Morony Dam and reservoir at issue. While the dismissal of these four facilities may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United

States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. On April 16, 2020 the Federal District Court set a scheduling conference for June 11, 2020 to develop a plan for discovery and schedule for disposition of the case.

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

Other Legal Proceedings

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

Sch.19	MONTANA PLANT IN SERVICE - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	19,995	$ -	$ 19,995	$ 19,995	0.00%
4	302 Franchises and Consents	17,527,584	-	17,527,584	17,527,584	0.00%
5	303 Miscellaneous Intangible Plant	3,823,017	-	3,823,017	6,397,715	-40.24%
6	**Total Intangible Plant**	21,370,595	-	21,370,595	23,945,294	-10.75%
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	432,650,899	-	432,650,899	427,560,197	1.19%
18	**Total Steam Production Plant**	432,650,899	-	432,650,899	427,560,197	1.19%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	5,884,456	-	5,884,456	5,732,621	2.65%
26	331 Structures and Improvements	124,714,342	-	124,714,342	124,225,753	0.39%
27	332 Reservoirs, Dams and Waterways	176,651,148	-	176,651,148	168,746,665	4.68%
28	333 Water Wheel, Turbine, Generators	134,819,467	-	134,819,467	124,933,741	7.91%
29	334 Accessory Electric Equipment	85,518,086	-	85,518,086	84,616,046	1.07%
30	335 Misc. Power Plant Equipment	20,144,764	-	20,144,764	20,144,764	0.00%
31	336 Roads, Railroads and Bridges	2,493,836	-	2,493,836	2,493,836	0.00%
32	**Total Hydraulic Production Plant**	550,226,100	-	550,226,100	530,893,427	3.64%
33						
34	**Other Production**					
35	340 Land and Land Rights	2,005,778		2,005,777.76	2,005,777	0.00%
36	341 Structures and Improvements	59,449,471	19,232	59,430,239.08	59,430,236	0.00%
37	342 Fuel Holders & Accessories	21,230,045	112,084	21,117,960.86	21,117,961	0.00%
38	343 Prime Movers	101,143,096		101,143,095.77	101,399,445	-0.25%
39	344 Generators	55,657,436	2,177,823	53,479,613.69	53,479,614	0.00%
40	345 Accessory Electric Equipment	18,956,267	770,151	18,186,115.89	18,105,292	0.45%
41	346 Misc. Power Plant Equipment	26,478,674	7,268	26,471,405.11	26,028,353	1.70%
42	**Total Other Production Plant**	284,920,766	3,086,557	281,834,208	281,566,677	0.10%
43	**Total Production Plant**	1,267,797,764	3,086,557	1,264,711,207	1,240,020,300	1.99%

Sch. 19 cont.)NTANA PLANT IN SERVICE - ELECTRIC

	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	This Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	38,975,215		38,975,215	37,602,744	3.65%
4	352 Structures and Improvements	32,639,149		32,639,149	33,620,251	-2.92%
5	353 Station Equipment	273,008,166		273,008,166	267,155,825	2.19%
6	354 Towers and Fixtures	28,717,133		28,717,133	28,725,249	-0.03%
7	355 Poles and Fixtures	350,391,712	1,045,379	349,346,333	307,901,718	13.46%
8	356 Overhead Conductors & Devices	164,866,640	716,080	164,150,560	158,658,802	3.46%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	856,499	0.00%
11	359 Roads and Trails	2,519,641	44,906	2,474,735	2,474,735	0.00%
12	**Total Transmission Plant**	892,666,069	2,462,687	890,203,382	837,031,415	6.35%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	13,863,365	601	13,862,764.55	11,205,930	23.71%
16	361 Structures and Improvements	24,747,117	1,249,523	23,497,593.87	19,013,324	23.58%
17	362 Station Equipment	241,936,315	4,585,660	237,350,654.41	210,105,276	12.97%
18	363 Storage Battery Equipment	-			-	-
19	364 Poles, Towers, and Fixtures	303,499,563	412,431	303,087,131.98	289,929,593	4.54%
20	365 Overhead Conductors & Devices	125,429,103	495,528	124,933,575.18	121,222,693	3.06%
21	366 Underground Conduit	131,527,494	550,601	130,976,893.54	123,419,017	6.12%
22	367 Undergrnd Conductors & Devices	223,577,345	3,658,831	219,918,514.16	209,374,727	5.04%
23	368 Line Transformers	225,417,395	907,339	224,510,055.33	218,413,890	2.79%
24	369 Services	141,893,470	249,781	141,643,689.82	132,820,840	6.64%
25	370 Meters	55,235,478	96,955	55,138,522.67	55,328,396	-0.34%
26	371 Installations on Cust. Premises	-			-	-
27	372 Leased Property on Cust. Premises	-			-	-
28	373 Street Lighting and Signal Systems	58,050,553	19,872.21	58,030,680.82	55,056,793	5.40%
29	**Total Distribution Plant**	1,545,177,197	12,227,121	1,532,950,076	1,445,890,479	6.02%
30						
31	**General Plant**					
32	389 Land and Land Rights	689,633	506,968.71	182,664.77	689,633	-73.51%
33	390 Structures and Improvements	10,702,478		10,702,478.14	10,196,509	4.96%
34	391 Office Furniture and Equipment	1,825,992		1,825,992.33	2,153,929	-15.23%
35	392 Transportation Equipment	57,055,441	229,388.89	56,826,051.77	54,119,874	5.00%
36	393 Stores Equipment	847,483		847,482.90	763,276	11.03%
37	394 Tools, Shop & Garage Equipment	9,140,210	3,270.49	9,136,939.35	8,334,977	9.62%
38	395 Laboratory Equipment	1,249,840		1,249,839.63	1,413,114	-11.55%
39	396 Power Operated Equipment	5,296,428		5,296,427.80	4,466,803	18.57%
40	397 Communication Equipment	40,650,836	2,050,053.67	38,600,782.08	35,194,121	9.68%
41	398 Miscellaneous Equipment	2,194,810		2,194,810.15	2,063,171	6.38%
42	399 Other Tangible Equipment	-			-	-
43	**Total General Plant**	129,653,151	2,789,682	126,863,469	119,395,408	6.25%
44	**Total Plant in Service**	3,856,664,777	20,566,048	3,836,098,729	3,666,282,896	4.63%
45						
46	4101 El Plant Allocated from Common	105,681,705		105,681,705	100,312,169	5.35%
47	103 Experimental Electric Plant Unclassified	1,631,264		1,631,264	1,631,264	0.00%
48	105 El Plant Held for Future Use	4,873,985		4,873,985	4,892,457	(0.00)
49	107 El Construction Work in Progress	61,701,808	399,790	61,302,017	66,585,035	-7.93%
50						
51						
52	**TOTAL ELECTRIC PLANT**	$ 4,030,553,539	$ 20,965,838	$ 4,009,587,701	$ 3,839,703,822	4.42%

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

	CONSOLIDATED PLANT IN SERVICE	December 31, 2019	December 31, 2018
1			
2	Montana Electric	$ 3,836,098,729	$ 3,666,282,896
3	Yellowstone National Park	20,566,048	20,268,356
4	Montana Natural Gas (Includes CMP)	878,523,540	822,869,563
5	Common	156,276,853	147,639,934
6	Townsend Propane	1,523,174	1,519,564
7	South Dakota Electric	919,455,466	903,543,099
8	South Dakota Natural Gas	214,087,657	190,186,412
9	South Dakota Common	65,126,233	59,390,829
10	Asset Retirement Obligation	28,419,923	28,635,029
11	**TOTAL PLANT**	$ 6,120,077,623	$ 5,840,335,682

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	$ 427,560,197	$ 111,528,717		$ 111,528,717	$ 97,855,936	2.94%
4							
5	Nuclear Production	-	-			-	-
6							
7	Hydraulic Production	553,226,100	128,864,987	-	128,864,987	35,190,602	2.00%
8							
9	Other Production	284,920,766	69,459,016	2,237,525	67,221,491	57,569,807	3.61%
10							
11	Transmission	892,666,069	362,659,115	2,196,161	360,462,954	352,995,524	2.95%
12							
13	Distribution	1,544,583,588	713,224,521	5,249,318	707,975,202	677,189,264	3.12%
14							
15	General and Intangible	150,839,723	82,367,822	679,816	81,688,006	72,245,091	7.27%
16							
17	Common	105,680,185	25,366,994	-	25,366,994	23,338,572	5.57%
18							
19							
20	**Total Accum Depreciation**	$ 3,959,476,627	$ 1,493,471,171	$ 10,362,821	$ 1,483,108,350	$ 1,316,384,796	3.11%
21							
22							
23							

24	**Consolidated**	December 31,	
25	**Accumulated Depreciation**	2019	2018
26			
27	Montana Electric	$1,457,741,356	$1,293,046,224
28	Yellowstone National Park	10,362,821	9,920,070
29	Montana Natural Gas (Includes CMP)	359,369,848	340,714,954
30	Common	39,758,905	36,559,425
31	Townsend Propane	965,806	933,035
32	South Dakota Electric	308,635,918	309,296,489
33	South Dakota Natural Gas	96,070,624	93,048,967
34	South Dakota Common	18,924,500	16,666,196
35	Acquisition Writedown	45,981,130	48,685,620
36	Basin Creek Capital Lease	27,141,417	25,130,941
37	FIN 47	5,934,936	5,318,160
38	CWIP-Capital Retirement Clearing	-6,072,919	-5,759,985
39	**Total Consolidated Accum Depreciation**	$2,364,814,342	$2,173,560,096

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	$ 1,553,012	$ -	$ 1,553,012	$ 2,084,293	-25.49%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	5,635,710		5,635,710	5,230,695	7.74%
9	Transmission Plant	5,866,104		5,866,104	4,536,697	29.30%
10	Distribution Plant	15,443,597		15,443,597	13,175,738	17.21%
11						
12						
13	**Total MT Materials and Supplies**	$ 28,498,423	$ -	$ 28,498,423	$ 25,027,423	13.87%
14						
15						

16	**Consolidated**	December 31,	
17	**Fuel Stock**	2019	2018
18			
19	Montana Electric	$1,553,012	$2,084,293
20	South Dakota	4,801,495	4,849,285
21			
22	**Total Fuel Stock**	$6,354,506	$6,933,578
23			
24			
25			

26	**Consolidated**	December 31,	
27	**Materials and Supplies**	2019	2018
28			
29	Montana Electric	26,945,411	$22,943,130
30	Montana Natural Gas	5,221,181	4,130,070
31	South Dakota	10,027,461	9,421,249
32			
33	**Total Consolidated Materials and Supplies**	42,194,053	$36,494,449

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC

Commission Accepted - Most Recent		% Capital Structure	% Cost Rate	Weighted Cost
Regulated Electric Transmission, Distribution and Production Utility				
Docket Number:	2018.02.012			
Order Number :	7604u			
Effective Date:	December 20, 2019			
Common Equity		49.38%	9.65%	4.77%
Long Term Debt		50.62%	4.26%	2.16%
TOTAL		100.00%		6.92%
Colstrip Unit 4				
Docket Number:	2018.02.012			
Order Number :	7604u			
Effective Date:	December 20, 2019			
Common Equity		50.00%	10.00%	5.00%
Long Term Debt		50.00%	6.50%	3.25%
TOTAL		100.00%		8.25%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(Decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 202,120,237	$ 196,960,321	2.62%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	143,573,417	148,108,959	-3.06%
6	Amortization, Net	34,025,653	31,026,389	9.67%
7	Other Noncash Charges to Net Income, Net	12,601,984	12,498,512	0.83%
8	Deferred Income Taxes, Net	(15,202,199)	(15,652,483)	2.88%
9	Investment Tax Credit Adjustments, Net	(11,504)	(32,790)	64.92%
10	Change in Operating Receivables, Net	(734,853)	8,967,155	-108.19%
11	Change in Materials, Supplies & Inventories, Net	(3,034,752)	1,616,538	-287.73%
12	Change in Operating Payables & Accrued Liabilities, Net	(22,950,788)	20,928,888	-209.66%
13	Allowance for Funds Used During Construction (AFUDC)	(5,767,108)	(4,164,801)	-38.47%
14	Change in Other Assets & Liabilities, Net	(49,866,185)	(8,812,717)	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,490,895)	(1,999,261)	-24.59%
17	Change in Regulatory Assets	3,192,037	(8,581,074)	137.20%
18	Change in Regulatory Liabilities	864,406	1,933,880	-55.30%
19	**Net Cash Provided by Operating Activities**	296,319,449	382,797,517	-22.59%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(315,726,633)	(302,398,259)	-4.41%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(135,049)	(2,500,000)	94.60%
24	Proceeds from Sale of Assets	-	70,671	-100.00%
25	**Net Cash Used in Investing Activities**	(315,861,683)	(304,827,588)	-3.62%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	150,000,000	-	100.00%
29	Line of Credit Borrowings, Net	-	308,000,000	-100.00%
30	Proceeds From Issuance of Common Stock, Net	-	44,796,104	-100.00%
31	Payments for Retirement of:			
32	Repayments of Short Term Borrowings, Net	-	(319,555,991)	100.00%
33	Line of Credit Repayments, Net	(19,000,000)	-	-
34	Dividends on Common Stock	(115,126,908)	(109,202,079)	-5.43%
35	Other Financing Activities:			
36	Debt Financing Costs	(1,114,915)	(90,898)	>-300.00%
37	Treasury Stock Activity	1,431,891	2,248,640	-36.32%
38	**Net Cash Used in Financing Activities**	16,190,069	(73,804,224)	121.94%
39	**Net Increase/Decrease in Cash and Cash Equivalents**	(3,352,165)	4,165,704	-180.47%
40	**Cash and Cash Equivalents at Beginning of Year**	13,500,593	9,334,889	44.63%
41	**Cash and Cash Equivalents at End of Year**	$ 10,148,428	$ 13,500,593	-24.83%
42				
43	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
44	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
45	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
46	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
47				
48				
49				
50				
51				
52				

Sch. 24

MONTANA LONG TERM DEBT 2019

Line	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
2	**First Mortgage Bonds**								
4	5.71% Series ($55M), Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
5	5.01% Series ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
6	4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
7	4.30% Series($40M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
8	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	730,647	4.87%
9	3.99% Series($35M), Due 2028	12/19/13	12/19/28	35,000,000	34,836,556	35,000,000	3.99%	1,409,343	4.03%
10	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,743,514	450,000,000	4.18%	19,570,295	4.35%
11	3.11% Series($75M), Due 2025	06/23/15	07/01/25	75,000,000	74,563,893	75,000,000	3.11%	2,746,650	3.66%
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11%	5,367,425	4.29%
13	4.03% Series ($250M) Due 2047	11/06/17	11/06/47	250,000,000	248,817,402	250,000,000	4.03%	10,644,517	4.26%
14	3.98% Series($50M), Due 2049	06/26/19	06/26/49	50,000,000	49,538,281	50,000,000	3.98%	2,005,288	4.01%
15	3.98% Series($150M), Due 2049	09/17/19	09/17/49	100,000,000	99,493,713	100,000,000	3.98%	3,996,883	4.00%
16	**Total First Mortgage Bonds**			$ 1,416,000,000	$ 1,406,094,317	$ 1,416,000,000		$ 62,444,577	4.41%
18	**Pollution Control Bonds**								
19	2.00% Series ($144.7M), Due 2023	08/11/16	08/01/23	$ 144,660,000	$ 138,906,956	$ 144,660,000	2.000%	$ 3,627,593	2.51%
21	**Total Pollution Control Bonds**			$ 144,660,000	$ 138,906,956	$ 144,660,000		$ 3,627,593	2.51%
23	**Other Long-Term Debt**								
24	New Market Tax Credit Financing - New G.O Bldg	07/01/14	07/01/46	$ 26,976,900	$ 26,292,348	$ 26,976,900	1.146%	$ 353,344	1.31%
26	**Total Other Long Term Debt**			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 353,344	1.31%
28	**TOTAL LONG TERM DEBT**			$ 1,587,636,900	$ 1,571,293,621	$ 1,587,636,900		$ 66,425,514	4.18%

31 This schedule does not reflect our obligations under capital lease which total $19,638,840.

Sch. 25 — PREFERRED STOCK

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

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	50,334,208	$39.10				$63.91	$59.76	
February	50,409,337	39.60				68.54	63.07	
March	50,439,805	39.45	$1.45	0.575		71.30	68.85	
April	50,440,459	39.63				70.70	67.56	
May	50,441,006	40.13				72.82	68.98	
June	50,442,844	39.85	0.94	0.575		73.84	71.48	
July	50,443,642	40.03				73.39	69.92	
August	50,444,305	40.21				72.44	68.21	
September	50,446,009	39.74	0.43	0.575		76.05	72.75	
October	50,446,875	40.08				75.35	72.52	
November	50,447,508	40.50				73.22	68.11	
December	50,452,231	40.42	1.19	0.575		72.71	69.74	
TOTAL Year End	50,428,560	$40.42	$4.01	$2.30	42.64%	$71.67		17.9

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2019.

Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
	Rate Base			
101	Plant in Service	$4,273,987,140	$4,015,898,560	6.43%
108	Accumulated Depreciation	(1,400,666,840)	(1,302,896,274)	-7.50%
Net Plant in Service		$2,873,320,300	$2,713,002,286	5.91%
	Additions:			
154, 156	Materials & Supplies	$21,151,359	$18,235,903	15.99%
165	Prepayments			
	Other Additions	20,232,633	21,985,169	-7.97%
Total Additions		$41,383,992	$40,221,072	2.89%
	Deductions:			
190	Accumulated Deferred Income Taxes	$128,784,379	$99,729,697	29.13%
252	Customer Advances for Construction	42,189,473	37,794,112	11.63%
255	Accumulated Def. Investment Tax Credits			
	Other Deductions	110,187,766	109,261,373	0.85%
Total Deductions		$281,161,619	$246,785,182	13.93%
Total Rate Base		$2,633,542,674	$2,506,438,176	5.07%
Net Earnings		$ 161,479,214	$ 152,883,262	5.62%
Rate of Return on Average Rate Base		6.132%	6.100%	0.52%
Rate of Return on Average Equity 1/		7.839%	7.190%	9.03%
	Major Normalizing and Commission Ratemaking Adjustments			
	Rate Schedule Revenues	$723,398	$4,208,259	-82.81%
	PCCAM Gain July 2017-December 2017 2/		(3,345,857)	100.00%
	PCCAM Loss July 2018 - December 2018 Recovery in 2019 3/	(4,194,588)		-
	Non-Allowables:			
	Advertising	1,598,759	421,513	279.29%
	Dues, Contributions, Other	117,435	141,041	-16.74%
	Associated Income Taxes 4/	1,237,120	3,225,685	-61.65%
Total Adjustments		($517,877)	$4,650,641	-111.14%
Revised Net Earnings		$160,961,337	$157,533,903	2.18%
	Rate Base Adjustment			
	Stipulation with MCC 5/	($17,339,332)	($18,204,999)	4.76%
Revised Rate Base		$2,616,203,342	$2,488,233,177	5.14%
Adjusted Rate of Return on Average Rate Base		6.152%	6.331%	-2.82%
Adjusted Rate of Return on Average Equity 1/		7.791%	7.211%	8.04%

1/ Return on Equity calculated using the capital structure approved in Docket No. D2018.2.12.

2/ PCCAM became effective with Order No. 7563c in Docket No. D2017.5.39. It replaced the former electricity supply tracker beginning July 1, 2017. Supply revenues net of expenses from July 1, 2017 thru December 31, 2017 were removed because they did not occur during 2018.

3/ Normalizing adjustment for the recovery of electric supply costs consistent with the change in statute removing the PCCAM deadband and removing QF costs from the 90% / 10% sharing calculation. These costs were incurred in 2018 and recovered in 2019.

4/ Associated Income taxes include an Interest synchronization adjustment based upon the approved capital structure in Docket No.D2018.2.12.

5/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting two-thirds of the $38.8 million allocated to electric as a rate base reduction.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	0	0	-
4	Cost of Refinancing Debt	18,487,313	19,978,328	-7.46%
5	Fuel Stock	1,745,320	2,006,841	-13.03%
6				-
7				
8	**Total Other Additions**	$20,232,633	$21,985,169	-7.97%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$4,391,763	$3,858,309	13.83%
12	Gross Cash Requirements	36,283,878	34,589,242	4.90%
13	Regulatory Liability (TCJA)	69,512,124	70,813,822	-1.84%
14	MPSC/MCC Taxes	$0	$0	-
15				
16	**Total Other Deductions**	$110,187,766	$109,261,373	0.85%
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
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)	$ 3,941,780,434
5	103	Experimental Electric Plant Unclassified	1,631,264
6	105	Plant Held for Future Use	4,873,985
7	107	Construction Work in Progress	61,302,017
8	114	Plant Acquisition Adjustments	451,564,554
9	151-163	Materials & Supplies	28,498,423
10		(Less):	
11	108, 111, 115	Depreciation & Amortization Reserves	1,529,385,301
12	252	Customer Advances	44,106,047
13	**NET BOOK COSTS**		2,916,159,329
14			
15		**Revenues & Expenses**	
16			
17	400	Operating Revenues	817,534,068
18			
19	**Total Operating Revenues**		817,534,068
20			
21	401-402	Other Operating Expenses (including regulatory amortizations)	389,614,839
22	403-407	Depreciation & Amortization Expenses	118,859,427
23	408.1	Taxes Other than Income Taxes	134,749,863
24	409-411	Federal & State Income Taxes	12,830,726
25	411.8	SO2 Allowances	(1)
26			
27	**Total Operating Expenses**		656,054,854
28	**Net Operating Income**		161,479,214
29			
30	415-421.1	Other Income	3,742,230
31	421.2-426.5	Other Deductions	1,013,432
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 164,208,012
33			
34		**Average Customers (Intrastate Only)**	
35		Residential	303,046
36		Commercial & Industrial	70,350
37		Other (including interdepartmental)	4,051
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		377,447
40			
41		**Other Statistics (Intrastate Only)**	
42		Average Annual Residential Use (Kwh)	8,511
43		Average Annual Residential Cost per (Kwh)	$0.120
44		Average Residential Monthly Bill	$85.21
45			
46		Plant in Service (Gross) per Customer	$10,443

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	476	114	5	595
2	Alberton	420	392	90	13	495
3	Alder	103	226	91	21	338
4	Amsterdam	180	134	38	7	179
5	Anaconda	9,298	4,350	874	54	5,278
6	Armington	-	1	-	-	1
7	Arrow Creek	-	4	4	-	8
8	Augusta	309	263	114	4	381
9	Avon	111	95	64	3	162
10	Barber	-	47	11	-	58
11	Basin	212	168	77	2	247
12	Bearcreek	79	61	23	3	87
13	Belfry	218	171	63	13	247
14	Belgrade	7,389	8,538	2,276	101	10,915
15	Belt	597	642	251	14	907
16	Benchland	-	6	6	-	12
17	Big Sandy	598	333	143	5	481
18	Big Sky	2,308	3,982	932	28	4,942
19	Big Timber	1,641	1,250	423	29	1,702
20	Billings	104,170	49,521	8,757	676	58,954
21	Black Eagle	904	455	178	15	648
22	Bonner	1,663	79	54	2	135
23	Boulder	1,183	855	266	25	1,146
24	Box Elder	87	144	64	10	218
25	Bozeman	37,280	32,309	6,749	429	39,487
26	Brady	140	84	39	5	128
27	Bridger	708	456	177	15	648
28	Broadview	192	227	160	2	389
29	Buffalo	-	-	3	5	8
30	Butte	33,525	15,137	2,691	275	18,103
31	Cameron	-	397	130	5	532
32	Canyon Creek	-	195	44	6	245
33	Carter	58	115	71	4	190
34	Cascade	685	1,137	351	28	1,516
35	Centerville	-	13	11	1	25
36	Checkerboard	-	54	9	1	64
37	Chester	847	475	315	17	807
38	Chinook	1,203	804	322	16	1,142
39	Choteau	1,684	1,000	382	26	1,408
40	Churchill	902	711	142	26	879
41	Clancy	1,661	891	170	9	1,070
42	Clinton	1,052	106	38	2	146
43	Coffee Creek	-	54	26	1	81
44	Collins	-	1	5	-	6
45	Colstrip	2,214	969	219	36	1,224
46	Columbus	1,893	1,032	350	20	1,402
47	Conrad	2,570	1,255	478	28	1,761
48	Corbin	-	1	2	-	3
49	Corvallis	976	854	184	36	1,074
50	Craig	43	94	40	7	141
51	Custer	159	1	3	-	4

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Darby	720	804	261	18	1,083
2	De Borgia	78	162	37	2	201
3	Deer Lodge	3,111	2,062	601	69	2,732
4	Denton	255	180	83	1	264
5	Dillon	4,134	2,070	590	62	2,722
6	Divide	-	71	15	4	90
7	Dodson	124	115	71	5	191
8	Drummond	309	368	220	30	618
9	Dutton	316	239	118	3	360
10	East Helena	1,984	3,093	439	25	3,557
11	Edgar	114	169	57	8	234
12	Elliston	219	206	63	4	273
13	Ennis	838	1,894	604	39	2,537
14	Fairfield	708	408	163	30	601
15	Fishtail	-	49	5	-	54
16	Florence	765	418	152	16	586
17	Floweree	-	105	61	1	167
18	Fort Belknap	1,293	431	100	24	555
19	Fort Benton	1,464	839	372	33	1,244
20	Fort Harrison	-	-	93	3	96
21	Fromberg	438	319	78	10	407
22	Gallatin Gateway	856	768	241	14	1,023
23	Gardiner	875	813	317	12	1,142
24	Garrison	96	122	62	5	189
25	Geraldine	261	286	155	2	443
26	Geyser	87	67	36	3	106
27	Gildford	179	89	65	2	156
28	Glasgow	3,250	1,671	733	60	2,464
29	Glasgow Air Base		1	1	-	2
30	Gold Creek	-	79	38	4	121
31	Grantsdale	-	20	3	1	24
32	Great Falls	58,505	29,789	5,416	370	35,575
33	Greycliff	112	52	30	10	92
34	Hall	-	287	85	18	390
35	Hamilton	4,348	5,598	1,471	114	7,183
36	Hardin	3,505	1,414	461	23	1,898
37	Harlem	808	451	207	25	683
38	Harlowton	997	677	289	10	976
39	Harrison	137	188	61	23	272
40	Haugan	-	86	38	2	126
41	Havre	10,026	4,922	1,233	187	6,342
42	Helena	53,457	25,824	5,327	421	31,572
43	Hingham	118	108	74	2	184
44	Hinsdale	217	137	52	5	194
45	Hobson	215	166	59	8	233
46	Huson	210	140	37	2	179
47	Hysham	312	-	1	-	1
48	Inverness	55	42	27	1	70
49	Jardine	57	1	1	-	2
50	Jeffers	-	3	1	-	4
51	Jefferson City	472	353	58	4	415
52	Joliet	595	500	140	17	657

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Joplin	157	97	49	2	148
2	Judith Gap	126	89	53	6	148
3	Kremlin	98	70	37	1	108
4	Laurel	6,718	3,258	519	23	3,800
5	Lavina	187	196	108	11	315
6	Lennep	-	20	13	1	34
7	Lewistown	5,910	3,343	924	57	4,324
8	Lincoln	1,013	1,084	286	13	1,383
9	Livingston	7,044	4,985	1,191	66	6,242
10	Logan	99	58	25	2	85
11	Lohman	-	28	31	7	66
12	Lolo	3,892	1,586	206	17	1,809
13	Loma	85	68	42	4	114
14	Lothair	-	16	13	-	29
15	Malta	1,997	1,324	512	46	1,882
16	Manhattan	1,520	1,302	374	90	1,766
17	Martinsdale	64	127	84	15	226
18	Marysville	80	77	38	2	117
19	Maxville	130	4	1	-	5
20	McAllister	-	250	59	7	316
21	Melrose	-	2	1	-	3
22	Melstone	96	159	284	19	462
23	Melville	-	68	51	4	123
24	Milltown	-	76	21	3	100
25	Missoula	66,788	38,533	6,722	604	45,859
26	Moccasin	-	47	35	1	83
27	Molt	-	33	34	-	67
28	Monarch	-	329	56	3	388
29	Montana City	2,715	1,161	221	4	1,386
30	Moore	193	109	44	4	157
31	Musselshell	60	62	28	1	91
32	Nashua	290	196	66	3	265
33	Neihart	51	199	41	1	241
34	Nevada City	-	-	7	-	7
35	Norris	-	55	47	2	104
36	Nye	-	16	2	1	19
37	Paradise	163	160	61	8	229
38	Park City	983	445	84	6	535
39	Philipsburg	820	1,909	363	24	2,296
40	Plains	1,048	1,701	484	25	2,210
41	Pompey's Pillar		1	-	-	1
42	Pony	118	146	30	6	182
43	Power	179	90	46	2	138
44	Pray	681	27	1	-	28
45	Radersburg	66	84	27	1	112
46	Ramsay	-	69	32	-	101
47	Raynesford	-	67	39	3	109
48	Red Lodge	2,125	2,051	423	26	2,500
49	Reedpoint	193	164	62	3	229
50	Ringling	-	43	27	3	73
51	Roberts	-	3	-	-	3
52	Rocker	-	63	24	2	89

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Rockvale	-	2	1	-	3
2	Roscoe	15	88	11	-	99
3	Roundup	1,788	1,082	398	18	1,498
4	Rudyard	258	149	69	2	220
5	Ryegate	245	148	70	7	225
6	Saco	197	167	101	2	270
7	Saint Marie	264	287	51	3	341
8	Saint Regis	319	523	193	13	729
9	Saltese	-	38	22	1	61
10	Sand Coulee	212	153	49	4	206
11	Sapphire Village	-	67	8	-	75
12	Shawmut	42	55	38	3	96
13	Sheridan	642	969	267	45	1,281
14	Silesia	96	42	9	-	51
15	Silverbow	-	11	8	1	20
16	Springdale	42	39	12	6	57
17	Square Butte	-	36	20	1	57
18	Stanford	401	339	217	7	563
19	Stevensville	1,809	2,236	620	71	2,927
20	Stockett	169	161	60	2	223
21	Sumatra	-	-	4	-	4
22	Superior	812	923	273	26	1,222
23	Taft	-	-	2	-	2
24	Tampico	-	9	5	-	14
25	Thompson Falls	1,313	1,154	372	30	1,556
26	Three Forks	1,869	1,518	544	67	2,129
27	Toston	108	52	40	22	114
28	Townsend	1,878	1,388	386	22	1,796
29	Tracy	-	92	12	4	108
30	Turah	306	26	2	-	28
31	Twin Bridges	375	318	170	29	517
32	Twodot	-	55	49	6	110
33	Ulm	738	425	125	10	560
34	Utica	-	2	5	1	8
35	Valier	509	369	181	40	590
36	Vaughn	658	244	53	6	303
37	Victor	745	816	279	26	1,121
38	Virginia City	190	204	106	1	311
39	Wagner	-	46	25	1	72
40	Walkerville	675	257	31	3	291
41	Warm Springs	-	-	3	-	3
42	Washoe	-	7	2	-	9
43	West Yellowstone	1,271	2	10	-	12
44	White Sulphur Springs	939	817	394	58	1,269
45	Whitehall	1,038	1,031	305	57	1,393
46	Wickes	-	1	-	-	1
47	Williamsburg	-	1	1	-	2
48	Willow Creek	210	146	63	21	230
49	Windham	-	48	33	2	83
50	Winston	147	147	51	3	201

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Wolf Creek	-	423	169	11	603
2	Yellowstone Club	-	556	5	-	561
3	Zurich	-	106	87	13	206
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	**Total**	503,001	303,046	68,865	5,536	377,447

1/ Customer populations represent an average of the 12 month period from 01/01/19 through 12/31/19. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	145	139	142
5	Finance	154	154	154
6	Distribution	443	449	446
7	Transmission	312	312	312
8	Supply	120	125	123
9	Legal	27	27	27
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,203	1,208	1,206

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2020 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Distribution - Wildfire Mitigation and Refurbishment	$10,000,000	$10,000,000
4	MT Transmission - TFalls Burke A&B 115 kV	$8,941,374	8,941,374
5	MT Distribution - Midway Substation	$8,251,749	8,251,749
6	MT Distribution - LED Street Light Program	7,399,975	7,399,975
7	MT Transmission -CAISO Energy Imbalance Market	6,540,258	6,540,258
8	MT Transmission - Rainbow - Two Dot 100 kv line recond	5,448,011	5,448,011
9	Mt Transmission - Meadow to Midway Recond	5,051,073	5,051,073
10	MT Transmission - Helena Valley 100kV 2nd	4,904,135	4,904,135
11	MT Distribution - Replace Open Wires Secondary	4,000,000	4,000,000
12	MT Transmission - Livingston - Emigrant recond	3,301,173	3,301,173
13	MT Transmission - Judith Gap Auto 100kV R	3,201,065	3,201,065
14	Montana Distribution - Montana St Substation Rework	3,033,215	3,033,215
15	MT Distribution - LED Proactive Yard Light Program	3,000,308	3,000,308
16	MT Distribution - LED Yard Lights	3,000,000	3,000,000
17	MT Transmission - Bonner - Mill Creek A pole replace	2,885,368	2,885,368
18	MT Transmission - East Helena Switchyard sub	2,802,404	2,802,404
19	MT Transmission - Mill Creek Bank 3 sub	2,356,071	2,356,071
20	MT Transmission -ETS Butte Mill Creed sub	2,241,335	2,241,335
21	MT Transmission - Helena Valley Sub	2,238,601	2,238,601
22	MT Distribution - Billings Shiloh Bank Two sub	2,129,320	2,129,320
23	MT Transmission - Wilsal 230 KV 25 MV sub	1,835,603	1,835,603
24	MT Distribution - Big Sky Midway Feeders	1,798,040	1,798,040
25	MT Transmission - East Gallatin Upgrade sub	1,772,725	1,772,725
26	MT Distribution - Great Falls Southside Substation	1,757,866	1,757,866
27	MT Transmission - Great Falls Switchyard	1,690,136	1,690,136
28	MT Distribution - Underground cable replace Bozeman Div	1,581,051	1,581,051
29	MT Transmission - Roundup Pump TapRebuild poles	1,422,445	1,422,445
30	MT Transmission - Billings Alkali CR 230kv sub	1,342,471	1,342,471
31	MT Transmission - Bozeman Riverside 50kV Breaker sub	1,183,656	1,183,656
32	MT Distribution - Reliability Circuit Refurbishment	1,000,000	1,000,000
33	19 MT AMI Metering & Infrastructure	1,000,000	1,000,000
34	SD Distribution - Yankton sbsq E Sub Build	1,557,301	
35	SD Distribution - HUR sbsq Harrold Sub Rebuild	1,500,389	
36	SD Distribution - HUR Blunt-Harrold Electric Storage	1,475,618	
37	SD Distribution - Yankton Wagner NE Sub Rebuild	1,306,325	
38	SD Distribution - Yankton Menno JCT-Relay and BU	1,066,904	
39			
40	All Other Projects < $1 Million Each	111,481,375	86,620,267
41			
42	**Total Electric Utility Construction Budget**	225,497,340	193,729,695
43			
44	**Natural Gas Operations**		
45			
46	MT Transmission - Belfry Comp Station	10,054,668	10,054,668
47	MT Distribution - Butte Division Base Gas One Plan	4,603,862	4,603,862
48	MT Transmission - Morel-Butte Replacement	1,572,855	1,572,855
49	MT Transmission - Helena Last Chance Chap	1,345,063	1,345,063
50			
51	All Other Projects < $1 Million Each	43,548,626	32,735,060
52			
53	**Total Natural Gas Utility Construction Budget**	61,125,074	50,311,508
54			
55	**Common**		
56	SD - Facilities Yankton Design and Build	4,893,070	
57	MT - Fleet vehicles and equipment	4,400,000	4,400,000
58	SD - Fleet vehicles and equipment	2,100,000	
59	MT - Gas Trans SCADA Upgrade Hardware&Software	1,446,807	1,446,807
60	MT - Telecom MPLS Core Network	1,283,609	1,283,609
61			
62	All Other Projects < $1 Million Each	17,227,229	12,964,780
63	(Includes BT, Communications, Facilities, Customer Services)		
64			
65	**Total Common Utility Construction Budget**	31,350,714	20,095,195
66			
67	**MT/SD Generation**		
68	SD - Huron Generating Station	40,000,000	
69	MT - CU4 Capital Items	10,764,581	10,764,581
70	MT - Hydro Hauser U2 Turbine-Gen Upgrade	3,078,053	3,078,053
71	MT - Hydro Black Eagle U1 Turbine Upgrade	2,756,364	2,756,364
72	MT - Hydro Madison U2 Turb-Gen Upgrade	2,099,804	2,099,804
73	MT - Hydro Madison U3 Turb-Gen Upgrade	2,099,804	2,099,804
74	MT- Hydro Madison U4 Turb-Gen Upgrade	2,099,804	2,099,804
75	MT - Hydro Madison U1 Turb-Gen Upgrade	2,099,804	2,099,804
76	SD - Generation Big Stone	1,716,044	
77	SD - Generation Mobile Fleet Expansion	1,308,528	
78	MT - Hydro Ryan U1 Generator Rewind	1,196,347	1,196,347
79	MT - Hydro Ryan U1 Turbine Upgrade	1,086,164	1,086,164
80	MT - Hydro Holter High Tension Flr Upgrade	1,062,884	1,062,884
81			
82	All Other Projects < $1 Million Each	9,358,547	7,444,335
83			
84	**Total MT/SD Generation**	80,726,729	35,787,945
85	**TOTAL CONSTRUCTION BUDGET**	$398,699,857	$299,924,343

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	30	8:00	2,078	722,584	112,106
2	February	5	19:00	2,228	633,360	118,619
3	March	4	8:00	2,198	762,268	91,205
4	April	29	8:00	1,832	640,074	66,576
5	May	1	8:00	1,808	589,720	128,759
6	June	17	16:00	1,924	576,501	135,844
7	July	23	17:00	2,195	617,291	98,075
8	August	5	17:00	2,202	661,246	97,091
9	September	4	17:00	2,092	665,144	105,059
10	October	30	8:00	2,044	625,919	138,135
11	November	11	19:00	1,992	673,802	87,116
12	December	16	19:00	1,891	699,190	115,985
13	**TOTALS**				7,867,099	1,294,570
14		**Montana Peak and Energy**				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			SAME AS ABOVE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,403,130		
3	Nuclear	-	**Sales to Ultimate Consumers**	6,101,277
4	Hydro - Conventional	2,753,679	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	378,812	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	4,535,621	Non-Requirement Sales	1,294,570
9	**Purchases**	3,328,473	**Sales for Resale**	1,294,570
10	Power Exchanges			
11	Received	554,285		
12	Delivered	551,280	Energy Furnished w/o Charge	-
13	**Net Power Exchanges**	3,005	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	10,711,984	Electric Department	
16	Delivered	10,711,984	(Less) Station Use	-
17	**Net Transmission Wheeling**	-	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	471,252
19	**TOTAL SOURCES**	7,867,099	**TOTAL DISPOSITIONS**	7,867,099

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 21,391 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	1,403,130
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	224,039
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	120,862
4	Wind Generation	Two Dot	Two Dot, MT	11.3	33,911
5	Hydro Generation	Black Eagle	Great Falls, MT	20.9	142,208
6	Hydro Generation	Cochrane	Great Falls, MT	59.9	326,084
7	Hydro Generation	Hauser	Helena, MT	19.5	126,084
8	Hydro Generation	Holter	Helena, MT	38.4	344,893
9	Hydro Generation	Madison	Ennis, MT	9.0	51,327
10	Hydro Generation	Morony	Great Falls, MT	46.5	318,712
11	Hydro Generation	Mystic	Columbus, MT	11.3	57,802
12	Hydro Generation	Rainbow	Great Falls, MT	59.0	453,370
13	Hydro Generation	Ryan	Great Falls, MT	52.8	484,121
14	Hydro Generation	Thompson Falls	Thompson Falls, MT	92.4	449,078
15	Total Generation			832.9	4,535,621
16					
17		Source of capacity	Seller	Avg Monthly Billing Demand (MW)	Annual Energy (Mwh)
18	Qualifying Facility Purchases	Wind	71 Ranch	2.7	10,621
19	Qualifying Facility Purchases	Thermal	Billings Generation Inc.	62.4	459,719
20	Qualifying Facility Purchases	Wind	Big Timber Wind LLC	24.7	78,700
21	Qualifying Facility Purchases	Solar	Black Eagle Solar, LLC	2.0	5,774
22	Qualifying Facility Purchases	Hydro	Boulder Hydro	0.4	1,502
23	Qualifying Facility Purchases	Hydro	Bruce Rauner/Barney Creek	0.0	47
24	Qualifying Facility Purchases	Hydro	Bruce Rauner/Cascade Creek	0.1	185
25	Qualifying Facility Purchases	Thermal	Colstrip Energy Ltd/Montana One	40.4	287,903
26	Qualifying Facility Purchases	Wind	Cycle Horseshoe Bend Wind, LLC	0.0	2,191
27	Qualifying Facility Purchases	Wind	DA Winds	2.7	10,914
28	Qualifying Facility Purchases	Wind	Fairfield Wind, LLC	10.1	28,319
29	Qualifying Facility Purchases	Hydro	Flint Creek Hydroelectric, LLC	2.1	13,786
30	Qualifying Facility Purchases	Wind	Gordon Butte Wind, LLC	10.1	32,546
31	Qualifying Facility Purchases	Solar	Great Divide Solar, LLC	3.1	5,954
32	Qualifying Facility Purchases	Wind	Greenfield Wind, LLC	25.0	82,052
33	Qualifying Facility Purchases	Solar	Green Meadow Solar, LLC	3.2	5,223
34	Qualifying Facility Purchases	Hydro	Hanover Hydro Project	0.0	332
35	Qualifying Facility Purchases	Hydro	Hydrodynamics - South Dry Creek	2.3	4,274
36	Qualifying Facility Purchases	Hydro	Hydrodynamics - Strawberry Creek	0.4	1,142
37	Qualifying Facility Purchases	Hydro	Lower South Fork Hydro, LLC	1.1	629
38	Qualifying Facility Purchases	Solar	Magpie Solar, LLC	3.0	5,248
39	Qualifying Facility Purchases	Wind	Musselshell Wind Project 1, LLC	10.0	19,441
40	Qualifying Facility Purchases	Wind	Musselshell Wind Project 2, LLC	10.2	25,420
41	Qualifying Facility Purchases	Wind	Oversight Resources	2.7	9,814
42	Qualifying Facility Purchases	Hydro	Pine Creek	0.3	1,537
43	Qualifying Facility Purchases	Hydro	Pony Hydro	0.3	1,117
44	Qualifying Facility Purchases	Solar	River Bend Solar, LLC	3.0	2,951
45	Qualifying Facility Purchases	Hydro	Ross Creek Hydro	0.5	2,743
46	Qualifying Facility Purchases	Solar	South Mills Solar 1, LLC	3.2	4,362
47	Qualifying Facility Purchases	Hydro	State of Montana - DNRC/Broadwater Dam	10.5	54,985
48	Qualifying Facility Purchases	Wind	Stillwater Wind, LLC	79.1	257,288
49	Qualifying Facility Purchases	Wind	Two Dot Wind, Broadview East, LLC	1.6	4,356
50	Qualifying Facility Purchases	Wind	Two Dot Wind Martinsdale Wind Farm	0.7	992
51	Qualifying Facility Purchases	Wind	Two Dot Moe Wind	0.2	85
52	Qualifying Facility Purchases	Wind	Two Dot Wind Sheeps Valley	0.5	609
53	Qualifying Facility Purchases	Hydro	Wisconsin Creek, LLC	0.4	882
54	Subtotal			319.0	1,423,643

Sch. 34A	SOURCES OF MONTANA ELECTRIC SUPPLY (continued)				
		see descriptions below	Seller	Annual Peak (MW) 1/	Annual Energy (Mwh)
1	Purchased Power	SF	Avangrid Renewables, LLC		23,123
2	Purchased Power	SF	Avista Corporation		79,952
3	Purchased Power	SF	Basin Electric Power Cooperative		34,849
4	Purchased Power	LU	Basin Creek Energy Partners	52.0	170,522
5	Purchased Power	SF	Black Hills Power Inc.		1,045
6	Purchased Power	SF	Bonneville Power Administration		29,425
7	Purchased Power	SF	Capital Power		90
8	Purchased Power	LF	Citigroup Energy, Inc.		219,000
9	Purchased Power	SF	Clatskanie Peoples Utility District		155
10	Purchased Power	SF	EDF Trading North America, LLC		369,931
11	Purchased Power	SF	Energy Keepers, Inc.		23,784
12	Purchased Power	SF	ETC Endure Energy, LLC		667
13	Purchased Power	SF	Eugene Water & Electric Board		255
14	Purchased Power	SF	Exelon Generation Company, LLC		1,440
15	Purchased Power	SF	Idaho Power Company		4,593
16	Purchased Power	LU	Judith Gap Energy LLC	135.0	436,282
17	Purchased Power	SF	Macquarie Energy LLC		9,529
18	Purchased Power	SF	Morgan Stanley Capital Group, Inc.		26,830
19	Purchased Power	SF	PacifiCorp		14,446
20	Purchased Power	SF	Portland General Electric		111,121
21	Purchased Power	SF	Powerex Corp.		6,326
22	Purchased Power	SF	Puget Sound Energy		16,179
23	Purchased Power	SF	Rainbow Energy Marketing Corporation		19,065
24	Purchased Power	SF	Seattle City Light		23,211
25	Purchased Power	SF	Shell Energy North America		56,190
26	Purchased Power	SF	Snohomish County PUD		230
27	Purchased Power	SF	Tacoma Power		6,722
28	Purchased Power	LF	Talen Energy Marketing, LLC		80,800
29	Purchased Power	SF	Tenaska Power Services		2
30	Purchased Power	SF	The Energy Authority, Inc.		13,846
31	Purchased Power	LU	Tiber Montana, LLC	not available	53,456
32	Purchased Power	LF	TransAlta Energy Marketing (US), Inc		9,542
33	Purchased Power	LU	Turnbull Hydro, LLC	13.0	39,283
34	Purchased Power	SF	Western Area Power Administration		21,919
35	Subtotal			200.0	1,903,810
36	Reserve Sharing				1,020
37	Total Purchases				3,328,473

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		
Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
Colstrip Unit 3	4/27/2019	Economizer tube leak	34
	4/28/2019	Correct maintenance backlog	140
	5/4/2019	Original outage extended	52
	5/16/2019	Condenser tube leaks	104
	7/8/2019	Loss of generator hydrogen pressure	46
	7/17/2019	Replace boiler water circ pump	102
	9/29/2019	Condenser tube leaks	82
	10/12/19	Condenser tube leaks, raw water and aux steam tie ins	169
	11/29/2019	Economizer tube leaks	119
	12/23/2019	Economizer tube leaks	27
Colstrip Unit 4	1/1/2019	Feedwater heater repairs	16
	1/8/2019	Isolate aux transformer	23
	1/31/2019	Replace boiler water circulating pump	111
	3/24/2019	Loss of both 500 kv lines	20
	5/21/2019	Reserve shutdown	173
	6/9/2019	Economizer tube leaks	107
	6/15/2019	High boiler water sulfate levels	29
	10/13/2019	Raw water and aux steam tie ins	176
	12/5/2019	Economizer tube leaks	132

Only outages greater than 12 hours are reported.

We own 30% of Colstrip Unit 4 and have a reciprocal sharing agreement with the 30% owner of Colstrip Unit 3 in which we share equally in the ownership benefits and liabilities of each.

Sch. 34C	THERMAL GENERATION OUTAGE REPORT		
Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
DGGS Unit 1	4/16/2019	Annual outage maintenance	87
	5/12/2019	Generator seal replacements, collector box alignments	130
	9/10/2019	Pipeline supply gas outage	63
	10/30/2019	Battery bank testing and inlet filter changes	12
	11/5/2019	Breaker maintenance	12
DGGS Unit 2	4/8/2019	Borescope inspection	184
	4/22/2019	Generator inspection	89
	6/16/2019	Exciter diode failure	47
	7/27/2019	601 chip detect	54
	8/27/2019	Collector box seals	36
	9/10/2019	Pipeline supply gas outage	66
DGGS Unit 3	1/2/2019	Remove partial discharge wiring flex	13
	3/5/2019	GT-A EGT high decoupled	213
	4/1/2019	Borescope inspection	160
	4/26/2019	Generator inspection, bearing replacement	373
	5/22/2019	Cracked stage 2 LPT	1,010
	7/10/2019	High bearing temperature	129
	7/26/2019	High bearing temperature	82
	9/10/2019	Pipeline supply gas outage	63
	10/8/2019	Inlet filters plugged with snow	13

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

Sch. 34D	HYDRO GENERATION OUTAGE REPORT				
	Plant	**Unit Name**	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**Black Eagle**	BE1	1/7/2019	Repair shaft sleeve and packing	780
2		BE1	2/8/2019	Repair shaft sleeve and packing	495
3		BE1	6/5/2019	Generator bearings	675
4		BE1	7/24/2019	Vibration issues	52
5		BE1	9/9/2019	Turbine bearing, shaft sleeve	195
6		BE2	5/1/2019	Bearing cooling system	32
7		BE2	10/10/2019	Bearing maintenance	172
8		BE3	3/1/2019	Repair shaft sleeve and packing	626
9		BE3	5/9/2019	Bearing cooling system	21
10		BE3	6/17/2019	Replace staves in turbine bearing	30
11		BE3	10/17/2019	Turbine bearing shaft sleeve repair	484
12					
13	**Cochrane**	CCH1	10/14/2019	Replace head gate seals	80
14		CCH2	1/21/2019	Governor and exciter replacement	1,420
15		CCH2	3/21/2019	Governor and exciter commissioning	46
16		CCH2	12/5/2018	Governor and exciter commissioning	49
17		CCH2	8/6/2019	Turbine governor adjustment	53
18		CCH2	10/18/2019	Head gate seal work	131
19					
20	**Hauser**	HAU1	6/10/2019	Annual inspection and maintenance	79
21		HAU1	7/27/2019	Wildfire in area	70
22		HAU1	10/7/2019	Annual inspection and maintenance	97
23		HAU2	6/24/2019	Annual inspection and maintenance	127
24		HAU2	7/1/2019	Annual inspection and maintenance	28
25		HAU2	7/27/2019	Wildfire in area	66
26		HAU2	10/7/2019	Annual inspection and maintenance	108
27		HAU2	10/11/2019	Annual inspection and maintenance	1,950
28		HAU3	1/8/2019	Annual inspection and maintenance	55
29		HAU3	1/14/2019	Annual inspection and maintenance	26
30		HAU3	7/27/2019	Wildfire in area	66
31		HAU3	10/7/2019	Annual inspection and maintenance	103
32		HAU4	1/1/2019	Generator overhaul	3,105
33		HAU4	5/11/2019	Generator overhaul	73
34		HAU4	5/14/2019	Generator overhaul	44
35		HAU4	5/16/2019	Generator overhaul	151
36		HAU4	5/22/2019	Generator overhaul	19
37		HAU4	5/23/2019	Generator overhaul	18
38		HAU4	5/24/2019	Generator overhaul	119
39		HAU4	5/29/2019	Generator overhaul	20
40		HAU4	5/30/2019	Generator overhaul	476
41		HAU4	6/22/2019	Braking system work	44
42		HAU4	6/24/2019	Braking system indication failure	22
43		HAU4	6/26/2019	Brake adjustments	32
44		HAU4	7/27/2019	Wildfire in area	66
45		HAU4	10/7/2019	Annual inspection and maintenance	99
46		HAU5	1/21/2019	Transmission line reroute	74
47		HAU5	1/24/2019	Transformer breaker failure	151
48		HAU5	6/13/2019	Transformer bushing leaking oil	125
49		HAU5	7/27/2019	Wildfire in area	66
50		HAU5	10/7/2019	Annual inspection and maintenance	104
51					

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

Sch. 34D	HYDRO GENERATION OUTAGE REPORT				
	Plant	**Unit Name**	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**Hauser**	HAU6	1/21/2019	Transmission line reroute	74
2	(continued)	HAU6	1/24/2019	Annual inspection and maintenance	151
3		HAU6	6/13/2019	Transformer bushing leaking oil	124
4		HAU6	7/27/2019	Wildfire in area	66
5		HAU6	10/7/2019	Annual inspection and maintenance	104
6					
7	**Holter**	HLT1	9/9/2019	Annual inspection and maintenance	616
8		HLT1	10/5/2019	Annual inspection and maintenance	157
9		HLT2	3/7/2019	Replace brushes	23
10		HLT2	8/16/2019	Ground fault relay action	131
11		HLT3	2/15/2019	Annual inspection and maintenance	252
12		HLT3	6/1/2019	Generator ground	149
13		HLT4	3/11/2019	Annual inspection and maintenance	252
14					
15	**Madison**	MAD1	10/21/2019	Generator overhaul	1,819
16		MAD2	10/22/2019	Generator overhaul	1,718
17		MAD3	10/23/2019	Generator overhaul	1,719
18		MAD4	10/24/2019	Generator overhaul	1,719
19					
20	**Morony**	MOR1	6/10/2019	Bearing cooling system	76
21		MOR2	6/11/2018	Annual inspection and maintenance	153
22					
23	**Mystic**	MYS1	5/7/2019	Annual inspection and maintenance	316
24		MYS2	4/30/2019	Annual inspection and maintenance	164
25					
26	**Rainbow**	RNB9	4/8/2019	Annual inspection and maintenance	85
27					
28	**Ryan**	RYN1	12/9/2019	Major overhaul	544
29		RYN2	9/16/2019	Major overhaul	1,106
30		RYN3	11/4/2019	Annual maintenance and governor upgrade	120
31		RYN3	11/9/2019	Annual maintenance and governor overhaul	651
32		RYN5	2/4/2019	Cooling water supply move	77
33		RYN5	7/11/2019	Cooling water header	25
34		RYN6	1/1/2019	Major overhaul	3,443
35		RYN6	5/4/2019	Major overhaul	3,122
36		RYN6	10/1/2019	Major overhaul	48
37		RYN6	10/3/2019	Major overhaul	15
38					
39	**Thompson Falls**	THF1	7/30/2019	Governor upgrade and annual inspection	756
40		THF1	8/31/2019	Governor upgrade and annual inspection	102
41		THF2	2/12/2019	Annual inspection and maintenance	248
42		THF2	7/30/2019	Governor upgrade and annual inspection	372
43		THF2	8/14/2019	Governor upgrade and annual inspection	522
44		THF3	6/26/2019	Speed sensor problems	25
45		THF3	10/15/2019	Governor upgrade and annual inspection	558
46		THF4	3/26/2019	Annual inspection and maintenance	252
47		THF4	10/15/2019	Governor upgrade	372
48		THF4	10/30/2019	Governor upgrade	188
49		THF5	2/10/2019	Annual inspection and maintenance	252
50		THF5	2/20/2020	Annual inspection and maintenance	690
51		THF5	11/16/2019	Governor upgrade	604
52		THF6	1/14/2019	Annual inspection and maintenance	252
53		THF6	1/24/2019	Annual inspection and maintenance	356
54		THF6	11/13/2019	Governor upgrade	372
55		THF6	11/29/2019	Governor upgrade	319
56		THF6	12/12/2019	Governor upgrade	30
57		THF7	9/9/2019	Annual inspection and maintenance	582
58					

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)
2019 E+ Residential Lighting Program*	$ 686,588	$ 721,681	-4.86%	-	17	17
- Initiated 2005, 2019 weighted average program life = 14 years, 3,901 participants.				6,540	12,836	6,297
2019 E+ Commercial Lighting Program	$ 5,048,814	$ 5,297,843	-4.70%	-	-	-
- Initiated 2005, 2019 weighted average program life = 14 years, 1,081 participants.				19,257	37,798	18,541
2019 E+ Electric Business Partners Program	$ 589,464	$ 853,431	-30.93%	0.07	0.13	0.07
- Initiated 2005, 2018 weighted average program life = 16 years, 9 participants.				1,107	2,172	1,066
2019 Northwest Energy Efficiency Alliance (NEEA)**	$ 1,220,999	$ 1,220,332	0.05%	-	-	-
- Initiated natural gas savings in 2006, program life is 15 years				6,279	12,325	6,046
2019 E+ Commercial Electric New Construction Program	$ 517,429	$ 188,305	174.78%	-	-	-
- Initiated 2005, 2019 weighted average program life = 13 years, 39 participants.				2,205	4,327	2,123
2019 E+ Commercial Electric Savings Program	$ 364,166	$ 246,793	47.56%	-	-	-
- Initiated 2005, 2019 weighted average program life = 13 years, 36 participants.				1,562	3,067	1,504
2019 General Expenses All Electric DSM Programs	$43,443	$7,022	518.64%	-	-	-
- N/A				-	-	-
TOTAL	$ 8,470,903	$ 8,535,408	-0.76%	0.07	17.54	17.48
				36,949	72,526	35,576

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

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

**Note: 2019 NEEA expeditures are allocated to electric DSM but there are gas savings as a result of some NEEA initiatives. Participant has not been defined or counted for NEEA.

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

Sch. 35a	Electric Universal System Benefits Programs						
	Program Description	Actual Expenditures	Contracted or Committed Expenditures	Total Allocations & Expenditures [(a)]	Expected savings [(b)]		Most recent program evaluation
1	Local Conservation				MWh	MW	
2	E+ Residential Audit/Sm. Comm Audit	$ 433,130	$ 126,187	$ 559,317	709	0.148	2012
3	E+ Business Partners / Irrigation Projects	$ 13,156	$ -	$ 13,156	164	0.019	2012
4	NWE Promotion	$ 140,069	$ -	$ 140,069			
5	NWE Labor	$ 28,269	$ -	$ 28,269			
6	NWE Admin. Non-labor	$ 274	$ -	$ 274			
7	USB Interest & Svc Chg	$ (349)	$ -	$ (349)			
8	Market Transformation						
9	E+ Commercial Lighting	$ 142,929	$ -	$ 142,929			
10	Motor Management Training	$ 14,375	$ -	$ 14,375			
11	Energy Star Homes	$ 104,111	$ 32,000	$ 136,111			
12	Building Operator Certification	$ 42,105	$ -	$ 42,105	353		2012
13	Regional Mkt Transformation	$ 45,682	$ -	$ 45,682			
14	NWE Promotion	$ 15,346	$ -	$ 15,346			
15	NWE Labor	$ 19,034	$ -	$ 19,034			
16	NWE Admin. Non-labor	$ 9,674	$ -	$ 9,674			
17	USB Interest & Svc Chg	$ (223)	$ -	$ (223)			
18	Renewable Resources						
19	Generation/Education	$ 600,151	$ 1,057,466	$ 1,657,617	668	0.508	2012
20	Green Power Product Offering	$ (23,388)	$ -	$ (23,388)			
21	NWE Promotion	$ 42	$ -	$ 42			
22	NWE Labor	$ 73,471	$ -	$ 73,471			
23	NWE Admin. Non-labor	$ 366	$ -	$ 366			
24	USB Interest & Svc Chg	$ (399)	$ -	$ (399)			
25	Research & Development						
26	R&D/ Infrastructure	$ 104,595	$ 211,275	$ 315,870			
27	Battery Storage	$ 1,146	$ -	$ 1,146			
28	NWE Promotion	$ 263	$ -	$ 263			
29	NWE Labor	$ 22,417	$ -	$ 22,417			
30	NWE Admin. Non-labor	$ 196	$ -	$ 196			
31	USB Interest & Svc Chg	$ (92)	$ -	$ (92)			
32	Low Income						
33	Bill Assistance	$ 2,450,189	$ -	$ 2,450,189			
34	Free Weatherization	$ 1,928,470	$ 669,628	$ 2,598,098	378	0.076	2012
35	Elec Wx Incentives	$ 23,412	$ -	$ 23,412			
36	Fuel Switch Analyses	$ 2,100	$ -	$ 2,100			
37	Energy Share	$ 403,143	$ 231,359	$ 634,502			
38	NWE Promotion	$ (87)	$ -	$ (87)			
39	NWE Labor	$ 31,147	$ -	$ 31,147			
40	NWE Admin. Non-labor	$ 987	$ -	$ 987			
41	USB Interest & Svc Chg	$ (3,429)	$ -	$ (3,429)			
42	Large Customer Self Directed						
43	Self-Directed Energy Reduction	$ 3,356,985	$ 1,126,040	4,483,026			
44	Self-Directed to Low Income	$ 112,564	$ -	112,564			
45	NWE Labor	$ 12,486	$ -	12,486			
46	USB Interest & Svc Chg	$ (2,366)	$ -	(2,366)			
47	Total	$ 10,101,951	$ 3,453,954	$ 13,555,905	2,270	0.751	
48	Number of customers that received low income rate discounts				11,533		
49	Average monthly bill discount amount ($/mo)				$ 17.70		
50	Average LIEAP-eligible household income				n/a		
51	Number of customers that received weatherization assistance				455 [(b)]		
52	Expected average annual bill savings from weatherization				830 Kwh		
53	Number of residential audits performed on-site				2,128 [(b)]		
54	Number of residential audits performed (mail in survey)				1,549 [(b)]		
55	[(a)] Total expenditures are reported for the combination of 2016 - 2019 electric USB funds spent in 2019. Total allocations are reported for the combination of 2016 - 2019 electric USB funds to be spent in 2020						
56	[(b)] Total savings and number of customers are reported for the combination of 2018 - 2019 electric and 2019 natural gas USB funds spent in 2019.						

Sch. 35b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Electric USB Programs)	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Allocations & Expenditures (a)	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2 3	E+ Energy Audit for the Home or Business	$ 433,130	$ 126,187	$ 559,317	0.15 709	2012
4 5	E+ Electric Business Partners Program / Irrigation	$ 13,156	$ -	$ 13,156	0.02 164	2012
6	Market Transformation					
7 8	E+ Commercial Lighting Program	$ 142,929	$ -	$ 142,929	- -	2012
10 11	Motor Management Training	$ 14,375	$ -	$ 14,375	- -	2012
12 13	Energy Star Homes	$ 104,111	$ 32,000	$ 136,111	- -	2012
14 15	Building Operator Certification	$ 42,105	$ -	$ 42,105	- 353	2012
16 17	Commercial Industrial Training & Conference	$ 45,682	$ -	$ 45,682	- -	2012
18	Renewables					
19 20	Generation/Education	$ 600,151	$ 1,057,466	$ 1,657,617	0.51 668	2012
21 22	Green Power Product	$ (23,388)	$ -	$ (23,388)	- -	2012
23	Research & Development					
24 25	R&D / Infrastructure	$ 104,595	$ 211,275	$ 315,870	- -	2012
26 27	Battery Storage	$ 1,146	$ -	$ 1,146	- -	2012
28	Low Income					
29 30	Free Weatherization	$ 1,928,470	$ 408,260	$ 2,336,730	0.08 378	2012
31 32	Elec Wx Incentives	$ 23,412	$ -	$ 23,412	- -	2012
33 34	Fuel Switch	$ 2,100	$ -	$ 2,100	- -	2012
35 36	Total	$ 3,431,975	$ 1,835,188	$ 5,267,162	0.75 2,270	2012
37	(a) Total expenditures are reported for the combination of 2016 - 2019 electric USB funds spent in 2019. Total allocations are reported for the combination of 2016 - 2019 electric USB funds to be spent in 2020.					

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES YNP)						
		Operating Revenues 1/		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$ 309,885,795	$295,264,873	2,579,216	2,516,447	303,046	299,266
4	Commercial & Industrial	397,983,996	385,366,078	6,816,512	6,470,759	70,350	68,986
5	Public Street & Highway Lighting	17,314,954	16,466,431	57,034	58,612	3,710	3,734
6	Sales to Other Utilities	36,001,206	24,878,366	1,294,570	995,240	22	22
7	Interdepartmental	996,055	1,009,279	8,829	9,294	341	303
8							
9	**TOTAL SALES**	$762,182,006	$722,985,027	10,756,161	10,050,352	377,469	372,311
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							