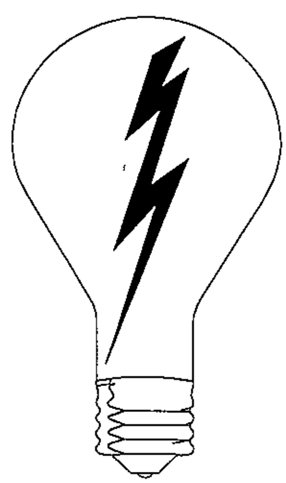
YEAR ENDING 2017

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY



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

Electric Annual Report

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Sch. 1	IDENTIFICATION
Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	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	
[redacted]	Director's Name & Address (City, State)	Remuneration
1		
2	See NorthWestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
	President & Chief Executive Officer	Executive	Robert Rowe
	Vice President, Chief Financial Officer	Tax, Internal Audit and Controls, Credit Financial Planning and Analysis Controller and Treasury Functions Investor Relations and Corporate Finance Cash Management and 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 & Shareholder Services Risk Management Regulatory Affairs Federal Governmental Affairs	Heather Grahame
	Vice President, Distribution	Distribution Operations - MT/SD/NE Construction, Asset Management Organizational Development & Labor Relations Project Management Safety/Health/Environmental Services Organizational Performance	Curt Pohl
	Vice President, Transmission	Transmission Planning, Engineering, Construction, and Operations Gas Transmission & Storage Grid & Substation Operations Transmission Business Development and Analysis FERC and NERC Compliance Support Services	Michael Cashell
	Vice President, Supply and Montana Government Affairs	Thermal and Wind Generation Hydro Operation and Maintenance Environmental Permitting & Compliance Long Term Resources Energy Supply Marketing Operations Montana Government Affairs	John Hines
	Vice President, Government & Regulatory Affairs		Patrick Corcoran
	Vice President, Customer Care, Communications and Human Resources	Corporate Communications Account and Analysis Customer Experience and Support Customer Interaction Community Connections Revenue Cycle Management Human Resources	Bobbi Schroeppel
	Chief Audit & Compliance Officer	Internal Audit Enterprise Risk	Michael Nieman
	Vice President, Controller	Financial Reporting Accounting Accounts Payable/Payroll Compensation and Benefits	Crystal Lail

Reflects active officers as of December 31, 2017.

On January 15, 2018, Patrick Corcoran retired. During November 2017, in anticipation of his retirement, the company announced that the employees that had previously reported to Patrick would be reassigned to other vice presidents, effective immediately.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 159,647	98.12%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP, HPC, 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		$ 3,056	1.88%
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		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		$ 162,703	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.	$15,724,172	70.32%	$6,636,420
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, CC - Assoc & Dispatch Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	23,116,725	72.68%	8,688,503
Legal Department	Includes the following departments: Chief Legal, Compliance, Contracts Administration, and Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	11,670,006	78.99%	3,103,537
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Capital Related Exp, Data Center, Project Management & Asset Control, Record Mgmt Systems, and Security.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	19,718,550	77.63%	5,682,571
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	4,153,422	81.57%	938,130
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.	3,339,259	75.21%	1,100,918
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.	846,155	77.00%	252,748
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	11,214	77.00%	3,350
TOTAL			$78,579,503	74.85%	$26,406,177

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	$222,232		
13	Havre Pipeline Company, LLC	Natural gas gathering, transmission, & compression	Gathering rate based on cost, transmission & compression are at tariffed rates	3,411,904		
14	**Total Utility Subsidiaries Revenues**			$3,634,136		
15	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	$500,400	14.4%	$500,400
14						
15	**Total Utility Subsidiaries**			$500,400		$500,400
16	**Total Utility Subsidiaries Expenses**			$3,509,769		
17	**TOTAL AFFILIATE TRANSACTIONS**			$500,400		$500,400

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	$ 969,237,523	$ 168,299,064	$ 800,938,459	$ 791,337,562	1.21%
3						
4	**Total Operating Revenues**	969,237,523	168,299,064	800,938,459	791,337,562	1.21%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	440,653,050	85,428,331	355,224,719	375,146,001	-5.31%
9	402 Maintenance Expense	51,965,548	9,609,501	42,356,047	40,080,236	5.68%
10	403 Depreciation Expense	129,817,413	27,435,796	102,381,617	97,628,545	4.87%
11	404-405 Amort. of Electric Plant	5,490,404	789,319	4,701,085	3,921,260	19.89%
12	406 Amort. of Plant Acquisition Adj.	6,342,974	(671,113)	7,014,087	7,014,087	0.00%
13	407.3 Regulatory Amortizations - Debit	10,224,174	957,742	9,266,432	3,109,220	198.03%
14	407.4 Regulatory Amortizations - Credit	(20,376,340)	-	(20,376,340)	(23,301,983)	12.56%
15	408.1 Taxes Other Than Income Taxes	133,681,118	5,472,221	128,208,897	115,912,517	10.61%
16	409.1 Income Taxes - Federal	(11,034,339)	(7,499,280)	(3,535,059)	(2,111,083)	-67.45%
17	- Other			-	220,123	-100.00%
18	410.1 Deferred Income Taxes-Dr.	153,898,886	17,961,650	135,937,236	161,531,453	-15.84%
19	411.1 Deferred Income Taxes-Cr.	(139,233,608)	(20,280,646)	(118,952,962)	(158,859,766)	25.12%
20	411.4 Investment Tax Credit Adj.	184,686	(93,673)	278,359	-	-
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**	761,613,960	119,109,843	642,504,117	620,290,609	3.58%
26	**NET OPERATING INCOME**	$ 207,623,563	$ 49,189,221	$ 158,434,342	$ 171,046,953	-7.37%

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 and the Hydro Transaction.

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	$ 358,861,981	$ 60,423,395	$ 298,438,586	$ 278,903,988	7.00%
5	442 Commercial	438,987,138	96,548,315	342,438,823	337,571,052	1.44%
6	Industrial	54,142,901	-	54,142,901	51,791,644	4.54%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	16,977,883	2,557,148	16,420,735	16,019,702	2.50%
9	448 Interdepartmental Sales	1,046,881	-	1,046,881	1,094,994	-4.39%
10						
11	**Total Sales to Ultimate Consumers**	872,016,784	159,528,858	712,487,926	685,381,380	3.95%
12	447 Sales for Resale	25,524,104	-	25,524,104	30,499,024	-16.31%
13						
14	**Total Sales of Electricity**	897,540,888	159,528,858	738,012,030	715,880,404	3.09%
15	449.1 Provision for Rate Refunds	2,365,681	-	2,365,681	3,700,846	-36.08%
16						
17	**Total Revenue Net of Rate Refunds**	899,906,569	159,528,858	740,377,711	719,581,250	2.89%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	484,373	484,373	-	-	-
21	451 Miscellaneous Service Revenue	292,458	292,458	-	-	-
22	453 Sales of Water & Water Power	-	-	-	-	-
23	454 Rent From Electric Property	4,481,361	273,117	4,208,244	3,578,505	17.60%
24	456 Other Electric Revenues	64,072,762	7,720,258	56,352,504	68,177,807	-17.34%
25						
26	**Total Other Operating Revenue**	69,330,954	8,770,206	60,560,748	71,756,312	-15.60%
27	**TOTAL OPERATING REVENUE**	$ 969,237,523	$ 168,299,064	$ 800,938,459	$ 791,337,562	1.21%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2						
3	**Steam Power Generation-Operation**					
4	500 Supervision & Engineering	991,086	932,220	58,866	$ 54,461	8.09%
5	501 Fuel	43,461,296	21,820,871	21,640,425	25,599,629	-15.47%
6	502 Steam Expenses	3,345,598	1,810,104	1,535,494	1,395,203	10.06%
7	503 Steam from Other Sources	-	-	-	-	-
8	505 Electric Plant	810,991	537,801	273,190	225,372	21.22%
9	506 Miscellaneous Steam Power	3,194,600	1,297,441	1,897,159	1,752,497	8.25%
10	507 Rents	66,844	28,390	38,454	40,272	-4.51%
11	**Total Operation-Steam Power Gen.**	51,870,415	26,426,827	25,443,588	29,067,434	-12.47%
12	**Steam Power Generation-Maintenance**					
13	510 Supervision & Engineering	910,189	578,020	332,169	405,402	-18.06%
14	511 Structures	986,206	404,799	581,407	585,987	-0.78%
15	512 Steam Boiler Plant	6,817,398	2,539,067	4,278,331	4,401,819	-2.81%
16	513 Electric Plant	2,104,176	384,013	1,720,163	1,063,806	61.70%
17	514 Miscellaneous Steam Plant	1,037,164	389,069	648,095	624,651	3.75%
18	**Total Maintenance-Steam Power Gen.**	11,855,133	4,294,968	7,560,165	7,081,665	6.76%
19	**Total Steam Power Generation**	63,725,548	30,721,795	33,003,753	36,149,099	-8.70%
20	**Hydro Power Generation-Operation**					
21	535 Supervision & Engineering	896,864	-	896,864	822,126	9.09%
22	536 Water for Power	956,721	-	956,721	1,173,807	-18.49%
23	537 Hydraulic Expenses	4,126,111	-	4,126,111	4,239,543	-2.68%
24	538 Electric Expenses	3,968,632	-	3,968,632	3,576,133	10.98%
25	539 Miscellaneous Hydraulic Power	2,192,481	-	2,192,481	2,605,943	-15.87%
26	540 Rents	738,524	-	738,524	736,019	0.34%
27	**Total Operation-Hydro Power Gen.**	12,879,333	-	12,879,333	13,153,571	-2.08%
28	**Hydro Power Generation-Maintenance**					
29	541 Supervision & Engineering	777,653	-	777,653	743,183	4.64%
30	542 Structures	1,031,536	-	1,031,536	861,528	19.73%
31	543 Reservoirs, Dams & Waterways	1,238,424	-	1,238,424	1,140,672	8.57%
32	544 Electric Plant	1,641,955	-	1,641,955	1,549,377	5.98%
33	545 Miscellaneous Hydro Plant	1,088,426	-	1,088,426	998,296	9.03%
34	**Total Maintenance-Hydro Power Gen.**	5,777,994	-	5,777,994	5,293,056	9.16%
35	**Total Hydraulic Power Generation**	18,657,327	-	18,657,327	18,446,627	1.14%
36	**Other Power Generation-Operation**					
37	546 Supervision & Engineering	1,009,127	294,068	715,059	775,084	-7.74%
38	547 Fuel	9,168,683	161,778	9,006,905	7,600,381	18.51%
39	548 Generation Expenses	5,505,589	2,869,586	2,636,003	2,550,860	3.34%
40	549 Miscellaneous Other Power	1,462,505	756,219	706,286	644,289	9.62%
41	550 Rents	-	-			
42	**Total Operation-Other Power Gen.**	17,145,904	4,081,651	13,064,253	11,570,614	12.91%
43	**Other Power Generation-Maintenance**					
44	551 Supervision & Engineering	83,499	83,499	-		
45	552 Structures	74,037	64,184	9,853	-1,374	>300.00%
46	553 Generating & Electric Plant	3,896,750	824,196	3,072,554	1,936,473	58.67%
47	554 Miscellaneous Other Power Plant	124,089	35,154	88,935	102,368	-13.12%
48	**Total Maintenance-Other Power Gen.**	4,178,375	1,007,033	3,171,342	2,040,215	55.44%
49	**Total Other Power Generation**	21,324,279	5,088,684	16,235,595	13,610,829	19.28%
50	**Other Power Supply Expenses**					
51	555 Purchased Power	195,937,052	17,224,766	178,712,286	190,704,444	-6.29%
52	556 System Control & Load Dispatch	280,356	280,356	-	-	-
53	557 Other Expenses	1,853,705	(2,029,852)	3,883,557	14,005,597	-72.27%
54	**Total Other Power Supply Expenses**	198,071,113	15,475,270	182,595,843	204,710,041	-10.80%
55	**Total Power Production Expenses**	301,778,267	51,285,749	250,492,518	272,916,596	-8.22%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	3,815,400	359,390	3,456,010	3,539,511	-2.36%
6	561 Load Dispatching	88,687	88,688	(1)	-	-
7	561.1 Load Dispatch - Reliability	1,089,541	-	1,089,541	1,006,109	8.29%
8	561.2 Load Disp-Monitor/Op	900,917	142,036	758,881	638,353	18.88%
9	561.3 Load Disp-Srv/Schedu	1,359,629	14,526	1,345,103	1,285,342	4.65%
10	561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
11	561.5 Reliab, Plan, Stds	78,620	78,620	-	-	-
12	561.6 Transmission Service Studies	-	-	-	-	-
13	561.8 Sch,Sys&Ctrl Srv-RTO			-	-	-
14	562 Station Expenses	1,814,151	139,232	1,674,919	1,619,118	3.45%
15	563 Overhead Lines	1,552,813	365,688	1,187,125	898,128	32.18%
16	564 Underground Lines	-	-	-	-	-
17	565 Transmission of Elec. by Others	25,755,641	20,080,527	5,675,114	5,750,970	-1.32%
18	566 Miscellaneous Transmission	224,089	65,770	158,319	99,419	59.24%
19	567 Rents	1,077,168	5,748	1,071,420	848,659	26.25%
20	**Total Operation-Transmission**	37,756,656	21,340,225	16,416,431	15,685,609	4.66%
21	**Transmission-Maintenance**					
22	568 Supervision & Engineering	1,086,228	113,502	972,726	909,297	6.98%
23	569 Structures	25,325	4,064	21,261	24,964	-14.83%
24	569.1 Maintenance of Computer Hardware	704,891	-	704,891	993,785	-29.07%
25	569.2 Maintenance of Computer Software	(36)	-	(36)	403,255	-100.01%
26	569.3 Maint-Comm Equip	120,976	120,976	-	-	-
27	570 Station Equipment	1,178,483	78,602	1,099,881	1,044,220	5.33%
28	571 Overhead Lines	2,576,306	456,197	2,120,109	3,099,777	-31.60%
29	572 Underground Lines	247	247	-	-	-
30	573 Miscellaneous Transmission Plant	-	-	-	-	-
31	**Total Maintenance-Transmission**	5,692,420	773,588	4,918,832	6,475,298	-24.04%
32	**Total Transmission Expenses**	43,449,076	22,113,813	21,335,263	22,160,907	-3.73%
33						
34	**Regional Market Operation**					
35	575.1 Operation Supervision	6,515	6,515	-	-	-
36	575.2 Day-Ahead & Real-time Admin	327,806	327,806	-	-	-
37	575.3 Transmision Rights Mkt Admin	3,258	3,258	-	-	-
38	575.5 Ancillary Services Mkt Admin	91,797	91,797	-	-	-
39	575.6 Market Monitoring & Complaince	45,899	45,899	-	-	-
40	**Total Operation-Regional Market**	475,275	475,275	-	-	-
41						
42	**Distribution Expenses**					
43						
44	**Distribution-Operation**					
45	580 Supervision & Engineering	3,858,510	661,220	3,197,290	3,301,182	-3.15%
46	581 Load Dispatching	-	-	-	-	-
47	582 Station Expenses	1,801,983	254,625	1,547,358	1,667,970	-7.23%
48	583 Overhead Lines	3,070,610	607,817	2,462,793	2,193,385	12.28%
49	584 Underground Lines	2,826,789	1,032,890	1,793,899	1,819,209	-1.39%
50	585 Street Lighting & Signal Systems	608,347	39,280	569,067	840,694	-32.31%
51	586 Meters	3,425,370	655,035	2,770,335	2,747,598	0.83%
52	587 Customer Installations	2,800,738	331,657	2,469,081	2,358,465	4.69%
53	588 Miscellaneous Distribution	4,931,312	647,462	4,283,850	4,124,827	3.86%
54	589 Rents	83,860	-	83,860	59,889	40.03%
55	**Total Operation-Distribution**	23,407,519	4,229,986	19,177,533	19,113,219	0.34%
56	**Distribution-Maintenance**					
57	590 Supervision & Engineering	1,926,668	291,173	1,635,495	1,576,427	3.75%
58	591 Structures	42,814	-	42,814	21,151	102.42%
59	592 Station Equipment	920,858	263,512	657,346	669,715	-1.85%
60	593 Overhead Lines	13,757,272	1,945,332	11,811,940	10,330,936	14.34%
61	594 Underground Lines	1,641,132	255,829	1,385,303	1,404,745	-1.38%
62	595 Line Transformers	194,984	8,256	186,728	124,004	50.58%
63	596 Street Lighting, Signal Systems	1,207,475	163,600	1,043,875	945,646	10.39%
64	597 Meters	1,462,859	161,375	1,301,484	1,308,092	-0.51%
65	598 Miscellaneous Distribution Plant	51,672	51,672	-	-	-
66	**Total Maintenance-Distribution**	21,205,734	3,140,749	18,064,985	16,380,716	10.28%
67	**Total Distribution Expenses**	44,613,253	7,370,735	37,242,518	35,493,935	4.93%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	2,535,019	808,027	1,726,992	1,601,650	7.83%
7	903 Customer Records & Collection	8,406,857	1,266,604	7,140,253	6,185,959	15.43%
8	904 Uncollectible Accounts	2,111,299	280,503	1,830,796	646,337	183.26%
9	905 Miscellaneous Customer Accts.	43,161	40,951	2,210	(1,262)	275.12%
10	**Total Customer Accounts Expenses**	13,096,336	2,396,085	10,700,251	8,432,684	26.89%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	4,138,812	1,184,973	2,953,839	3,388,697	-12.83%
17	909 Inform. & Instruct. Advertising	1,051,470	134,575	916,895	803,943	14.05%
18	910 Misc. Customer Service & Info.	841,035	-	841,035	824,023	2.06%
19	**Total Customer Service & Info. Expense**	6,031,317	1,319,548	4,711,769	5,016,663	-6.08%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling	-	-	-	-	-
26	913 Advertising	522,381	58,043	464,338	403,605	15.05%
27	916 Miscellaneous Sales	-	-	-	-	-
28	**Total Sales Expenses**	522,381	58,043	464,338	403,605	15.05%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	34,875,233	5,030,074	29,845,159	29,755,935	0.30%
34	921 Office Supplies & Expenses	10,264,866	1,873,017	8,391,849	7,770,061	8.00%
35	922 Admin. Expense Transferred-Cr.	(5,543,539)	(1,245,893)	(4,297,646)	(4,121,238)	-4.28%
36	923 Outside Services Employed	4,936,588	681,566	4,255,022	4,863,555	-12.51%
37	924 Property Insurance	2,832,533	513,214	2,319,319	2,233,052	3.86%
38	925 Injuries & Damages	7,158,487	878,395	6,280,092	6,849,434	-8.31%
39	926 Employee Pensions & Benefits	6,829,729	730,236	6,099,493	4,725,956	29.06%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	2,145,050	21,017	2,124,033	2,269,652	-6.42%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	13,870,104	707,324	13,162,780	12,072,765	9.03%
44	931 Rents	2,027,750	436,471	1,591,279	1,573,387	1.14%
45	**Total Operation-Admin. & General**	79,396,801	9,625,421	69,771,380	67,992,559	2.62%
46	**Admin. & General-Maintenance**					
47	935 General Plant	3,255,892	393,163	2,862,729	2,809,288	1.90%
48	**Total Maintenance-Admin. & General**	3,255,892	393,163	2,862,729	2,809,288	1.90%
49	**Total Admin. & General Expenses**	82,652,693	10,018,584	72,634,109	70,801,847	2.59%
50	**TOTAL OPER. & MAINT. EXPENSES**	492,618,598	95,037,832	397,580,766	$ 415,226,237	-4.25%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	5,080,552.00	$4,912,798	3.41%
3	Property Taxes	117,095,801	106,052,556	10.41%
4	Electric Energy License Tax	1,559,607	818,694	90.50%
5	Crow Tribe RR and Utility Tax	76,284	53,544	42.47%
	Fort Peck	300	288	4.17%
6	City Tax	4,446	7,874	-43.54%
7	Consumer Counsel Tax	554,118	517,951	6.98%
8	Public Service Commission Tax	2,113,692	1,923,285	9.90%
9	Heavy Highway Use Tax	14,684	13,481	8.92%
10	Vehicle Use Tax	238,455	189,678	25.72%
11	Wholesale Energy Transaction Tax	1,362,929	1,316,051	3.56%
12	Delaware Franchise Tax	108,029	106,317	1.61%
13				
14				
15				
16				
17	**TOTAL TAXES OTHER THAN INCOME**	$128,208,897	$115,912,517	10.61%
18				
19				

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
[redacted]	Name of Recipient	Nature of Service	Total
1	A & A ASPHALT MAINTENANCE	Asphalt Services	125,966
2	A EXCAVATION	Excavation Contractor	202,496
3	A&E ARCHITECTS P C	Architectural Services	648,619
4	ACCION GROUP LLC	Information Technology Consulting	287,956
5	AFFCO INC	Hydro Construction Services	856,493
6	ALME CONSTRUCTION, INC.	Construction	744,810
7	ALSTOM GRID INC	Software Support Services	351,868
8	ALVAREZ & MARSAL DISPUTES & INVESTIGATIONS, LLC	Legal Services	420,335
9	AMERICAN INNOVATIONS INC	Software Support Services	131,465
10	AMERICAN PUBLIC LAND EXCHANGE	Consulting Services - Environmental	311,137
11	ARCADIS US INC	Engineering Services	1,951,730
12	ARCOS LLC	Reliability Consulting Services	429,299
13	ASCEND ANALYTICS LLC	Hydro Expert Analysis	639,558
14	ASPLUNDH TREE EXPERT CO	Tree Trimming	4,637,770
15	ASSOCIATED UNDERWATER SERVICE	Inspection Services	123,412
16	AUTOMOTIVE RENTALS INC	Fleet Management	9,104,534
17	BARNARD CONSTRUCTION COMPANY INC	Construction	997,409
18	BART ENGINEERING COMPANY	Engineering Services	470,829
19	BILL FIELD TRUCKING INC	Hauling Services	596,950
20	BILLINGS FLYING SERVICE, INC.	Pole Installation Services	249,080
21	BLACKEAGLE ENERGY SERVICES	Construction	229,266
22	BROOKS JACKSON & LITTLE INC	Legal Services	123,506
23	BROWNING, KALECZYC, BERRY & HOVEN	Legal Services	109,757
24	BRUSH AFTERMARKET GMS	Inspection Services	464,516
25	BURK EXCAVATION & 1ST MONTANA	Construction	694,002
26	CASCADE ELECTRIC COMPANY INC	Construction	89,879
27	CEATI INTERNATIONAL TRUST	Inspection Services	92,450
28	CEB INC	Customer Care Services	208,255
29	CENTERPOINT ENERGY SERVICES INC	Transmission Services	4,090,118
30	CENTRAL AIR SERVICE INC	Aerial Pilot Services	118,634
31	CENTRON SERVICES INC	Customer Collection Service	91,022
32	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	896,026
33	CN UTILITY CONSULTING INC	Utility Consulting Services	110,766
34	COMPLETE CAREER CENTER INC	Meter Reader Services	198,797
35	COMPUTER FINANCIAL CONSULTANTS	Computer Financial Consultant Services	175,089
36	CONTINENTAL STEEL WORKS	Fabrication Services	1,320,482
37	CRANE SERVICES & INSPECTIONS	DOT Inspection Services	128,228
38	CRIST, KROGH, BUTLER & NORD LLC	Legal Services	248,566
39	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	819,664
40	CUDA DIRECTIONAL LLC	Boring Services	260,027
41	DAVEY TREE SURGERY COMPANY	Tree Trimming	2,375,923
42	DELOITTE & TOUCHE LLP	Audit Services	1,601,529
43	DEPT OF HEALTH & HUMAN SERVICE	Weatherization Program Services	3,418,271
44	DEVLIN ENTERPRISES	Lobbying Services	77,726
45	DGR ENGINEERING	Engineering Services	320,122
46	DHC INC	Boring Services	97,655
47	DICK ANDERSON CONSTRUCTION	Construction	642,692
48	DONNES INC	Construction	99,045
49	DONOVAN CONSTRUCTION	Construction	980,671
50	DORSEY & WHITNEY LLP	Legal Services	467,801
51	DOWL HKM	Geotechnical Services	289,406
52	E SOURCE COMPANIES LLC	Strategic Services	165,815
53	EAGLE GAS MARKETING LLC	Marketing Services	250,920
54	EAGLE LANDSCAPING	Landscape Service	77,490
55	EIDEBAILLY	Audit Services	102,799
56	ELLIOT CONSTRUCTION INC	Boring Services	606,183
57	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	3,154,456
58	ENABLON NORTH AMERICA CORPORATION	Software Implementation Support Services	101,290
59	ENERGY CONTRACT SERVICES LLC	Energy Services	250,462
60	ENERGY LABORATORIES INC	Environmental Consultants	101,082

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	ENERGY SHARE OF MONTANA	USBC Services	900,720
62	ESSNOVA SOLUTIONS INC	Computer Consultants	77,670
63	FAIRBANKS MORSE ENGINE	Engineering Services	289,153
64	FALLS CONSTRUCTION COMPANY	Construction	737,393
65	FLYNN WRIGHT INC	Advertising Services	1,263,354
66	FORBES TATE PARTNERS LLC	Regulatory Consultants	110,000
67	G L TILEY & ASSOCIATES LTD	Engineering Services	99,118
68	G2 INTEGRATED SOLUTIONS LLC	Computer System Implementation	955,665
69	GARLINGTON, LOHN & ROBINSON	Legal Services	242,239
70	GARTNER INC	Information Technology Consulting	156,267
71	GE ELECTRIC INTERNATIONAL INC	Environmental Consultants	113,900
72	GEI CONSULTANTS INC	Environmental Consultants	387,811
73	GENERATOR & MOTOR SERVICES OF PA, LLC	Inspection Services	127,951
74	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	369,372
75	GLOBAL DIVING & SALVAGE INC	Construction	233,933
76	GUY TABACCO CONSTRUCTION	Construction	198,612
77	H & H ASPHALT & MAINTENANCE LLC	Asphalt Services	91,174
78	H & H CONTRACTING INC	Concrete and Asphalt Services	1,061,190
79	H2E INC	Engineering Services	102,327
80	HAIDER CONSTRUCTION INC	Backhoe Services	449,185
81	HARVEST SOLAR MT	Solar System Installation	94,709
82	HDR ENGINEERING INC	Engineering Services	1,344,101
83	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	306,115
84	HEATH CONSULTANTS INC	Gas Leak Surveys	522,538
85	HIGHMARK MEDIA	Marketing Services	110,445
86	HSNO THE FORENSICS FIRM	Legal Services	483,851
87	HUNTON & WILLIAMS LLP	Legal Services	117,953
88	HYDRO ARCH	Construction	2,042,455
89	HYDROINSIGHT LLC	Construction	123,583
90	IMCO GENERAL CONSTRUCTION INC	Construction	1,188,690
91	INTEC SERVICES INC	Pole Inspection Services	2,624,170
92	J2 OFFICE PRODUCTS	Computer/Printer Purchases	348,336
93	JACOBSEN TREE EXPERTS	Tree Trimming	966,967
94	JD ENGINEERING P C	Engineering Services	296,977
95	JONES DAY	Legal Services	275,742
96	JSSI JET SUPPORT SERVICES INC	Flight Services	234,786
97	KB CONSTRUCTION LLC	Construction	80,810
98	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	240,057
99	KM CONSTRUCTION CO INC	Construction	123,914
100	KNIFE RIVER	Construction	131,918
101	KOCHER SCHIRRA GOHARIZI CONSULTING	Engineering Services	111,633
102	LARSON DIGGING INC	Excavation Services	361,844
103	LAST BEST PLACE LANDSCAPING INC	Landscape Service	102,861
104	LOCKMER PLUMBING HEATING & UTILITIES, INC	Gas Meter Relocations	387,427
105	LODGEPOLE LAND SERVICES LLC	Construction	176,697
106	M & P EXCAVATING	Excavation Services	370,142
107	MADISON CONSERVATION DISTRICT	Restoration Services	103,750
108	MANAGEMENT APPLICATIONS CONSUL	Regulatory Consulting	149,062
109	MARSH & MCLENNAN AGENCY LLC	BEN Consulting Service	99,044
110	MCMILLEN LLC	Construction	352,354
111	MERCER HUMAN RESOURCE CONSULTI	HR Consulting	196,888
112	MERIDIAN IT INC	Information Technology Services	471,563
113	MICHELS CORPORATION	Construction	1,448,200
114	MIDCON UNDERGROUND CONSTRUCTION	Construction	618,260
119	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	866,242
120	MONTROSE AIR QUALITY SERVICES	Air Quality Services	94,776
121	MOODY'S ANALYTICS	Debt Rating Services	155,307
122	MOODY'S INVESTORS SERVICE	Debt Rating Services	313,000
123	MORRISON MAIERLE INC	Engineering Services	759,855
124	MOUNTAIN POWER CONSTRUCTION COMPANY	Construction	23,998,519
125	MOUNTAIN WEST HOLDING COMPANY	Construction	187,702
126	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	111,084
127	MUSE, STANCIL & CO	Legal Services	376,503
129	NATIONAL CENTER FOR APPROPRIATE	Conservation Program Consultants	422,415

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
[redacted]	Name of Recipient	Nature of Service	Total
130	NAVIGANT CONSULTING INC	Renewables Consulting Service	121,747
131	NCSG CRANE & HEAVY HAUL SERVICE	Heavy Haul Services	148,883
132	NORTH AMERICAN CONTRACT	Staffing Services	82,871
133	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,218,340
134	NORTHWEST TOWER	Construction	215,050
135	OMIMEX CANADA LTD	Gas Lease Operating Expenses	153,835
136	OPEN ACCESS TECHNOLOGY INT'L INC	Software Support Services	711,985
137	OUTBACK POWER COMPANY	Pole Replacement Services	211,359
137	P2 ENERGY SOLUTIONS INC	Computer System Implementation	100,723
138	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	17,628,106
139	POTEET CONSTRUCTION	Traffic Safety Services	155,967
140	POWERPLAN INC	Software Implementation Support Services	2,141,375
141	PROPAK SYSTEMS LTD	Generator Repair Services	4,088,832
142	PUETZ CORPORATION	Construction	2,343,790
143	Q3 CONTRACTING INC	Construction	184,345
144	QUORUM BUSINESS SOLUTIONS	Software Implementation Support Services	189,844
145	REVENEW INTERNATIONAL LLC	Audit Services	102,512
146	RIVER DESIGN GROUP INC	Engineering Services	298,376
147	RML INCORPORATED	Boring Services	222,929
148	ROBINS KAPLAN LLP	Legal Services	95,780
149	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	32,341,559
150	ROD TABBERT CONSTRUCTION INC	Construction	276,958
151	ROUNDS BROTHERS TRENCHING	Boring Services	572,566
152	SCENIC CITY ENTERPRISES INC	Engineering Services	113,398
153	SCHNEIDER ELECTRIC SOFTWARE CANADA	Computer Support Services	189,138
154	SEDGWICK CMS	Customer Collection Service	1,075,825
155	SELLON FORENSICS INC	Legal Services	151,598
156	SIDEWINDERS LLC	Generator Repair Services	1,451,792
157	SIOUX FALLS TOWER & COMMUNICATIONS	Construction	187,794
158	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	368,853
159	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	140,000
160	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,113,572
161	STINSON LEONARD STREET LLP	Legal Services	3,562,352
162	SUMTOTAL SYSTEMS INC	Software Implementation Support Services	85,428
163	TAMIETTI CONSTRUCTION COMPANY	Construction	110,343
164	TAYLOR SERVICES INC	Construction	78,723
165	TERRA REMOTE SENSING (USA) INC	Surveying Services	219,898
166	TEXTRON AVIATION INC	Repair Services	337,320
167	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	1,031,904
168	THE LAWN RANGER	Landscape service	85,932
169	TIMBERLINE SECURITY & SERVICES	Security Services	75,525
170	TITAN CONSTRUCTION	Construction	227,524
171	TODD O BRUESKE CONSTRUCTION	Construction	582,479
172	TOWERS WATSON DELAWARE INC	Compensation Services	170,689
173	TRADEMARK ELECTRIC INC	Construction	478,037
174	TRI-COUNTY MECHANICAL & ELECTRICAL	Construction	103,833
175	ULTEIG ENGINEERS INC	Project Manager Services	286,348
176	UNITED STATES GEOLOGICAL SURVEY	Environmental Consultants	207,400
177	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	154,816
178	VAISALA INC	Environmental Consultants	100,806
179	VARSITY CONTRACTORS INC	Janitorial Services	301,240
180	VERTEX	Billing Services and System Implementation	2,861,575
181	VESTA PARTNERS LLC	Information Technology Consulting	138,750
182	WASHINGTON FORESTRY CONSULTANTS INC	Forestry Consultants	253,427
183	WATER & ENVIRONMENTAL TECHNOLOGIES	Engineering Services	157,602
184	WATSON TRUCKING	Water Hauling Services	97,827
185	WILLIAMSON FENCING & SPR.,INC.	Construction	209,816
186	WIRTH CONSTRUCTION LLC	Construction	197,222
187	WIT PIPELINE INSPECTION	Inspection Services	155,946
188			
189			
190			
191			
	Total of Payments Set Forth Above		**$ 181,464,844**

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

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
[redacted]	Description	Total Company	Montana	% Montana
	There are three employee political action committees (PAC)s:			
	a. NorthWestern Energy Montana Employee PAC for Montana employees;			
	b. Employees of NorthWestern Corporation (NorthWestern Energy) PAC for South Dakota employees;			
	c. NorthWestern Public Service Employees PAC for Nebraska employees.			
	All of the money contributed by members is dedicated to support political candidates and ballot issues. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating, postage, and meeting expenses are paid by the company as provided by law. These costs are charged to shareholder expense.			
	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	$ 583,527,303	$ 565,361,292	3.21%
8	Service cost	10,028,157	10,711,339	-6.38%
9	Interest cost	23,305,061	23,762,971	-1.93%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	40,967,092	8,068,651	>300.00%
13	Acquisition	-	-	-
14	Benefits paid	(23,465,494)	(24,376,950)	3.74%
15	Benefit obligation at end of year	$ 634,362,119	$ 583,527,303	8.71%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 465,129,734	$ 442,627,471	5.08%
18	Actual return on plan assets	73,075,228	35,379,213	106.55%
19	Acquisition	-	-	-
20	Employer contribution	8,000,000	11,500,000	-30.43%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(23,465,494)	(24,376,950)	3.74%
23	Fair value of plan assets at end of year	$ 522,739,468	$ 465,129,734	12.39%
24	**Funded Status**	$ (111,622,651)	$ (118,397,569)	5.72%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (111,622,651)	$ (118,397,569)	5.72%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	3.60%	4.10%	-12.20%
32	Expected return on plan assets	4.70%	5.80%	-18.97%
33	Rate of compensation increase	1.05% Union & 2.77% Non-Union	3.20% Union & 3.25% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 10,028,157	$ 10,711,339	-6.38%
36	Interest cost	23,305,061	23,762,971	-1.93%
37	Expected return on plan assets	(21,304,851)	(25,094,948)	15.10%
38	Amortization of prior service cost	4,448	246,363	-98.19%
39	Recognized net actuarial gain	7,718,452	9,591,156	-19.53%
40	Net periodic benefit cost (SEC Basis)	$ 19,751,267	$ 19,216,881	2.78%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 8,000,000	$ 11,500,000	-30.43%
43	Pension Costs Capitalized	1,662,729	2,210,908	-24.79%
44	Accumulated Pension Asset (Liability) at Year End	$ (111,622,651)	$ (118,397,569)	5.72%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,660	2,709	-1.81%
47	Not Covered by the Plan 2/	622	557	11.67%
48	Active	749	824	-9.10%
49	Retired	1,586	1,537	3.19%
50	Deferred Vested Terminated 2/	325	348	-6.61%

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	$ 344,243,945	$ 320,552,638	-6.88%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 10,043,673	$ 9,777,034	2.73%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 395,411,056	$ 344,243,945	14.86%
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	$ 7,479,474	$ 7,241,843	3.28%
44	401(k) Plan Defined Contribution Costs Capitalized	1,554,543	1,392,265	11.66%
45	Accumulated Pension Asset (Liability) at Year End		Not Applicable	
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,545	1,539	0.39%
48	Not Covered by the Plan			
49	Active - Participating	1,534	1,499	2.33%
50	Retired			
51	Vested Former Employees, Retirees and Active-	289	271	6.64%
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)

[redacted]	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**	[redacted]		
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	($433,344)	($398,709)	-8.69%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.20%	3.40%	-5.88%
8	Expected return on plan assets	4.70%	5.80%	-18.97%
9	Medical Cost Inflation Rate 3/	5.0% fixed rate annually	7.59%,4.5%:22	
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	1.05% Union & 2.77% Non-Union	3.20% Union & 3.25% 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	None.			

1/ Obtained from NorthWestern Energy-Montana's 2017 FASB 106 Valuation. Assumptions and data are as of December 31, 2017.
2/ Obtained from NorthWestern Energy-Montana's 2016 FASB 106 Valuation. Assumptions and data are as of December 31, 2016.
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	$19,194,132	$20,784,657	-7.65%
10	Service cost	365,276	399,099	-8.47%
11	Interest Cost	610,058	689,114	-11.47%
12	Plan participants' contributions	784,850	638,872	22.85%
13	Amendments 5/	-	-	-
14	Actuarial loss/(gain)	(842,631)	68,944	>-300.00%
15	Acquisition	-	-	-
16	Benefits paid	(2,645,533)	(3,386,554)	21.88%
17	Benefit obligation at end of year	$17,466,152	$19,194,132	-9.00%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$18,604,936	$17,972,924	3.52%
20	Actual return on plan assets	2,690,303	1,276,360	110.78%
21	Acquisition	-	-	-
22	Employer contribution	946,023	2,103,334	-55.02%
23	Plan participants' contributions	784,850	638,872	22.85%
24	Benefits paid	(2,645,533)	(3,386,554)	21.88%
25	Fair value of plan assets at end of year	$20,380,579	$18,604,936	9.54%
26	**Funded Status**	$2,914,427	($589,196)	>300.00%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$2,914,427	($589,196)	>300.00%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$365,276	$399,099	-8.47%
33	Interest cost	610,058	689,114	-11.47%
34	Expected return on plan assets	(846,760)	(1,042,430)	18.77%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,032,848)	(2,032,848)	
37	Recognized net actuarial loss/(gain)	318,293	315,181	0.99%
38	Net periodic benefit cost	($1,585,981)	($1,671,884)	5.14%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	946,023	2,103,334	-55.02%
43	TOTAL	$946,023	$2,103,334	-55.02%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(433,344)	(398,709)	-8.69%
47	TOTAL	($433,344)	($398,709)	-8.69%
48	**Montana Intrastate Costs:**	-		
49	Pension Costs	($433,344)	($398,709)	-8.69%
50	Pension Costs Capitalized	(90,067)	(76,653)	-17.50%
51	Accumulated Pension Asset (Liability) at Year End	2,914,427	(589,196)	>300.00%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,732	1,816	-4.63%
54	Not Covered by the Plan	1,567	1,434	9.27%
55	Active	729	807	-9.67%
56	Retired	900	903	-0.33%
57	Spouses/Dependants covered by the Plan	103	106	-2.83%
	4/ There is approximately an additional $5,455,489 and $7,023,139 in other company OPEBS liabilities outstanding at December 31, 2017 and 2016, 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
1	Michael R. Cashell Vice President, Transmission	262,610	91,702 A	34,037 B 142,717 C 212,281 D 3,808 E 5,251 F	752,406	665,098	13.1%
2	John D. Hines Vice President, Supply & Montana Government Affairs	262,610	91,702 A	20,752 B 142,717 C 109,752 D 3,158 E	630,691	590,290	6.8%
3	Patrick R. Corcoran Former Vice President, Government & Regulatory Affairs	262,572	91,689 A	29,212 B 103,045 C 138,621 D	625,139	593,666	5.3%
4	Crystal D. Lail Vice President & Controller	241,536	84,343 A	33,043 B 131,278 C 18,419 D	508,619	503,183	1.1%
5	Jason Merkel General Manager, Operations	184,009	36,843 A	32,349 B 35,804 C 143,714 D 4,922 E	437,641	0	N/A
6	John P. Kasperick Director, Financial Planning and Analysis	174,734	39,198 A	31,057 B 34,316 C 150,444 D	429,749	0	N/A
7	William T. Rhoads Former General Manager, Generation	185,808	23,135 A	25,700 B 36,812 C 141,910 D 531 E 148 G 7,830 H	421,874	382,090	10.4%
8	Michael L. Nieman Chief Audit and Compliance Officer	221,780	55,280 A	51,123 B 54,474 C 23,562 D	406,219	392,612	3.5%
9	Daniel L. Rausch Treasurer	210,782	52,538 A	50,342 B 51,787 C 18,582 D 7,467 E	391,498	379,861	3.1%
10	Timothy P. Olson Corporate Counsel & Corp Secretary	176,718	35,238 A	44,754 B 34,748 C	291,458	287,430	1.4%

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
1	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2017 Annual						
4	Incentive Compensation Plan. Amounts were earned in 2017 and paid in the first quarter of 2018. Based on company						
5	performance against plan, the incentive plan was funded at 99% of target.						
6	Individual awards varied from the funded level based on individual performance.						
7							
8	2/ All Other Compensation for named employees consists of the following:						
9							
10	B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical,						
11	dental, vision, employee assistance program, group term life, health savings account, wellness incentive,						
12	401(k) match, and non-elective 401(k) contribution, as applicable.						
13							
14	C> Values reflect the grant date fair value for performance stock awards.						
15							
17	D> Change in pension value over previous year. The present value of accumulated benefits was calculated						
18	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
19	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
20	in our Annual Report on Form 10-K for the year ended December 31, 2017.						
21							
22	E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sell back.						
23							
24	F> Value of executive physical examination and associated tax gross-up.						
27							
28	G> Noncash taxable award and associated tax gross-up.						
29							
30	H> Accumulated vacation paid at termination.						

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	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	607,232	605,836 A	23,767 B 1,497,280 C 94,609 D 16,214 E 3,341 F	2,848,279	2,680,067	6.3%
2	Brian B. Bird Vice President & Chief Financial Officer	420,012	209,524 A	52,101 B 517,798 C 22,378 D 2,822 F	1,224,635	1,209,682	1.2%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	367,773	165,117 A	49,527 B 362,718 C	945,135	944,946	0.0%
4	Curtis T. Pohl Vice President, Distribution	285,399	113,898 A	49,257 B 225,507 C 38,024 D	712,085	703,713	1.2%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	263,577	92,103 A	51,162 B 168,940 C 24,602 D 2,822 F	603,206	586,222	2.9%

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the Northwestern Energy 2017 Annual Incentive Compensation Plan. Amounts were earned in 2017 and paid in the first quarter of 2018. Based on company performance against plan, the incentive plan was funded at 99% of target.

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.

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, 2017.

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

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

Sch. 18	BALANCE SHEET 1/				
[redacted]	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$5,615,200,534	$5,327,612,349	$287,588,185	5.40%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	103 Experimental Electric Plant Unclassified	1,631,264	1,576,812	54,452	3.45%
6	105 Plant Held for Future Use	4,769,005	4,769,005	-	0.00%
7	107 Construction Work in Progress	61,848,139	107,202,396	($45,354,257)	-42.31%
8	108 Accumulated Depreciation Reserve	(1,963,441,051)	(1,858,838,290)	($104,602,761)	5.63%
9	108.1 Accumulated Depreciation - Capital Leases	(23,120,462)	(21,109,982)	($2,010,480)	9.52%
10	111 Accumulated Amortization & Depletion Reserves	(67,324,467)	(51,260,575)	($16,063,892)	31.34%
11	114 Electric Plant Acquisition Adjustments	380,714,172	380,714,172	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(24,668,473)	(16,453,993)	(8,214,480)	49.92%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	32,121,152	32,119,605	1,547	0.00%
15	**Total Utility Plant**	4,415,524,877	4,304,126,563	111,398,314	2.59%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	5,667,242	(4,980,437)	-87.88%
18	122 Accumulated Depr. & Amort.-Nonutility Property	(47,652)	(1,829,946)	1,782,294	-97.40%
19	123.1 Investments in Assoc Companies and Subsidiaries	(129,965,362)	(132,916,808)	2,951,446	-2.22%
20	124 Other Investments	46,794,567	43,705,178	3,089,389	7.07%
21	128 Miscellaneous Special Funds	250,000	250,000	-	0.00%
23	**Total Other Property & Investments**	(82,281,642)	(85,124,334)	2,842,692	-3.34%
24	**Current and Accrued Assets**				
25	131 Cash	7,390,697	410,208	6,980,489	>300.00%
26	134 Other Special Deposits	1,670,617	2,358,634	(688,017)	-29.17%
27	135 Working Funds	23,575	22,934	641	2.79%
30	142 Customer Accounts Receivable	78,422,397	72,413,252	6,009,145	8.30%
31	143 Other Accounts Receivable	18,748,330	11,274,193	7,474,137	66.29%
32	144 Accumulated Provision for Uncollectible Accounts	(2,859,950)	(2,947,870)	87,920	-2.98%
34	146 Accounts Receivable-Associated Companies	430,318	832,656	(402,338)	-48.32%
35	151 Fuel Stock	8,051,234	9,584,006	(1,532,772)	-15.99%
36	154 Plant Materials and Operating Supplies	34,228,012	31,071,487	3,156,525	10.16%
37	164 Gas Stored - Current	9,458,237	7,703,909	1,754,328	22.77%
38	165 Prepayments	11,099,817	10,683,106	416,711	3.90%
41	172 Rents Receivable	105,515	18,888	86,627	>300.00%
42	173 Accrued Utility Revenues	89,068,916	80,425,143	8,643,773	10.75%
43	174 Miscellaneous Current & Accrued Assets	638,932	88,131	550,801	>300.00%
48	**Total Current & Accrued Assets**	256,476,647	223,938,677	32,537,970	14.53%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	13,221,232	13,261,882	(40,630)	-0.31%
51	182 Regulatory Assets	345,290,690	615,249,945	(269,959,255)	-43.88%
53	184 Clearing Accounts	1,452	137	1,315	>300.00%
55	186 Miscellaneous Deferred Debits	2,735,704	1,125,726	1,609,978	143.02%
56	189 Unamortized Loss on Reacquired Debt	37,090,302	24,810,484	12,279,818	49.49%
57	190 Accumulated Deferred Income Taxes	174,177,161	229,754,877	(55,577,716)	-24.19%
58	191 Unrecovered Purchased Gas Costs	12,581,232	14,093,347	(1,512,115)	-10.73%
59	**Total Deferred Debits**	585,097,773	898,296,378	(313,198,605)	-34.87%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 5,174,817,655	$ 5,341,237,284	$ (166,419,629)	-3.12%

Sch. 18	cont. BALANCE SHEET 1/				
[redacted]	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 529,812	$ 519,589	$ 10,223	1.97%
6	211 Miscellaneous Paid-In Capital	1,445,181,120	1,384,270,571	60,910,549	4.40%
10	216 Unappropriated Retained Earnings	458,352,058	396,919,032	61,433,026	15.48%
12	217 Reacquired Capital Stock	(96,376,075)	(95,769,402)	(606,673)	0.63%
13	219 Accumulated Other Comprehensive Income	(8,772,079)	(9,713,734)	941,655	-9.69%
14	**Total Proprietary Capital**	1,798,914,836	1,676,226,056	122,688,780	7.32%
15	**Long Term Debt**				
16	221 Bonds	1,779,660,000	1,779,660,000	-	0.00%
18	224 Other Long Term Debt	26,976,900	26,976,900	-	0.00%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	-	37,688	(37,688)	-100.00%
20	**Total Long Term Debt**	1,806,636,900	1,806,599,212	37,688	0.00%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	22,213,443	24,346,170	(2,132,727)	-8.76%
24	228.2 Accumulated Provision for Injuries and Damages	5,360,150	8,453,894	(3,093,744)	-36.60%
25	228.3 Accumulated Provision for Pensions and Benefits	11,339,112	16,319,082	(4,979,970)	-30.52%
26	228.4 Accumulated Miscellaneous Operating Provisions	162,739,851	165,336,401	(2,596,550)	-1.57%
27	229 Accumulated Provision for Rate Refunds	1,607,624	4,522,161	(2,914,537)	-64.45%
28	230 Asset Retirement Obligations	39,285,823	39,401,895	(116,072)	-0.29%
29	**Total Other Noncurrent Liabilities**	242,546,003	258,379,603	(15,833,600)	-6.13%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	319,555,991	300,810,573	18,745,418	6.23%
32	232 Accounts Payable	92,462,564	91,608,698	853,866	0.93%
34	234 Accounts Payable to Associated Companies	1,640,365	1,584,095	56,270	3.55%
35	235 Customer Deposits	5,978,744	6,427,078	(448,334)	-6.98%
36	236 Taxes Accrued	58,967,909	52,002,042	6,965,867	13.40%
37	237 Interest Accrued	16,356,048	18,557,440	(2,201,392)	-11.86%
40	241 Tax Collections Payable	1,476,279	1,521,649	(45,370)	-2.98%
41	242 Miscellaneous Current and Accrued Liabilities	52,552,038	52,930,296	(378,258)	-0.71%
42	243 Obligations Under Capital Leases-Current	2,132,734	1,979,319	153,415	7.75%
45	**Total Current and Accrued Liabilities**	551,122,672	527,421,190	23,701,482	4.49%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	45,376,055	40,208,508	5,167,547	12.85%
48	253 Other Deferred Credits	170,225,443	172,284,732	(2,059,289)	-1.20%
49	254 Regulatory Liabilities	22,002,745	29,109,829	(7,107,084)	-24.41%
50	255 Accumulated Deferred Investment Tax Credits	326,197	160,004	166,193	103.87%
52	281-283 Accumulated Deferred Income Taxes	537,666,804	830,848,150	(293,181,346)	-35.29%
53	**Total Deferred Credits**	775,597,244	1,072,611,223	(297,013,979)	-27.69%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 5,174,817,655	$ 5,341,237,284	$ (166,419,629)	-3.12%
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 and the Hydro Transaction.				
60					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 718,300 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 accountng principles generally accepted in the United States of America (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 is 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 $408.4 million and $386.4 million as of December 31, 2017 and December 31, 2016, 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 adjustment of $357.6 million as of December 31, 2017 and December 31, 2016, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2017 and December 31, 2016, 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;
- 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 separately presented for GAAP reporting;

- Electric purchase and sale transactions within the Southwest Power Pool are reflected on a net basis in accordance with regulatory treatment, as compared to gross for GAAP 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;

- 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;

- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are separately presented for GAAP; and

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, asset retirement obligations, regulatory assets and liabilities, uncollectible accounts, our Qualifying Facility (QF) liability, environmental costs, unbilled revenues and actuarially determined benefit costs. 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

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

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 $2.9 million at December 31, 2017 and 2016, respectively. Unbilled revenues were $89.1 million and $80.4 million at December 31, 2017 and December 31, 2016, respectively.

Inventories

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

	December 31,	
	2017	2016
Fuel stock	$ 8,051	$ 9,584
Plant materials and operating supplies	34,228	31,071
Gas stored underground (including the non-current portion reflected in utility plant)	41,579	39,824
Total Inventory	$ 83,858	$ 80,479

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 Statement of Income at that time. This would result in a charge to earnings, 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 accumulated other comprehensive income (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 utility plant are assets under capital 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 7.2% and 7.2%, for Montana and South Dakota for 2017 and 2016, respectively. AFUDC capitalized totaled $8.5 million and $7.0 million for the years ended December 2017 and 2016, 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 three to 50 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 3.0% for 2017 and 2016.

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.

Accounting Standards Issued

Revenue Recognition - In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance on the recognition of revenue from contracts with customers, which will supersede nearly all existing revenue recognition guidance under GAAP. Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers.

We adopted this standard for interim and annual periods beginning January 1, 2018, as required, and used the modified retrospective method of adoption. We have also elected to utilize certain practical expedients, which allow us to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date.

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

Based on our analysis, we did not have a cumulative-effect adjustment to retained earnings at January 1, 2018. Disclosures in 2018 will include a reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance in order to help facilitate comparability with the prior periods. We expect our disclosures to reflect our disaggregated revenue by segment for each geographical region.

Retirement Benefits - In March 2017, the FASB issued new guidance on the presentation of net periodic costs related to benefit plans. The new guidance requires the service cost component of net periodic benefit cost to be included within operating income within the same line as other compensation expenses. All other components of net periodic benefit costs must be outside of operating income. In addition, the updated guidance permits only the service cost component of net periodic benefit costs to be capitalized to inventory or utility plant. This represents a change from current accounting and financial reporting, with presentation of the aggregate net periodic benefit costs on the income statement within operating income, and which permits all components of net periodic benefit costs to be capitalized.

This guidance is effective for interim and annual periods beginning January 1, 2018 for GAAP purposes. These amendments will be applied retrospectively for the presentation of the various components of net periodic benefit costs and prospectively for the change in eligible costs to be capitalized. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the current ratemaking treatment.

Leases - In February 2016, the FASB issued revised guidance on accounting for leases. The new standard requires a lessee to recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term for all leases with terms longer than 12 months. Leases with a term of 12 months or less will be accounted for similar to existing guidance for operating leases. Recognition, measurement and presentation of expenses will depend on classification as a finance or operating lease. The new guidance will be effective for us for interim and annual periods beginning January 1, 2019 and early adoption is permitted. A modified retrospective transition approach is required for lessees for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. An additioual transition approach allows an entity to not assess on transition whether any expired or existiug land easements are, or contain, leases that were not previously accounted for as leases. We are curreutly evaluating the impact of adoption of this guidance. We do not have a significant amount of capital or operating leases. Therefore, based on our analysis to this point we do not expect this guidance to have a significant impact on our Financial Statements and disclosures other than an expected increase in assets and liabilities.

Statement of Cash Flows - In August 2016, the FASB issued guidance that addresses eight classification issues related to the presentation of cash receipts and cash payments in the statement of cash flows. The uew guidance will be effective for us in our first quarter of 2018. The adoption of this guidance will not have a significant impact on our Statement of Cash Flows.

In November 2016, the FASB issued guidance that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as other special deposits. The new guidance will be effective for us in our first quarter of 2018. The adoption of this guidance will not have a significant impact on our Statement of Cash Flows.

Supplemental Cash Flow Information

	Year Ended December 31,	
	2017	2016
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ 60	$ (2,922)
Interest	82,692	84,953
Significant non-cash transactions:		
Capital expenditures included in accounts payable	15,848	13,783

(3) Regulatory Matters

Tax Cuts and Jobs Act

In December 2017, H.R.1 (the Tax Cuts and Jobs Act) was signed into law, which enacts significant changes to U.S. tax and related laws. The primary iupact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Each of our regulatory jurisdictions initiated dockets regarding the impact of the Tax Cuts and Jobs Act on customer rates. Our Montana and South Dakota jurisdictional filings are discussed below. We do not expect the required FERC or Nebraska filings to be significant. In each of our jurisdictions, we expect the Tax Cuts and Jobs Act related credits to continue and be subject to true-up until base rates are reset in a general rate case filing. As of March 31, 2018, we have deferred revenue of approximately $7.3 million associated with the impacts of the Tax Cuts and Jobs Act. This estimate is based upon an expected annual revenue reduction of approximately $15 million to $20 million, which is our expected income tax expense reduction in 2018. For purposes of the filings discussed below, we have also calculated the customer benefit using an alternate method based on historic test periods. This alternate calculation could result in an additional reduction in revenue ranging from approximately $8 million to $12 million, which would reduce net income. We cannot predict how each jurisdiction may calculate the amount of credits due to customers.

Montana - In March 2018, we submitted a filing to the Montana Public Service Commission (MPSC) calculating the estimated benefit of the Tax Cuts and Jobs Act related savings to customers using two alternative methods. The first method was calculated based on the expected income tax expense reduction in 2018, with no impact to net income. The second method, was calculated by revising the electric and natural gas revenue requirements in the last applicable test years. For our electric customers, we proposed to use 50% of the benefit as a direct refund to customers, and to use the other 50% to remove trees outside our electric transmission and distribution lines rights of way, which pose a risk of unfavorable events on our system including disruption of service, property damage, and / or forest fires. For our natural gas customers, we proposed to use the benefit as a direct refund to customers. A procedural schedule has not been established in this docket.

South Dakota - In April 2018, we submitted a filing with the South Dakota Public Utilities Commission (SDPUC) calculating the estimated benefit of the Tax Cuts and Jobs Act related savings to customers based on the expected income tax expense reduction in 2018, with no impact to net income. We also presented a calculation revising the electric and natural gas revenue requirements in the last applicable test years. We proposed to either refund the benefit to customers, or to hold this amount in a regulatory liability to provide rate moderation in our next electric and natural gas rate cases, at the SDPUC's option. The SDPUC has not established a procedural schedule in this docket.

Montana QF Tariff Filing

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. In May 2016, we filed an application for approval of a revised tariff for standard rates for small QFs (3 MW or less). In November 2017, the MPSC issued an order revising the QF tariff to establish a maximum contract length of 15 years and substantially lowering the rate for future QF contracts. In this order, the MPSC also upheld an initial decision to apply the contract term to our future owned and contracted electric supply resources. We, as well as the QFs, sought judicial review of the November 2017 order.

As a result of this order, we terminated our competitive solicitation process for 20-year resources to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. We continue to evaluate the impact of this order, as we have significant generation capacity deficits and negative reserve margins, and our 2015 resource plan identified price and reliability risks to our customers if we rely solely upon market purchases to address these capacity needs. In addition to our responsibility to meet peak demand, national transmission-related reliability standards effective July 2016 require us to have even greater dispatchable generation capacity available and be capable of increasing or decreasing output to address the irregular nature of intermittent generation such as wind or solar. We expect to file our next electric supply resource procurement plan in late 2018.

Cost Recovery Mechanisms

Montana House Bill 193 / Electric Tracker - In April 2017, the Montana legislature passed House Bill 193 (HB 193), amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric Power Cost and Credit Adjustment Mechanism (PCCAM). In December 2017, after the intervenors filed testimony, the MPSC issued a Notice of Additional Issues stating that the range of options proposed by the parties was not sufficient and directing parties to consider alternatives incorporating risk-sharing features of other utilities in the region.

We filed testimony in February 2018, responsive to both the intervenors' testimony and the MPSC's Notice of Additional Issues addressing alternative risk-sharing mechanisms. Intervenors filed testimony on the Notice of Additional Issues in March

2018. A hearing is scheduled to begin May 31, 2018. If the MPSC approves a new mechanism, the MPSC may apply the mechanism to variable costs on a retroactive basis to the effective date of HB 193 (July 1, 2017).

Montana Electric Tracker Open Dockets - 2015/2016 - 2016/2017 - Under the previous statutory tracker mechanism, each year we submitted an electric tracker filing for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period, which were subject to a prudency review. In June 2017, the MPSC consolidated the current-period supply costs portion of the 2016/2017 docket with the 2015/2016 docket. The rates for this consolidated docket were approved on an interim basis. The MPSC has not established a schedule regarding this consolidated docket under the prior statutory tracker. In addition, the MPSC consolidated the projected supply costs portion of the 2016/2017 docket with the PCCAM docket, discussed above.

Montana Electric Tracker Litigation - 2012/2013 - 2013/2014 (Consolidated Docket) and 2014/2015 (2015 Tracker) - In 2016, we received two orders in separate electric tracker dockets filed with the MPSC, which, in total, resulted in a $12.4 million disallowance of costs, including interest. The first order (Consolidated Docket) included a disallowance of replacement power costs from a 2013 outage at Colstrip Unit 4. In September 2016, we appealed that order to the Montana District Court, arguing that the order was arbitrary and capricious and violated Montana law. We expect a decision on this appeal within the next nine months.

The second order (2015 Tracker), included a disallowance of approximately $0.4 million of portfolio modeling costs. In June 2016, we filed an appeal of the second order in Montana District Court arguing that the decision violated Montana law. In March 2018, the Montana District Court upheld our appeal of the disallowance of these costs. The Court remanded the matter to the MPSC and directed the MPSC to issue an order to restore the modeling costs to the deferred account from which the MPSC ordered it be removed. On April 10, 2018, the MPSC voted not to appeal the Montana District Court's decision.

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 January 2018, the MPSC issued an order in our 2017 filing applying an alternate allocation methodology both prospectively and retroactively, which reduces our annual recovery of these taxes by approximately $1.7 million. The change in methodology results in a lower property tax allocation to our Montana electric retail customers and a higher property tax allocation to Federal Energy Regulatory Commission (FERC) transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes). We sought reconsideration of the retroactive application of this change in methodology. On April 5, 2018, the MPSC voted to apply the change on a prospective basis only. We expect to receive a written order during the second quarter of 2018.

Dave Gates Generating Station at Mill Creek (DGGS)

In May 2016, we received an order from the FERC denying a May 2014 request for rehearing and requiring us to make refunds. The request for rehearing challenged a September 2012 FERC Administrative Law Judge's (ALJ) initial decision regarding cost allocation at DGGS between retail and wholesale customers. The 2012 decision concluded that only a portion of these costs should be allocated to FERC jurisdictional customers. We had cumulative deferred revenue of approximately $27.3 million, consistent with the ALJ's initial decision, which was refunded to wholesale and choice customers in June 2016 in accordance with the FERC order.

In June 2016, we filed a petition for review of the FERC's May 2016 order with the United States Circuit Court of Appeals for the District of Columbia Circuit (D.C. Circuit). In March 2018, the D.C. Circuit denied all of our requests.

(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,	
	2017	2016
Colstrip Unit 4 Basis Adjustment	$ (147,543)	$ (150,631)
Havre Pipeline Company, LLC	14,245	14,349
NorthWestern Services, LLC	1,920	1,915
Risk Partners Assurance, Ltd.	1,413	1,450
Total Investments in Subsidiary Companies	**$ (129,965)**	**$ (132,917)**

(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.

			December 31,	
	Note Reference	Remaining Amortization Period	2017	2016
			(in thousands)	
Income taxes	14	Plant Lives	$ 162,843	$ 411,546
Pension	16	Undetermined	115,504	127,133
Employee related benefits	16	Undetermined	17,729	20,256
State & local taxes & fees		Various	10,890	17,835
Environmental clean-up	19	Various	12,399	13,601
Distribution infrastructure projects		-	—	3,136
Other		Various	25,926	21,743
Total Regulatory Assets			**$ 345,291**	**$ 615,250**
Gas storage sales		22 Years	9,149	9,569
Unbilled revenue		1 Year	9,969	11,973
State & local taxes & fees		1 Year	1,520	1,154
Environmental clean-up		Various	1,365	6,414
Total Regulatory Liabilities			**$ 22,003**	**$ 29,110**

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. This reflects the estimated impact of the Tax Cuts and Job Acts enacted in December 2017. 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 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. The MPSC allows recovery of other employee related benefits on a cash basis.

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

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

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 19 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Montana Distribution System Infrastructure Project (DSIP)

We have an accounting order to defer certain incremental operating and maintenance expenses associated with DSIP. Pursuant to the order, we deferred expenses incurred during 2011 and 2012 as a regulatory asset associated with the phase-in portion of the DSIP. These costs are being amortized into expense over five years, which began in 2013 and concluded in 2017.

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 (years)	December 31, 2017	2016
		(in thousands)	
Land and improvements	53 – 96	$ 156,637	$ 147,036
Building and improvements	27 – 64	443,420	425,518
Storage, distribution, and transmission	15 – 85	3,277,218	3,054,601
Generation	25 – 50	1,680,713	1,680,254
Construction work in process	25 – 50	61,848	107,202
Other equipment	2 – 45	484,536	447,473
Total utility plant		6,104,372	5,862,084
Less accumulated depreciation		(2,078,554)	(1,947,663)
Net utility plant		$ 4,025,818	$ 3,914,421

Utility plant under capital lease were $17.5 million and $19.3 million as of December 31, 2017 and 2016, respectively, which included $17.1 million and $19.1 million as of December 31, 2017 and 2016, 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 an obligation under capital 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, 2017				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,682	$ 60,859	$ 49,968	$ 307,712
Accumulated depreciation	44,373	33,189	40,993	86,309
December 31, 2016				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,623	$ 60,491	$ 50,802	$ 297,289
Accumulated depreciation	38,894	29,235	37,099	77,513

(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. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated ARO 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, Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, and our obligation to plug and abandon oil and gas wells at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2017	2016
Liability at January 1,	$ 39,402	$ 35,532
Accretion expense	2,062	1,885
Liabilities incurred	—	164
Liabilities settled	(61)	—
Revisions to cash flows	(2,117)	1,821
Liability at December 31,	$ 39,286	$ 39,402

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, 2017 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, 2017 and 2016. 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, 2017
Interest rate contracts	Interest on long-term debt	$ 613

A pre-tax loss of approximately $16.5 million is remaining in AOCI as of December 31, 2017, 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 natnre of cash and cash equivalents, accounts receivable, net, and accounts payable, the carrying amount of each such items approximate 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 sonrce 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, 2017	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)		
Other special deposits	$ 1,671	$ —	$ —	$ —	$ 1,671
Rabbi trust investments	28,135	—	—	—	28,135
Total	$ 29,806	$ —	$ —	$ —	$ 29,806
December 31, 2016					
Other special deposits	$ 2,359	$ —	$ —	$ —	$ 2,359
Rabbi trust investments	25,064	—	—	—	25,064
Total	**$ 27,423**	$ —	$ —	$ —	**$ 27,423**

Other special deposits represents amonnts 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, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 1,806,637	$ 1,901,915	$ 1,806,599	$ 1,852,052

Notes payable consist of commercial paper and are not included in the table above as carrying value approximates fair value. 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) Notes Payable and Credit Arrangements

Notes Payable

Notes Payable and the corresponding weighted average interest rates as of December 31 were as follows (dollars in millions):

	2017		2016	
Notes Payable	Balance	Interest Rate	Balance	Interest Rate
Commercial Paper	$ 319.6	1.75%	$ 300.8	1.07%

The following information relates to commercial paper for the years ended December 31 (dollars in millions):

	2017	2016
Maximum notes payable outstanding	$ 332.5	$ 300.8
Average notes payable outstanding	$ 251.7	$ 210.7
Weighted-average interest rate	1.35%	0.86%

Under our commercial paper program we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $340 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility.

Unsecured Revolving Line of Credit

On December 12, 2016, we amended and restated our existing revolving credit facility to, among other things, increase the size of the facility to $400 million (from $350 million) and extend the maturity date to December 12, 2021 (from November 5, 2018). We retained 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 or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.875% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2017. Commitment fees for the unsecured revolving line of credit were $0.5 million and $0.4 million for the years ended December 31, 2017 and 2016.

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

(12) Long-Term Debt

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

		December 31,	
	Due	2017	2016
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ —	$ —
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—6.34%	2019	—	250,000
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	—
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
Discount on Notes and Bonds	—	—	(38)
Total Long-Term Debt		$ 1,806,637	$ 1,806,599

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. All of such 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 November 2017, we issued $250 million aggregate principal amount of Montana First Mortgage Bonds, at a fixed interest rate of 4.03% maturing in 2047. The bonds are secured by our electric and natural gas assets in Montana. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to redeem our 6.34%, $250 million of Montana First Mortgage Bonds due 2019.

In August 2016, the City of Forsyth, Rosebud County, Montana issued $144.7 million aggregate principal amount of Pollution Control Revenue Refunding Bonds on our behalf. The bonds were issued at a fixed interest rate of 2.00% maturing in 2023. The proceeds of the issuance were loaned to us pursuant to a Loan Agreement and have been used to partially fund the redemption of the 4.65%, $170.2 million City of Forsyth Pollution Control Revenue Refunding Bonds due 2023 (Prior Bonds) issued on our behalf. We paid the remaining portion of the Prior Bonds with available funds. Our obligation under the Loan Agreement is secured by the issuance of $144.7 million of Montana First Mortgage Bonds. These bonds are secured by our electric and natural gas assets in Montana and Wyoming. The City of Forsyth bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

In June 2016, we issued $60 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.80% maturing in 2026. Proceeds were used to redeem our 6.05%, $55 million South Dakota First Mortgage Bonds due 2018. In addition, in September 2016, we issued $45 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.66% maturing in 2026. Proceeds from this issuance were used for general corporate purposes. Both series of these bonds are secured by our electric and natural gas assets in South Dakota, Nebraska, North Dakota, and Iowa and were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended.

As of December 31, 2017, we are 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 $2.1 million in 2018, $2.3 million in 2019, $2.5 million in 2020, $2.7 million in 2021 and $2.9 million in 2022.

(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,	
	2017	2016
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 412	$ 815
Risk Partners Assurance, Ltd.	18	18
	$ 430	$ 833
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,640	$ 1,584

(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 statutory tax rate will reduce the impact of these deductions. 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.

During the twelve months ended December 31, 2016, we recorded an income tax benefit of approximately $17.0 million due to the adoption of a tax accounting method change related to the costs to repair generation assets, which allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. Approximately $12.5 million of this deduction related to 2015 and prior tax years. This is reflected in the flow-through repairs deductions line due to the regulatory treatment.

On December 22, 2017, the Tax Cuts and Jobs act was signed into law, which enacts significant changes to U.S. tax and related laws. The primary impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. We revalued our deferred tax assets and liabilities as of December 31, 2017 based on the reduction in the overall future tax impact expected to be realized at the lower tax rate. This resulted in a reduction in our deferred tax assets of approximately $70 million and a reduction in our deferred tax liabilities of approximately $391 million. These reductions were offset in regulatory assets and liabilities.

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

	December 31,	
	2017	2016
NOL carryforward	$ 62,522	$ 78,324
Production tax credit	28,067	17,034
Pension / postretirement benefits	26,887	45,847
AMT credit carryforward	13,599	13,599
Compensation accruals	12,113	18,715
Customer advances	11,949	15,837
Unbilled revenue	5,944	12,743
Environmental liability	5,821	9,698
Interest rate hedges	4,323	7,192
Reserves and accruals	1,126	1,730
Property taxes	430	3,765
QF obligations	234	—
Regulatory liabilities	114	2,290
Other, net	1,048	2,981
Deferred Tax Asset	**$ 174,177**	**$ 229,755**
Excess tax depreciation	$ (361,185)	$ (464,969)
Goodwill amortization	(130,075)	(192,615)
Flow through depreciation	(45,998)	(160,604)
Regulatory assets	(409)	(12,230)
Reserves and accruals	—	(430)
Deferred Tax Liability	**$ (537,667)**	**$ (830,848)**

The revaluation of deferred income taxes reflects our estimate of the impact of the Tax Cuts and Jobs Act. We will continue to evaluate subsequent regulations and iuterpretations and assumptions made, which could materially change our estimate. Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code Section 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

At December 31, 2017 we estimate our total federal NOL carryforward to be approximately $420.8 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $105.2 million in 2031; $13.3 million in 2033; $73.3 million in 2034; $174.6 million in 2036 and $54.4 million in 2037. We estimate our state NOL carryforward as of December 31, 2017 is approximately $315.7 million. If unused, our state NOL carryforwards will expire as follows: $67.0 million in 2018; $10.5 million in 2020; $58.3 million in 2021; $135.9 million in 2023 and $44.0 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):

	2017	2016
Unrecognized Tax Benefits at January 1	$ 88,429	$ 92,387
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	(22,973)	—
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(7,983)	(3,958)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 57,473	$ 88,429

The reduction in unrecognized tax benefits during the twelve months ended December 31, 2017 reflects the effect of the lower statutory rate in the Tax Cuts and Jobs Act. Our unrecognized tax benefits include approximately $47.8 million and $66.5 million related to tax positions as of December 31, 2017 and 2016, 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. During the years ended December 31, 2017 and 2016, we recognized $0.8 million and $0.7 million, respectively, of expense for interest in the Statements of Income. As of December 31, 2017 and 2016, we had $1.5 million and $0.7 million, respectively, of interest accrued in the Balance Sheets.

Our federal tax returns from 2000 forward remain subject to examination by the IRS.

(15) Comprehensive Income (Loss)

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

	December 31,					
	2017			2016		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit (Expense)	Net-of-Tax Amount
Foreign currency translation adjustment	$ (202)	$ —	$ (202)	$ 25	—	$ 25
Reclassification of net losses (gains) on derivative instruments	613	(242)	371	(2,169)	831	(1,338)
Postretirement medical liability adjustment	1,257	(484)	773	317	(122)	195
Other comprehensive income (loss)	$ 1,668	$ (726)	$ 942	$ (1,827)	$ 709	$ (1,118)

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

	December 31,	
	2017	2016
Foreign currency translation	$ 1,178	$ 1,380
Derivative instruments designated as cash flow hedges	(9,981)	(10,352)
Postretirement medical plans	31	(742)
Accumulated other comprehensive income	$ (8,772)	$ (9,714)

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

		December 31, 2017			
		Year Ended			
	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,352)	$ (742)	$ 1,380	$ (9,714)
Other comprehensive income before reclassifications		—	—	(202)	(202)
Amounts reclassified from AOCI	Interest on long-term debt	371	—	—	371
Amounts reclassified from AOCI		—	773	—	773
Net current-period other comprehensive income (loss)		371	773	(202)	942
Ending Balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)

	Affected Line Item in the Statements of Income	December 31, 2016 Year Ended Interest Rate Derivative Instruments Designated as Cash Flow	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,014)	$ (937)	$ 1,355	$ (8,596)
Other comprehensive income before reclassifications		—	—	25	25
Amounts reclassified from AOCI	Interest on long-term debt	(1,338)	—	—	(1,338)
Amounts reclassified from AOCI		—	195	—	195
Net current-period other comprehensive (loss) income		(1,338)	195	25	(1,118)
Ending Balance		$ (10,352)	$ (742)	$ 1,380	$ (9,714)

(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. 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,	
	2017	2016	2017	2016
Change in benefit obligation:				
Obligation at beginning of period	$ 646,032	$ 628,883	$ 26,217	$ 28,652
Service cost	10,994	11,759	456	492
Interest cost	25,633	26,210	715	795
Actuarial loss (gain)	41,719	7,006	(1,884)	(71)
Settlements	—	—	390	390
Benefits paid	(27,582)	(27,826)	(2,973)	(4,041)
Benefit Obligation at End of Period	$ 696,796	$ 646,032	$ 22,921	$ 26,217
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 524,637	$ 500,044	$ 18,605	$ 17,972
Return on plan assets	80,253	39,719	2,690	1,277
Employer contributions	9,200	12,700	2,058	3,397
Benefits paid	(27,582)	(27,826)	(2,973)	(4,041)
Fair value of plan assets at end of period	$ 586,508	$ 524,637	$ 20,380	$ 18,605
Funded Status	$ (110,288)	$ (121,395)	$ (2,541)	$ (7,612)
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	2,535	—	5,061	—
Total Assets	2,535	—	5,061	—
Current liability	—	—	(3,353)	(1,789)
Noncurrent liability	(112,823)	(121,395)	(4,249)	(5,823)
Total Liabilities	(112,823)	(121,395)	(7,602)	(7,612)
Net amount recognized	$ (110,288)	$ (121,395)	$ (2,541)	$ (7,612)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	(4)	(9)	9,955	11,988
Net actuarial loss	(105,545)	(127,953)	(1,735)	(4,739)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(698)	(849)
Net actuarial gain	—	—	1,079	38
Total	$ (105,549)	$ (127,962)	$ 8,601	$ 6,438

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):

	Pension Benefits	
	December 31,	
	2017	2016
Projected benefit obligation	$ 634.4	$ 646.0
Accumulated benefit obligation	634.4	643.6
Fair value of plan assets	522.7	524.6

As of December 31, 2017, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2017	2016	2017	2016
Components of Net Periodic Benefit Cost				
Service cost	$ 10,994	$ 11,759	$ 456	$ 492
Interest cost	25,633	26,210	715	795
Expected return on plan assets	(23,964)	(28,248)	(846)	(1,042)
Amortization of prior service cost (credit)	4	246	(1,882)	(1,882)
Recognized actuarial loss	7,837	9,888	318	315
Settlement loss recognized	—	—	390	390
Net Periodic Benefit Cost (Credit)	$ 20,504	$ 19,855	$ (849)	$ (932)

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.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2018 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service credit (cost)	$ (4)	$ 1,882
Accumulated loss	(4,286)	78

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2017 and 2016. 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.

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 2017 increased our projected benefit obligation by approximately $43.6 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 increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 4.97% and decreased our assumption on the NorthWestern Corporation Pension Plan to 4.47% for 2018.

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

	Pension Benefits		Other Postretirement	
	December 31,		December 31,	
	2017	2016	2017	2016
Discount rate	3.50-3.60 %	3.95-4.10 %	3.20-3.30 %	3.40-3.55 %
Expected rate of return on assets	4.70	5.80	4.70	5.80
Long-term rate of increase in compensation levels (nonunion)	2.89	3.28	2.89	3.28
Long-term rate of increase in compensation levels (union)	2.03	3.20	2.03	3.20

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 fully 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,	
	2017	2016	2017	2016	2017	2016
Domestic debt securities	55.0%	55.0%	70.0%	65.0%	40.0%	40.0%
International debt securities	4.0	5.0	2.5	5.0	—	—
Domestic equity securities	16.5	34.0	11.0	25.0	50.0	50.0
International equity securities	24.5	6.0	16.5	5.0	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,	
	2017	2016	2017	2016	2017	2016
Cash and cash equivalents	0.1%	—%	—%	0.1%	1.5%	1.0%
Domestic debt securities	54.5	53.4	70.0	64.4	35.2	37.0
International debt securities	4.0	4.6	2.5	4.4	—	—
Domestic equity securities	16.7	36.0	11.1	26.0	53.4	52.6
International equity securities	24.7	6.0	16.4	5.1	9.9	9.4
	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. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

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 2018 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 2017 and 2016 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2017	2016
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 11,500
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 9,200	$ 12,700

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

	Pension Benefits	Other Postretirement Benefits
2018	$ 30,326	$ 3,353
2019	31,721	2,927
2020	33,452	2,714
2021	34,703	2,502
2022	35,997	2,254
2023-2027	200,820	7,607

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 year ended December 31, 2017 and 2016 were $10.0 million and $9.8 million, respectively.

(17) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. In 2014, an additional 600,000 shares of common stock were authorized by the shareholders for issuance under the ECP. As of December 31, 2017, there were 822,695 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:

	2017	2016
Risk-free interest rate	1.50%	0.85%
Expected life, in years	3	3
Expected volatility	17.0% to 22.7%	17.1% to 22.1%
Dividend yield	3.7%	3.4%

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

A summary of nonvested shares as of and changes during the year ended December 31, 2017, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	175,257	$ 46.35
Granted	93,108	47.99
Vested	(87,438)	42.47
Forfeited	(5,459)	47.60
Remaining nonvested grants	175,468	$ 49.11

We recognized compensation expense of $3.9 million and $5.3 million for the years ended December 31, 2017 and 2016, respectively, and a related income tax expense of $0.4 million and $1.8 million, for the years ended December 31, 2017 and 2016, respectively. As of December 31, 2017, we had $5.5 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $3.7 million and $3.5 million for the years ended December 31, 2017 and 2016, 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, 2017, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	62,591	$ 41.14
Granted	13,394	52.20
Vested	(8,445)	27.42
Forfeited	—	—
Remaining nonvested grants	67,540	$ 43.09

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, 2017 and 2016, DSUs issued to members of our Board totaled 54,920 and 28,338, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2017 and 2016 was approximately $2.9 million and $2.4 million, respectively.

(18) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a \$0.01 par value and 50,000,000 shares of preferred stock with a \$0.01 par value. 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.

In September 2017, we entered into an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner, & Smith, Incorporated and J. P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to \$100 million. During 2017, we sold 888,938 shares of our common stock at an average price of \$61.30 per share. Proceeds received were approximately \$53.7 million, which are net of sales commissions paid of approximately \$0.8 million and other fees. During the three months ended December 31, 2017, we issued 805,169 shares at an average price of \$61.48, for net proceeds of \$48.9 million, which is net of sales conunissions of approximately \$0.6 million and other fees.

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 34,208 and 49,514 during the years ended December 31, 2017 and 2016, 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. These contracts require us to purchase minimum amounts of energy at prices ranging from \$61 to \$136 per MWH through 2029. Our estimated gross contractual obligation related to these contracts is approximately \$807.4 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately \$625.6 million through 2029. 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,	
	2017	2016
Beginning QF liability	\$ 134,324	\$ 138,310
Unrecovered amount	(12,009)	(14,829)
Interest on long-term debt	10,471	10,843
Ending QF liability	\$ 132,786	\$ 134,324

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

	Gross Obligation	Recoverable Amounts	Net
2018	76,703	58,401	18,302
2019	78,836	59,020	19,816
2020	80,984	59,647	21,337
2021	82,941	60,136	22,805
2022	84,948	60,639	24,309
Thereafter	403,009	327,773	75,236
Total	$ 807,421	$ 625,616	$ 181,805

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 26 years. Costs incurred under these contracts are included in operating expenses in the Statements of Income and were approximately $228.4 million and $216.8 million for the years ended December 31, 2017 and 2016, respectively. As of December 31, 2017, our commitments under these contracts are $190.6 million in 2018, $179.0 million in 2019, $134.8 million in 2020, $113.9 million in 2021, $116.0 million in 2022, and $1.3 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the Hydro Transaction, 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 $20.0 million between 2018 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, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us and is estimated to range between $26.7 million to $31.2 million. As of December 31, 2017, we have 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 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 $23.5 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, 2017, the reserve for remediation costs at this site is approximately $9.6 million, and we estimate that approximately $4.6 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 September 2017, we submitted a Draft Remedial Investigation Work Plan for the Helena site, based on the request of the MDEQ. Comments from the MDEQ are expected in the first quarter of 2018.

An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells have been 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. This is expected to prompt MDEQ to reevaluate its position concerning listing the Missoula site on the State of Montana's superfund list. New landowners purchased a portion of the Missoula site using funding provided by a third party. The terms of the funding require the new landowners to address environmental issues. The new landowners contacted us and we addressed their immediate concerns. After researching historical ownership we have identified another potentially responsible party with whom we have initiated communications regarding 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 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, 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, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, EPA is presently regulating new and existing sources of GHG emissions through regulations. EPA is currently reviewing its existing regulations as a result of an Executive Order issued by President Trump on March 28, 2017 (the Executive Order) instructing all federal agencies to review all regulations and other policies (specifically including the Clean Power Plan, which is discussed in further detail below) that burden the development or use of domestically produced energy resources and suspend, revise or rescind those that pose an undue burden beyond that required to protect the public interest.

As a result of the Executive Order review, on October 10, 2017, the EPA proposed to repeal the Clean Power Plan (CPP). Subsequently, the EPA issued an Advance Notice of Proposed Rulemaking, soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act, for a possible replacement of the CPP, which was published in the Federal Register on December 28, 2017. The CPP was published in October 2015 and was intended to establish GHG performance standards for existing power plants under Clean Air Act Section 111(d). The CPP established CO2 emission performance standards for existing electric utility steam generating units and natural gas combined cycle units. In its repeal proposal, EPA indicated that it had not yet determined whether it will promulgate a new rule to replace the CPP and the form, if any, such a replacement would take.

Following the issuance of the CPP in October 2015, judicial appeals were filed in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), including an appeal by us. The United States Supreme Court (Supreme Court) issued a stay pending resolution of the appeals by the D.C. Circuit. The D.C. Circuit filed an order on November 9, 2017, holding the case in abeyance for 60 days. On January 10, 2018, EPA filed a status report requesting the D.C. Circuit continue to hold the case in abeyance pending conclusion of its rulemaking.

In addition, administrative requests for reconsideration of the CPP were filed with the EPA, including one filed by us in December 2015. We requested the EPA reconsider the CPP, in part, on the grounds that the CO_2 reductions in the CPP applicable to Montana were substantially greater than the reductions the EPA had originally proposed. The EPA denied the petition for reconsideration on January 11, 2017, and we appealed that denial to the D.C. Circuit on March 13, 2017. The EPA has also requested that this case be held in abeyance.

We cannot predict what, if any, action the D.C. Circuit may take in either of these two cases, particularly in light of the EPA's proposal to repeal the CPP. If the CPP ultimately is not repealed, survives the legal challenges described above, and is implemented as written, or if a replacement to the CPP is adopted with similar requirements, it could result in significant additional compliance costs that would 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 impacts customers in our region.

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

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

On January 10, 2017, the EPA published amendments to the requirements under the Clean Air Act for state plans for protection of visibility. 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. Therefore, 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 EPA has not responded to our petition. On January 19, 2018, EPA advised the D.C. Circuit that it intended to initiate rulemaking to revisit the amendment, and asked that the case be held in abeyance. On January 30, 2018, the D.C. Circuit granted the EPA's request to hold the case in abeyance pending further order of the Court.

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 CPP, as discussed above, we cannot predict the impact of the CPP on us until there is a definitive judicial decision or administrative action by the EPA repealing or significantly changing the CPP.

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 an Oregon solar QF developer with which we began negotiating in early 2016 to purchase capacity and energy at our avoided cost under the QF-1 option 1(a) standard rates in accordance with PURPA as implemented by the FERC and the MPSC.

On June 16, 2016, however, the MPSC entered a Notice of Commission Action (MPSC Notice) suspending the availability of QF-1 option 1(a) standard rates for solar projects greater than 100 kW, which included the various projects proposed by PNWS. The MPSC exempted from the suspension any contracts at the standard tariff rate with solar QFs greater than 100 kW, but no larger than 3 MW, if prior to the date of the MPSC Notice, the QF had submitted a signed power purchase agreement and had executed an interconnection agreement. PNWS had not obtained interconnection agreements for any of its projects as of June 16, 2016, so based on the MPSC Notice and subsequent July 25, 2016 Order 7500 of like effect from the MPSC, we discontinued further negotiations with PNWS.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and other relief, including a judicial declaration that some or all of the 21 proposed power purchase agreements were in effect. We removed the state lawsuit to the United States District Court for the District of Montana.

On July 19, 2017, we entered into a partial settlement agreement with PNWS that resolved some but not all of PNWS' litigation claims. As a result of that settlement, on August 14, 2017, PNWS amended its original complaint to seek enforcement and/or damages related to four of the 21 power purchase agreements.

Currently pending before the United States District Court are our motion to dismiss, our motion for partial summary judgment, and PNWS's motion for summary judgment on its request for declaratory relief regarding those four power purchase agreements.

We dispute the remaining claims in PNWS' lawsuit and intend to vigorously defend those claims. This matter is in the initial stages, and we cannot predict an outcome or estimate the amount or range of loss that would result from an adverse outcome in the remaining claims.

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 as defendants. The State claims 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 in the litigation 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 and following briefing and argument, on October 10, 2017, the Federal District Court Judge entered an order denying the State's motion. As 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. The motions to dismiss have been fully briefed and are awaiting decision.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is in the initial stages, and we cannot predict an outcome. If the Federal District Court determines the riverbeds under all 10 of the hydroelectric facilities are navigable (including the five hydroelectric facilities on the Great Falls Reach) and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $7 million commencing in November 2014, when we acquired the facilities. 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.

Wilde Litigation

On October 10, 2017, Martin Wilde, a Montana resident and wind developer, and three entities with which he is affiliated, commenced a lawsuit against the MPSC, each individual commissioner of the MPSC (in each of their official and individual capacities), and us in the Montana Eighth Judicial District Court (Eighth District Court). The plaintiffs allege that the MPSC collaborated with NorthWestern to set discriminatory rates and contract durations for QF developers. The plaintiffs seek power purchase agreements at $45.19 per megawatt hour for a 25-year term or, as an alternative remedy to the alleged discrimination, a reduction in NorthWestern's rates by $17.03 per megawatt hour. The plaintiffs also seek compensatory damages of not less than $4.8 million, various forms of declaratory relief, injunctive relief, unspecified damages, and punitive damages.

On October 20, 2017, the Eighth District Court conducted a hearing on the plaintiffs' application for a preliminary injunction to stop the defendants from the alleged ongoing discrimination that harms development of renewable energy in Montana. At the hearing's conclusion, the court did not rule on the requested injunction but orally ordered post-hearing briefs and set deadlines for answers and dispositive motions. On November 11, 2017, Mr. Wilde died in a farming accident, and, at plaintiffs' request, the Eighth District Court has stayed the proceeding through May 11, 2018. We have received no indication whether or not Mr. Wilde's estate or the other plaintiff entities will continue the litigation after the stay expires.

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	2,004	>300.00%
5	303 Miscellaneous Intangible Plant	7,395,147	-	7,395,147	8,399,670	-11.96%
6	**Total Intangible Plant**	24,942,726	-	24,942,726	8,421,669	196.17%
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	427,859,259	-	427,859,259	422,316,846	1.31%
18	**Total Steam Production Plant**	427,859,259	-	427,859,259	422,316,846	1.31%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	5,732,621	-	5,732,621	5,732,621	0.00%
26	331 Structures and Improvements	123,420,566	-	123,420,566	123,207,218	0.17%
27	332 Reservoirs, Dams and Waterways	167,589,524	-	167,589,524	157,126,292	6.66%
28	333 Water Wheel, Turbine, Generators	120,972,361	-	120,972,361	120,302,681	0.56%
29	334 Accessory Electric Equipment	84,118,034	-	84,118,034	83,098,411	1.23%
30	335 Misc. Power Plant Equipment	19,363,883	-	19,363,883	36,672,650	-47.20%
31	336 Roads, Railroads and Bridges	2,493,836	-	2,493,836	2,453,164	1.66%
32	**Total Hydraulic Production Plant**	523,690,825	-	523,690,825	528,593,037	-0.93%
33						
34	**Other Production**					
35	340 Land and Land Rights	2,005,777		2,005,777	2,054,300	-2.36%
36	341 Structures and Improvements	51,404,540	19,232	51,385,308	51,253,893	0.26%
37	342 Fuel Holders & Accessories	21,230,045	112,084	21,117,961	21,117,961	0.00%
38	343 Prime Movers	100,614,123	-	100,614,123	97,085,542	3.63%
39	344 Generators	47,711,321	2,247,016	45,464,305	46,696,068	-2.64%
40	345 Accessory Electric Equipment	16,208,757	770,151	15,438,606	15,406,495	0.21%
41	346 Misc. Power Plant Equipment	25,920,249	7,268	25,912,981	25,727,544	0.72%
42	**Total Other Production Plant**	265,094,812	3,155,751	261,939,061	259,341,803	1.00%
43	**Total Production Plant**	1,216,644,896	3,155,751	1,213,489,145	1,210,251,685	0.27%

Sch. 19 cont.

MONTANA PLANT IN SERVICE - ELECTRIC

	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	This Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	37,632,337	-	37,632,337	33,767,733	11.44%
4	352 Structures and Improvements	30,995,178	-	30,995,178	27,680,052	11.98%
5	353 Station Equipment	249,370,391	-	249,370,391	235,241,103	6.01%
6	354 Towers and Fixtures	28,727,724	-	28,727,724	28,727,724	0.00%
7	355 Poles and Fixtures	279,640,025	968,526	278,671,499	232,523,966	19.85%
8	356 Overhead Conductors & Devices	158,635,628	716,080	157,919,548	149,093,685	5.92%
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**	789,069,337	2,385,834	786,683,503	710,401,089	10.74%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	10,560,890	601	10,560,289	5,849,238	80.54%
16	361 Structures and Improvements	19,088,103	1,226,604	17,861,499	12,816,584	39.36%
17	362 Station Equipment	205,014,444	4,345,487	200,668,957	165,148,347	21.51%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	278,687,203	422,546	278,264,657	262,103,757	6.17%
20	365 Overhead Conductors & Devices	118,997,468	495,865	118,501,603	113,695,752	4.23%
21	366 Underground Conduit	116,024,132	493,118	115,531,014	101,958,854	13.31%
22	367 Undergrnd Conductors & Devices	200,069,425	3,199,302	196,870,123	177,852,023	10.69%
23	368 Line Transformers	210,715,294	903,916	209,811,378	202,997,309	3.36%
24	369 Services	124,949,932	259,582	124,690,350	116,886,661	6.68%
25	370 Meters	54,766,934	96,955	54,669,979	53,639,266	1.92%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	54,493,194	19,872	54,473,322	54,153,846	0.59%
29	**Total Distribution Plant**	1,393,367,019	11,463,848	1,381,903,171	1,267,101,637	9.06%
30						
31	**General Plant**					
32	389 Land and Land Rights	689,633	-	689,633	689,633	0.00%
33	390 Structures and Improvements	9,058,535	506,969	8,551,566	8,577,363	-0.30%
34	391 Office Furniture and Equipment	2,482,128	-	2,482,128	2,800,445	-11.37%
35	392 Transportation Equipment	51,417,502	229,389	51,188,113	48,500,814	5.54%
36	393 Stores Equipment	638,697	-	638,697	644,465	-0.90%
37	394 Tools, Shop & Garage Equipment	8,113,371	5,175	8,108,196	7,533,315	7.63%
38	395 Laboratory Equipment	1,521,272	1,297	1,519,975	1,701,835	-10.69%
39	396 Power Operated Equipment	4,328,230	-	4,328,230	4,290,317	0.88%
40	397 Communication Equipment	33,472,032	2,038,244	31,433,788	25,868,311	21.51%
41	398 Miscellaneous Equipment	2,065,294	-	2,065,294	2,065,294	0.00%
42	399 Other Tangible Equipment	-	-	-	-	-
43	**Total General Plant**	113,786,694	2,781,074	111,005,620	102,671,792	8.12%
44	**Total Plant in Service**	3,537,810,672	19,786,507	3,518,024,165	3,298,847,873	6.64%
45						
46	4101 El Plant Allocated from Common	91,328,590	-	91,328,590	82,610,024	10.55%
47	103 Experimental Electric Plant Unclassified	1,631,264	-	1,631,264	1,576,812	3.45%
48	105 El Plant Held for Future Use	4,764,105	-	4,764,105	4,764,105	-
49	107 El Construction Work in Progress	50,383,463	24,680	50,358,783	93,429,526	-46.10%
50						
51						
52	**TOTAL ELECTRIC PLANT**	$ 3,685,918,094	$ 19,811,187	$ 3,666,106,908	$ 3,481,228,340	5.31%

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC		
	CONSOLIDATED PLANT IN SERVICE	December 31, 2017	2016
1			
2	Montana Electric	$ 3,518,024,165	$ 3,298,847,873
3	Yellowstone National Park	19,786,507	19,414,223
4	Montana Natural Gas (Includes CMP)	793,388,754	763,632,169
5	Common	135,376,180	123,877,637
6	Townsend Propane	1,519,564	1,519,564
7	South Dakota Electric	877,763,048	860,324,872
8	South Dakota Natural Gas	182,730,749	175,034,946
9	South Dakota Common	57,381,499	53,553,212
10	Asset Retirement Obligation	29,230,068	31,407,853
11	**TOTAL PLANT**	$ 5,615,200,534	$ 5,327,612,349

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	$ 427,859,259	$ 89,257,403	$ -	$ 89,257,403	$ 76,195,118	2.94%
4							
5	Nuclear Production	-	-	-	-	-	-
6							
7	Hydraulic Production	523,690,825	26,644,092	-	26,644,092	18,956,936	2.00%
8							
9	Other Production	265,094,812	47,946,988	2,756,244	45,190,744	38,943,339	3.62%
10							
11	Transmission	789,069,337	338,144,144	2,111,260	336,032,884	322,669,887	2.88%
12							
13	Distribution	1,393,367,019	648,411,019	4,819,084	643,591,935	615,089,203	3.15%
14							
15	General and Intangible	138,729,420	65,823,089	498,558	65,324,531	58,825,953	8.39%
16							
17	Common	91,327,572	22,052,748	-	22,052,748	17,399,683	5.40%
18							
19							
20	**Total Accum Depreciation**	$ 3,629,138,244	$ 1,238,279,483	$ 10,185,146	$ 1,228,094,337	$ 1,148,080,119	3.11%
21							
22							
23							

		December 31,	
24	**Consolidated**		
25	**Accumulated Depreciation**	2017	2016
26			
27	Montana Electric	$1,206,041,589	$1,130,680,436
28	Yellowstone National Park	10,185,146	9,754,156
29	Montana Natural Gas (Includes CMP)	323,232,339	303,627,188
30	Common	34,519,406	28,020,639
31	Townsend Propane	892,408	851,781
32	South Dakota Electric	299,417,542	285,819,969
33	South Dakota Natural Gas	89,410,312	85,162,714
34	South Dakota Common	16,362,957	15,875,159
35	Acquisition Writedown	51,390,109	54,094,598
36	Basin Creek Capital Lease	23,120,462	21,109,982
37	FIN 47	4,651,008	3,750,578
38	CWIP-Capital Retirement Clearing	-5,337,298	-7,538,353
39	**Total Consolidated Accum Depreciation**	$2,053,885,980	$1,931,208,847

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
151 Fuel Stock	$ 1,935,705	$ -	$ 1,935,705	$ 2,099,483	-7.80%
154 Plant Materials & Operating Supplies					
Assigned and Allocated to:					
Operation & Maintenance	-		-	-	-
Construction	-		-	-	-
Production Plant	5,088,795		5,088,795	5,036,525	1.04%
Transmission Plant	5,028,729		5,028,729	3,370,229	49.21%
Distribution Plant	11,508,705		11,508,705	11,148,918	3.23%
Total MT Materials and Supplies	$23,561,934	$ -	$23,561,934	$21,655,155	8.81%

Consolidated Fuel Stock	December 31, 2017	December 31, 2016
Montana Electric	$1,935,705	$2,099,483
South Dakota	6,115,530	7,484,523
Total Fuel Stock	$8,051,234	$9,584,006

Consolidated Materials and Supplies	December 31, 2017	December 31, 2016
Montana Electric	21,626,229	$19,555,672
Montana Natural Gas	3,831,530	3,430,468
South Dakota	8,770,253	8,085,347
Total Consolidated Materials and Supplies	$34,228,012	$31,071,487

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC				
	Commission Accepted - Most Recent		% Capital Structure	% Cost Rate	Weighted Cost
1					
2	**Regulated Electric Transmission and Distribution Utility**				
3					
4	Docket Number:	2009.9.129			
5	Order Number :	7046i			
6	Effective Date:	July 8, 2011			
7					
8	Common Equity		48.00%	10.25%	4.92%
9	Long Term Debt		52.00%	5.76%	3.00%
10					
11	**TOTAL**		100.00%		7.92%
12					
13	**Colstrip Unit 4**				
14					
15	Docket Number:	2008.6.69			
16	Order Number :	6925f			
17	Effective Date:	January 1, 2009			
18					
19	Common Equity		50.00%	10.00%	5.00%
20	Long Term Debt		50.00%	6.50%	3.25%
21					
22	**TOTAL**		100.00%		8.25%
23					
24	**Dave Gates Generating Station**				
25					
26	Docket Number:	2008.8.95			
27	Order Number :	6943e			
28	Effective Date:	January 1, 2011			
29					
30	Common Equity		50.00%	10.25%	5.13%
31	Long Term Debt		50.00%	6.07%	3.03%
32					
33	**TOTAL**		100.00%		8.16%
34					
35	**Spion Kop Wind**				
36					
37	Docket Number:	2011.5.41			
38	Order Number :	7159l			
39	Effective Date:	December 1, 2012			
40					
41	Common Equity		48.00%	10.00%	4.80%
42	Long Term Debt		52.00%	4.23%	2.20%
43					
44	**TOTAL**		100.00%		7.00%
45					
46	**Hydro Assets**				
47					
48	Docket Number:	2013.12.85			
49	Order Number :	7323k			
50	Effective Date:	November 18, 2014			
51					
52	Common Equity		48.00%	9.80%	4.70%
53	Long Term Debt		52.00%	4.25%	2.21%
54					
55	**TOTAL**		100.00%		6.91%
56					
57					

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	$ 162,702,800	$ 164,171,857	-0.89%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	146,632,297	140,114,080	4.65%
6	Amortization, Net	24,318,621	18,958,796	28.27%
7	Other Noncash Charges to Net Income, Net	9,908,598	14,018,040	-29.32%
8	Deferred Income Taxes, Net	10,373,635	(6,771,384)	253.20%
9	Investment Tax Credit Adjustments, Net	166,193	(196,376)	184.63%
10	Change in Operating Receivables, Net	(13,168,865)	860,619	>-300.00%
11	Change in Materials, Supplies & Inventories, Net	(3,378,081)	3,365,478	-200.37%
12	Change in Operating Payables & Accrued Liabilities, Net	2,904,555	16,004,227	-81.85%
13	Allowance for Funds Used During Construction (AFUDC)	(5,563,937)	(4,581,196)	-21.45%
14	Change in Other Assets & Liabilities, Net	(5,123,658)	(36,351,861)	85.91%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,945,962)	(2,297,510)	-28.22%
17	Change in Regulatory Assets	438,662	(15,485,060)	102.83%
18	Change in Regulatory Liabilities	(7,107,084)	(411,739)	>-300.00%
19	**Net Cash Provided by Operating Activities**	320,157,774	291,397,972	9.87%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(269,400,928)	(287,062,468)	6.15%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	379,491	1,354,211	-71.98%
25	**Net Cash Used in Investing Activities**	(269,021,437)	(285,708,257)	5.84%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	250,000,000	249,660,000	0.14%
29	Issuance of Short Term Borrowings, Net	18,745,418	70,936,129	-73.57%
30	Proceeds From Issuance of Common Stock, Net	53,668,520	-	100.00%
31	Payments for Retirement of:			
34	Long-term Debt	(250,000,000)	(225,205,000)	-11.01%
35	Dividends on Common Stock	(101,269,773)	(95,765,571)	-5.75%
36	Other Financing Activities:			
37	Debt Financing Costs	(16,382,233)	(8,430,186)	-94.33%
38	Treasury Stock Activity	1,082,861	(560,077)	293.34%
39	**Net Cash Used in Financing Activities**	(44,155,206)	(9,364,705)	>-300.00%
40	**Net Increase/Decrease in Cash and Cash Equivalents**	6,981,130	(3,674,990)	289.96%
41	**Cash and Cash Equivalents at Beginning of Year**	433,142	4,108,132	-89.46%
42	**Cash and Cash Equivalents at End of Year**	$ 7,414,272	$ 433,142	>300.00%
43				
44	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
45	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
46	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
47	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
48				

Sch. 24

MONTANA LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
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%
5.01% 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%
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%
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%
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%
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%
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%
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%
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%
4.03% Series($250M), Due 2047	11/06/17	11/06/2047	250,000,000	248,817,402	250,000,000	4.03%	10,631,783	4.25%
Total First Mortgage Bonds			$ 1,266,000,000	$ 1,257,062,324	$ 1,266,000,000		$ 56,429,672	4.46%
Pollution Control Bonds								
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%
Total Pollution Control Bonds			$ 144,660,000	$ 138,906,956	$ 144,660,000		$ 3,627,593	2.51%
Other Long-Term Debt								
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%	$ 348,054	1.29%
Total Other Long Term Debt			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 348,054	1.29%
TOTAL LONG TERM DEBT			$ 1,437,636,900	$ 1,422,261,628	$ 1,437,636,900		$ 60,405,319	4.20%

This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is $22,213,443

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not Applicable									
3										
4										
5										
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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	48,338,900	$35.29				$57.51	$56.41	
February	48,426,606	35.60				58.50	56.09	
March	48,444,284	35.28	$1.17	0.525		59.01	56.51	
April	48,445,078	35.48				60.42	58.56	
May	48,451,537	35.59				61.96	59.75	
June	48,470,756	35.25	0.45	0.525		63.78	61.02	
July	48,471,447	35.54				61.77	57.79	
August	48,472,926	35.81				61.26	58.92	
September	48,563,559	35.54	0.75	0.525		60.65	56.94	
October	48,594,516	35.79				59.28	57.27	
November	49,231,437	36.40				64.26	58.87	
December	49,372,463	36.44	0.98	0.525		63.76	58.52	
TOTAL Year End	48,557,599	$36.44	$3.35	$2.10	37.31%	$59.70		17.8

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2017.

Sch. 27

MONTANA EARNED RATE OF RETURN - ELECTRIC

Description	This Year	Last Year	% Change
Rate Base			
101 Plant in Service	$3,804,570,662	$3,643,588,891	4.42%
108 Accumulated Depreciation	(1,212,379,014)	(1,134,978,092)	-6.82%
Net Plant in Service	$2,592,191,648	$2,508,610,799	3.33%
Additions:			
154, 156 Materials & Supplies	$17,232,680	$16,341,186	5.46%
165 Prepayments			
Other Additions 1/	283,183,591	244,724,953	15.72%
Total Additions	$300,416,271	$261,066,139	15.07%
Deductions:			
190 Accumulated Deferred Income Taxes	$487,724,362	$399,789,527	22.00%
252 Customer Advances for Construction	33,868,784	30,459,885	11.19%
255 Accumulated Def. Investment Tax Credits			
Other Deductions	38,072,116	38,687,778	-1.59%
Total Deductions	$559,665,263	$468,937,190	19.35%
Total Rate Base	$2,332,942,657	$2,300,739,748	1.40%
Net Earnings	$ 158,434,342	$ 171,046,953	-7.37%
Rate of Return on Average Rate Base	6.791%	7.434%	-8.65%
Rate of Return on Average Equity 2/	8.573%	9.892%	-13.33%
Major Normalizing and Commission Ratemaking Adjustments			
Rate Schedule Revenues	($2,874,012)	$9,479,097	-130.32%
Income Taxes - Generation Tax Repair 3/	-	(8,504,530)	100.00%
DSM Lost Revenues 4/	-	(13,433,970)	100.00%
CU4 Outage Disallowance 5/	-	8,243,475	-100.00%
Modeling Cost Disallowance 6/	-	733,515	-100.00%
Non-Allowables:			
Advertising	471,700	407,678	15.70%
Dues, Contributions, Other	144,411	116,169	24.31%
Associated Income Taxes 7/	3,197,401	(1,612,740)	298.26%
Total Adjustments	$939,500	($4,571,306)	120.55%
Revised Net Earnings	$159,373,842	$166,475,647	-4.27%
Rate Base Adjustment			
Stipulation with MCC 8/	($19,070,666)	($19,936,332)	4.34%
Revised Rate Base	$2,313,871,991	$2,280,803,416	1.45%
Adjusted Rate of Return on Average Rate Base	6.888%	7.299%	-5.63%
Adjusted Rate of Return on Average Equity 2/	8.521%	9.736%	-12.48%

1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated deferred taxes.

2/ Return on Equity calculated using the capital structure approved in Docket No. D2009.9.129, Docket No. D2008.8.69, Docket No. D2008.8.95, Docket No. D2011.5.41 and Docket No. D2013.12.85.

3/ Generation Tax repairs related to prior years.

4/ Demand-side management lost revenue was adjusted to normalize out balances related to prior periods.

5/ Colstrip Unit 4 outage costs disallowed by Order No. 7283h.

6/ Modeling costs disallowed by Order No. 7283b and Order No. 7418d.

7/ Associated Income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket No.D2009.9.129, Docket No. D2008.6.69, Docket No. D2008.8.95, Docket No. D2011.5.41, and Docket No. D2013.12.85.

8/ 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
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$269,173,827	$232,215,220	15.92%
4	Cost of Refinancing Debt	12,047,883	10,467,959	15.09%
5	Fuel Stock	1,961,881	2,041,774	-3.91%
8	**Total Other Additions**	$283,183,591	$244,724,953	15.72%
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$4,249,327	$5,989,454	-29.05%
12	Gross Cash Requirements	33,822,789	32,698,324	3.44%
13	MPSC/MCC Taxes	-	-	-
16	**Total Other Deductions**	$38,072,116	$38,687,778	-1.59%

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)	$ 3,609,352,755
5	103	Experimental Electric Plant Unclassified	1,631,264
6	105	Plant Held for Future Use	4,764,105
7	107	Construction Work in Progress	50,358,783
8	114	Plant Acquisition Adjustments	350,704,330
9	151-163	Materials & Supplies	23,561,934
10		(Less):	
11	108, 111, 115	Depreciation & Amortization Reserves	1,250,061,924
12	252	Customer Advances	35,693,464
13	**NET BOOK COSTS**		2,754,617,783
14			
15		**Revenues & Expenses**	
16			
17	400	Operating Revenues	800,938,459
18			
19	**Total Operating Revenues**		800,938,459
20			
21	401-402	Other Operating Expenses (including regulatory amortizations)	386,470,858
22	403-407	Depreciation & Amortization Expenses	114,096,789
23	408.1	Taxes Other than Income Taxes	128,208,897
24	409-411	Federal & State Income Taxes	13,727,574
25	411.8	SO2 Allowances	(1)
26			
27	**Total Operating Expenses**		642,504,117
28	**Net Operating Income**		158,434,342
29			
30	415-421.1	Other Income	4,251,864
31	421.2-426.5	Other Deductions	498,878
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 162,187,328
33			
34		**Average Customers (Intrastate Only)**	
35		Residential	295,252
36		Commercial & Industrial	67,933
37		Other (including interdepartmental)	4,035
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		367,220
40			
41		**Other Statistics (Intrastate Only)**	
42		Average Annual Residential Use (Kwh)	8,595
43		Average Annual Residential Cost per (Kwh)	$0.118
44		Average Residential Monthly Bill	$84.23
45			
46		Plant in Service (Gross) per Customer	$9,829

Sch. 29	Montana Customer Information- Electric, 1/					
[redacted]	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	477	114	5	596
2	Alberton	420	386	87	12	485
3	Alder	103	218	87	21	326
4	Amsterdam	180	132	38	7	177
5	Anaconda	9,298	4,317	844	58	5,219
6	Armington	-	1	-	-	1
7	Arrow Creek	-	4	4	-	8
8	Augusta	309	255	110	4	369
9	Avon	111	96	63	3	162
10	Barber	-	48	12	1	61
11	Basin	212	166	73	2	241
12	Bearcreek	79	63	21	3	87
13	Belfry	218	173	61	14	248
14	Belgrade	7,389	8,003	1,991	101	10,095
15	Belt	597	641	244	14	899
16	Benchland	-	6	6	-	12
17	Big Sandy	598	333	144	5	482
18	Big Sky	2,308	3,717	877	29	4,623
19	Big Timber	1,641	1,233	411	29	1,673
20	Billings	104,170	48,562	8,459	681	57,702
21	Black Eagle	904	459	171	15	645
22	Bonner	1,663	78	45	1	124
23	Boulder	1,183	835	258	26	1,119
24	Box Elder	87	141	63	9	213
25	Bozeman	37,280	30,371	6,251	401	37,023
26	Brady	140	88	40	4	132
27	Bridger	708	453	174	14	641
28	Broadview	192	230	165	1	396
29	Buffalo	-	-	3	5	8
30	Butte	33,525	14,995	2,623	275	17,893
31	Cameron	-	379	118	5	502
32	Canyon Creek	-	188	42	7	237
33	Carter	58	115	72	3	190
34	Cascade	685	1,121	327	29	1,477
35	Centerville	-	13	11	1	25
36	Checkerboard	-	54	9	1	64
37	Chester	847	478	312	16	806
38	Chinook	1,203	811	315	16	1,142
39	Choteau	1,684	1,005	372	25	1,402
40	Churchill	902	717	140	25	882
41	Clancy	1,661	878	157	10	1,045
42	Clinton	1,052	106	35	2	143
43	Coffee Creek	-	56	24	1	81
44	Collins	-	-	5	-	5
45	Colstrip	2,214	971	212	34	1,217
46	Columbus	1,893	1,022	347	19	1,388
47	Conrad	2,570	1,271	473	27	1,771
48	Corbin	-	1	2	-	3
49	Corvallis	976	819	179	37	1,035
50	Craig	43	92	36	7	135
51	Custer	159	1	3	-	4

Sch. 29	Montana Customer Information- Electric, 1/					
[redacted]	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Darby	720	796	258	19	1,073
2	De Borgia	78	152	35	2	189
3	Deer Lodge	3,111	2,066	600	70	2,736
4	Denton	255	182	84	1	267
5	Dillon	4,134	2,036	567	62	2,665
6	Divide	-	68	14	4	86
7	Dodson	124	116	67	6	189
8	Drummond	309	367	219	30	616
9	Dutton	316	243	115	4	362
10	East Helena	1,984	2,986	410	27	3,423
11	Edgar	114	170	55	7	232
12	Elliston	219	202	61	3	266
13	Ennis	838	1,793	585	38	2,416
14	Fairfield	708	407	159	29	595
15	Fishtail	-	51	5	-	56
16	Florence	765	401	146	17	564
17	Floweree	-	105	59	1	165
18	Fort Belknap	1,293	441	105	24	570
19	Fort Benton	1,464	830	364	32	1,226
20	Fort Harrison	-	-	93	3	96
21	Fromberg	438	318	77	12	407
22	Gallatin Gateway	856	739	209	14	962
23	Gardiner	875	803	309	12	1,124
24	Garrison	96	117	61	6	184
25	Geraldine	261	284	153	2	439
26	Geyser	87	64	37	4	105
27	Gildford	179	91	66	2	159
28	Glasgow	3,250	1,657	713	62	2,432
29	Glasgow Air Base	-	1	1	-	2
30	Gold Creek	-	76	38	5	119
31	Grantsdale	-	24	3	1	28
32	Great Falls	58,505	29,476	5,312	370	35,158
33	Greycliff	112	53	31	11	95
34	Hall	-	280	83	20	383
35	Hamilton	4,348	5,425	1,423	114	6,962
36	Hardin	3,505	1,426	457	24	1,907
37	Harlem	808	449	205	25	679
38	Harlowton	997	676	283	8	967
39	Harrison	137	184	60	24	268
40	Haugan	-	84	38	2	124
41	Havre	10,026	4,928	1,205	186	6,319
42	Helena	53,457	25,210	5,179	432	30,821
43	Hingham	118	111	72	2	185
44	Hinsdale	217	136	51	6	193
45	Hobson	215	164	60	8	232
46	Huson	210	140	38	2	180
47	Hysham	312	-	1	-	1
48	Inverness	55	40	27	1	68
49	Jardine	57	1	1	-	2
50	Jeffers	-	3	1	-	4
51	Jefferson City	472	333	56	3	392
52	Joliet	595	492	131	19	642

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Joplin	157	96	49	2	147
2	Judith Gap	126	91	54	6	151
3	Kremlin	98	71	35	1	107
4	Laurel	6,718	3,235	504	24	3,763
5	Lavina	187	189	105	15	309
6	Lennep	-	20	13	-	33
7	Lewistown	5,910	3,340	919	57	4,316
8	Lincoln	1,013	1,072	278	14	1,364
9	Livingston	7,044	4,870	1,153	67	6,090
10	Logan	99	59	26	2	87
11	Lohman	-	28	31	6	65
12	Lolo	3,892	1,532	199	17	1,748
13	Loma	85	68	40	3	111
14	Lothair	-	16	13	-	29
15	Malta	1,997	1,331	505	47	1,883
16	Manhattan	1,520	1,196	354	90	1,640
17	Martinsdale	64	129	81	10	220
18	Marysville	80	72	37	2	111
19	Maxville	130	4	-	-	4
20	McAllister	-	235	54	7	296
21	Melrose	-	2	1	-	3
22	Melstone	96	160	274	19	453
23	Melville	-	71	55	4	130
24	Milltown	-	75	20	3	98
25	Missoula	66,788	37,193	6,555	607	44,355
26	Moccasin	-	47	34	1	82
27	Molt	-	30	33	-	63
28	Monarch	-	329	55	3	387
29	Montana City	2,715	1,125	206	4	1,335
30	Moore	193	110	45	5	160
31	Musselshell	60	62	27	1	90
32	Nashua	290	199	65	3	267
33	Neihart	51	199	41	2	242
34	Nevada City	-	-	7	-	7
35	Norris	-	56	47	2	105
36	Nye	-	15	2	1	18
37	Paradise	163	158	61	8	227
38	Park City	983	441	80	5	526
39	Philipsburg	820	1,850	348	25	2,223
40	Plains	1,048	1,654	466	27	2,147
41	Pompey's Pillar		1	-	-	1
42	Pony	118	138	27	5	170
43	Power	179	89	47	2	138
44	Pray	681	25	1	1	27
45	Radersburg	66	85	26	1	112
46	Ramsay	-	63	29	1	93
47	Raynesford	-	67	36	3	106
48	Red Lodge	2,125	2,019	416	28	2,463
49	Reedpoint	193	168	61	4	233
50	Ringling	-	43	25	2	70
51	Roberts	-	3	-	-	3
52	Rocker	-	60	23	2	85

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Rockvale	-	2	-	-	2
2	Roscoe	15	89	10	-	99
3	Roundup	1,788	1,096	400	21	1,517
4	Rudyard	258	152	65	2	219
5	Ryegate	245	148	69	12	229
6	Saco	197	163	101	2	266
7	Saint Marie	264	303	49	3	355
8	Saint Regis	319	504	186	14	704
9	Saltese	-	40	22	1	63
10	Sand Coulee	212	155	52	3	210
11	Sapphire Village	-	66	8	-	74
12	Shawmut	42	55	35	3	93
13	Sheridan	642	945	260	41	1,246
14	Silesia	96	41	9	1	51
15	Silverbow	-	11	6	1	18
16	Springdale	42	39	14	7	60
17	Square Butte	-	39	21	1	61
18	Stanford	401	337	215	7	559
19	Stevensville	1,809	2,124	584	72	2,780
20	Stockett	169	160	58	3	221
21	Sumatra	-	-	4	-	4
22	Superior	812	905	280	24	1,209
23	Taft	-	-	2	-	2
24	Tampico	-	11	5	-	16
25	Thompson Falls	1,313	1,122	362	29	1,513
26	Three Forks	1,869	1,456	523	67	2,046
27	Toston	108	52	38	23	113
28	Townsend	1,878	1,319	362	24	1,705
29	Tracy	-	93	12	4	109
30	Turah	306	18	2	-	20
31	Twin Bridges	375	317	166	26	509
32	Twodot	-	54	50	6	110
33	Ulm	738	425	119	10	554
34	Utica	-	2	5	1	8
35	Valier	509	374	178	36	588
36	Vaughn	658	247	49	8	304
37	Victor	745	812	275	24	1,111
38	Virginia City	190	194	105	1	300
39	Wagner	-	47	26	1	74
40	Walkerville	675	252	30	3	285
41	Warm Springs	-	-	3	-	3
42	Washoe	-	7	2	-	9
43	West Yellowstone	1,271	2	11	-	13
44	White Sulphur Springs	939	817	380	60	1,257
45	Whitehall	1,038	1,021	299	57	1,377
46	Wickes	-	1	-	-	1
47	Williamsburg	-	1	1	-	2
48	Willow Creek	210	144	61	21	226
49	Windham	-	47	31	2	80
50	Winston	147	140	49	3	192

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Wolf Creek	-	415	166	11	592
2	Yellowstone Club	-	415	3	-	418
3	Zurich	-	106	84	11	201
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49	**Total**	503,001	295,252	66,422	5,546	367,220

1/ Customer populations represent an average of the 12 month period from 01/01/17 through 12/31/17. 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	150	159	155
5	Finance	151	154	153
6	Regulatory Affairs	28	1	15
7	Distribution	449	445	447
8	Transmission	309	315	312
9	Supply	114	123	119
10	Legal	20	25	23
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,223	1,224	1,224

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

On January 15, 2018, Patrick Corcoran, the company's Vice President of Government and Regulatory Affairs, retired. During November 2017, in anticipation of his retirement, the company announced that the employees that had previously reported to Patrick would be reassigned to other vice presidents, effective immediately.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2018 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Trans - Holter - Drummond 100kv NERC	$7,702,170	$7,702,170
4	MT Elec Trans - Substation Wicks Lane 230 kV Breaker	4,454,629	4,454,629
5	MT Elec Trans - Substation Big Timber Auto Breaker	3,268,632	3,268,632
6	MT Elec Trans - Substation Kerr A Line Auto Banks	3,190,683	3,190,683
7	MT Elec Dist - Bozeman Substation Jackrabbit Transformer	2,863,106	2,863,106
8	MT Elec Dist - Substation SSIP Spare Transformers	2,730,296	2,730,296
9	MT Electric - Distribution Management System	2,592,760	2,592,760
10	MT Elec Dist - OHRC MT Talc - Three Forks	1,560,475	1,560,475
11	MT Elec Trans - OHRC Big Timber-Melville 50kv	1,460,311	1,460,311
12	MT Elec Trans - Holter Helena Vly Tap Reconductor	1,389,041	1,389,041
13	MT Elec Trans - Butte Substation Sheridan Auto Upgrade	1,380,311	1,380,311
14	MT Elec Trans - 0419 C Falls to Chester Reliability	1,243,551	1,243,551
15	MT Elec Dist - Missoula UGCA New CKT 92	1,132,598	1,132,598
16	MT Elec Dist - OHCU Billings Eastside New Height	1,110,264	1,110,264
17	MT Elec Trans - 500KV SBSB Colstrip Reactor Replace	1,092,113	1,092,113
18	MT Elec Dist - SBSQ Belgrade West Substation	1,014,034	1,014,034
19			
20	All Other Projects < $1 Million Each	116,210,432	83,406,327
21			
22	**Total Electric Utility Construction Budget**	**154,395,405**	**121,591,300**
23			
24	**Natural Gas Operations**		
25	MT Gas Trans - Absarokee Compress and Upgrade	6,146,333	6,146,333
26	MT Gas Dist - Butte Base Gas Infrastructure	4,445,600	4,445,600
27	MT Gas Trans - Compliance Warren-Billings Steam Plant	2,825,863	2,825,863
28	MT Gas Trans - PIM Carway Line Piggable	2,004,569	2,004,569
29	MT Gas Dist - Bozeman HVGC Express Feed Extension Year 2	1,434,655	1,434,655
30	MT Gas Dist - Livingston Base Gas Infrastructure	1,194,455	1,194,455
31			
32	All Other Projects < $1 Million Each	23,680,946	16,395,837
33			
34	**Total Natural Gas Utility Construction Budget**	**41,631,451**	**34,447,312**
35			
36	**Common**		
37	SD AMI Metering	16,915,640	-
38	MT Fleet and Equipment Upgrades	4,365,912	4,365,912
39	MT Communications Fiber Backbone	2,135,710	2,135,710
40	Business Tech - LAM Software Gas Transmission	1,298,132	1,298,132
41	MT Facilities - Bozeman Facility Expansion and Upgrade	6,976,211	6,976,211
42	MT Communications MPLS Core Network	1,292,233	1,292,233
43	MT Facilities - Bozeman City Property Acquisition	1,057,073	1,057,073
44	SD Fleet and Equipment Upgrades	2,075,000	-
45			
46	All Other Projects < $1 Million Each	27,926,954	13,898,129
47	(Includes BT, Communications, Facilities, Customer Services)		
48			
49	**Total Common Utility Construction Budget**	**64,042,865**	**31,023,400**
50			
51	**MT/SD Generation**		
52	MT Colstrip Unit 4 Capital Additions - PPL invoice	5,205,322	5,205,322
53	MT - Hydro Hauser Unit 4 Turbine Upgrade	2,483,031	2,483,031
54	MT - Hydro Thompson Falls Spillway Upgrade	1,734,668	1,734,668
55	MT - Hydro Ryan Unit 6 Gen Rewind-Restack	1,669,471	1,669,471
56	MT - Hydro Madison Unit 4 Turbine Upgrade	1,035,389	1,035,389
57	MT - Dave Gates S/N 743177 25K Hour Maintenance	2,530,942	2,530,942
58	SD Big Stone, Neal 4, Coyote Partner Capital, Internal	5,169,561	-
59			
60	All Other Projects < $1 Million Each	7,251,769	7,251,769
61			
62	**Total MT/SD Generation**	**27,080,153**	**21,910,592**
63	**TOTAL CONSTRUCTION BUDGET**	**$287,149,874**	**$208,972,604**

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	4	18:00	2,338	793,902	120,453
2	February	2	8:00	2,260	686,828	98,474
3	March	9	21:00	2,127	648,453	78,845
4	April	4	8:00	1,960	667,911	92,177
5	May	31	17:00	2,001	604,260	146,240
6	June	26	18:00	2,252	598,713	134,640
7	July	13	17:00	2,376	654,134	109,541
8	August	1	17:00	2,333	711,352	72,274
9	September	2	18:00	2,162	654,378	89,035
10	October	31	8:00	1,973	610,665	82,861
11	November	6	19:00	2,091	634,684	118,148
12	December	26	18:00	2,233	700,674	75,978
13	**TOTALS**				7,965,954	1,218,666
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	1,344,614		
3	Nuclear	-	**Sales to Ultimate Consumers**	6,148,252
4	Hydro - Conventional	2,556,205	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	380,241	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	4,281,060	Non-Requirement Sales	1,218,666
9	**Purchases**	3,685,431	**Sales for Resale**	1,218,666
10	Power Exchanges			
11	Received	58,152		
12	Delivered	58,689	Energy Furnished w/o Charge	-
13	**Net Power Exchanges**	(537)	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	10,823,470	Electric Department	
16	Delivered	10,823,470	(Less) Station Use	-
17	**Net Transmission Wheeling**	-	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	599,036
19	**TOTAL SOURCES**	7,965,954	**TOTAL DISPOSITIONS**	7,965,954

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 31;161 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	1,344,614
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	249,058
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	131,183
4	Hydro Generation	Black Eagle	Great Falls, MT	21.0	126,346
5	Hydro Generation	Cochrane	Great Falls, MT	69.0	288,168
6	Hydro Generation	Hauser	Helena, MT	19.0	130,317
7	Hydro Generation	Holter	Helena, MT	48.0	299,866
8	Hydro Generation	Madison	Ennis, MT	8.0	62,279
9	Hydro Generation	Morony	Great Falls, MT	48.0	289,766
10	Hydro Generation	Mystic	Columbus, MT	12.0	61,891
11	Hydro Generation	Rainbow	Great Falls, MT	60.0	376,048
12	Hydro Generation	Ryan	Great Falls, MT	63.0	423,168
13	Hydro Generation	Thompson Falls	Thompson Falls, MT	94.0	498,356
14	Total Generation			854.0	4,281,060
15				Annual	Annual
16		Source of capacity	Seller	Peak (MW)	Energy (Mwh)
17	Qualifying Facility Purchases	Thermal	Billings Generation Inc.	61.4	459,472
18	Qualifying Facility Purchases	Solar	Black Eagle Solar, LLC	3.1	837
19	Qualifying Facility Purchases	Hydro	Boulder Hydro	0.5	1,108
20	Qualifying Facility Purchases	Hydro	Bruce Rauner/Barney Creek	0.4	98
21	Qualifying Facility Purchases	Hydro	Bruce Rauner/Cascade Creek	0.1	263
22	Qualifying Facility Purchases	Thermal	Colstrip Energy Ltd/Montana One	40.1	189,925
23	Qualifying Facility Purchases	Wind	Cycle Horseshoe Bend Wind, LLC	9.0	7,968
24	Qualifying Facility Purchases	Hydro	Flint Creek Hydro	2.2	13,709
25	Qualifying Facility Purchases	Wind	Foundation Windpower LLC/Fairfield Wind	10.6	31,602
26	Qualifying Facility Purchases	Wind	Gordon Butte Wind	9.8	36,145
27	Qualifying Facility Purchases	Solar	Great Divide Solar, LLC	2.9	810
28	Qualifying Facility Purchases	Wind	Greenfield Wind	26.8	79,562
29	Qualifying Facility Purchases	Solar	Green Meadow Solar, LLC	3.1	4,364
30	Qualifying Facility Purchases	Hydro	Hanover Hydro	0.0	291
31	Qualifying Facility Purchases	Hydro	Hydrodynamics - South Dry Creek	2.4	8,110
32	Qualifying Facility Purchases	Hydro	Hydrodynamics - Strawberry Creek	0.3	1,027
33	Qualifying Facility Purchases	Hydro	Lower South Fork	0.4	1,290
34	Qualifying Facility Purchases	Solar	Magpie Solar, LLC	2.9	814
35	Qualifying Facility Purchases	Wind	Martinsdale Wind Farm	0.7	1,355
36	Qualifying Facility Purchases	Wind	Moe Wind	0.3	321
37	Qualifying Facility Purchases	Wind	Musselshell Wind 1	10.7	25,300
38	Qualifying Facility Purchases	Wind	Musselshell Wind 2	10.6	29,764
39	Qualifying Facility Purchases	Hydro	Pine Creek	0.3	1,558
40	Qualifying Facility Purchases	Hydro	Pony Hydro	0.3	1,479
41	Qualifying Facility Purchases	Solar	River Bend Solar, LLC	2.0	2,912
42	Qualifying Facility Purchases	Hydro	Ross Creek Hydro	0.5	2,753
43	Qualifying Facility Purchases	Wind	Sheeps Valley	0.5	715
44	Qualifying Facility Purchases	Solar	South Mills Solar 1, LLC	3.0	4,272
45	Qualifying Facility Purchases	Hydro	State of Montana - DNRC/Broadwater	10.4	52,958
46	Qualifying Facility Purchases	Wind	Two Dot Wind Farm	9.7	30,774
47	Qualifying Facility Purchases	Wind	United Materials of Great Falls	8.9	2,475
48	Qualifying Facility Purchases	Hydro	Wisconsin Creek	0.4	477
49	Subtotal			234.3	994,508

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		169,927
2	Purchased Power	SF	Avista Corporation		40,358
3	Purchased Power	SF	Basin Electric Power Cooperative		17,838
4	Purchased Power	LU	Basin Power Plant	52.6	103,379
5	Purchased Power	SF	Black Hills Power Inc.		674
6	Purchased Power	SF	Bonneville Power Administration		42,761
7	Purchased Power	SF	Cargill Power Markets LLC		3,431
8	Purchased Power	LF	Citigroup Energy, Inc.		219,000
9	Purchased Power	SF	Clark County PUD No. 1		5,102
10	Purchased Power	SF	EDF Trading North America, LLC		110,075
11	Purchased Power	SF	Energy Keepers, Inc.		56,158
12	Purchased Power	SF	Eugene Water & Electric Board		70
13	Purchased Power	SF	Exelon Generation Company, LLC		2,202
14	Purchased Power	SF	Idaho Power Company		24,241
15	Purchased Power	SF	Invenergy Energy Markets LLC	136.3	455,459
16	Purchased Power	SF	Macquarie Energy LLC		7,434
17	Purchased Power	LF	Morgan Stanley Capital Group, Inc.		292,236
18	Purchased Power	SF	PacifiCorp		66,633
19	Purchased Power	SF	Portland General Electric		118,161
20	Purchased Power	SF	Powerex Corp.		4,232
21	Purchased Power	SF	Puget Sound Energy		19,850
22	Purchased Power	SF	Rainbow Energy Marketing Corporation		90,027
23	Purchased Power	SF	Seattle City Light		43,435
24	Purchased Power	SF	Shell Energy North America		29,607
25	Purchased Power	SF	Tacoma Power		9,600
26	Purchased Power	LF	Talen Energy Marketing, LLC		351,940
27	Purchased Power	SF	Tenaska Power Services		310
28	Purchased Power	SF	The Energy Authority, Inc.		12,477
29	Purchased Power	LU	Tiber Montana, LLC	not available	49,868
30	Purchased Power	LF	TransAlta Energy Marketing (US), Inc		310,793
31	Purchased Power	SF	Turnbull Hydro, LLC	13.8	29,302
32	Subtotal			202.8	2,686,580
33	Reserve Sharing				4,343
34	Total Purchases				3,685,431

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
[redacted]	

Unit	Outage Start Date	Description	Outage Duration (hours)
Colstrip Unit 3	1/19/2017	Water wall tube leak	57
	2/14/2017	Tube leaks	62
	3/8/2017	ATR trip - loss of 500 kv lines	38
	5/4/2017	Planned boiler overhaul	649
	6/1/2017	Major boiler overhaul	629
	7/1/2017	High amps on air preheater	19
	7/3/2017	High amps on air preheater	20
	9/14/2017	ATR trip - loss of 500 kv lines	22
	9/15/2017	Secondary air fan failure	21
	10/28/2017	Boiler tube leak	79
	11/17/2017	Boiler feed pump discharge valve packing blow out	29
Colstrip Unit 4	3/8/2017	ATR trip - loss of 500 kv lines	69
	3/19/2017	Condensor tube leak	101
	3/28/2017	ATR trip - loss of 500 kv lines	12
	6/15/2017	Boiler tube leak	76
	9/14/2017	ATR trip - loss of 500 kv lines	14
	10/5/2017	Condensor tube leak	88

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	1/10/2017	Generator upgrade	106
	1/14/2017	Failure to light wind milling engine	20
	1/15/2017	Generator installation	20
	1/25/2017	Unit tripping - NHDOT flameout	21
	4/17/2017	Generator removal, rotor inspection, and repair	1,274
	6/14/2017	Unit experiencing high vibration	20
	6/15/2017	PMG low voltage recharge	159
	6/22/2017	Data collection for balancing of generator	89
	10/12/2017	Annual outage and inspection	67
	11/30/2017	U1A borescope	157
DGGS Unit 2	4/12/2017	Burner can replacement	52
	4/29/2017	Circuit switcher malfunction	118
	8/14/2017	U2A experiencing vibration issues	32
	10/2/2017	Annual outage and U2B GG removal	163
	10/12/2017	U2A power turbine removed	530
	11/28/2017	U2B power turbine alignment	43
DGGS Unit 3	1/17/2017	Unit 3 generator installation	13
	4/14/2017	Burner can replacement	49
	6/23/2017	U3B borescope	35
	10/8/2017	Annual outage and inspection	110

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	4/3/2017	Annual maintenance forebay work	437
2		BE1	9/4/2017	Generator inspection	241
3		BE2	4/3/2017	Annual maintenance forebay work	437
4		BE2	7/2/2017	Turbine bearing cooling water loss	73
5		BE3	3/13/2017	Phase temp measurement trouble	23
6		BE3	3/28/2017	Generator bearing voltage detected	145
7		BE3	4/3/2017	Forebay work	437
8					
9	**Cochrane**	CCH1	9/5/2017	Generator inspection	51
10		CCH1	10/7/2017	Turbine governor problem	57
11					
12	**Hauser**	HAU1	1/1/2017	Hydro pump storage overhaul	87
13		HAU1	1/4/2017	Testing, load rejection	26
14		HAU1	1/10/2017	Pump storage overhaul testing	161
15		HAU1	1/17/2017	Pump storage overhaul testing	171
16		HAU4	10/23/2017	Annual maintenance, inspection	1,673
17		HAU6	11/13/2017	Annual maintenance, inspection	99
18					
19	**Holter**	HLT3	4/4/2017	Annual maintenance, inspection	46
20					
21	**Madison**	MAD1	4/21/2017	Thrust collar problems	844
22		MAD1	9/9/2017	Threaded insert for thrust bolt broken	316
23		MAD2	10/2/2017	Annual maintenance, inspection	73
24		MAD3	10/9/2017	Annual maintenance, inspection	102
25		MAD4	10/16/2017	Annual maintenance, inspection	80
26					
27	**Morony**	MOR1	9/5/2017	PSMP testing	225
28		MOR2	3/14/2017	Generator inspection	79
29		MOR2	9/5/2017	PSMP testing	57
30		MOR2	9/26/2017	Exciter transformer failure	176
31					
32	**Mystic**	MYS1	5/18/2017	Trees fell into transmission lines	12
33		MYS2	5/18/2017	Trees fell into transmission lines	12
34					
35	**Rainbow**	RNB9	3/27/2017	Annual maintenance, inspection	105
36		RNB9	3/31/2017	Reserve shutdown	64
37		RNB9	5/12/2017	Reserve shutdown	21
38					
39	**Ryan**	RYN1	7/10/2017	Annual maintenance, inspection	198
40		RYN2	2/20/2017	Annual maintenance, inspection	292
41		RYN2	10/19/2017	Recharge governor bladders	26
42		RYN3	4/20/2017	Lower guide bearing vibration	96
43		RYN3	8/10/2017	Major pump storage overhaul	3,442
44		RYN5	5/1/2017	Annual maintenance, inspection	273
45		RYN5	5/12/2017	Thrust bearing repair and alignment	623
46					
47	**Thompson Falls**	THF1	3/13/2017	Transformer maintenance	96
48		THF2	3/13/2017	Transformer maintenance	96
49		THF3	2/28/2017	Exciter trouble	75
50		THF3	3/13/2017	Transformer maintenance	96
51		THF4	3/17/2017	Generator control protective permissive tripped	81

Only outages greater than 12 hours are reported, excluding low water and partial unit outages .

Sch. 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

[redacted]	Program Description (These are Electric DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (MW & MWh)	Achieved Savings (MW & MWh)	Difference (MW & MWh)
1							
2	2017 E+ Residential Lighting Program*	$ 1,015,301	$ 706,933	43.62%	-	18	18
3	- Initiated 2005, 2017 weighted average program life = 14 years, 8,430 participants.				7,733	13,275	5,542
4							
5	2017 E+ Commercial Lighting Program	$ 4,186,595	$ 2,377,253	76.11%	-	1	1
6	- Initiated 2005, 2017 weighted average program life = 14 years, 874 participants.				15,609	26,795	11,186
7							
8	2017 E+ Electric Business Partners Program	$ 737,896	$ 476,909	54.72%	-	0.04	0.04
9	- Initiated 2005, 2017 weighted average program life = 18 years, 11 participants.				1,254	2,153	899
10							
11	2017 Northwest Energy Efficiency Alliance (NEEA)**	$ 1,220,724	$ 1,220,218	0.04%	-	-	-
12	- Initiated natural gas savings in 2006, program life is 15 years				9,240	15,861	6,621
13							
14	2017 E+ Commercial Electric New Construction Program	$ 232,080	$ 240,108	-3.34%	-	-	-
15	- Initiated 2005, 2017 weighted average program life = 19 years, 28 participants.				1,637	2,811	1,173
16							
17	2017 E+ Commercial Electric Savings Program	$ 361,486	$ 561,102	-35.58%	-	-	-
18	- Initiated 2005, 2017 weighted average program life = 19 years, 71 participants.				1,217	2,088	872
19							
20	2017 General Expenses All Electric DSM Programs	$8,064	$203,707	-96.04%	-	-	-
21	- N/A				-	-	-
22							
23	A program participant is a Montana residential and/or						
24	commercial electric customer who installs eligible						
25	energy conservation measures and receives financial						
26	incentives/rebates either directly or indirectly.						
27							
28	* Number of participants cannot be counted for the Manufacturer Buydown						
29	portion of the E+ Residential Lighting Program.						
30							
31							
32	**Note: 2017 NEEA expeditures are allocated to electric DSM						
33	but there are gas savings as a result of some NEEA initiatives.						
34	Participant has not been defined or counted for NEEA.						
35							
36	Units reported are in megawatts ("MW") and megawatt-hours ("MWh")						
37							
38							
39	TOTAL	$ 7,762,146	$ 5,786,229	34.15%	-	18.94	18.94
40					36,691	62,983	26,293

Sch. 35a	Electric Universal System Benefits Programs						
	Program Description	Actual Expenditures	Contracted or Committed Expenditures	Total Allocations & Expenditures [a]	Expected savings [c]		Most recent program evaluation
1	Local Conservation				MWh	MW	
2	E+ Residential Audit/Sm. Comm Audit	$ 579,535	$ 207,157	$ 786,692	887	0.190	2012
3	E+ Business Partners / Irrigation Projects	20,167	-	$ 20,167	207	-	2012
4	NWE Promotion	79,129	-	$ 79,129			
5	NWE Labor	28,031	-	$ 28,031			
6	NWE Admin. Non-labor	1,138	-	$ 1,138			
7	USB Interest & Svc Chg	(94)	-	$ (94)			
8	Market Transformation						
9	E+ Commercial Lighting	-	-	$ -			
10	Motor Management Training	17,067	-	$ 17,067			
11	Energy Star Homes	123,307	-	$ 123,307			
12	Building Operator Certification	47,359	10,000	$ 57,359	580	-	2012
13	Commercial Industrial Training & Conference	40,455	-	$ 40,455			
14	NWE Promotion	14,683	-	$ 14,683			
15	NWE Labor	18,475	-	$ 18,475			
16	NWE Admin. Non-labor	7,421	-	$ 7,421			
17	USB Interest & Svc Chg	(60)	-	$ (60)			
18	Renewable Resources						
19	Generation/Education	651,757	1,019,239	$ 1,670,996	368	0.280	2012
20	Green Power Product Offering	(12,728)	-	$ (12,728)			
21	NWE Promotion	2,341	-	$ 2,341			
22	NWE Labor	45,302	-	$ 45,302			
23	NWE Admin. Non-labor	609	-	$ 609			
24	USB Interest & Svc Chg	(107)	-	$ (107)			
25	NWE Reallocated to Free Weatherization	33,567	-	$ 33,567			
26	NWE Reallocated to Energy Share	14,386	-	$ 14,386			
27	Research & Development						
28	R&D/ Infrastructure	153,424	237,459	$ 390,883			
29	Battery Storage	1,034	-	$ 1,034			
30	NWE Promotion	3,375	-	$ 3,375			
31	NWE Labor	10,671	-	$ 10,671			
32	NWE Admin. Non-labor	245	-	$ 245			
33	USB Interest & Svc Chg	(25)	-	$ (25)			
34	Low Income						
35	Bill Assistance	2,415,021	-	$ 2,415,021			
36	Free Weatherization	1,989,159	444,796	$ 2,433,955	388	0.030	2012
37	Elec Wx Incentives	19,047	-	$ 19,047			
38	Fuel Switch Analyses	3,500	-	$ 3,500			
39	Energy Share	446,395	149,956	$ 596,351			
40	NWE Promotion	9,702	-	$ 9,702			
41	NWE Labor	30,836	-	$ 30,836			
42	NWE Admin. Non-labor	3,080	-	$ 3,080			
43	USB Interest & Svc Chg	(737)	-	$ (737)			
44	Large Customer Self Directed						
45	Self-Directed Energy Reduction	2,732,386	780,474	3,512,860			
46	Self-Directed to Low Income	154,841	-	154,841			
47	Self-Directed to Renewable Energy	135,709	-				
48	NWE Labor	13,763	-	13,763			
49	USB Interest & Svc Chg	(451)	-	(451)			
50	NWE Reallocated to Free Weatherization	2,545	1,753	4,298			
51	NWE Reallocated to Energy Share	1,090	751	1,841			
52	Total	$ 9,836,351	$ 2,851,584	$ 12,687,935	2,430	0.500	
53	Number of customers that received low income rate discounts				11,337		
54	Average monthly bill discount amount ($/mo)				$ 17.75		
55	Average LIEAP-eligible household income				n/a		
56	Number of customers that received weatherization assistance				473 [c]		
57	Expected average annual bill savings from weatherization				821	Kwh	
58	Number of residential audits performed on-site				2,157 [c]		
59	Number of residential audits performed (mail in survey)				2,836 [c]		
60	[a] Total allocations and expenditures are reported for the combination of 2014 - 2017 electric USB funds spent in 2017.						
61	[b] The 2017 Large Customer Admin Costs of $13,763 less the interest income of $451 exceeded the amount of unclaimed 2017 Large Customer funds of $1,428. NWE has committed unclaimed 2016 Large Customer funds in the amount of $13,312 to cover the deficit.						
62	[c] Total savings and number of customers are reported for the combination of 2014 - 2017 electric and 2017 natural gas USB funds spent in 2017.						

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 Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	E+ Energy Audit for the Home or Business	$ 579,535	$ 207,157	$ 786,692	0.19	2012
3					887	
4	E+ Electric Business Partners Program / Irrigation	$ 20,167	$ -	$ 20,167	-	2012
5					207	
6	Market Transformation					
7	E+ Commercial Lighting Program	$ -	$ -	$ -	-	2012
8					-	
10	Motor Management Training	$ 17,067	$ -	$ 17,067	-	2012
11					-	
12	Energy Star Homes	$ 123,307	$ -	$ 123,307	-	2012
13					-	
14	Building Operator Certification	$ 47,359	$ 10,000	$ 57,359	-	2012
15					580	
16	Commercial Industrial Training & Conference	$ 40,455	$ -	$ 40,455	-	2012
17					-	
18	Renewables					
19	Generation/Education	$ 651,757	$ 1,019,239	$ 1,670,996	0.28	2012
20					368	
21	Green Power Product	$ (12,728)	$ -	$ (12,728)	-	2012
22					-	
23	Research & Development					
24	R&D / Infrastructure	$ 153,425	$ 237,459	$ 390,883	-	2012
25					-	
26	Battery Storage	$ 1,034	$ -	$ 1,034	-	2012
27					-	
28	Low Income					
29	Free Weatherization	$ 2,025,271	$ 446,549	$ 2,471,820	0.03	2012
30					388	
31	Elec Wx Incentives	$ 19,047	$ -	$ 19,047	-	2012
32					-	
33	Fuel Switch	$ 3,500	$ -	$ 3,500	-	2012
34					-	
35	Total	$ 3,669,196	$ 1,920,404	$ 5,589,600	0.50	
36					2,430	2012

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	$298,438,586	$278,903,988	2,537,646	2,370,465	295,252	291,175
4	Commercial & Industrial	396,581,724	389,362,696	6,293,831	6,156,733	67,933	66,990
5	Public Street & Highway Lighting	16,420,735	16,019,702	59,177	59,422	3,732	3,731
6	Sales to Other Utilities	25,524,104	30,499,024	1,218,666	1,595,568	22	22
7	Interdepartmental	1,046,881	1,094,994	9,483	9,924	303	300
8							
9	**TOTAL SALES**	$738,012,030	$715,880,404	10,118,803	10,192,112	367,242	362,218
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							