YEAR ENDING 2018

ANNUAL REPORT
OF

NorthWestern Energy
(Townsend Propane)

GAS UTILITY

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

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

Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Robert Rowe
Chief Financial Officer	Tax, Internal Audit and Controls, Financial Planning and Analysis Controller and Treasury Functions Investor Relations and Corporate Finance Business Technology Energy Risk Management Flight Services, Executive Compensation	Brian Bird
Vice President, General Counsel and Regulatory and Federal Government Affairs	Legal Services Corporate Secretary & 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 Substation Operations Transmission Policy, Services, and Operations Transmission Market Strategy Grid Realtime and Scada Operations 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, Customer Care, Communications and Human Resources	Brand, Advertising, and Customer Communications Customer Experience and Support Customer Interaction Community Connections Revenue Cycle Management Human Resources	Bobbi Schroeppel
Chief Audit & Compliance Officer	Internal Audit Enterprise Risk	Michael Nieman
Vice President & Controller	Financial Reporting Accounting Accounts Payable/Payroll Compensation and Benefits	Crystal Lail

Reflects active officers as of December 31, 2018.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 194,387	98.69%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ 2,573	1.31%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
NorthWestern Energy Solutions, Inc.	Non-regulated customer services		
Total Corporation		$ 196,960	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.	$22,171,978	77.24%	$6,531,908
Customer Care	Includes the following departments: Customer Care, Communications and Contributions, Human Resources, Print Services, Business Development, and Regulatory Support Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	23,225,437	72.74%	8,703,556
Legal Department	Includes the following departments: Chief Legal, Contracts Administration, Regulatory Affairs, and Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	13,705,546	78.08%	3,847,344
Finance	Includes the following departments: CFO, Treasury, FP&A, Tax , Investor Relations, Corporate Aircraft, and Business Technology	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	21,204,260	78.19%	5,914,751
Regulatory and Gov't Affairs	Includes the following departments: VP of Regulatory Affairs	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	80,161	77.00%	23,944
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.	3,241,379	75.03%	1,078,658
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.	835,046	77.00%	249,429
Distribution	Includes the following departments: Sioux Falls Facilities and Helena Building	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	30,938	77.00%	9,241
TOTAL			$84,494,745	76.22%	$26,358,831

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	$252,909		
13						
14	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	3,117,455		
15		transmission, & compression	transmission & compression			
16			are at tariffed rates			
17	**Total Utility Subsidiaries Revenues**			$3,370,364		
18	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	$500,400	15.3%	$500,400
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	$1,226,746	37.5%	$1,226,746
15						
16	**Total Utility Subsidiaries**			$1,727,146		$1,727,146
17	**Total Utility Subsidiaries Expenses**			$3,302,534		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,727,146		$1,727,146

Sch. 8

MONTANA UTILITY INCOME STATEMENT - PROPANE

	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 721,793	$ -	$ 721,793	$ 592,918	21.74%
3						
4	**Total Operating Revenues**	721,793	-	721,793	592,918	21.74%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	548,227	-	548,227	442,190	23.98%
9	402 Maintenance Expense	53,017	-	53,017	46,103	15.00%
10	403 Depreciation Expense	40,627	-	40,627	40,627	0.00%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	60,325	-	60,325	63,285	-4.68%
13	409.1 Income Taxes-Federal			-	-	-
14	-Other			-	-	-
15	410.1 Deferred Income Taxes-Dr.	5,289	-	5,289	2,321	127.88%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	707,485	-	707,485	594,526	19.00%
19	**NET OPERATING INCOME**	$ 14,308	$ -	$ 14,308	$ (1,608)	>300.00%

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.

Sch. 9	MONTANA REVENUES - PROPANE					
	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	$ 428,643	$ -	$ 428,643	$ 358,145	19.68%
5	442 Commercial & Industrial-Small	293,150	-	293,150	234,773	24.87%
6						
7	**Total Sales to Ultimate Consumers**	721,793	-	721,793	592,918	21.74%
8						
9	447 Sales for Resale					
10						
11	**Total Sales of Propane**	721,793	-	721,793	592,918	21.74%
12						
13	449.1 Provision for Rate Refunds					
14						
15	**Total Revenue Net of Rate Refunds**	721,793	-	721,793	592,918	21.74%
16						
17	Miscellaneous Revenues					
18						
19	**Total Other Operating Revenue**	-	-	-	-	-
20	**TOTAL OPERATING REVENUE**	$ 721,793	$ -	$ 721,793	$ 592,918	21.74%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Supply Expenses**					
2	**Other Propane Supply Expense-Operation**					
3	804 Purchases	$ -	$ -	$ -	$ -	-
4	805 Other Propane Purchases	16,517	-	16,517	(16,938)	197.51%
5	807 Purchased Propane Expense			-	-	-
6	808 Propane Withdrawn from Storage	456,906	-	456,906	376,522	21.35%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	473,423	-	473,423	359,584	31.66%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	9,353	-	9,353	7,191	30.07%
14	**Total Operation-Other Storage**	9,353	-	9,353	7,191	30.07%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	9,353	-	9,353	7,191	30.07%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	12,264	-	12,264	13,253	-7.46%
24	878 Meter & House Regulators	9,419	-	9,419	15,549	-39.42%
25	879 Customer Installation	4,333	-	4,333	6,037	-28.23%
26	880 Other	1,337	-	1,337	1,561	-14.35%
27	**Total Operation-Distribution**	27,353	-	27,353	36,400	-24.85%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	52,690	-	52,690	45,587	15.58%
31	892 Maint. of Services	327	-	327	-	-
32	893 Maint. of Meters & House Regulators	-	-	-	517	-100.00%
33	894 Maintenance of Other Equipment			-	-	-
34	**Total Maintenance-Distribution**	53,017	-	53,017	46,104	14.99%
35	**Total Distribution Expenses**	80,370	-	80,370	82,504	-2.59%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	224	-	224	492	-54.47%
41	903 Customer Records & Collection Expense	-	-	-	391	-100.00%
42	**Total Customer Accounts Expenses**	224	-	224	883	-74.63%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	986	-	986	746	32.17%
46	921 Office Supplies & Expenses	29	-	29	18	61.11%
47	923 Outside Services	36,859	-	36,859	37,367	-1.36%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	37,874	-	37,874	38,131	-0.67%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	37,874	-	37,874	38,131	-0.67%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 601,244	$ -	$ 601,244	$ 488,293	23.13%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,761	$2,102	-16.22%
3	Real Estate & Personal Property	56,831	59,760	-4.90%
4	Consumer Counsel	217	178	21.91%
5	Public Service Commission	1,516	1,245	21.77%
6	Vehicle Use Tax	-	-	-
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$60,325	$63,285	-4.68%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	271,529
2	A&E ARCHITECTS P C	Architectural Services	240,828
3	ACE ELECTRIC INC	Electric Construction Service	135,364
4	A-CORE OF MONTANA INC	Construction	209,609
5	ACUREN INSPECTION INC	Inspection Services	167,259
6	AECOM TECHNICAL SERVICES INC	Inspection Services	142,448
7	AFFCO INC	Hydro Construction Services	1,424,531
8	ALME CONSTRUCTION, INC.	Construction	1,398,562
9	ALSTOM GRID INC	Software Support Services	495,840
10	AMERICAN INNOVATIONS INC	Software Support Services	92,049
11	AMERICAN PUBLIC LAND EXCHANGE	Consulting services - environmental	353,282
12	AMPED I LLC	Engineering Services	154,760
13	ARCADIS US INC	Engineering Services	2,202,803
14	ARMS RELIABILITY ENGINEERS LLC	Engineering Services	87,066
15	ASCEND ANALYTICS LLC	Hydro Expert Analysis	530,627
16	ASPLUNDH TREE EXPERT LLC	Tree Trimming	6,941,421
17	ASSOCIATED UNDERWATER SERVICE	Inspection Services	147,146
18	AUTOMOTIVE RENTALS INC	Fleet Management	9,306,997
19	BART ENGINEERING COMPANY	Engineering Services	470,340
20	BEVERIDGE INCORPORATED	Drilling Services	101,921
21	BIG SKY COMMUNICATION & CABLE	Communications Construction	203,022
22	BILL FIELD TRUCKING INC	Hauling Services	507,196
23	BISON ENGINEERING INC	Engineering Services	126,501
24	BLACKEAGLE ENERGY SERVICES	Construction	899,228
25	BLUE MOUNTAIN DIRECTIONAL DRILLING LLC	Boring Services	683,933
26	BURK EXCAVATION AND UTILITIES	Construction	2,722,505
27	CAPCON LLC	Construction	85,674
28	CCI INC	Inspection Services	75,870
29	CEB INC	HR Consulting	116,801
30	CENTRAL AIR SERVICE INC	Aerial Pilot Services	99,085
31	CENTRON SERVICES INC	Customer Collection service	108,229
32	CLARK ENGINEERING CORPORATION	Engineering Services	111,570
33	CLAUSEN AND SONS INC	Construction	114,796
34	CLAUSEN CONSTRUCTION INC	Construction	332,785
35	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	650,392
36	CN UTILITY CONSULTING INC	Utility Consulting Services	526,839
37	COMMERCIAL ROOFING INC	Construction	298,830
38	COMPLETE CAREER CENTER INC	Meter Reader Services	243,006
39	CONTINENTAL STEEL WORKS	Fabrication Services	1,036,751
40	COPPER CREEK LLC	Construction	75,967
41	CROOKED HOLE DRILLING LLC	Drilling Services	84,675
42	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	1,262,167
43	CUDA DIRECTIONAL LLC	Boring Services	124,761
44	DAVEY TREE SURGERY COMPANY	Tree Trimming	3,282,047
45	DELOITTE & TOUCHE LLP	Audit Services	1,497,401
46	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	3,561,152
47	DGR ENGINEERING	Engineering Services	443,784
48	DICK ANDERSON CONSTRUCTION INC	Construction	164,557
49	DIETZEL ENTERPRISES INC	Construction	211,795
50	DJ&A P C CONSULTING ENGINEERS	Engineering Services	92,483
51	DOME TECHNOLOGY LLC	Construction	984,493
52	DONOVAN CONSTRUCTION	Electric Construction Service	1,107,514
53	DORSEY & WHITNEY LLP	Legal Services	303,645
54	DOWL HKM	Geotechnical Services	248,562
55	E SOURCE COMPANIES LLC	Consulting Services	118,824
56	EIDE BAILLY LLP	Audit Services	102,356
57	ELLIOT CONSTRUCTION INC	Boring Services	917,611
58	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	2,874,043
59	ENERGY CONTRACT SERVICES LLC	Inspection Services	202,403
60			

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
[redacted]	Name of Recipient	Nature of Service	Total
61	ENERGY LABORATORIES INC	Environmental Consultants	123,777
62	ENERGY SHARE OF MONTANA	USBC Services	888,544
63	ENVIRONMENTAL CONTRACTORS LLC	Construction	111,145
64	EVERGREEN CAISSONS INC	Construction	534,400
65	FLEMING & O'LEARY PLLP	Legal Services	103,436
66	FLYNN WRIGHT INC	Advertising Services	1,287,682
67	FOOTHILLS RIG SERVICE	Well Services	98,990
68	FORBES TATE PARTNERS LLC	Regulatory Consulting	110,000
69	FOSTER ASSOCIATES CONSULTANTS	Regulatory Consulting	140,495
70	FOUR O SIX UNDERGROUND INC	Boring Services	211,998
71	G2 INTEGRATED SOLUTIONS LLC	Computer System Implementation	2,300,038
72	G4S SECURE INTEGRATION	Fence Materials/Installation	100,438
73	GARLINGTON, LOHN & ROBINSON	Legal Services	154,951
74	GARTNER INC	Information Technology Consulting	164,033
75	GEI CONSULTANTS INC	Environmental Consultants	363,389
76	GENERAL ELECTRIC INTERNATIONAL	Plant Operator Services	4,786,212
77	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	99,853
78	GLOBAL DIVING & SALVAGE INC	Construction	142,946
79	GUY TABACCO CONSTRUCTION	Construction	591,229
80	H & H ASPHALT & MAINTENANCE LLC	Asphalt Services	150,672
81	H & H CONTRACTING INC	Concrete and Asphalt Services	865,345
82	H2E INC	Engineering Services	251,649
83	HAIDER CONSTRUCTION INC	Boring Services	545,052
84	HDR ENGINEERING INC	Engineering Services	1,289,409
85	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	204,152
86	HEATH CONSULTANTS INC	Gas Leak Surveys	605,724
87	HIGHMARK MEDIA	Safety Training	125,840
88	IMCO GENERAL CONSTRUCTION INC	Construction	1,664,654
89	INSULATING COATINGS CORPORATION	Construction	334,527
90	INTEC SERVICES INC	Pole Inspection Services	2,233,160
91	J D POWER AND ASSOCIATES	Energy Study	75,438
92	J2 BUSINESS PRODUCTS	Copier Maintenance	174,672
93	JACKSON UTILITIES LLC	Construction	125,977
94	JACOBSEN TREE EXPERTS	Tree Trimming	964,209
95	JAY FORTUNE CONSTRUCTION INC.	Construction	569,798
96	JD ENGINEERING P C	Engineering Services	308,930
97	JEFFERY CONTRACTING LLC	Construction	109,902
98	JONES DAY	Legal Services	141,811
99	JSSI JET SUPPORT SERVICES INC	Flight Services	246,553
100	KARV LLC	Boring Services	131,003
101	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	192,514
102	KENNEBEC TELEPHONE CO., INC	Boring Services	109,153
103	KM CONSTRUCTION CO INC	Construction	139,308
104	KNIFE RIVER	Construction	181,768
105	LACY CONSTRUCTION	Construction	345,977
106	LARSON DIGGING INC	Boring Services	247,362
107	LEARJET INC	Repair Services	107,684
108	LIEN TRANSPORTATION CO	Excavation Contractor	1,398,964
109	LIQUID GOLD WELL SERVICE INC	Well Services	133,583
110	LOCKMER PLUMBING HEATING & UTILITIES INC	Gas Meter Relocations	490,432
111	LODGEPOLE LAND SERVICES LLC	Real Estate Services	366,206
112	M & P EXCAVATING	Excavation Services	399,552
113	M&D CONSTRUCTION INC	Construction	114,200
114	MANAGEMENT APPLICATIONS CONSULTING	Regulatory Consulting	264,036
119	MARTEL CONSTRUCTION, INC.	Construction	4,150,488
120	MCMILLEN LLC	Construction	101,491
121	MERCER HUMAN RESOURCE CONSULTING	HR Consulting	177,459
122	MERIDIAN IT INC	Information Technology Services	330,943
123	MERKEL ENGINEERING INC	Consulting Services	100,519
124	MICHAELS FENCE & SUPPLY CO	Fence Materials/Installation	155,038
125	MICHELS CANADA CO	Construction	1,126,488
126	MICHELS CORPORATION	Construction	834,575
127	MICROSOFT SERVICES	Software Support Services	117,868
129	MIKE WIRTH CONSTRUCTION	Excavation Contractor	75,177

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	MINUTEMAN AVIATION INC.	Helicopter Charter Services	98,328
131	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	559,152
132	MOODY'S ANALYTICS	Debt Rating Services	162,296
133	MOODY'S INVESTORS SERVICE	Debt Rating Services	288,500
134	MORGAN, LEWIS & BOCKIUS LLP	Legal Services	200,248
135	MORRISON MAIERLE INC	Engineering Services	443,730
136	MOUNTAIN POWER CONSTRUCTION COMPANY	Electric Construction and Maintenance	16,764,317
137	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	264,986
138	MOVESAFE INC	Safety Training	129,126
139	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	266,773
140	MUTH ELECTRIC INC	Construction	239,270
141	NACD BOARD ADVISORY SERVICES	Board Advisory Services	94,854
142	NATIONAL CENTER FOR APPROPRIATE TECHNLOGY	Conservation Program Consultants	366,932
143	NAVIGANT CONSULTING INC	Renewables Consulting Service	272,058
144	NCSG CRANE & HEAVY HAUL SERVICE	Heavy Haul Services	79,249
145	NEWEDGE INC	Consulting Services	157,293
146	NORTHERN HYDRAULICS INC	Construction	93,276
147	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,218,340
148	NORTHWEST TOWER	Construction	127,770
149	OLSON LAND SERVICES	Real Estate Services	80,085
150	OLTROGGE CONSTRUCTION INC	Construction	596,895
151	OPEN ACCESS TECHNOLOGY INT'L I	Software Support Services	490,477
152	OUTBACK POWER COMPANY	Construction	478,803
153	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	9,821,057
154	PIONEER TECHNICAL SERVICES INC	Environmental Services	79,523
155	POTEET CONSTRUCTION	Traffic Safety Services	104,301
156	POWERPLAN INC	Software Support Services	154,647
157	PUETZ CORPORATION	Construction	202,489
158	PYRAMID CABINET SHOP INC	Construction	144,708
159	QUANTA UTILITY ENGINEERING	Engineering Services	5,185,743
160	REISER CONSTRUCTION LLC	Construction	75,253
161	RESPEC	Real Estate Services	157,873
162	RIVER DESIGN GROUP INC	Engineering Services	297,808
163	RML INCORPORATED	Boring Services	255,671
164	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	25,970,931
165	ROD TABBERT CONSTRUCTION INC	Construction	267,964
166	ROUNDS BROTHERS TRENCHING	Boring Services	843,285
167	SANDERSON STEWART	Engineering Services	205,752
168	SAPERE CONSULTING	Consulting Services	108,374
169	SCENIC CITY ENTERPRISES INC	Construction	128,273
170	SCHNEIDER ELECTRIC SOFTWARE CANADA	Computer Support Services	185,588
171	SIDEWINDERS LLC	Generator Repair Services	1,569,919
172	SIME CONSTRUCTION INC	Trenching Services	247,987
173	SIOUX FALLS TOWER & COMMUNICATIONS	Construction	482,034
174	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	223,285
175	SPHERION STAFFING	Temporary Labor	119,501
176	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	215,000
177	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,059,132
178	STEEL STRUCTURES OF ABERDEEN	Construction	130,500
179	STEPHEN P ADIK	Board of Director Fees	113,162
180	STINSON LEONARD STREET LLP	Legal Services	942,317
181	STREAM WORKS INC	Construction	82,848
182	SUMTOTAL SYSTEMS INC	Software Implementation Support Services	114,299
183	TAYLOR SERVICES INC	Construction	91,021
119	TDW SERVICES INC	Inspection Services	177,165
120	TERRA REMOTE SENSING (USA) INC	Surveying Services	402,093
121	TERRACON CONSULTANTS INC	Geotechnical Services	157,158
122	TEXTRON AVIATION INC	Repair Services	373,943
123	THE BRATTLE GROUP INC	Regulatory Consulting	184,506
124	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	1,639,593
125	THE LAWN RANGER	Landscape service	94,191
126	TIMBERLINE SECURITY & SERVICES	Security Services	84,041
127	TLC SEPTIC SERVICE	Excavation Contractor	89,571
129	TODD O BRUESKE CONSTRUCTION	Construction	493,428

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	TRADEMARK ELECTRIC INC	Construction	894,818
131	TRENTON CORP	Construction	114,025
132	TRI-COUNTY MECHANICAL & ELECTRICAL	Construction	86,293
133	TURNER ENTERPRISES INC	Construction	75,000
134	ULTEIG ENGINEERS INC	Project Manager Services	285,965
135	ULTIMATE LANDSCAPE REPAIR LLC	Landscape Service	122,807
136	UNDERGROUND CONSTRUCTION	Construction	81,315
137	UNITED STATES GEOLOGICAL SURVEY	Environmental Consulting	207,400
137	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	166,282
138	VAISALA INC	Wind Forecasting Services	90,201
139	VARSITY CONTRACTORS INC	Janitorial Services	251,588
140	VEOLIA ES TECNICAL SOLUTIONS	Oil Recycling	176,160
141	VERTEX	Billing Services and Programming	2,717,762
142	VESTA PARTNERS LLC	Information Technology Consulting	1,181,233
143	WATER & ENVIRONMENTAL TECHNOLOGIES	Engineering Services	121,793
144	WATSON TRUCKING	Water Hauling Services	110,248
145	WAYNE MARVIN HITT	Consulting Services	117,657
146	WILLIAMSON FENCING INC	Fence Materials/Installation	304,021
147	WILLIS TOWERS WATSON US LLC	Compensation Services	88,672
148	WIRTH CONSTRUCTION LLC	Construction	85,012
149	ZACHA UNDERGROUND CONSTRUCTION	Construction	86,905
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	Total of Payments Set Forth Above		**$ 170,684,300**

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

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	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	$ 634,362,119	$ 583,527,303	8.71%
8	Service cost	10,798,164	10,028,157	7.68%
9	Interest cost	22,325,211	23,305,061	-4.20%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(48,907,131)	40,967,092	-219.38%
13	Acquisition	-	-	-
14	Benefits paid	(26,092,932)	(23,465,494)	-11.20%
15	Benefit obligation at end of year	$ 592,485,431	$ 634,362,119	-6.60%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 522,739,468	$ 465,129,734	12.39%
18	Actual return on plan assets	(37,948,745)	73,075,228	-151.93%
19	Acquisition	-	-	-
20	Employer contribution	8,000,000	8,000,000	-
21	Plan participants' contributions	-	-	-
22	Benefits paid	(26,092,932)	(23,465,494)	-11.20%
23	Fair value of plan assets at end of year	$ 466,697,791	$ 522,739,468	-10.72%
24	**Funded Status**	$ (125,787,640)	$ (111,622,651)	-12.69%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (125,787,640)	$ (111,622,651)	-12.69%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	4.20%	3.60%	16.67%
32	Expected return on plan assets	4.97%	4.70%	5.74%
33	Rate of compensation increase	1.05% Union & 2.67% Non-Union	1.05% Union & 2.77% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 10,798,164	$ 10,028,157	7.68%
36	Interest cost	22,325,211	23,305,061	-4.20%
37	Expected return on plan assets	(25,430,379)	(21,304,851)	-19.36%
38	Amortization of prior service cost	4,453	4,448	0.11%
39	Recognized net actuarial gain	4,359,524	7,718,452	-43.52%
40	Net periodic benefit cost (SEC Basis)	$ 12,056,973	$ 19,751,267	-38.96%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 8,000,000	$ 8,000,000	-
43	Pension Costs Capitalized	1,730,858	1,662,729	4.10%
44	Accumulated Pension Asset (Liability) at Year End	$ (125,787,640)	$ (111,622,651)	-12.69%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,628	2,660	-1.20%
47	Not Covered by the Plan 2/	675	622	8.52%
48	Active	686	749	-8.41%
49	Retired	1,629	1,586	2.71%
50	Deferred Vested Terminated 2/	313	325	-3.69%

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	$ 395,411,056	$ 344,243,945	-12.94%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 10,613,868	$ 10,043,673	5.68%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 356,074,413	$ 395,411,056	-9.95%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 8,005,766	$ 7,479,474	7.04%
44	401(k) Plan Defined Contribution Costs Capitalized	1,732,106	1,554,543	11.42%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,523	1,545	-1.42%
48	Not Covered by the Plan			
49	Active - Participating	1,512	1,534	-1.43%
50	Retired			
51	Vested Former Employees, Retirees and Active-	306	289	5.88%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	($1,218,014)	($433,344)	-181.07%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.90%	3.20%	21.88%
8	Expected return on plan assets	4.82%	4.70%	2.55%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate anually	5.0% fixed rate annually	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	1.05% Union & 2.67% Non-Union	1.05% Union & 2.77% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for the fiscal year ending December 31, 2018.			

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

2/ Obtained from NorthWestern Energy-Montana's 2017 FASB 106 Valuation. Assumptions and data are as of December 31, 2017.

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	$17,466,152	$19,194,132	-9.00%
10	Service cost	342,560	365,276	-6.22%
11	Interest Cost	514,079	610,058	-15.73%
12	Plan participants' contributions	956,828	784,850	21.91%
13	Amendments 5/	-	-	-
14	Actuarial loss/(gain)	(1,643,464)	(842,631)	-95.04%
15	Acquisition	-	-	-
16	Benefits paid	(2,434,354)	(2,645,533)	7.98%
17	Benefit obligation at end of year	$15,201,801	$17,466,152	-12.96%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$20,380,579	$18,604,936	9.54%
20	Actual return on plan assets	(865,545)	2,690,303	-132.17%
21	Acquisition	-	-	-
22	Employer contribution	633,606	946,023	-33.02%
23	Plan participants' contributions	956,828	784,850	21.91%
24	Benefits paid	(2,434,354)	(2,645,533)	7.98%
25	Fair value of plan assets at end of year	$18,671,114	$20,380,579	-8.39%
26	**Funded Status**	$3,469,313	$2,914,427	19.04%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$3,469,313	$2,914,427	19.04%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$342,560	$365,276	-6.22%
33	Interest cost	514,079	610,058	-15.73%
34	Expected return on plan assets	(953,892)	(846,760)	-12.65%
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	-100.00%
38	Net periodic benefit cost	($2,130,101)	($1,585,981)	-34.31%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	633,606	946,023	-33.02%
43	TOTAL	$633,606	$946,023	-33.02%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(1,218,014)	(433,344)	-181.07%
47	TOTAL	($1,218,014)	($433,344)	-181.07%
48	**Montana Intrastate Costs:**	-		
49	Pension Costs	($1,218,014)	($433,344)	-181.07%
50	Pension Costs Capitalized	(263,526)	(90,067)	-192.59%
51	Accumulated Pension Asset (Liability) at Year End	3,469,313	2,914,427	19.04%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,630	1,732	-5.89%
54	Not Covered by the Plan	1,707	1,567	8.93%
55	Active	666	729	-8.64%
56	Retired	861	900	-4.33%
57	Spouses/Dependants covered by the Plan	103	103	-

4/ There is approximately an additional $5,410,095 and $5,455,489 in other company OPEBS liabilities outstanding at December 31, 2018 and 2017, 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	John D. Hines Vice President, Supply & Montana Government Affairs	270,303	148,291 A	21,611 B 146,729 C 26,940 D 7,984 E 101 G	621,959	630,691	-1.4%
2	Michael R. Cashell Vice President, Transmission	270,303	148,291 A	33,895 B 146,729 C 2,863 E	602,081	752,406	-20.0%
3	Crystal D. Lail Vice President & Controller	248,611	119,341 A	33,577 B 135,003 C 2,710 F	539,242	508,619	6.0%
4	Michael L. Nieman Chief Audit and Compliance Officer	227,802	78,066 A	51,508 B 55,851 C	413,227	406,219	1.7%
5	Daniel L. Rausch Treasurer	216,504	74,194 A	50,339 B 53,067 C	394,104	391,498	0.7%
6	Jeanne M. Vold Business Technology Officer	197,457	67,328 A	22,457 B 49,009 C 1,634 D	337,885	0	N/A
7	Jason Merkel General Manager, Operations	190,708	52,384 A	32,484 B 37,234 C 198 G	313,008	437,641	-28.5%
8	Timothy P. Olson Corporate Counsel & Corp Secretary	181,452	49,739 A	44,053 B 35,603 C	310,847	291,458	6.7%
9	John P. Kasperick Director, Financial Planning and Analysis	180,041	49,420 A	31,307 B 35,205 C 9,172 E	305,145	429,749	-29.0%
10	Michael J. Schmit General Manager, Construction	182,463	50,085 A	32,749 B 35,683 C 2,829 E	303,809	0	N/A

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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 2018 Annual Incentive Compensation Plan. Amounts were earned in 2018 and paid in the first quarter of 2019. Based on company performance against plan, the incentive plan was funded at 136% 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, 2018. Most of the pension values decreased due to the increased discount rate, which results in an overall reduction in liability. For employees closer to age 65 normal retirement age, the values decreased less or increased somewhat due to the shorter duration for the reduction in liabiity to impact the present value. The overall change in the cash balance amount year over year also factored into the degree and direction of change.

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.

G> Noncash taxable award and tax gross-up on award.

SCHEDULE 17

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	625,019	857,228 A	30,930 B 1,602,080 C 34,793 D 12,838 E 2,943 F 100 G	3,165,931	2,848,279	11.2%
2	Brian B. Bird Chief Financial Officer	432,315	326,112 A	52,676 B 532,315 C 5,939 D	1,349,357	1,224,635	10.2%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	391,204	271,689 A	52,266 B 413,461 C 2,944 F	1,131,564	945,135	19.7%
4	Curtis T. Pohl Vice President, Distribution	293,760	161,159 A	49,905 B 231,817 C 2,943 F 62 G	739,646	712,085	3.9%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	275,267	151,831 A	52,214 B 174,755 C	654,067	603,206	8.4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the Northwestern Energy 2018 Annual Incentive Compensation Plan. Amounts were earned in 2018 and paid in the first quarter of 2019. Based on company performance against plan, the incentive plan was funded at 136% 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, 2018. Most of the pension values decreased due to the increased discount rate, which results in an overall reduction in liability. For employees closer to age 65 normal retirement age, the values decreased less or increased somewhat due to the shorter duration for the reduction in liabiity to impact the present value. The overall change in the cash balance amount year over year also factored into the degree and direction of change.

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.

G> Noncash taxable award and tax gross-up on award

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$5,840,335,682	$5,615,200,534	$225,135,148	4.01%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	103 Experimental Electric Plant Unclassified	1,631,264	1,631,264	-	0.00%
6	105 Plant Held for Future Use	4,922,322	4,769,005	153,317	3.21%
7	107 Construction Work in Progress	99,808,223	61,848,139	$37,960,084	61.38%
8	108 Accumulated Depreciation Reserve	(2,071,616,130)	(1,963,441,051)	($108,175,079)	5.51%
9	108.1 Accumulated Depreciation - Capital Leases	(25,130,941)	(23,120,462)	($2,010,479)	8.70%
10	111 Accumulated Amortization & Depletion Reserves	(76,813,025)	(67,324,467)	($9,488,558)	14.09%
11	114 Electric Plant Acquisition Adjustments	381,625,879	380,714,172	911,707	0.24%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(32,882,953)	(24,668,473)	(8,214,480)	33.30%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	33,038,099	32,121,152	916,947	2.85%
15	**Total Utility Plant**	4,552,713,484	4,415,524,877	137,188,607	3.11%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutility Property	(47,652)	(47,652)	-	0.00%
19	123.1 Investments in Assoc Companies and Subsidiaries	(125,437,362)	(129,965,362)	4,528,000	-3.48%
20	124 Other Investments	40,469,134	46,794,567	(6,325,433)	-13.52%
21	128 Miscellaneous Special Funds	250,000	250,000	-	0.00%
23	**Total Other Property & Investments**	(84,079,075)	(82,281,642)	(1,797,433)	2.18%
24	**Current and Accrued Assets**				
25	131 Cash	7,522,207	7,390,697	131,510	1.78%
26	134 Other Special Deposits	5,705,336	1,670,617	4,034,719	241.51%
27	135 Working Funds	23,050	23,575	(525)	-2.23%
30	142 Customer Accounts Receivable	73,325,455	78,422,397	(5,096,942)	-6.50%
31	143 Other Accounts Receivable	14,369,677	18,748,330	(4,378,653)	-23.35%
32	144 Accumulated Provision for Uncollectible Accounts	(2,280,211)	(2,859,950)	579,739	-20.27%
34	146 Accounts Receivable-Associated Companies	359,020	430,318	(71,298)	-16.57%
35	151 Fuel Stock	6,933,578	8,051,234	(1,117,656)	-13.88%
36	154 Plant Materials and Operating Supplies	36,494,449	34,228,012	2,266,437	6.62%
37	164 Gas Stored - Current	6,692,917	9,458,237	(2,765,320)	-29.24%
38	165 Prepayments	10,330,909	11,099,817	(768,908)	-6.93%
41	172 Rents Receivable	136,641	105,515	31,126	29.50%
42	173 Accrued Utility Revenues	78,204,239	89,068,916	(10,864,677)	-12.20%
43	174 Miscellaneous Current & Accrued Assets	100,176	638,932	(538,756)	-84.32%
48	**Total Current & Accrued Assets**	237,917,443	256,476,647	(18,559,204)	-7.24%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	12,291,542	13,221,232	(929,690)	-7.03%
51	182 Regulatory Assets	599,139,637	345,290,690	253,848,947	73.52%
53	184 Clearing Accounts	2,044	1,452	592	40.77%
55	186 Miscellaneous Deferred Debits	3,033,001	2,735,704	297,297	10.87%
56	189 Unamortized Loss on Reacquired Debt	34,079,779	37,090,302	(3,010,523)	-8.12%
57	190 Accumulated Deferred Income Taxes	140,591,723	174,177,161	(33,585,438)	-19.28%
58	191 Unrecovered Purchased Gas Costs	6,566,452	12,581,232	(6,014,780)	-47.81%
59	**Total Deferred Debits**	795,704,178	585,097,773	210,606,405	36.00%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 5,502,256,030	$ 5,174,817,655	$ 327,438,375	6.33%

Sch. 18	cont. BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 538,894	$ 529,812	$ 9,082	1.71%
6	211 Miscellaneous Paid-In Capital	1,499,069,743	1,445,181,120	53,888,623	3.73%
10	216 Unappropriated Retained Earnings	546,110,299	458,352,058	87,758,241	19.15%
12	217 Reacquired Capital Stock	(95,545,989)	(96,376,075)	830,086	-0.86%
13	219 Accumulated Other Comprehensive Income	(7,791,798)	(8,772,079)	980,281	-11.18%
14	**Total Proprietary Capital**	1,942,381,149	1,798,914,836	143,466,313	7.98%
15	**Long Term Debt**				
16	221 Bonds	1,779,660,000	1,779,660,000	-	0.00%
18	224 Other Long Term Debt	334,976,900	26,976,900	308,000,000	>300.00%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	-	-	-	-
20	**Total Long Term Debt**	2,114,636,900	1,806,636,900	308,000,000	17.05%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	19,915,440	22,213,443	(2,298,003)	-10.35%
24	228.2 Accumulated Provision for Injuries and Damages	6,475,282	5,360,150	1,115,132	20.80%
25	228.3 Accumulated Provision for Pensions and Benefits	12,131,093	11,339,112	791,981	6.98%
26	228.4 Accumulated Miscellaneous Operating Provisions	131,495,876	162,739,851	(31,243,975)	-19.20%
27	229 Accumulated Provision for Rate Refunds	2,567,455	1,607,624	959,831	59.70%
28	230 Asset Retirement Obligations	40,659,427	39,285,823	1,373,604	3.50%
29	**Total Other Noncurrent Liabilities**	213,244,573	242,546,003	(29,301,430)	-12.08%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	-	319,555,991	(319,555,991)	-100.00%
32	232 Accounts Payable	95,824,027	92,462,564	3,361,463	3.64%
34	234 Accounts Payable to Associated Companies	1,678,806	1,640,365	38,441	2.34%
35	235 Customer Deposits	7,134,336	5,978,744	1,155,592	19.33%
36	236 Taxes Accrued	55,658,065	58,967,909	(3,309,844)	-5.61%
37	237 Interest Accrued	16,953,728	16,356,048	597,680	3.65%
40	241 Tax Collections Payable	1,577,187	1,476,279	100,908	6.84%
41	242 Miscellaneous Current and Accrued Liabilities	76,229,323	52,552,038	23,677,285	45.05%
42	243 Obligations Under Capital Leases-Current	2,298,029	2,132,734	165,295	7.75%
45	**Total Current and Accrued Liabilities**	257,353,501	551,122,672	(293,769,171)	-53.30%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	50,088,672	45,376,055	4,712,617	10.39%
48	253 Other Deferred Credits	182,429,084	170,225,443	12,203,641	7.17%
49	254 Regulatory Liabilities	185,559,637	22,002,745	163,556,892	>300.00%
50	255 Accumulated Deferred Investment Tax Credits	293,407	326,197	(32,790)	-10.05%
52	281-283 Accumulated Deferred Income Taxes	556,269,107	537,666,804	18,602,303	3.46%
53	**Total Deferred Credits**	974,639,907	775,597,244	199,042,663	25.66%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 5,502,256,030	$ 5,174,817,655	$ 327,438,375	6.33%
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.

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 726,400 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

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

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810, Consolidation. ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 5). The other significant differences consist of the following:

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

- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $428.5 million and $408.4 million as of December 31, 2018 and December 31, 2017, 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, 2018 and December 31, 2017, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 9);

- 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, 2018 and December 31, 2017, 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 presented separately for GAAP reporting;

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

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

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

- Stranded tax effects associated with the Tax Cuts and Jobs Act are included in accumulated other comprehensive income (AOCI) in accordance with regulatory treatment, while included in retained earnings for GAAP purposes;

- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes;

- Net periodic benefit costs and net periodic postretirement benefit costs are reflected in operating expense for FERC purposes, as compared to the GAAP presentation, which reflects the current service costs component of the net periodic benefit costs in operating expenses and the other components outside of income from operations. In addition, only the service cost component of net periodic benefit cost is eligible for capitalization for GAAP purposes, as compared to the total net periodic benefit costs for FERC purposes;

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

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 $2.3 million and $2.9 million at December 31, 2018 and December 31, 2017, respectively. Unbilled revenues were $78.2 million and $89.1 million at December 31, 2018 and December 31, 2017, respectively.

Inventories

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

	December 31,	
	2018	2017
Fuel stock	$ 6,934	$ 8,051
Plant materials and operating supplies	36,494	34,228
Gas stored underground (including the non-current portion reflected in utility plant)	39,731	41,579
Total Inventory	$ 83,159	$ 83,858

Regulation of Utility Operations

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

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

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

Derivative Financial Instruments

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

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 10 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Utility Plant

Utility Plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under 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 7.1% and 7.2% for Montana for 2018 and 2017, respectively. This rate averaged 6.7% and 7.2% for South Dakota for 2018 and 2017, respectively. AFUDC capitalized totaled $5.9 million and $8.5 million for the years ended December 31, 2018 and 2017, 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 2018 and 2017.

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

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.

We adopted this standard for interim and annual periods beginning January 1, 2019, as required, and used the modified retrospective method of adoption. We elected a package of practical expedients that allow us to carry forward historical conclusions related to (1) whether any expired or existing contract is a lease or contains a lease, (2) the lease classification of any expired or existing leases and easements, and (3) the initial direct costs for any existing leases. In addition, as our easements are primarily entered into in perpetuity, they do not meet the definition of a lease in accordance with this guidance. We did not restate comparative periods upon adoption. We have one capital lease that is classified as property under capital leases. We also lease office equipment and facilities under various long-term operating leases. These operating leases will increase our property under capital leases and obligation under capital leases by approximately $3 million. As a result, this guidance will have minimal impact on our Financial Statements and disclosures.

Accounting Standards Adopted

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. We adopted this standard as of January 1, 2018, with no material impact to our Statements of Cash Flows, and although the guidance requires retrospective treatment, we did not have any cash receipts or payments during the prior two years that needed to be reclassified.

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 and special funds. Amounts generally described as other special deposits and special funds should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. We adopted this standard as of January 1, 2018 with retrospective application. For the twelve months ended December 31, 2017, this change resulted in a $2.6 million and $1.9 million increase in cash, cash equivalents, other special funds, and special deposits at the beginning and end of the period on our Statements of Cash Flows, respectively. In addition, removing the change in other special funds and special deposits from operating activities in the Statements of Cash Flows resulted in a decrease of $0.7 million in our cash provided by operating activities for the twelve months ended December 31, 2017.

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

	December 31, 2018	December 31, 2017
Cash (131)	$ 7,522	$ 7,391
Working funds (135)	23	24
Special funds (125-128)	250	250
Other special deposits	5,705	1,671
Total shown in the Statements of Cash Flows	$ 13,500	$ 9,336

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

Disclosure Requirements for Defined Benefit Plans - In August 2018, the FASB issued amended guidance to add, remove, and clarify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. During the fourth quarter of 2018, we early adopted this guidance with minimal impact to our disclosures in Note 17 - Employee Benefit Plans.

Supplemental Cash Flow Information

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ 55	$ 60
Interest	76,499	82,692
Significant non-cash transactions:		
Capital expenditures included in accounts payable	21,625	15,848

(3) Acquisition

Montana Wind Generation

In June 2018, we completed the purchase of the 9.7 MW Two Dot wind project near Two Dot, Montana for approximately $18.5 million. The Two Dot purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition as follows (in thousands):

Purchase Price Allocation

Assets Acquired		
Net Utility plant	$	18,542
Prepayments		26
Total Assets Acquired		18,568
Liabilities Assumed		
Taxes Accrued		56
Miscellaneous Current and Accrued Liabilities		8
Total Liabilities Assumed		64
Total Purchase Price	$	18,504

(4) Regulatory Matters

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the Montana Public Service Commission (MPSC) requesting an annual increase to electric rates of approximately \$34.9 million, which represents an approximate 6.6% increase in annual base revenues. Our request is based on a return on equity of 10.65% and an overall rate of return of 7.42% (except for Colstrip Unit 4, which the MPSC previously set for the life of the facility at a 10% return on equity and an 8.25% rate of return), based on approximately \$2.35 billion of electric rate base and a capital structure of 51% debt and 49% equity.

We also requested that approximately \$13.8 million of the proposed rate increase be approved on an interim basis effective November 1, 2018. In March, 2019, the MPSC issued an order approving an increase in rates of approximately \$10.5 million on an interim and refundable basis effective April 1, 2019. On April 5, 2019, we filed rebuttal testimony, which responded to intervenor testimony and included certain known and measurable adjustments. This testimony reflects a request for an annual increase of \$30.7 million, an approximately \$4.2 million reduction from our original request.

A hearing is scheduled to commence on May 13, 2019. Interim rates will remain in effect on a refundable basis until the MPSC issues a final order.

Montana QF Tariff Filing

Under the Public Utility Regulatory Policies Act, 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 (QF Order) approving new rates that were substantially lower than the previous rates and reducing the maximum contract term from 25 to 15 years. In the QF Order, the MPSC also ordered that it would apply the same 15-year contract term to our future owned and contracted electric supply resources. We, as well as Cypress Creek Renewables, LLC, Vote Solar, and Montana Environmental Information Center (collectively, Vote Solar), sought judicial review of the QF Order before the Montana State District Court.

On April 2, 2019, the Montana State District Court (Court) reversed the MPSC's decisions to reduce the contract term to 15 years and apply that term to our supply resources. In addition, the Court found that the MPSC approved rates were too low to reflect avoided cost and ordered the MPSC to provide new calculations to the Court within 20 days. While the Court's decision regarding application of maximum contract length to our future owned and contracted resources is consistent with our initial request for judicial review, we appealed the portion of the Court's decision to increase standard rates to the Montana Supreme Court. In addition, we filed a joint motion along with the MPSC and Montana Consumer Counsel to stay the requirement to provide calculations to the Court. Vote Solar filed a motion to amend the District Court's decision to address inconsistencies in the order. Our QF purchased power expenses are tracked through the Power Cost and Credits Adjustment Mechanism (PCCAM), so any future increases in rates paid to QFs will be reflected through the application of that mechanism.

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 impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Dockets were opened in each of our jurisdictions to investigate the customer benefit of this reduction in the federal corporate income tax rate. During 2018, we received approval of settlement agreements regarding the customer benefit of the Tax Cuts and Jobs Act, as described below.

- In Montana the settlement provides a one-time credit of approximately $20.5 million to customers in early 2019. This includes a $19.2 million credit to electric customers and $1.3 million credit to natural gas customers.
    - In addition to eligible customers receiving a one-time bill credit, the settlement also reduces rates for all natural gas customers by approximately $1.3 million annually beginning January 1, 2019, and provides funds for low-income energy assistance and weatherization programs.
    - The settlement also reflects the agreement of the intervening parties not to oppose our request to include up to $3.5 million of costs to address hazard tree removal in our current Montana rate case.
    - Issues related to the revaluation of deferred income taxes will be addressed in our current Montana rate case.

- In South Dakota we credited electric and natural gas customers approximately $3 million in the fourth quarter of 2018, and agreed to a two-year rate moratorium until January 1, 2021.

Cost Recovery Mechanisms

Electric Tracker - Effective July 1, 2017, the Montana legislature granted the MPSC discretion whether to approve an electric supply tracking mechanism. After considering our application in a contested case proceeding, the MPSC issued a final order in January 2019 approving an electric Power Cost and Credit Adjustment Mechanism (PCCAM) with the following provisions:

- A baseline of power supply costs;
- Annual adjustment of customer prices to reflect a portion of the difference between the established base revenues and actual costs, to the extent such difference is outside a +/- $4.1 million "deadband" from the base, with 90% of the variance above or below the deadband collected from or refunded to customers; and
- Retroactive implementation to the effective date of the new legislation (July 1, 2017).

Our 2018 results include a net reduction in the recovery of supply costs from customers of approximately $1.5 million for the period July 1, 2017 through December 31, 2018 in the Statements of Income and a deferred electric costs in the Balance Sheet of approximately $6.9 million reflecting costs to be recovered from customers in excess of the deadband.

We submitted electric tracker filings for recovery of supply costs for the 12-month periods ended June 30, 2016 and 2017, which are subject to a prudency review. The MPSC approved interim rates for these tracker periods, but has not established a schedule for adjudication of these filings.

(5) Equity Investments

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

	December 31,	
	2018	2017
Colstrip Unit 4 Basis Adjustment	$ (144,906)	$ (147,543)
Havre Pipeline Company, LLC	13,700	14,245
NorthWestern Services, LLC	1,946	1,920
NorthWestern Energy Solutions, Inc.	2,474	—
Risk Partners Assurance, Ltd.	1,349	1,413
Total Investments in Subsidiary Companies	**$ (125,437)**	**$ (129,965)**

(6) Regulatory Assets and Liabilities

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

	Note Reference	Remaining Amortization Period	December 31, 2018	2017
			(in thousands)	
Income taxes	15	Plant Lives	$ 335,289	$ 162,843
Pension	17	Undetermined	130,193	115,504
Tax Cut and Jobs Act		1 Year	56,768	—
Employee related benefits	17	Undetermined	19,458	17,729
State & local taxes & fees		Various	15,527	10,890
Environmental clean-up	20	Various	11,221	12,399
Other		Various	30,684	25,926
Total Regulatory Assets			**$ 599,140**	**$ 345,291**
Tax Cut and Jobs Act		1 Year	161,623	—
Gas storage sales		21 Years	8,728	9,149
Unbilled revenue		1 Year	12,215	9,969
State & local taxes & fees		1 Year	1,747	1,520
Environmental clean-up		Various	1,247	1,365
Total Regulatory Liabilities			**$ 185,560**	**$ 22,003**

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. See Note 15 - Income Taxes for further discussion.

Pension and Employee Related Benefits

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

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

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

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 20 - 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.

Tax Cut and Jobs Act

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

Gas Storage Sales

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

Unbilled Revenue

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

(7) Utility Plant

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

	Estimated Useful Life	December 31, 2018	December 31, 2017
	(years)	(in thousands)	
Land and improvements	50 – 96	$ 157,708	$ 156,637
Building and improvements	26 – 64	467,628	443,420
Storage, distribution, and transmission	15 – 85	3,440,524	3,277,218
Generation	25 – 50	1,870,027	1,680,713
Construction work in process	—	99,808	61,848
Other equipment	2 – 45	332,838	484,536
Total utility plant		6,368,533	6,104,372
Less accumulated depreciation		(2,206,443)	(2,078,554)
Net utility plant		$ 4,162,090	$ 4,025,818

Utility plant under capital lease was $15.4 million and $17.5 million as of December 31, 2018 and 2017, respectively, which included $15.1 million and $17.1 million as of December 31, 2018 and 2017, 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, 2018				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,359	$ 60,758	$ 50,325	$ 309,163
Accumulated depreciation	45,894	34,394	41,379	89,734
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

(8) Asset Retirement Obligations

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

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

	December 31,	
	2018	2017
Liability at January 1,	$ 39,286	$ 39,402
Accretion expense	2,031	2,062
Liabilities incurred	773	—
Liabilities settled	(63)	(61)
Revisions to cash flows	(1,368)	(2,117)
Liability at December 31,	$ 40,659	$ 39,286

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.

(9) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2018 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.

(10) 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, 2018 and 2017. 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, 2018
Interest rate contracts	Interest on long-term debt	$ 613

A pre-tax loss of approximately $15.9 million is remaining in AOCI as of December 31, 2018, 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.

(11) Fair Value Measurements

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

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

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

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, and accounts payable, the carrying amount of each such items 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 source table as they are not recorded at fair value. See Note 10 - 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, 2018		Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)		Margin Cash Collateral Offset		Total Net Fair Value
						(in thousands)				
Special funds and other special deposits	$	5,705	$	—	$	—	$	—	$	5,705
Rabbi trust investments		22,270		—		—		—		22,270
Total	$	27,975	$	—	$	—	$	—	$	27,975
December 31, 2017										
Other special deposits		1,671	$	—	$	—	$	—	$	1,671
Rabbi trust investments		28,135		—		—		—		28,135
Total	$	29.806	$	—	$	—	$	—	$	29,806

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

Financial Instruments

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

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,114,637	$ 2,130,204	$ 1,806,637	$ 1,901,915

Notes payable as of December 31, 2017, 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.

(12) Unsecured Revolving Line of Credit

Unsecured Revolving Line of Credit

We have a $400 million revolving credit facility, which matures December 12, 2021. The facility includes an accordion feature that allows us to increase the size to $450 million with the consent of the lenders. The facility does not amortize and is unsecured. The facility bears interest at the lower of prime plus a credit spread, ranging from 0% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2020, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13%, or available rates tied to the Eurodollar rate plus a credit spread of 0.65%. Commitment fees for the unsecured revolving lines of credit were $0.4 million and $0.5 million for the years ended December 31, 2018 and 2017. The weighted-average interest rate on commercial paper was 1.35% for the year ended December 31, 2017.

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

	2018	2017
Unsecured revolving line of credit, expiring December 2021	$ 400.0	$ 400.0
Unsecured revolving line of credit, expiring March 2020	25.0	—
	425.0	**400.0**
Amounts outstanding at December 31:		
LIBOR borrowings	308.0	—
Letters of credit	0.2	—
Commercial paper issuances	—	319.6
	308.2	**319.6**
Net availability as of December 31, 2018	**$ 116.8**	**$ 80.4**

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

(13) Long-Term Debt

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

	Due	December 31, 2018	December 31, 2017
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ 290,000	$ —
Unsecured Revolving Line of Credit	2020	18,000	—
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Total Long-Term Debt		$ 2,114,637	$ 1,806,637

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. 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.

As of December 31, 2018, 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 $2.3 million in 2019, $20.5 million in 2020, $292.7 million in 2021, $2.9 million in 2022 and $3.1 million in 2023.

(14) 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,	
	2018	2017
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 308	$ 412
NorthWestern Energy Solutions, Inc.	33	—
Risk Partners Assurance, Ltd.	18	18
	$ 359	$ 430
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,679	$ 1,640

(15) Income Taxes

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. 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.

The income tax benefit during the twelve months ended December 31, 2018, includes finalization of the remeasurement of deferred taxes associated with the Tax Cuts and Jobs Act following the conclusion of the associated regulatory dockets.

As of December 31, 2018, deficient and excess accumulated deferred tax assets and liabilities associated with the Tax Cuts and Jobs Act are classified as follows in the Balance Sheets (in thousands):

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

Excess and deficient accumulated deferred income taxes (ADITs) in 2018 were amortized in the Statement of Income as follows (in thousands):

	Protected	
	Montana	South Dakota/ Nebraska
Provision for Deferred Income Taxes	$ 799	$ 133
Provision for Deferred Income Taxes-Cr.	$ 3,343	$ 1,319

ADIT accounts were re-measured by adjusting the pre-tax portion of federal ADIT items by the 14% change in federal tax rate at December 31, 2017 in order to determine the amount of excess deferred taxes subject to amortization. Protected ADITs, which are required by IRS normalization rules to be provided to customers, are typically amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. In the event that remaining book lives are undeterminable, an average book life of assets in the same asset class will be used under the Reverse South Georgia Method. We expect unprotected ADITs will be amortized based on the results of the next rate case filing in each jurisdiction. See Note 4 – Regulatory Matters, for further information regarding the Tax Cuts and Jobs Act.

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,	
	2018	2017
Production tax credit	$ 38,957	$ 28,067
Pension / postretirement benefits	30,634	26,887
NOL carryforward	8,192	62,522
Customer advances	13,190	11,949
Unbilled revenue	12,305	5,944
Compensation accruals	11,885	12,113
AMT credit carryforward	6,799	13,599
Environmental liability	5,810	5,821
Interest rate hedges	4,074	4,323
Reserves and accruals	1,099	1,126
QF obligations	557	234
Property taxes	523	430
Regulatory liabilities	77	114
Other, net	2,477	1,048
Deferred Tax Asset	**$ 140,592**	**$ 174,177**
Excess tax depreciation	$ (373,513)	$ (361,185)
Goodwill amortization	(119,454)	(130,075)
Flow through depreciation	(57,456)	(45,998)
Regulatory assets	(1,218)	(409)
Deferred Tax Liability	**$ (556,269)**	**$ (537,667)**

At December 31, 2018 our total federal NOL carryforward is approximately $257.7 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $4.9 million in 2034; $174.6 million in 2036 and $78.2 million in 2037. Our state NOL carryforward as of December 31, 2018 is approximately $181.5 million. If unused, our state NOL carryforwards will expire as follows: $120.4 million in 2023 and $61.1 million in 2024. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

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

	2018	2017
Unrecognized Tax Benefits at January 1	$ 57,473	$ 88,429
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	—	(22,973)
Gross increases - tax positions in current period	338	—
Gross decreases - tax positions in current period	(1,661)	(7,983)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 56,150	$ 57,473

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 $47.5 million and $47.8 million related to tax positions as of December 31, 2018 and 2017, respectively that, if recognized, would impact our annual effective tax rate. It is reasonably possible that our unrecognized tax benefits may decrease by up to approximately $20 million in the next 12 months due to expiration of statutes of limitation.

Our policy is to recognize interest related to uncertain tax positions in interest expense. During the years ended December 31, 2018 and 2017, we recognized $1.2 million and $0.8 million, respectively, of expense for interest in the Statements of Income. As of December 31, 2018 and 2017, we had $2.7 million and $1.5 million, respectively, of interest accrued in the Balance Sheets.

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

(16) 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,					
	2018			2017		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit (Expense)	Net-of-Tax Amount
Foreign currency translation adjustment	$ 270	$ —	$ 270	$ (202)	—	$ (202)
Reclassification of net losses (gains) on derivative instruments	613	(116)	497	613	(242)	371
Postretirement medical liability adjustment	346	(133)	213	1,257	(484)	773
Other comprehensive income (loss)	$ 1,229	$ (249)	$ 980	$ 1,668	$ (726)	$ 942

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

	December 31,	
	2018	2017
Foreign currency translation	$ 1,448	$ 1,178
Derivative instruments designated as cash flow hedges	(9,491)	(9,981)
Postretirement medical plans	251	31
Accumulated other comprehensive income	$ (7,792)	$ (8,772)

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

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

	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
		December 31, 2017 Year Ended			
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 (loss) income		371	773	(202)	942
Ending Balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)

(17) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our Financial Statements. See Note 6 - 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,	
	2018	2017	2018	2017
Change in benefit obligation:				
Obligation at beginning of period	$ 696,796	$ 646,032	$ 22,921	$ 26,217
Service cost	11,776	10,994	398	456
Interest cost	24,420	25,633	578	715
Actuarial loss (gain)	(53,496)	41,719	(1,903)	(1,884)
Settlements	—	—	390	390
Benefits paid	(29,870)	(27,582)	(1,773)	(2,973)
Benefit Obligation at End of Period	$ 649,626	$ 696,796	$ 20,611	$ 22,921
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 586,508	$ 524,637	$ 20,380	$ 18,605
Return on plan assets	(40,528)	80,253	(866)	2,690
Employer contributions	9,200	9,200	929	2,058
Benefits paid	(29,870)	(27,582)	(1,773)	(2,973)
Fair value of plan assets at end of period	$ 525,310	$ 586,508	$ 18,670	$ 20,380
Funded Status	$ (124,316)	$ (110,288)	$ (1,941)	$ (2,541)
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	2,672	2,535	4,565	5,061
Total Assets	2,672	2,535	4,565	5,061
Current liability	—	—	(2,271)	(3,353)
Noncurrent liability	(126,988)	(112,823)	(4,235)	(4,249)
Total Liabilities	(126,988)	(112,823)	(6,506)	(7,602)
Net amount recognized	$ (124,316)	$ (110,288)	$ (1,941)	$ (2,541)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	—	(4)	7,922	9,955
Net actuarial loss	(116,425)	(105,545)	(1,910)	(1,735)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(548)	(698)
Net actuarial gain	—	—	1,260	1,079
Total	$ (116,425)	$ (105,549)	$ 6,724	$ 8,601

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

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

	NorthWestern Energy Pension Plan	
	December 31,	
	2018	2017
Projected benefit obligation	$ 592.5	$ 634.4
Accumulated benefit obligation	592.5	634.4
Fair value of plan assets	466.7	522.7

As of December 31, 2018, 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,	
	2018	2017	2018	2017
Components of Net Periodic Benefit Cost				
Service cost	$ 11,776	$ 10,994	$ 398	$ 456
Interest cost	24,420	25,633	578	715
Expected return on plan assets	(28,207)	(23,964)	(954)	(846)
Amortization of prior service cost (credit)	4	4	(1,882)	(1,882)
Recognized actuarial loss	4,360	7,837	(79)	318
Settlement loss recognized	—	—	390	390
Net Periodic Benefit Cost (Credit)	$ 12,353	$ 20,504	$ (1,549)	$ (849)

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

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2018 and 2017. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in discount rate during 2018 decreased our projected benefit obligation by approximately $51.5 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 5.06% and decreased our assumption on the NorthWestern Corporation Pension Plan to 4.23% for 2019.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2018	2017	2018	2017
Discount rate	4.15-4.20 %	3.50-3.60 %	3.90-3.95 %	3.20-3.30 %
Expected rate of return on assets	4.47-4.97	4.70		4.70
Long-term rate of increase in compensation levels (nonunion)	2.84		2.84	2.89
Long-term rate of increase in compensation levels (union)	2.03		2.03	2.03
Interest crediting rate	4.00-6.00	4.00-6.00	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00% fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and

- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

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

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

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2018	2017	2018	2017	2018	2017
Domestic debt securities	55.0%	55.0%	75.0%	70.0%	40.0%	40.0%
International debt securities	4.0	4.0	2.5	2.5	—	—
Domestic equity securities	16.5	16.5	9.0	11.0	50.0	50.0
International equity securities	24.5	24.5	13.5	16.5	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2018	2017	2018	2017	2018	2017
Cash and cash equivalents	0.1%	0.1%	—%	—%	1.0%	1.5%
Domestic debt securities	57.5	54.5	81.3	70.0	40.8	35.2
International debt securities	4.4	4.0	2.6	2.5	—	—
Domestic equity securities	15.0	16.7	6.3	11.1	49.1	53.4
International equity securities	23.0	24.7	9.8	16.4	9.1	9.9
	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 2019 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2018 and 2017 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2018	2017
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 8,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 9,200	$ 9,200

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

	Pension Benefits	Other Postretirement Benefits
2019	$ 32,618	$ 3,208
2020	33,880	2,785
2021	35,391	2,731
2022	36,726	2,432
2023	38,124	2,186
2024-2028	206,071	6,606

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, 2018 and 2017 were $10.6 million and $10.0 million, respectively.

(18) 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, 2018, there were 751,071 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:

	2018	2017
Risk-free interest rate	2.30%	1.50%
Expected life, in years	3	3
Expected volatility	16.5% to 21.9%	17.0% to 22.7%
Dividend yield	4.2%	3.7%

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, 2018, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	175,468	$ 49.11
Granted	110,164	47.99
Vested	(83,276)	50.32
Forfeited	(4,653)	48.65
Remaining nonvested grants	197,703	$ 47.99

We recognized compensation expense of $6.3 million and $3.9 million for the years ended December 31, 2018 and 2017, respectively, and a related income tax expense of $0.3 million and $0.4 million for the years ended December 31, 2018 and 2017, respectively. As of December 31, 2018, we had $2.0 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 $4.2 million and $3.7 million for the years ended December 31, 2018 and 2017 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, 2018, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	67,540	$ 45.05
Granted	15,916	54.21
Vested	(8,496)	35.14
Forfeited	(1,569)	44.46
Remaining nonvested grants	73,391	$ 48.19

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, 2018 and 2017, DSUs issued to members of our Board totaled 29,870 and 54,920, respectively. During 2018, DSUs withdrawn by our Board totaled 136,640. Total compensation expense attributable to the DSUs during the years ended December 31, 2018 and 2017 was approximately $1.9 million and $2.9 million, respectively. During 2018, DSUs of $8.2 million were withdrawn.

(19) 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 18 - 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 offered and sold shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. We concluded this program during the second quarter of 2018. During 2018, we issued 835,765 shares of our common stock at an average price of $54.45, for net proceeds of $44.9 million. Since inception of the program, we sold 1,724,703 shares of our common stock at an average price of $57.98 per share. Net proceeds received were approximately $98.5 million, which are net of sales commissions and other fees paid of approximately $1.4 million.

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 12,193 and 34,208 during the years ended December 31, 2018 and 2017, 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.

(20) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act (PURPA). These contracts require us to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. As of December 31, 2018, our estimated gross contractual obligation related to these contracts is approximately $709.8 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $567.2 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within operation expenses and operating revenues in our Statements of Income. The present value of the remaining liability is recorded in accumulated miscellaneous operating provisions in our Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2018	2017
Beginning QF liability	$ 132,786	$ 134,324
Unrecovered amount (1)	(39,827)	(12,009)
Interest on long-term debt	9,301	10,471
Ending QF liability	$ 102,260	$ 132,786

(1) The unrecovered amount includes (i) a periodic adjustment of the liability for price escalation, which was less than modeled, resulting in a liability reduction of $17.5 million and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF supply costs due to outages at two facilities.

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

	Gross Obligation	Recoverable Amounts	Net
2019	$ 75,278	$ 59,020	$ 16,258
2020	77,319	59,647	17,672
2021	79,166	60,136	19,030
2022	81,060	60,639	20,421
2023	83,178	61,280	21,898
Thereafter	313,794	266,493	47,301
Total	$ 709,795	$ 567,215	$ 142,580

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 25 years. Costs incurred under these contracts are included in operating expenses in the Statements of Income and were approximately $209.3 million, and $228.4 million for the years ended December 31, 2018 and 2017, respectively. As of December 31, 2018, our commitments under these contracts are $197.0 million in 2019, $149.6 million in 2020, $124.3 million in 2021, $126.9 million in 2022, $122.1 million in 2023, and $1.3 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $18.0 million between 2019 and 2040. These commitments are not reflected in our Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

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

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us, is estimated to range between $26.6 million to $34.6 million. As of December 31, 2018, we have a reserve of approximately $29.7 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 $22.5 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, 2018, the reserve for remediation costs at this site is approximately $8.4 million, and we estimate that approximately $3.7 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 January 2019, we submitted a revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments on a previously submitted draft RIWP. The revised RIWP requires additional investigation including vapor intrusion and potential contamination from transformers and treated poles. MDEQ is expected to complete its review by the second quarter of 2019.

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 greenhouse gas (GHG) including, most significantly, 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 (CPP), 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.

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 CO_2 emission performance standards for existing electric utility steam generating units and natural gas combined cycle units. As a result of the Executive Order review, on October 10, 2017, the EPA proposed to repeal the CPP. In addition, petitions for review and reconsideration of the CPP were filed by numerous parties, including us. Those proceedings are currently being held in abeyance, at the request of the EPA, in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) pending implementation of the Executive Order.

On August 31, 2018, EPA published the proposed Affordable Clean Energy Rule (ACE), intended to serve as a replacement for the CPP. If finalized as proposed, it is expected that the ACE would generally require a lower level of CO_2 emission reductions than the CPP and provide more regulatory flexibility to individual states.

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

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

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 D.C. Circuit has granted EPA's request to hold the case in abeyance while EPA considers further administrative action to revisit the rule.

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 and ACE proposals, 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

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

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

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

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

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

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

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

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

In August 2017, pursuant to a non-monetary, partial settlement with us, PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. We subsequently filed a motion to dismiss and a motion for partial summary judgment, and PNWS filed a motion for summary judgment on its request for declaratory relief regarding those four power purchase agreements. The United States District Court denied all of those motions in August of 2018.

Discovery concluded in November 2018, and we subsequently filed additional dispositive pre-trial motions which have been denied. PNWS also renewed its prior motion for summary judgment on Count VI of its lawsuit, which seeks a judicial declaration that the four power purchase agreements in question are valid and enforceable. The Court also denied that motion. PNWS is currently seeking approximately $8 million in damages for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019.

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

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

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

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed between Black Eagle Falls and the Great Falls. In particular the dismissal pertains to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. This leaves a portion of the Black Eagle reservoir and Morony Dam and reservoir at issue. While the dismissal of these four facilities is subject to appeal, that appeal would not likely occur until after judgment in the case. We and Talen filed our respective answers to the State's Complaint on August 22, 2018. Additionally, we and Talen filed a motion to join the United States as a defendant to the litigation. The Federal District Court granted the motion, on February 12, 2019, and has ordered the State to name the United States as a party defendant under the Federal Quiet Title Act by October 31, 2019.

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

Wilde Litigation

In October 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 NorthWestern 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.

Mr. Wilde died in a farming accident in November 2017 and the plaintiffs requested a stay of the proceeding. The Eighth District Court lifted the stay on January 11, 2019. On March 4, 2019, the Eighth District Court entered an order granting NorthWestern's and the MPSC's motions for summary judgment and dismissing the case. On April 3, 2019, plaintiffs appealed the Eighth District Court's decision to the Montana Supreme Court. We are awaiting a procedural schedule for the appeal.

We dispute the claims in the lawsuit and will continue to vigorously defend those claims. We cannot predict an outcome or estimate the amount or range of loss that would result from an adverse outcome.

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 - PROPANE			
	Account Number & Title	This Year Utility	Last Year Utility	% Change
1	**Local Storage Plant**			
2	3360 Land and Land Rights	$ 64,954	$ 64,954	0.00%
3	3363 Other Equipment	385,262	385,262	0.00%
4	**Total Local Storage Plant**	450,216	450,216	0.00%
5				
6	**Distribution Plant**			
7	3376 Mains	490,965	490,965	0.00%
8	3380 Services	493,066	493,066	0.00%
9	3381 Customers Meters and Regulators	33,429	33,429	0.00%
10	3382 Meter Installations	-	-	-
11	3389 Other Equipment	51,888	51,888	0.00%
12	**Total Distribution Plant**	1,069,348	1,069,348	0.00%
13	**Total Propane Plant in Service**	1,519,564	1,519,564	0.00%
14				
15	3107 Construction Work in Progress	-	-	-
16	3117 Gas in Underground Storage	32,279	24,839	29.95%
17				
18				
19	**TOTAL PROPANE PLANT**	$ 1,551,843	$ 1,544,403	0.48%
20				
21				
22	**CONSOLIDATED**	December 31,		
23	**PLANT IN SERVICE**	2018	2017	
24				
25	Montana Electric	$ 3,666,282,896	$ 3,518,024,165	
26	Yellowstone National Park	20,268,356	19,786,507	
27	Montana Natural Gas (Includes CMP)	822,869,563	793,388,754	
28	Common	147,639,934	135,376,180	
29	Townsend Propane	1,519,564	1,519,564	
30	South Dakota Electric	903,543,099	877,763,048	
31	South Dakota Natural Gas	190,186,412	182,730,749	
32	South Dakota Common	59,390,829	57,381,499	
33	Asset Retirement Obligation	28,635,029	29,230,068	
34	**TOTAL PLANT**	$ 5,840,335,682	$ 5,615,200,534	

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE			
Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
Accumulated Depreciation				
Local Storage Plant	$ 385,262	$ 267,710	$ 259,543	2.12%
Distribution	1,069,348	665,325	632,865	3.04%
Total Accumulated Depreciation	$ 1,454,610	$ 933,035	$ 892,408	2.79%

Consolidated Accumulated Depreciation	December 31, 2018	December 31, 2017
Montana Electric	1,293,046,224	1,206,041,588
Yellowstone National Park	9,920,070	10,185,147
Montana Natural Gas (Includes CMP)	340,714,954	323,232,339
Common	36,559,425	34,519,406
Townsend Propane	933,035	892,408
South Dakota Electric	309,296,489	299,417,542
South Dakota Natural Gas	93,048,967	89,410,312
South Dakota Common	16,666,196	16,362,957
Acquisition Writedown	48,685,620	51,390,109
Basin Creek Capital Lease	25,130,941	23,120,462
FIN 47	5,318,160	4,651,008
CWIP-Capital Retirement Clearing	(5,759,985)	(5,337,298)
Total Consolidated Accum Depreciation	$ 2,173,560,096	$ 2,053,885,980

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
[redacted]	**Commission Accepted - Most Recent**	% Capital Structure	% Cost Rate	Weighted Cost
1				
2	Docket Number: 2016.9.68			
3	Order Number : 7522g			
4	Effective Date : September 1, 2017			
5				
6	Common Equity	46.79%	9.55%	4.47%
7	Long Term Debt	53.21%	4.67%	2.49%
8				
9	**TOTAL**	100.00%	[redacted]	6.96%

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	$ 196,960,321	$ 162,702,800	21.06%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	148,108,959	146,632,297	1.01%
6	Amortization, Net	31,026,389	24,318,621	27.58%
7	Other Noncash Charges to Net Income, Net	12,498,512	9,908,598	26.14%
8	Deferred Income Taxes, Net	(15,652,483)	10,373,635	-250.89%
9	Investment Tax Credit Adjustments, Net	(32,790)	166,193	-119.73%
10	Change in Operating Receivables, Net	8,967,155	(13,168,865)	168.09%
11	Change in Materials, Supplies & Inventories, Net	1,616,538	(3,378,081)	147.85%
12	Change in Operating Payables & Accrued Liabilities, Net	20,928,888	2,904,555	>300.00%
13	Allowance for Funds Used During Construction (AFUDC)	(4,164,801)	(5,563,937)	25.15%
14	Change in Other Assets & Liabilities, Net	(8,812,717)	(5,811,676)	-51.64%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(1,999,261)	(2,945,962)	32.14%
17	Change in Regulatory Assets	(8,581,074)	438,662	>-300.00%
18	Change in Regulatory Liabilities	1,933,880	(7,107,084)	127.21%
19	**Net Cash Provided by Operating Activities**	382,797,516	319,469,757	19.82%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(302,398,259)	(269,400,928)	-12.25%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(2,500,000)	-	-
24	Proceeds from Sale of Assets	70,671	379,491	-81.38%
26	**Net Cash Used in Investing Activities**	(304,827,588)	(269,021,437)	-13.31%
27	**Cash Flows from Financing Activities:**			
28	Proceeds from Issuance of:			
29	Issuance of Long-Term Debt	-	250,000,000	-100.00%
30	Issuance of Short Term Borrowings, Net	-	18,745,418	-100.00%
31	Line of Credit Borrowings, Net	308,000,000	-	100.00%
32	Proceeds From Issuance of Common Stock, Net	44,796,104	53,668,520	-16.53%
33	Payments for Retirement of:			
34	Repayments of Short Term Borrowings, Net	(319,555,991)	-	-
35	Long-term Debt	-	(250,000,000)	100.00%
36	Dividends on Common Stock	(109,202,079)	(101,269,773)	-7.83%
37	Other Financing Activities:			
38	Debt Financing Costs	(90,898)	(16,382,233)	99.45%
39	Treasury Stock Activity	2,248,640	1,082,861	107.66%
40	**Net Cash Used in Financing Activities**	(73,804,224)	(44,155,206)	-67.15%
41	**Net Increase/Decrease in Cash and Cash Equivalents**	4,165,704	6,293,113	-33.81%
42	**Cash and Cash Equivalents at Beginning of Year**	9,334,889	3,041,776	206.89%
43	**Cash and Cash Equivalents at End of Year**	$ 13,500,593	$ 9,334,889	44.63%
44				
45	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
46	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
47	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
48	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
49				
50	The 2017 disclosure has been restated to reflect the adoption of FASB Accounting Standards Update No. 2016-18, Statement of Cash			
51	Flows, Restricted Cash, which we adopted January 1, 2018, with retrospective application. This standard requires that amounts			
52	generally described as restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and			
53	end-of-period amounts shown in the statements of cash flows.			
54				

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	06/23/15	07/01/45	250,000,000	248,817,402	250,000,000	4.03%	10,644,517	4.26%
Total First Mortgage Bonds			$ 1,266,000,000	$ 1,257,062,324	$ 1,266,000,000		$ 56,442,406	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%	$ 353,344	1.31%
Total Other Long Term Debt			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 353,344	1.31%
TOTAL LONG TERM DEBT			$ 1,437,636,900	$ 1,422,261,628	$ 1,437,636,900		$ 60,423,343	4.20%

This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is $19,915,440.

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

Sch. 26

COMMON STOCK

[redacted]	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	49,379,120	$36.87				$58.30	$53.21	
February	49,433,229	37.34				53.44	50.33	
March	49,473,225	37.08	$1.18	0.55		53.80	50.84	
April	49,475,707	37.36				55.36	52.83	
May	50,183,695	37.73				55.53	53.15	
June	50,315,414	37.72	0.88	0.55		57.57	51.84	
July	50,317,398	37.92				59.35	56.75	
August	50,318,464	38.17				61.89	58.23	
September	50,320,400	37.76	0.56	0.55		60.76	56.99	
October	50,321,086	37.98				61.40	57.96	
November	50,321,910	38.60				63.96	58.91	
December	50,323,689	38.60	1.32	0.55		64.46	58.02	
TOTAL Year End	49,984,562	$38.60	$3.94	$2.20	44.16%	$59.44		15.1

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2018.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$1,519,564	$1,519,564	0.00%
3	108 Accumulated Depreciation	(912,722)	(872,095)	-4.66%
4				
5	**Net Plant in Service**	$606,843	$647,470	-6.27%
6	Additions:			
7	Propane on Hand	$24,839	$24,839	0.00%
8				
9	**Total Additions**	$24,839	$24,839	0.00%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	$21,910	$37,251	-41.18%
12	Reg Liab (TCJA)	24,464		
13	**Total Deductions**	$46,375	$37,251	24.49%
14	**Total Rate Base**	$585,307	$635,058	-7.83%
15	**Net Earnings**	$ 14,308	$ (1,608)	>300.00%
16	**Rate of Return on Average Rate Base**	2.445%	-0.253%	>300.00%
17	**Rate of Return on Average Equity**	Not applicable	Not applicable	
18				
19	**Major Normalizing and**			
20	**Commission Ratemaking Adjustments**			
21				
22				
23		None		
24				
25				
26				
27				
28				
29	**Total Adjustments**			
30	**Revised Net Earnings**			
31	**Adjusted Rate of Return on Average Rate Base**			
32	**Adjusted Rate of Return on Average Equity**			
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				

Sch. 28	MONTANA COMPOSITE STATISTICS - PROPANE		
		Description	Amount
1			
2		**Plant**	
3			
4	101	Plant in Service	$ 1,519,564
5	107	Construction Work in Progress	
6	117	Gas in Underground Storage	32,279
7	108, 111	Depreciation & Amortization Reserves	933,035
8			
9	**NET BOOK COSTS**		618,808
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	721,793
14			
15	**Total Operating Revenues**		721,793
16			
17	401-402	Operation & Maintenance Expenses	601,244
18	403-407	Depreciation Expense	40,627
19	408.1	Taxes Other than Income Taxes	60,325
20	409-411	Federal & State Income Taxes	5,289
21			
22	**Total Operating Expenses**		707,485
23	**Net Operating Income**		14,308
24			
25	415-421.1	Other Income	-
26	421.2-426.5	Other Deductions	-
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ 14,308
28			
29		**Average Customers**	
30		Residential	519
31		Commercial / Industrial	72
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		591
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	59.2
37		Average Annual Residential Cost per (Dkt)	$13.94
38		Average Residential Monthly Bill	$68.83
39			
40		Plant in Service (Gross) per Customer	$2,571

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,878	519	72	-	591
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,878	519	72	-	591
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/18 through 12/31/18.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	159	145	152
5	Finance	154	154	154
6	Distribution	445	443	444
7	Transmission	315	312	314
8	Supply	123	120	122
9	Legal	25	27	26
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,224	1,203	1,214

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2019 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Trans - Holter Helena Vly Tap Reconductor	$10,141,790	$10,141,790
4	MT Elec Trans - Helena Valley 100kv 2nd	$7,776,606	7,776,606
5	MT Elec Dist - SBSQ Belgrade West Substation	$7,488,036	7,488,036
6	MT Elec Trans - Thompson Falls-Burke A&B 115kv corrections	4,659,530	4,659,530
7	MT Elec Dist - Bozeman Midway Substation	4,463,949	4,463,949
8	MT Elec Trans - Lake Helena switchyard sub	4,416,151	4,416,151
9	MT Elec Trans- Custer Auto Substation	4,034,258	4,034,258
10	MT Elec Dist - LED Street Light program	4,116,299	4,116,299
11	MT Elec Trans - Kerr A Line auto bank sub	3,356,258	3,356,258
12	MT Elec Trans - Rainbow - Two Dot 100 kv compliance	3,274,831	3,274,831
13	MT Elec Trans - Livingston-Emigrant reconductor	2,885,474	2,885,474
14	MT Elec Trans - Holter - GF NW pole replacements	2,086,330	2,086,330
15	MT Elec Trans - Trident Auto Sub	1,934,754	1,934,754
16	MT Elec Dist - Belgrade West capacity reconductor	1,712,909	1,712,909
17	MT Elec Trans - worst circuit reliability upgrades	1,449,541	1,449,541
18	MT Elec Trans - Baseline-Meridian 100kv reconductor	1,104,195	1,104,195
19	MT Elec Trans - Livingston Northside sub maint	1,101,899	1,101,899
20	MT Elec Trans - East Gallatin Upgrade substation	1,076,849	1,076,849
21	MT Elec Trans - Gordon BT - Loweth pole replacements	1,035,059	1,035,059
22	SD Elec Trans - Aberdeen 115kv loop	3,218,479	-
23			
24	All Other Projects < $1 Million Each	104,668,882	79,442,122
25			
26	**Total Electric Utility Construction Budget**	**176,002,079**	**147,556,840**
27			
28	**Natural Gas Operations**		
29	MT Gas Trans - Warren-Billings Steam Plant compliance	14,961,841	14,961,841
30	MT Gas Dist - Butte Base Gas Infrastructure	4,611,648	4,611,648
31	MT Gas Trans - Absarokee Compr 1 addition	3,260,791	3,260,791
32	MT Gas Trans - Belfry Comp Station capacity	1,503,444	1,503,444
33	MT Gas Dist - Whitefish Mountain upgrade capacity	1,246,217	1,246,217
34	MT Gas Trans - 8" Cenex YR Washout	1,074,025	1,074,025
35	MT Gas - Dist HVCG express feed extension	1,063,466	1,063,466
36			
37	All Other Projects < $1 Million Each	26,699,948	19,522,466
38			
39	**Total Natural Gas Utility Construction Budget**	**54,421,379**	**47,243,897**
40			
41	**Common**		
42	SD AMI Metering	18,016,117	-
43	MT Facilities Bozeman Service Center expansion	6,644,819	6,644,819
44	MT Fleet and Equipment Upgrades	5,173,000	5,173,000
45	MT CAISO Energy Imbalance Market	2,929,561	2,929,561
46	MT Facilities Grid Operations Security Fence	1,375,761	1,375,761
47	MT Telecom - MPLS Core Network	1,291,647	1,291,647
48	MT Community Sustainability R&D	1,094,813	1,094,813
49	MT Facilities - Bozeman City Property Acquisition	1,010,695	1,010,695
50	SD Fleet and Equipment Upgrades	2,500,000	-
51			
52	All Other Projects < $1 Million Each	19,733,265	15,934,974
53	(Includes BT, Communications, Facilities, Customer Services)		
54			
55	**Total Common Utility Construction Budget**	**59,769,678**	**35,455,270**
56			
57	**MT/SD Generation**		
58	MT - Generation Interconnections	10,000,000	10,000,000
59	MT Colstrip Unit 4 Capital Additions - PPL invoice	4,587,763	4,587,763
60	MT - Hydro MDS U4 Turb-Gen Upgrade	2,227,325	2,227,325
61	MT - Hydro RYN U1 Generator Rewind	1,744,813	1,744,813
62	MT - Hydro HAU U4 Turb-Gen Upgrade	1,712,479	1,712,479
63	MT - Hydro RYN U6 Gen Rewind-Restack	1,296,268	1,296,268
64	MT - Hydro HLT Wastegate Replacement	1,283,337	1,283,337
65	MT - Hydro MDS U3 Turb-Gen Upgrade	1,255,917	1,255,917
66	MT - Hydro HAU U5 Turb-Gen Upgrade	1,166,627	1,166,627
67	SD - Mobile fleet expansion	7,000,000	-
68	SD Big Stone, Neal 4, Coyote Partner Capital, Internal	3,824,807	-
69			
70	All Other Projects < $1 Million Each	9,317,017	9,317,017
71			
72	**Total MT/SD Generation**	**45,416,353**	**34,591,546**
73	TOTAL CONSTRUCTION BUDGET	$335,609,489	$264,847,553

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2018 Year	2017 Year	2018 Year	2017 Year
1	**Name of Supplier**				
2					
3	AmeriGas		28,326		$6.2439
4	Gibson Energy, LLC / Midstream	53,162	27,305	$8.9105	$7.0779
5					
6	**Total Propane Supply Volumes**	53,162	55,631	$8.9105	$6.6532

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2018 Year	2017 Year	2018 Year	2017 Year	2018 Year	2017 Year
1	**Sales of Propane**						
2							
3	Residential	$428,643	$358,145	30,742	29,281	519	516
4	Commercial / Industrial	293,150	234,773	21,829	20,056	72	70
5							
6							
7	**TOTAL SALES**	$721,793	$592,918	52,571	49,337	591	586