YEAR ENDING 2016

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:	40 East Broadway 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
1		
2	See NorthWestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
	President & Chief Executive Officer	Executive	Robert Rowe
	Vice President,	Tax, Internal Audit and Controls, Credit	Brian Bird
	Chief Financial Officer	Financial Planning and Analysis	
		Controller and Treasury Functions	
		Investor Relations and Corporate Finance	
		Cash Management and Business Technology	
		Energy Risk Management	
		Flight Services, Executive Compensation	
	Vice President,	Legal Services	Heather Grahame
	General Counsel	Corporate Secretary & Shareholder Services	
		Risk Management	
		FERC & NERC Compliance	
	Vice President,	Distribution Operations - MT/SD/NE	Curt Pohl
	Distribution	Construction, Asset Management	
		Organizational Development & Labor Relations	
		Project Management	
		Safety/Health/Environmental Services	
		Organizational Performance	
	Vice President,	Transmission Engineering, Construction, and Planning	Michael Cashell
	Transmission	Gas Transmission & Storage	
		Grid & Substation Operations	
		Transmission Business Development and Analysis	
		Support Services	
	Vice President,	Production & Generation Operations	John Hines
	Supply	Energy Supply Planning, Regulatory, & Marketing	
		Energy Supply Long-Term Resources	
		Gas Growth & Storage	
	Vice President,	Government & Regulatory Affairs	Patrick Corcoran
	Government & Regulatory Affairs		
	Vice President,	Corporate Communications	Bobbi Schroeppel
	Customer Care, Communications &	Account and Analysis	
	Human Resources	Customer Experience and Support	
		Customer Interaction	
		Key Accounts/Customer Education	
		Revenue Cycle Management	
		Human Resources	
	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
		Enterprise Risk	
	Vice President, Controller	Financial Reporting	Crystal Lail
		Accounting	
		Accounts Payable/Payroll	
		Compensation and Benefits	

Reflects active officers as of December 31, 2016.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 161,133	98.15%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP, HPC, Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ 3,039	1.85%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		$ 164,172	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.	$20,092,778	78.84%	$5,394,168
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, CC - Assoc & Dispatch Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	22,648,642	75.28%	7,436,132
Legal Department	Includes the following departments: Chief Legal, Compliance, Contracts Administration, and Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	12,956,673	81.67%	2,907,421
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Capital Related Exp, Data Center, Project Management & Asset Control, Record Mgmt Systems, and Security.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	18,808,321	78.72%	5,083,054
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,909,088	81.65%	878,370
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.	2,970,006	76.32%	921,447
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.	842,821	78.00%	237,719
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	105,810	78.00%	29,844
TOTAL			$82,334,139	78.25%	$22,888,155

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	$198,187		
13	Havre Pipeline Company, LLC	Natural gas gathering, transmission, & compression	Gathering rate based on cost, transmission & compression are at tariffed rates	3,632,385		
14	**Total Utility Subsidiaries Revenues**			$3,830,572		
15	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	$500,400	12.0%	$500,400
14						
15	**Total Utility Subsidiaries**			$500,400		$500,400
16	**Total Utility Subsidiaries Expenses**			$4,177,678		
17	**TOTAL AFFILIATE TRANSACTIONS**			$500,400		$500,400

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	$ 495,329	$ -	$ 495,329	$ 744,778	-33.49%
3						
4	**Total Operating Revenues**	495,329	-	495,329	744,778	-33.49%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	386,589	-	386,589	631,670	-38.80%
9	402 Maintenance Expense	42,044	-	42,044	30,041	39.95%
10	403 Depreciation Expense	40,899	-	40,899	40,899	0.00%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	59,788	-	59,788	60,208	-0.70%
13	409.1 Income Taxes-Federal			-	-	-
14	-Other			-	-	-
15	410.1 Deferred Income Taxes-Dr.	(12,101)	-	(12,101)	(5,112)	-136.72%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	517,219	-	517,219	757,706	-31.74%
19	**NET OPERATING INCOME**	$ (21,890)	$ -	$ (21,890)	$ (12,928)	-69.32%

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	$ 294,653	$ -	$ 294,653	$ 441,052	-33.19%
5	442 Commercial & Industrial-Small	200,676	-	200,676	303,726	-33.93%
6						
7	**Total Sales to Ultimate Consumers**	495,329	-	495,329	744,778	-33.49%
8						
9	447 Sales for Resale					
10						
11	**Total Sales of Propane**	495,329	-	495,329	744,778	-33.49%
12						
13	449.1 Provision for Rate Refunds					
14						
15	**Total Revenue Net of Rate Refunds**	495,329	-	495,329	744,778	-33.49%
16						
17	Miscellaneous Revenues					
18						
19	**Total Other Operating Revenue**	-	-	-	-	-
20	**TOTAL OPERATING REVENUE**	$ 495,329	$ -	$ 495,329	$ 744,778	-33.49%

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	9,774	-	9,774	36,399	-73.15%
5	807 Purchased Propane Expense			-	-	-
6	808 Propane Withdrawn from Storage	290,031	-	290,031	504,458	-42.51%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	299,805	-	299,805	540,857	-44.57%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	5,985	-	5,985	10,155	-41.06%
14	**Total Operation-Other Storage**	5,985	-	5,985	10,155	-41.06%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	5,985	-	5,985	10,155	-41.06%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	12,888	-	12,888	10,039	28.38%
24	878 Meter & House Regulators	21,605	-	21,605	26,339	-17.97%
25	879 Customer Installation	5,205	-	5,205	5,209	-0.08%
26	880 Other	1,670	-	1,670	1,481	12.76%
27	**Total Operation-Distribution**	41,368	-	41,368	43,068	-3.95%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	37,571	-	37,571	28,344	32.55%
31	892 Maint. of Services	3,551	-	3,551	236	>300.00%
32	893 Maint. of Meters & House Regulators	922	-	922	1,329	-30.62%
33	894 Maintenance of Other Equipment			-	132	-100.00%
34	**Total Maintenance-Distribution**	42,044	-	42,044	30,041	39.96%
35	**Total Distribution Expenses**	83,412	-	83,412	73,109	14.09%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	694	-	694	624	11.22%
41	903 Customer Records & Collection Expense	183	-	183	182	0.55%
42	**Total Customer Accounts Expenses**	877	-	877	806	8.81%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	673	-	673	639	5.32%
46	921 Office Supplies & Expenses	4	-	4	13	-69.23%
47	923 Outside Services	37,877	-	37,877	36,132	4.83%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	38,554	-	38,554	36,784	4.81%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	38,554	-	38,554	36,784	4.81%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 428,633	$ -	$ 428,633	$ 661,711	-35.22%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$2,571	$2,033	26.46%
3	Real Estate & Personal Property	56,028	56,388	-0.64%
4	Consumer Counsel	149	223	-33.18%
5	Public Service Commission	1,040	1,564	-33.50%
6	Vehicle Use Tax	-	-	-
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$59,788	$60,208	-0.70%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A & A ASPHALT MAINTENANCE	Asphalt Services	145,710
2	A EXCAVATION	Excavation Contractor	196,272
3	A&E ARCHITECTS P C	Architectural Services	121,325
4	AFFCO INC	Hydro Construction Services	966,670
5	ALME CONSTRUCTION, INC	Construction	1,232,948
6	ALSTOM GRID INC	Software Support Services	334,821
7	ALSTOM POWER INC	Generator Repair Services	169,910
8	ALTEC PARTS	Excavation Services	738,344
9	AMERICAN INNOVATIONS INC	Software Support Services	106,132
10	AMERICAN PUBLIC LAND EXCHANGE	Environmental Consultants	307,144
11	APPALACHIAN PIPELINE CONTRACTORS	Construction	3,060,308
12	ARCADIS US INC	Engineering Services	2,085,545
13	ARCHROCK SERVICES LP	Compression Service	88,061
14	ASCEND ANALYTICS LLC	Hydro Expert Analysis	613,651
15	ASPLUNDH TREE EXPERT COMPANY	Tree Trimming	3,603,113
16	AUTOMOTIVE RENTALS INC	Fleet Management	7,062,289
17	BAKER BOTTS LLP	Legal Services	143,236
18	BART ENGINEERING COMPANY	Engineering Services	472,576
19	BC RANCH REPAIR LLC	Generator Repair Services	89,069
20	BEARTOOTH ELECTRIC CO-OP	Meter Read Services	1,124,716
21	BIG COUNTRY ENERGY SERVICES LLC	Construction	75,687
22	BILL FIELD TRUCKING INC	Hauling Services	431,040
23	BOZEMAN GREEN BUILD	Solar System Installation	101,976
24	BROWNING, KALECZYC, BERRY & HOVEN	Legal Services	78,577
25	BRYAN CAVE LLP	Legal Services	100,276
26	BURK EXCAVATION & FIRST MONTANA BANK	Construction	1,051,594
27	CASCADE ELECTRIC COMPANY INC	Construction	167,861
28	CEB INC	Customer Care Services	216,197
29	CENTERPOINT ENERGY SERVICES INC	Transmission Services	2,478,369
30	CENTRAL AIR SERVICE INC	Aerial Pilot Services	155,480
31	CENTRON SERVICES INC	Customer Collection Services	99,041
32	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	347,751
33	CHAPMAN AND CUTLER LLP	Legal Services	144,595
34	CLAUSEN AND SONS INC	Construction	791,238
35	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	398,251
36	CONTINENTAL STEEL WORKS	Fabrication Services	1,096,711
37	CREDIT BUREAU OF MISSOULA INC	Customer Collection Services	79,289
38	CRIST, KROGH, BUTLER & NORD LLC	Legal Services	348,732
39	CRUX SUBSURFACE INC	Construction	1,919,320
40	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	427,991
41	D & A TRENCHING INC	Boring Services	94,175
42	DAVEY TREE SURGERY COMPANY	Tree Trimming	1,814,708
43	DELOITTE & TOUCHE LLP	Audit Services	1,691,140
44	DELOITTE TAX LLP	Tax Services	358,601
45	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	4,389,156
46	DGR ENGINEERING	Engineering Services	267,879
47	DHC INC	Boring Services	421,685
48	DICK ANDERSON CONSTRUCTION	New GO Construction	337,875
49	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	485,390
50	DJ&A P C CONSULTING ENGINEERS	Environmental Consultants	151,047
51	DNV KEMA RENEWABLES (USA) INC	Engineering Services	115,746
52	DONOVAN CONSTRUCTION	Construction	1,651,715
53	DORSEY & WHITNEY LLP	Legal Services	394,553
54	DOWL HKM	Geotechnical Services	166,871
55	E SOURCE COMPANIES LLC	Strategic Services	97,800
56	EAGLE GAS MARKETING LLC	Marketing Services	216,993
57	EIDEBAILLY	Audit Services	76,054
58	ELLIOT CONSTRUCTION INC	Boring Services	334,093
59	ELM LOCATING & UTILITY SERVICES LTD	Locating Services and Excavation Notifications	3,144,781
60	EMC CORPORATION HEADQUARTERS	Software Support Services	111,510

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	ENABLON NORTH AMERICA CORPORATION	Software Implementation Support Services	227,100
62	ENERGY AND ENVIRONMENTAL ECONOMICS	Benefits Analysis Services	96,466
63	ENERGY CONTRACT SERVICES LLC	Energy Services	374,433
64	ENERGY SHARE OF MONTANA	USBC Services	914,959
65	FAIRBANKS MORSE ENGINE	Engineering Services	81,136
66	FALLS CONSTRUCTION COMPANY	Construction	400,778
67	FITCH INC	Debt Rating Services	138,796
68	FLYNN WRIGHT INC	Advertising Services	1,211,003
69	FORBES TATE PARTNERS LLC	Regulatory Consultants	120,000
70	GARTNER INC	Information Technology Consulting	151,210
71	GE BETZ INC	Chemical Management Services	179,480
72	GEI CONSULTANTS INC	Environmental Consultants	253,548
73	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	760,793
74	GLACIER ELECTRIC COOPERATIVE	Construction	151,262
75	GLOBAL DIVING & SALVAGE INC	Construction	371,616
76	GUY TABACCO CONSTRUCTION	Construction	532,237
77	H & H ASPHALT & MAINTENANCE LLC	Asphalt Services	259,874
78	H & H CONTRACTING INC	Concrete and Asphalt Services	813,596
79	HAIDER CONSTRUCTION INC	Backhoe Services	384,031
80	HARVEST SOLAR MT	Solar System Installation	84,059
81	HDR ENGINEERING INC	Engineering Services	1,339,282
82	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	348,923
83	HEATH CONSULTANTS INC	Gas Leak Surveys	629,292
84	HIGHMARK MEDIA	Marketing Services	117,295
85	IMS CONSTRUCTION INC	Construction	462,017
86	INSIGHT KNOWLEDGE MANAGEMENT	Software Implementation Support Services	210,700
87	INTEC SERVICES INC	Pole Inspection Services	2,548,406
88	J&J EXCAVATING & TRUCKING INC	Excavation Services	507,476
89	J2 OFFICE PRODUCTS	Computer/Printer Purchases	278,370
90	JACOBSEN TREE EXPERTS	Tree Trimming	548,313
91	JD ENGINEERING P C	Engineering Services	378,565
92	JODY KLESSENS CONSTRUCTION LLC	Construction	159,783
93	JONES CONSTRUCTION	Construction	75,547
94	JONES DAY	Legal Services	175,480
95	JSSI JET SUPPORT SERVICES INC	Flight Services	223,326
96	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	269,202
97	KLEINSCHMIDT ASSOCIATES	Engineering Services	287,601
98	KM CONSTRUCTION CO INC	Construction	94,224
99	KNIFE RIVER	Construction	99,858
100	KUTAK ROCK LLP	Legal Services	141,542
101	LARSON DIGGING INC	Excavation Services	253,638
102	LAST BEST PLACE LANDSCAPING INC	Landscape Service	105,859
103	LIEN TRANSPORTATION COMPANY	Construction	525,510
104	LIQUID GOLD WELL SERVICE INC	Well Services	116,291
105	LOCKMER PLUMBING HEATING & UTILITIES, INC	Gas Meter Relocations	400,816
106	LOCUSVIEW SOLUTIONS INCORPORATED	Data Collection Services	176,500
107	LODGEPOLE LAND SERVICES LLC	Construction	91,303
108	M & P EXCAVATING	Excavation Services	326,882
109	MANAGEMENT APPLICATIONS CONSULTING	Regulatory Consulting	84,617
110	MARSH & MCLENNAN AGENCY LLC	BEN Consulting Service	98,847
111	MCCARTER & ENGLISH LLP	Legal Services	75,380
112	MCMILLEN LLC	Construction	6,549,201
113	MERCER HUMAN RESOURCE CONSULTING	HR Consulting	115,574
114	MERIDIAN IT INC	Information Technology Services	1,104,958
119	MIDWESTERN MECHANICAL INC	Construction	213,583
120	MIKE WIRTH CONSTRUCTION	Construction	83,991
121	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	744,257
122	MOODY'S INVESTORS SERVICE	Debt Rating Services	414,645
123	MORRISON MAIERLE INC	Engineering Services	878,464
124	MOUNTAIN POWER CONSTRUCTION COMPANY	Construction	17,563,095
125	MOUNTAIN WEST HOLDING COMPANY	Construction	464,801
126	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	148,209
127	MUTH ELECTRIC INC	Transformer Installation	156,412
129	NATIONAL CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	387,257

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	NCSG CRANE & HEAVY HAUL SERVICES	Heavy Haul Services	138,958
131	NEXANT INC	Energy Efficiency Consultants	217,984
132	NORLEY CONSULTING	Gas Compressor Consultant	115,633
133	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,218,340
134	OMIMEX CANADA LTD	Gas Lease Operating Expenses	586,823
135	ONSITE ENERGY INC	Construction	774,755
136	OPEN ACCESS TECHNOLOGY INTERNATIONAL, INC	Software Support Services	397,243
137	OSMOSE UTILITIES SERVICES INC	Construction	127,149
137	P2 ENERGY SOLUTIONS INC	Computer System Implementation	106,501
138	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	19,012,403
139	PIONEER TECHNICAL SERVICES INC	Engineering Services	174,650
140	POTEET CONSTRUCTION	Traffic Safety Services	133,071
141	POWERPLAN INC	Software Implementation Support Services	1,765,866
142	PRICEWATERHOUSECOOPERS LLP	Audit Services	1,511,532
143	PROPAK SYSTEMS LTD	Generator Repair Services	3,187,499
144	Q3 CONTRACTING INC	Construction	88,721
145	QUORUM BUSINESS SOLUTIONS	Software Implementation Support Services	825,578
146	RESPEC	Right of Way Consulting Services	115,398
147	RIVER DESIGN GROUP INC	Engineering Services	236,759
148	RML INCORPORATED	Boring Services	289,993
149	ROBERT PECCIA AND ASSOCIATES INC	Engineering Services	394,275
150	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	37,869,006
151	ROD TABBERT CONSTRUCTION INC	Construction	278,006
152	ROUNDS BROTHERS TRENCHING	Boring Services	498,660
153	SCENIC CITY ENTERPRISES INC	Engineering Services	83,044
154	SCHNEIDER ELECTRIC	Computer Support Services	168,284
155	SEDGWICK CMS	Customer Collection Services	244,394
156	SEPA SMART ELECTRIC POWER ALLIANCE	Stakeholder Engagement Services	137,067
157	SIDEWINDERS LLC	Generator Repair Services	169,837
158	SIME CONSTRUCTION INC	Construction	177,397
159	SIOUX FALLS INTERIORS LLC	Construction	143,400
160	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	721,895
161	SLETTEN CONSTRUCTION COMPANY	Construction	134,063
162	SPHERION STAFFING	Temporary Employment Services	109,543
163	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	235,000
164	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	1,069,192
165	STATE OF MONTANA/A&E DIVISION	Construction	81,214
166	STEEL STRUCTURES LLC	Construction	180,000
167	STINSON LEONARD STREET LLP	Legal Services	1,737,003
168	SUMTOTAL SYSTEMS INC	Software Implementation Support Services	540,065
169	SUPERIOR CONCRETE PRODUCTS INC	Construction	94,710
170	TALEN ENERGY	Legal Services	81,982
171	TAMIETTI CONSTRUCTION COMPANY	Construction	196,285
172	TAYLOR SERVICES INC	Construction	101,726
173	TDW SERVICES INC	Inspection Services	76,935
174	TERRA REMOTE SENSING (USA) INC	Surveying Services	168,696
175	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	743,664
176	TIMBERLINE SECURITY & SERVICES	Security Services	76,701
177	TITAN CONSTRUCTION	Construction	383,111
178	TODD O BRUESKE CONSTRUCTION	Construction	292,335
179	TOWERS WATSON DELAWARE INC	Compensation Services	102,245
180	TP CONSTRUCTION INCORPORATED	Construction	83,387
181	TRADEMARK ELECTRIC INC	Construction	404,157
182	TRI-COUNTY MECHANICAL & ELECTRICAL	Construction	167,679
183	TURBO JET SERVICES	Construction	91,337
184	ULTEIG ENGINEERS INC	Project Manager Services	279,251
185	UNITED STATES GEOLOGICAL SURVEY	Environmental Consultants	202,400
186	UNIVERSITY OF MONTANA	Research Services	82,569
187	UTILICAST LLC	Market Assessment Services	97,268
188	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	164,013
189	UTILITY MAPPING SERVICES INC	Line Location Services	441,270
190	VAISALA INC	Environmental Consultants	91,069
191	VARSITY CONTRACTORS INC	Janitorial Services	305,520

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
193	VEIT & COMPANY	Construction	136,969
194	VERTEX	Billing Services and System Implementation	2,774,224
195	WASHINGTON FORESTRY CONSULTANTS	Forestry Consultants	384,410
196	WATER & ENVIRONMENTAL TECHNOLOGIES	Engineering Services	95,640
197	WATSON TRUCKING	Water Hauling Services	91,835
198	WESTERN ECOSYSTEMS TECHNOLOGY	Engineering Services	76,756
199	WILLIAMSON FENCING INC	Construction	199,324
200	WIT PIPELINE INSPECTION	Inspection Services	196,836
201	ZACHA UNDERGROUND CONSTRUCTION	Construction	148,209
202			
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	Total of Payments Set Forth Above		**$ 181,803,972**

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. Employees of NorthWestern Corporation (NorthWestern Energy) PAC;			
b. NorthWestern Energy Employees PAC; and			
c. NorthWestern Public Service Employees PAC.			
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	$ 565,361,292	$ 621,367,413	-9.01%
8	Service cost	10,711,339	11,211,631	-4.46%
9	Interest cost	23,762,971	23,790,829	-0.12%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	8,068,651	(43,302,089)	118.63%
13	Acquisition	-	-	-
14	Benefits paid	(24,376,950)	(47,706,492)	48.90%
15	Benefit obligation at end of year	$ 583,527,303	$ 565,361,292	3.21%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 442,627,471	$ 496,012,024	-10.76%
18	Actual return on plan assets	35,379,213	(14,678,061)	>300.00%
19	Acquisition	-	-	-
20	Employer contribution	11,500,000	9,000,000	27.78%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(24,376,950)	(47,706,492)	48.90%
23	Fair value of plan assets at end of year	$ 465,129,734	$ 442,627,471	5.08%
24	**Funded Status**	$ (118,397,569)	$ (122,733,821)	3.53%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (118,397,569)	$ (122,733,821)	3.53%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	4.10%	4.30%	-4.65%
32	Expected return on plan assets	5.80%	5.80%	
33	Rate of compensation increase	3.20% Union & 3.25% Non-Union	3.50% Union & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 10,711,339	$ 11,211,631	-4.46%
36	Interest cost	23,762,971	23,790,829	-0.12%
37	Expected return on plan assets	(25,094,948)	(28,232,855)	11.11%
38	Amortization of prior service cost	246,363	246,361	0.00%
39	Recognized net actuarial gain	9,591,156	10,298,339	-6.87%
40	Net periodic benefit cost (SEC Basis)	$ 19,216,881	$ 17,314,305	10.99%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 11,500,000	$ 9,000,000	27.78%
43	Pension Costs Capitalized	2,210,908	1,821,176	21.40%
44	Accumulated Pension Asset (Liability) at Year End	$ (118,397,569)	$ (122,733,821)	3.53%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,709	3,086	-12.22%
47	Not Covered by the Plan 2/	557	520	7.12%
48	Active	824	880	-6.36%
49	Retired	1,537	1,498	2.60%
50	Deferred Vested Terminated 2/	348	708	-50.85%

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. The large drop in deferred vested terminated employees was due to the vested terminated cash out offering in 2015. This also is reflected in decrease in total number of employees covered by the Plan.

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	$ 320,552,638	$ 329,680,178	2.85%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 9,777,034	$ 9,450,630	3.45%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 344,243,945	$ 320,552,638	7.39%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 7,241,843	$ 6,942,301	4.31%
44	401(k) Plan Defined Contribution Costs Capitalized	1,392,265	1,404,794	-0.89%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,539	1,589	-3.15%
48	Not Covered by the Plan			
49	Active - Participating	1,499	1,549	-3.23%
50	Retired			
51	, Vested Former Employees, Retirees and Active-	271	244	11.07%
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	($398,709)	($90,216)	>-300.00%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.40%	3.60%	-5.56%
8	Expected return on plan assets	5.80%	5.80%	
9	Medical Cost Inflation Rate 3/	7.59%,4.5%:22	7.94%,4.5%:23	
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	3.20% Union & 3.25% Non-Union	3.50% Union & 3.55% 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	The hydro generation facility group participant data and benefit provisions are incorporated in the 2015 valuation.			

1/ Obtained from NorthWestern Energy-Montana's 2016 FASB 106 Valuation. Assumptions and data are as of December 31, 2016.

2/ Obtained from NorthWestern Energy-Montana's 2015 FASB 106 Valuation. Assumptions and data are as of December 31, 2015.

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	$20,784,657	$20,967,136	-0.87%
10	Service cost	399,099	430,615	-7.32%
11	Interest Cost	689,114	687,100	0.29%
12	Plan participants' contributions	638,872	606,124	5.40%
13	Amendments 5/	-	1,044,607	-100.00%
14	Actuarial loss/(gain)	68,944	(308,969)	122.31%
15	Acquisition	-	-	-
16	Benefits paid	(3,386,554)	(2,641,956)	-28.18%
17	Benefit obligation at end of year	$19,194,132	$20,784,657	-7.65%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$17,972,924	$18,040,317	-0.37%
20	Actual return on plan assets	1,276,360	479	>300.00%
21	Acquisition	-	-	-
22	Employer contribution	2,103,334	1,967,960	6.88%
23	Plan participants' contributions	638,872	606,124	5.40%
24	Benefits paid	(3,386,554)	(2,641,956)	-28.18%
25	Fair value of plan assets at end of year	$18,604,936	$17,972,924	3.52%
26	**Funded Status**	($589,196)	($2,811,733)	79.05%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($589,196)	($2,811,733)	79.05%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$399,099	$430,615	-7.32%
33	Interest cost	689,114	687,100	0.29%
34	Expected return on plan assets	(1,042,430)	(968,659)	-7.62%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,032,848)	(2,032,848)	
37	Recognized net actuarial loss/(gain)	315,181	384,803	-18.09%
38	Net periodic benefit cost	($1,671,884)	($1,498,989)	-11.53%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	2,103,334	1,967,960	6.88%
43	TOTAL	$2,103,334	$1,967,960	6.88%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(398,709)	(90,216)	>-300.00%
47	TOTAL	($398,709)	($90,216)	>-300.00%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($398,709)	($90,216)	>-300.00%
50	Pension Costs Capitalized	(76,653)	(18,255)	>-300.00%
51	Accumulated Pension Asset (Liability) at Year End	(589,196)	(2,811,733)	79.05%
52	**Number of Montana Employees:**			
53	Covered by the Plan 6/	1,816	1,889	-3.86%
54	Not Covered by the Plan 7/	1,434	1,685	-14.90%
55	Active 6/	807	868	-7.03%
56	Retired 6/	903	918	-1.63%
57	Spouses/Dependants covered by the Plan	106	103	2.91%

4/ There is approximately an additional $7,023,139 and $7,867,997 in other company OPEBS liabilities outstanding at December 31, 2016 and 2015, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

5/ Amendment portion of change in benefit obligation was largely due to the addition of PPL Montana, LLC employees who became eligible to participate in the plan on November 18, 2014.

6/ Employee counts were restated for 2015 for incorrectly including 38 disabled participants in active and for a reclassification of 11 active participants that were included in retiree counts.

7/ Employee counts for not covered by plan were restated for 2015 to include all who were not eligible for the plan rather than just those waiving coverage. Decrease in not covered by plan was impacted by deferred vested lump sum pension payouts in September 2015.

SCHEDULE 16

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

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Michael R. Cashell Vice President, Transmission	255,435	101,869 A	33,389 B 138,665 C 8,837 D 126,903 E	665,098	477,923	39%
2	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	255,398	101,854 A	28,589 B 138,665 C 69,160 E	593,666	463,955	28%
3	John D. Hines Vice President, Supply	255,435	101,869 A	19,870 B 138,665 C 2,254 D 72,197 E	590,290	487,433	21%
4	Crystal Lail Vice President & Controller	234,936	93,694 A	32,921 B 127,501 C 11,309 E 2,822 F	503,183	0	
5	Michael L. Nieman Chief Audit and Compliance Officer	216,244	61,558 A	50,209 B 53,032 C 11,569 E	392,612	358,615	9%
6	William T. Rhoads General Manager, Generation	184,114	39,737 A	24,857 B 36,831 C 1,660 D 90,699 E 3,866 G 326 H	382,090	319,871	19%
7	Daniel L. Rausch Treasurer	205,520	58,505 A	47,309 B 50,365 C 7,268 D 10,894 E	379,861	371,152	2%
8	Kendall Kliewer Former Vice President & Controller	9,643	0 A	2,737 B 262,716 I 13,530 J 47,487 K	336,113	468,230	-28%
9	Jeanne M. Vold Business Technology Officer	188,418	53,774 A	26,452 B 45,887 C 9,232 E	323,763	306,606	6%
10	Timothy P. Olson Corporate Counsel & Corp Secretary	172,143	39,240 A	42,386 B 33,661 C	287,430	276,889	4%

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 2016 Annual Incentive Compensation Plan. Amounts were earned in 2016 and paid in the first quarter of 2017. Based on company performance against plan, the incentive plan was funded at 113% of target.
Individual awards varied from the funded level based on individual performance.

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

E> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2016.

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

G> Merit cash payment.

H> Noncash taxable award and associated tax gross-up.

I> Lump sum payment paid upon termination of employment in accordance with termination agreement.

J> Reimbursement of COBRA premiums to maintain medical, dental and vision benefits after termination in accordance with termination agreement.

K> Accumulated vacation paid at termination.

SCHEDULE 17

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

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	Robert C. Rowe President & Chief Executive Officer	590,641	538,403 A	24,180 B 1,454,138 C 68,952 D 3,753 E	2,680,067	2,155,605	24%
2	Brian B. Bird Vice President & Chief Financial Officer	408,536	232,752 A	50,027 B 502,909 C 15,458 D	1,209,682	1,078,330	12%
3	Heather H. Grahame Vice President & General Counsel	357,724	183,423 A	48,420 B 352,303 C 3,076 F	944,946	825,064	15%
4	Curtis T. Pohl Vice President, Distribution	277,602	126,525 A	48,240 B 219,010 C 21,421 D 7,840 E 3,076 F	703,713	634,720	11%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	255,929	102,066 A	50,148 B 164,014 C 13,992 D 73 G	586,222	508,368	15%

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 2016 Annual Incentive Compensation Plan. Amounts were earned in 2016 and paid in the first quarter of 2017. Based on company performance against plan, the incentive plan was funded at 113% 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, 2016.

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 associated tax gross-up.

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	$5,327,612,349	$5,133,213,168	$194,399,181	3.79%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	103 Experimental Electric Plant Unclassified	1,576,812	658,807	918,005	139.34%
6	105 Plant Held for Future Use	4,769,005	3,783,001	986,004	26.06%
7	107 Construction Work In Progress	107,202,396	63,741,643	$43,460,753	68.18%
8	108 Accumulated Depreciation Reserve	(1,858,838,290)	(1,766,993,982)	($91,844,308)	5.20%
9	108.1 Accumulated Depreciation - Capital Leases	(21,109,982)	(19,099,502)	($2,010,480)	10.53%
10	111 Accumulated Amortization & Depletion Reserves	(51,260,575)	(45,773,447)	($5,487,128)	11.99%
11	114 Electric Plant Acquisition Adjustments	380,714,172	380,714,172	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(16,453,993)	(8,239,513)	(8,214,480)	99.70%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	32,119,605	32,117,397	2,208	0.01%
15	**Total Utility Plant**	4,304,126,563	4,171,916,808	132,209,755	3.17%
16	**Other Property and Investments**				
17	121 Nonutility Property	5,667,242	6,749,606	(1,082,364)	-16.04%
18	122 Accumulated Depr. & Amort.-Nonutility Property	(1,829,946)	(1,492,272)	(337,674)	22.63%
19	123.1 Investments in Assoc Companies and Subsidiaries	(132,916,808)	(135,251,446)	2,334,638	-1.73%
20	124 Other Investments	43,705,178	42,541,769	1,163,409	2.73%
21	128 Miscellaneous Special Funds	250,000	855,040	(605,040)	-70.76%
23	**Total Other Property & Investments**	(85,124,334)	(86,597,303)	1,472,969	-1.70%
24	**Current and Accrued Assets**				
25	131 Cash	410,208	4,085,198	(3,674,990)	-89.96%
26	134 Other Special Deposits	2,358,634	3,508,309	(1,149,675)	-32.77%
27	135 Working Funds	22,934	22,934	-	0.00%
30	142 Customer Accounts Receivable	72,413,252	73,702,625	(1,289,373)	-1.75%
31	143 Other Accounts Receivable	11,274,193	12,243,185	(968,992)	-7.91%
32	144 Accumulated Provision for Uncollectible Accounts	(2,947,870)	(3,998,768)	1,050,898	-26.28%
34	146 Accounts Receivable-Associated Companies	832,656	485,808	346,848	71.40%
35	151 Fuel Stock	9,584,006	8,240,873	1,343,133	16.30%
36	154 Plant Materials and Operating Supplies	31,071,487	30,372,676	698,811	2.30%
37	164 Gas Stored - Current	7,703,909	13,111,331	(5,407,422)	-41.24%
38	165 Prepayments	10,683,106	7,664,332	3,018,774	39.39%
41	172 Rents Receivable	18,888	59,037	(40,149)	-68.01%
42	173 Accrued Utility Revenues	80,425,143	74,456,572	5,968,571	8.02%
43	174 Miscellaneous Current & Accrued Assets	88,131	19,175	68,956	>300.00%
48	**Total Current & Accrued Assets**	223,938,677	223,973,287	(34,610)	-0.02%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	13,261,862	13,944,763	(682,901)	-4.90%
51	182 Regulatory Assets	615,249,945	522,719,480	92,530,465	17.70%
52	183 Preliminary Survey and Investigation Charges	-	1,185,617	(1,185,617)	-100.00%
53	184 Clearing Accounts	137	3,239	(3,102)	-95.77%
55	186 Miscellaneous Deferred Debits	1,125,726	164,979	960,747	>300.00%
56	189 Unamortized Loss on Reacquired Debt	24,810,484	19,978,298	4,832,186	24.19%
57	190 Accumulated Deferred Income Taxes	229,754,877	201,297,196	28,457,681	14.14%
58	191 Unrecovered Purchased Gas Costs	14,093,347	25,765,650	(11,672,303)	-45.30%
59	**Total Deferred Debits**	898,296,378	785,059,222	113,237,156	14.42%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 5,341,237,284	$ 5,094,352,014	$ 246,885,270	4.85%

Sch. 18	cont. BALANCE SHEET 1/				
	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 519,589	$ 517,894	$ 1,695	0.33%
6	211 Miscellaneous Paid-In Capital	1,384,270,571	1,376,291,019	7,979,552	0.58%
10	216 Unappropriated Retained Earnings	396,919,032	325,909,358	71,009,674	21.79%
12	217 Reacquired Capital Stock	(95,769,402)	(93,948,186)	(1,821,216)	1.94%
13	219 Accumulated Other Comprehensive Income	(9,713,734)	(8,596,115)	(1,117,619)	13.00%
14	**Total Proprietary Capital**	1,676,226,056	1,600,173,970	76,052,086	4.75%
15	**Long Term Debt**				
16	221 Bonds	1,779,660,000	1,755,205,000	24,455,000	1.39%
18	224 Other Long Term Debt	26,976,900	26,976,900	-	0.00%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	37,688	54,438	(16,750)	-30.77%
20	**Total Long Term Debt**	1,806,599,212	1,782,127,462	24,471,750	1.37%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	24,346,170	26,325,495	(1,979,325)	-7.52%
24	228.2 Accumulated Provision for Injuries and Damages	8,453,894	8,642,245	(188,351)	-2.18%
25	228.3 Accumulated Provision for Pensions and Benefits	16,319,082	19,558,642	(3,239,560)	-16.56%
26	228.4 Accumulated Miscellaneous Operating Provisions	165,336,401	169,001,631	(3,665,230)	-2.17%
27	229 Accumulated Provision for Rate Refunds	4,522,161	55,190,626	(50,668,465)	-91.81%
28	230 Asset Retirement Obligations	39,401,895	35,532,209	3,869,686	10.89%
29	**Total Other Noncurrent Liabilities**	258,379,603	314,250,848	(55,871,245)	-17.78%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	300,810,573	229,874,444	70,936,129	30.86%
32	232 Accounts Payable	91,608,698	81,679,866	9,928,832	12.16%
34	234 Accounts Payable to Associated Companies	1,584,095	1,525,951	58,144	3.81%
35	235 Customer Deposits	6,427,078	6,608,591	(181,513)	-2.75%
36	236 Taxes Accrued	52,002,042	44,567,955	7,434,087	16.68%
37	237 Interest Accrued	18,557,440	21,400,048	(2,842,608)	-13.28%
40	241 Tax Collections Payable	1,521,649	1,353,247	168,402	12.44%
41	242 Miscellaneous Current and Accrued Liabilities	52,930,296	52,760,668	169,628	0.32%
42	243 Obligations Under Capital Leases-Current	1,979,319	1,836,946	142,373	7.75%
45	**Total Current and Accrued Liabilities**	527,421,190	441,607,716	85,813,474	19.43%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	40,208,508	36,045,534	4,162,974	11.55%
48	253 Other Deferred Credits	172,284,732	169,368,167	2,916,565	1.72%
49	254 Regulatory Liabilities	29,109,829	29,521,568	(411,739)	-1.39%
50	255 Accumulated Deferred Investment Tax Credits	160,004	356,380	(196,376)	-55.10%
52	281-283 Accumulated Deferred Income Taxes	830,848,150	720,900,369	109,947,781	15.25%
53	**Total Deferred Credits**	1,072,611,223	956,192,018	116,419,205	12.18%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 5,341,237,284	$ 5,094,352,014	$ 246,885,270	4.85%

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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.
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 709,600 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. 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 accounting principles generally accepted in the United States of America (GAAP). This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810 "Consolidation". ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 5). The other significant differences consist of the following:

- Earnings per share is not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $386.4 million and $368.5 million as of December 31, 2016 and December 31, 2015, 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, 2016 and December 31, 2015, 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, 2016 and December 31, 2015, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to inventory for GAAP purposes;

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

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

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

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

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

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

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our 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 electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

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

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.9 million and $4.0 million at December 31, 2016 and December 31, 2015, respectively. Unbilled revenues were $80.4 million and $74.5 million at December 31, 2016 and December 31, 2015, respectively.

Inventories

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

	December 31,	
	2016	**2015**
Fuel stock	$9,584	$8,241
Plant materials and operating supplies	31,071	30,373
Gas stored underground (including the non-current portion reflected in utility plant)	39,824	45,229
Total Inventory	**$80,479**	**$83,843**

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980. 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 (regulatory liabilities).

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

Derivative Financial Instruments

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

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

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 7.2% and 7.5% for Montana and South Dakota for 2016 and 2015, respectively. AFUDC capitalized totaled $7.0 million for the year ended December 31, 2016 and $13.6 million for the year ended December 31, 2015 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% and 3.3% for 2016 and 2015, respectively.

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

Income Taxes

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

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance on the recognition of revenue from contracts with customers, which will supersede nearly all existing revenue recognition guidance under GAAP. Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers. The FASB delayed the effective date of this guidance to the first quarter of 2018, with early adoption permitted as of the original effective date of the first quarter of 2017. We are in the process of evaluating the impact of adoption of this new guidance on our Financial Statements and disclosures. Our revenues are primarily from tariff based sales, which are in the scope of the standard. We provide gas or electricity to customers under these tariffs without a defined contractual term ('at-will'). We expect that the revenue from these arrangements will be equivalent to the electricity or gas supplied and billed in that period (including estimated billings). As such, we do not expect that there will be a significant shift in the timing or pattern of revenue recognition for such sales. The evaluation of other revenue streams is ongoing, including those tied to longer term contractual commitments. We are also selecting the transition method, either full or modified retrospective, and developing an approach to complying with the disclosure requirements. In addition, there are open industry related transition issues being considered that may change whether the guidance has significant impact on us. We will continue to assess the guidance and expect to conclude our analysis of expected impact during the first half of 2017.

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

In August 2016, the FASB issued guidance that addresses eight classification issues related to the presentation of cash receipts and cash payments in the statement of cash flows. The new guidance will be effective for us in our first quarter of 2018, with early adoption permitted. We are currently evaluating the impact of adoption of this guidance on our Statement of Cash Flows.

In November 2016, the FASB issued guidance that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The new guidance will be effective for us in our first quarter of 2018, with early adoption permitted. We are currently evaluating the impact of adoption of this guidance on our Statement of Cash Flows.

Accounting Standards Adopted

In March 2016, the FASB issued Financial Accounting Standards Update No. 2016-09 (ASU 2016-09), Improvements to Employee Share-Based Payment Accounting, revising certain elements of the accounting for share-based payments. The new standard is intended to simplify several aspects of the accounting for share-based payment award transactions including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. We elected to early adopt in the fourth quarter of 2016 as of January 1, 2016. For each share award, we determine whether the difference between the deduction for tax purposes and the compensation cost recognized in the Financial Statements results in either an excess tax benefit or an excess tax deficit. Previously, excess tax benefits were recognized in Paid-in capital on our Balance Sheet. The new guidance increases income statement volatility by requiring all excess tax benefits and deficits to be recognized in income taxes and treated as discrete items in the period in which they occur. During the fourth quarter of 2016, excess tax benefits of $1.8 million related to vested share-based compensation awards were recorded as a decrease in income tax expense in the Statement of Income. These provisions were adopted prospectively. We applied the modified-retrospective approach to excess tax benefits from prior periods, and recorded a cumulative-effect adjustment to retained earnings as of the date of adoption of $2.6 million in the Balance Sheets. Additionally, the cash flow presentation guidance is consistent with our historical presentation, and therefore did not have an impact on our current presentation. Finally, we did not change our accounting policy with regard to estimating forfeitures at the date of grant.

(3) Acquisitions

South Dakota Wind Generation

In September 2015, we completed the purchase of the 80 MW Beethoven wind project near Tripp, South Dakota, for approximately $143 million. The Beethoven 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:

Purchase Price Allocation

Assets Acquired		
Utility Plant	$	143.0
Prepayments		0.1
Total Assets Acquired		143.1
Liabilities Assumed		
Miscellaneous Current and Accrued Liabilities		0.3
Total Liabilities Assumed		0.3
Total Purchase Price	$	142.8

The purchase accounting was completed during the fourth quarter of 2015.

(4) Regulatory Matters

Montana Natural Gas General Rate Filing

In September 2016, we filed a natural gas rate case with the Montana Public Service Commission (MPSC) requesting an annual increase to natural gas rates of approximately $10.9 million, which includes approximately $7.4 million for delivery service and approximately $3.5 million for natural gas production. Our request was based on a return on equity of 10.35%, rate base of $432.1 million, and a capital structure of 53% debt and 47% equity. On April 7, 2017, we filed rebuttal testimony supporting a revised requested annual increase to rates of approximately $9.4 million, due primarily to the impact of adjusting estimated Montana property taxes to the final amount.

The natural gas production part of this filing includes a request for cost-recovery and permanent inclusion in base rates of fields acquired in August 2012 and December 2013 in northern Montana's Bear Paw Basin. Actual production costs are currently recovered in customer rates on an interim basis through our supply tracker.

With our initial filing, we requested that approximately $5.6 million of the rate increase for delivery service be approved on an interim basis to allow recovery of costs prior to the conclusion of the full rate case. The amount from the initial filing was reduced due to the final amount of Montana property taxes and changes in rate design since the original filing. As the lower incremental increase in revenues would be collected during lower usage months, the effect of interim rates would be minimal. As such, in March 2017, we withdrew our request for interim rates.

This general rate filing is separated into two phases, the revenue requirement component discussed above, and an allocated cost of service / rate design component. The date for submitting this second phase of the filing has been extended to May 31, 2017, to allow for the possible inclusion of a decoupling proposal, if needed. The MPSC has nine months from the filing date in which to issue a final decision in the revenue requirement phase of this docket. A hearing is scheduled for May 2017.

Hydro Compliance Filing

In December 2015, we submitted the required compliance filing associated with our 2014 purchase of Montana hydroelectric (hydro) generation assets, to remove the Kerr Project from cost of service, adjust for actual revenue credits and increase property taxes to actual amounts. In December 2016, the MPSC issued a final order in this filing reducing the annual amount we are allowed to recover in hydro generation rates by approximately $1.2 million. In addition, in the final order, the MPSC included language requiring us to indicate by April 30, 2017, whether we intend to file a Montana electric rate case based on a 2016 test year.

On April 26, 2017, we filed our required annual report with the MPSC regarding 2016 results, which indicates we earned less than our authorized rate of return. At the same time, we also submitted a filing to the MPSC responsive to the hydro compliance order, indicating we do not expect to file an electric rate case in 2017 based on a 2016 test year. However, we expect to file a general electric rate case in 2018 based on a 2017 test year. In the hydro compliance order, the MPSC indicated that if we do not intend to file a rate case in 2017, the MPSC may require us to make an additional financial filing that would facilitate an assessment of whether the MPSC believes additional action would be required to fulfill its obligation to authorize just and reasonable rates.

Montana Electric and Natural Gas Tracker Filings

Each year we submit an electric and natural gas tracker filing for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings, and historically made its cost recovery determination based on whether or not our supply procurement activities were prudent. In April 2017, the Montana legislature passed House Bill 193 (HB 193). This bill amends the current electric tracker statute, which mandated that the MPSC use an electric cost recovery mechanism that provides for full cost recovery of prudently incurred electric supply costs. HB 193 increases the discretion the MPSC may exercise with regard to costs included in tracker filings. While the text of HB 193 does not address the specifics of changes in cost recovery, testimony provided by the MPSC in support of HB 193 suggests our electric tracker filings may be handled similarly to the mechanism applied to Montana-Dakota Utilities (MDU). The MDU adjustment mechanism allows for recovery of 90 percent of the increases or decreases in fuel and purchased power costs from an established baseline. However, due to the discretion allowed in HB 193, we cannot guarantee how the MPSC may apply the statute to our electric tracker filings. HB 193 is expected to go into effect on July 1, 2017. HB 193 does not impact our natural gas recovery mechanism.

During the second quarter of 2016, we filed our 2016 annual electric and natural gas tracker filings for the 2015/2016 tracker period. The MPSC issued orders in July 2016 approving the filings on an interim basis. In

November 2016, the MPSC issued a final order approving the natural gas interim rates. A schedule has not been established regarding the 2016 electric tracker filing.

Electric Trackers - 2012/2013 - 2013/2014 (Consolidated Docket) and 2014/2015 (2015 Tracker) - In 2016, we received final electric tracker orders from the MPSC in the Consolidated Docket and 2015 Tracker, resulting in a $12.4 million disallowance of costs, including interest. In June 2016, we filed an appeal in Montana District Court (Lewis & Clark County) of the MPSC decision in our 2015 Tracker docket to disallow certain portfolio modeling costs. Also, in September 2016, we appealed the MPSC's decisions in the Consolidated Docket regarding the disallowance of replacement power costs from a 2013 outage at Colstrip Unit 4 and the modeling/planning costs, arguing that these decisions were arbitrary and capricious, and violated Montana law. We brought this action in Montana District Court, as well (Yellowstone County). The briefing in the Consolidated Docket appeal is scheduled to conclude by the end of the second quarter of 2017, and the briefing in the 2015 Tracker appeal is scheduled to conclude by the end of the third quarter of 2017. While the courts are not obligated to rule on these appeals within a certain period of time, based on our experience, we believe we are likely to receive orders from the courts in these matters within 9-20 months of filing.

FERC Filing - Dave Gates Generating Station at Mill Creek (DGGS)

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

In June 2016, we filed a petition for review of the FERC's May 2016 order with the United States Circuit Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The matter is fully briefed, and we are waiting for the Court to set a date for oral argument. We do not expect a decision in this matter until the fourth quarter of 2017, at the earliest.

(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, 2016	December 31, 2015
Colstrip Unit 4 Basis Adjustment	$ (150,631)	$ (153,718)
Havre Pipeline Company, LLC	14,349	15,054
NorthWestern Services, LLC	1,915	1,899
Risk Partners Assurance, Ltd.	1,450	1,514
Total Investments in Subsidiary Companies	**$ (132,917)**	**$ (135,251)**

(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 the 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, 2016	December 31, 2015
			(in thousands)	
Income taxes	15	Plant Lives	$ 411,546	$ 319,973
Pension	17	Undetermined	127,133	135,057
Employee related benefits	17	Undetermined	20,256	21,054
State & local taxes & fees		Various	17,835	7,715
Environmental clean-up	20	Various	13,601	14,237
Distribution infrastructure projects		1 Year	3,136	6,272
Other	—	Various	21,743	18,411
Total Regulatory Assets			**$ 615,250**	**$ 522,719**
Gas storage sales		23 Years	9,569	9,990
Environmental clean-up		Various	6,414	7,121
Unbilled Revenue		1 Year	11,973	10,808
State & local taxes & fees		1 Year	1,154	1,566
Other		Various	—	37
Total Regulatory Liabilities			**$ 29,110**	**$ 29,522**

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.

Pension and Employee Related Benefits

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

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

The MPSC has authorized recovery in the property tax tracker of approximately 60% of the estimated increase in property taxes as compared with the related amount included in rates during our last rate case.

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.

Montana Distribution System Infrastructure Project (DSIP)

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

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):

	December 31,	
	2016	2015
	(in thousands)	
Land and improvements	$ 147,036	$ 142,154
Building and improvements	425,518	397,883
Storage, distribution, and transmission	3,054,601	3,066,824
Generation	1,680,254	1,696,141
Construction work in process	107,202	63,742
Other equipment	447,473	255,576
Total utility plant	5,862,084	5,622,320
Less accumulated depreciation	(1,947,663)	(1,840,106)
Net utility plant	$ 3,914,421	$ 3,782,214

In 2015, we acquired the Beethoven wind project, which resulted in an increase of approximately $143 million in utility plant. We recorded the plant assets at original cost, less accumulated depreciation with an acquisition adjustment in accordance with FERC rules. Utility plant under capital lease were $19.3 million and $21.3 million as of December 31, 2016 and 2015, respectively, which included $19.1 million and $21.1 million as of December 31, 2016 and 2015, 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, 2016				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,623	$ 60,491	$ 50,802	$ 297,289
Accumulated depreciation	38,894	29,235	37,099	77,513
December 31, 2015				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,740	$ 60,088	$ 46,387	$ 289,604
Accumulated depreciation	37,522	27,940	37,160	73,328

(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. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

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

	December 31,	
	2016	2015
Liability at January 1,	$ 35,532	$ 21,435
Accretion expense	1,885	1,437
Liabilities incurred	164	12,682
Liabilities settled	—	(22)
Revisions to cash flows	1,821	—
Liability at December 31,	$ 39,402	$ 35,532

The EPA's rule regulating Coal Combustion Residuals (CCRs) became effective in October 2015. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Based on our assessment of these requirements, we recorded an increase to our existing AROs of approximately $12.0 million during the second quarter 2015, and an additional $1.9 million during the fourth quarter 2016 based on further information.

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 Hydro Transaction; 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, 2016 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. These commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by the applicable state regulatory commissions. 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; 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 normal purchase and normal sale scope exception (NPNS) 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, 2016 and 2015. 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, 2016
Interest rate contracts	Interest on long-term debt	$ 2,169

A net pre-tax loss of approximately $17.1 million is remaining in AOCI as of December 31, 2016, and we expect to reclassify approximately $0.6 million of net 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. 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, 2016	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other special deposits	$ 2,359	$ —	$ —	$ —	$ 2,359
Rabbi trust investments	25,064	—	—	—	25,064
Total	**$ 27,423**	**$ —**	**$ —**	**$ —**	**$ 27,423**
December 31, 2015					
Other special deposits	$ 3,508	$ —	$ —	$ —	$ 3,508
Rabbi trust investments	24,245	—	—	—	24,245
Total	**$ 27,753**	**$ —**	**$ —**	**$ —**	**$ 27,753**

Other special deposits represents amounts held in money market mutual funds. Rabbi trust assets 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, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 1,806,599	$ 1,852,052	$ 1,782,128	$ 1,844,974

Notes payable consist of commercial paper and are not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(12) Notes Payable and Credit Arrangements

Notes Payable

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

	2016		2015	
Notes Payable	**Balance**	**Interest Rate**	**Balance**	**Interest Rate**
Commercial Paper	$ 300.8	1.07%	$ 229.9	0.82%

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

	2016	2015
Maximum notes payable outstanding	$ 300.8	$ 267.8
Average notes payable outstanding	$ 210.7	$ 192.8
Weighted-average interest rate	0.86%	0.61%

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

Unsecured Revolving Line of Credit

On December 12, 2016, we amended and restated our existing revolving credit facility to, among other things, increase the size of the facility to $400 million (from $350 million) and extend the maturity date to December 12, 2021 (from November 5, 2018). We retained an accordion feature that allows us to increase the size up to $450 million with the consent of the lenders. The facility does not amortize and is unsecured. The facility bears interest at the lower of prime or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.875% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2016. Commitment fees for the unsecured revolving line of credit were $0.4 million for each of the years ended December 31, 2016 and 2015.

The credit facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, 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 facility 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, 2016	December 31, 2015
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ —	$ —
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	—	55,000
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	—
South Dakota—2.66%	2026	45,000	—
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Pollution control obligations—			
Montana—4.65%	2023	—	170,205
Montana—2.00%	2023	144,660	—
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Discount on Notes and Bonds	—	(38)	(54)
		$ 1,806,599	$ 1,782,128

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

In June 2016, we issued $60 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.80% maturing in 2026. Proceeds were used to redeem our 6.05%, $55 million South Dakota First Mortgage Bonds due 2018. In addition, in September 2016, we issued $45.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.66% maturing in 2026. Proceeds from this issuance were used for general corporate purposes. Both series of these bonds are secured by our electric and natural gas assets in South Dakota, Nebraska, North Dakota, and Iowa and were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended.

During September 2015, we issued $70 million of South Dakota First Mortgage Bonds at a fixed interest rate of 4.26% maturing in 2040 to finance the Beethoven wind project. The bonds are secured by our electric and natural gas assets in South Dakota and were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

In June 2015, we issued $200 million aggregate principal amount of Montana First Mortgage Bonds, which includes $75 million at a fixed interest rate of 3.11% maturing in 2025 and $125 million at a fixed interest rate of 4.11% maturing in 2045. 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 6.04%, $150 million of Montana First Mortgage Bonds due 2016 and finance incremental Montana capital expenditures.

As of December 31, 2016, 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 $2.0 million in 2017, $2.1 million in 2018, $252.3 million in 2019, $2.5 million in 2020 and $2.7 million in 2021.

(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, 2016	December 31, 2015
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 815	$ 468
Risk Partners Assurance, Ltd.	18	18
	$ 833	$ 486
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,584	$ 1,526

(15) Income Taxes

Our effective tax rate typically differs from the federal statutory tax rate of 35% 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 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.

We adopted the provisions of ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, during the fourth quarter of 2016. The excess tax benefit of vested share awards is treated as a discrete item in the current quarter. See Note 2 - Significant Accounting Policies, for further discussion of the impacts of this standard.

In 2013, the IRS issued guidance related to the repair and maintenance of utility generation assets. During the third quarter of 2016, we filed a tax accounting method change with the IRS consistent with the guidance for generation property. This enabled us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. As discussed above, we flow this current tax deduction through to our customers in rate cases. Consistent with this regulatory treatment, we recorded an income tax benefit of approximately $17.0 million during the twelve months ended December 31, 2016, of which approximately $12.5 million related to 2015 and prior tax years.

The income tax benefit for 2014 reflects the release of approximately $12.6 million of unrecognized tax benefits due to the lapse of statutes of limitation in the third quarter of 2014. In addition, in the third quarter of 2014, we elected the safe harbor method related to the deductibility of repair costs. This resulted in an income tax benefit of approximately $4.3 million for the cumulative adjustment for years prior to 2014, which is included in the prior year permanent return to accrual adjustments.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code Section 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

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

	December 31,	
	2016	2015
NOL carryforward	$ 78,324	$ 18,244
Pension / postretirement benefits	45,847	54,440
Compensation accruals	18,715	17,441
Production tax credit	17,034	6,550
Customer advances	15,837	14,197
AMT credit carryforward	13,599	13,143
Unbilled revenue	12,743	28,390
Environmental liability	9,698	9,410
Interest rate hedges	7,192	6,483
Property taxes	3,765	24,648
Regulatory liabilities	2,290	2,862
Reserves and accruals	1,730	1,820
QF obligations	---	1,098
Other, net	2,981	2,571
Deferred Tax Asset	**229,755**	**201,297**
Excess tax depreciation	(464,969)	(396,068)
Goodwill amortization	(192,615)	(178,084)
Flow through depreciation	(160,604)	(125,441)
Regulatory assets	(12,230)	(14,901)
Reserves and accruals	(430)	(6,406)
Deferred Tax Liability	**(830,848)**	**(720,900)**
Deferred Tax Liability, net	**$ (601,093)**	**$ (519,603)**

At December 31, 2016 we estimate our total federal NOL carryforward to be approximately $365.1 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $105.2 million in 2031; $13.3 million in 2033; $73.4 million in 2034 and $173.2 million in 2036. We estimate our state NOL carryforward as of December 31, 2016 is approximately $276.0 million. If unused, our state NOL carryforwards will expire as follows: $67.0 million in 2018; $10.5 million in 2020; $58.3 million in 2021 and $140.2 million in 2023. 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):

		2016		2015
Unrecognized Tax Benefits at January 1	$	92,387	$	95,929
Gross increases - tax positions in prior period		—		44
Gross decreases - tax positions in prior period		—		(2,903)
Gross increases - tax positions in current period		—		494
Gross decreases - tax positions in current period		(3,958)		(1,177)
Lapse of statute of limitations		—		—
Unrecognized Tax Benefits at December 31	$	88,429	$	92,387

Our unrecognized tax benefits include approximately $66.5 million and $65.2 million related to tax positions as of December 31, 2016 and 2015, respectively, that if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest related to uncertain tax positions in interest expense. During the year ended December 31, 2016, we recognized $0.7 million of expense for interest in the Statements of Income. As of December 31, 2016, we had $0.7 million of interest accrued in the Balance Sheets. During the year ended December 31, 2015, we did not recognize expense for interest and penalties in the Statements of Income and did not have any amounts accrued in the Balance Sheets.

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

(16) Comprehensive Loss

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

	December 31,					
	2016			2015		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	$ 25	$ —	$ 25	$ 558	—	$ 558
Reclassification of net gains on derivative instruments	(2,169)	831	(1,338)	(1,125)	427	(698)
Realized loss on cash flow hedging derivatives	—	—	—	—	—	—
Postretirement medical liability adjustment	317	(122)	195	504	(194)	310
Other comprehensive (loss) income	$ (1,827)	$ 709	$ (1,118)	$ (63)	$ 233	$ 170

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

	December 31, 2016	December 31, 2015
Foreign currency translation	$ 1,380	$ 1,355
Derivative instruments designated as cash flow hedges	(10,352)	(9,014)
Postretirement medical plans	(742)	(937)
Accumulated other comprehensive loss	$ (9,714)	$ (8,596)

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

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

	Affected Line Item in the Statements of Income	Year Ended December 31, 2015 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,316)	$ (1,247)	$ 797	$ (8,766)
Other comprehensive income before reclassifications		—	—	558	558
Amounts reclassified from AOCI	Interest on long-term debt	(698)	—	—	(698)
Amounts reclassified from AOCI		—	310	—	310
Net current-period other comprehensive (loss) income		(698)	310	558	170
Ending Balance		$ (9,014)	$ (937)	$ 1,355	$ (8,596)

(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, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our Financial Statements. See Note 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,	
	2016	2015	2016	2015
Change in benefit obligation:				
Obligation at beginning of period	$ 628,883	$ 688,444	$ 28,652	$ 30,004
Service cost	11,759	12,362	492	526
Interest cost	26,210	26,174	795	786
Plan amendments	—	—	—	1,045
Actuarial loss (gain)	7,006	(47,351)	(71)	(616)
Settlements	—	—	390	390
Benefits paid	(27,826)	(50,746)	(4,041)	(3,483)
Benefit Obligation at End of Period	$ 646,032	$ 628,883	$ 26,217	$ 28,652
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 500,044	$ 556,051	$ 17,972	$ 18,040
Return on plan assets	39,719	(15,461)	1,277	—
Employer contributions	12,700	10,200	3,397	3,415
Benefits paid	(27,826)	(50,746)	(4,041)	(3,483)
Fair value of plan assets at end of period	$ 524,637	$ 500,044	$ 18,605	$ 17,972
Funded Status	$ (121,395)	$ (128,839)	$ (7,612)	$ (10,680)

Amounts Recognized in the Balance Sheet Consist of:				
Current liability	—	—	(1,789)	(2,584)
Noncurrent liability	(121,395)	(128,839)	(5,823)	(8,096)
Net amount recognized	$ (121,395)	$ (128,839)	$ (7,612)	$ (10,680)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	(9)	(255)	11,988	14,021
Net actuarial loss	(127,953)	(142,305)	(4,739)	(5,219)
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	(849)	(1,000)
Net actuarial gain	—	—	38	(102)
Total	$ (127,962)	$ (142,560)	$ 6,438	$ 7,700

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

	Pension Benefits	
	December 31,	
	2016	2015
Projected benefit obligation	$ 646.0	$ 628.9
Accumulated benefit obligation	643.6	626.0
Fair value of plan assets	524.6	500.0

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,	
	2016	2015	2016	2015
Components of Net Periodic Benefit Cost				
Service cost	$ 11,759	$ 12,362	$ 492	$ 526
Interest cost	26,210	26,174	795	786
Expected return on plan assets	(28,248)	(31,561)	(1,042)	(969)
Amortization of prior service cost (credit)	246	246	(1,882)	(1,882)
Recognized actuarial loss	9,888	10,634	315	385
Settlement loss recognized	—	—	390	390
Net Periodic Benefit Cost (Credit)	$ 19,855	$ 17,855	$ (932)	$ (764)

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

We estimate amortizations from regulatory assets into net periodic benefit cost during 2017 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service credit (cost)	$ (9)	$ 1,882
Accumulated loss	(7,901)	(313)

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2016 and 2015. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

We set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The decrease in discount rate during 2016 increased our projected benefit obligation by approximately $16.1 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 are lowering our long term rate of return on assets assumption to 4.70% for 2017.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2016	2015	2016	2015
Discount rate	3.95-4.10 %	4.15-4.30 %	3.40-3.55 %	3.60-3.75 %
Expected rate of return on assets	5.80	5.80	5.80	5.80
Long-term rate of increase in compensation levels (nonunion)	3.28	3.58	3.28	3.58
Long-term rate of increase in compensation levels (union)	3.20	3.50	3.20	3.50

The postretirement benefit obligation is calculated assuming that health care costs increase by 7.59% in 2017 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease to an ultimate trend of 4.5% by the year 2038. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

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

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

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

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

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2016	2015	2016	2015
Domestic debt securities	55.0%	55.0%	40.0%	40.0%
International debt securities	5.0	5.0	—	—
Domestic equity securities	34.0	34.0	50.0	50.0
International equity securities	6.0	6.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2016	2015	2016	2015	2016	2015
Cash and cash equivalents	—%	0.4%	0.1%	—%	1.0%	0.1%
Domestic debt securities	53.4	54.9	64.4	65.8	37.0	37.0
International debt securities	4.6	4.7	4.4	4.5	—	—
Domestic equity securities	36.0	33.9	26.0	24.9	52.6	54.2
International equity securities	6.0	6.1	5.1	4.8	9.4	8.7
	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 2017 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 2016, 2015 and 2014 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2016	2015
NorthWestern Energy Pension Plan (MT)	$ 11,500	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 12,700	$ 10,200

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

	Pension Benefits	Other Postretirement Benefits
2017	$ 30,637	$ 3,513
2018	32,346	3,464
2019	33,574	3,218
2020	34,847	2,844
2021	35,906	2,634
2022-2026	198,236	9,195

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, 2016 and 2015 were $9.8 million and $9.5 million.

(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, 2016, there were 870,186 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:

	2016	2015
Risk-free interest rate	0.85%	1.06%
Expected life, in years	3	3
Expected volatility	17.1% to 22.1%	14.2% to 19.0%
Dividend yield	3.4%	3.5%

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

A summary of nonvested shares as of and changes during the year ended December 31, 2016, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	187,572	$ 40.39
Granted	88,107	50.32
Vested	(90,417)	38.33
Forfeited	(10,005)	42.12
Remaining nonvested grants	175,257	$ 46.35

We recognized compensation expense of $5.3 million and $4.4 million for the years ended December 31, 2016 and 2015, respectively, and a related income tax expense of $1.8 million and $1.8 million for the years ended December 31, 2016 and 2015, respectively. As of December 31, 2016, we had $5.1 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 2.0 years. The total fair value of shares vested was $3.5 million and $2.8 million for the years ended December 31, 2016 and 2015, 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, 2016, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	57,313	$ 37.76
Granted	15,708	45.78
Vested	(8,112)	28.00
Forfeited	(2,318)	35.11
Remaining nonvested grants	62,591	$ 41.14

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, 2016 and 2015, DSUs issued to members of our Board totaled 28,338 and 35,030, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2016 and 2015 was approximately $2.4 million and $1.3 million, respectively.

(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.

Beethoven Issuance - During October 2015, we issued 1,100,000 shares of our common stock at $51.81 per share, for aggregate net proceeds of $57 million to finance a portion of the Beethoven wind project.

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 49,514 and 39,504 during the years ended December 31, 2016 and 2015, 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. The QFs require us to purchase minimum amounts of energy at prices ranging from $74 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $882.0 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $683.4 million through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as an accumulated miscellaneous operating provisions. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2016	2015
Beginning QF liability	$ 138,310	$ 136,893
Unrecovered amount	(14,829)	(9,379)
Interest on long-term debt	10,843	10,796
Ending QF liability	$ 134,324	$ 138,310

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

		Gross Obligation		Recoverable Amounts		Net
2017		74,607		57,789		16,818
2018		76,703		58,401		18,302
2019		78,836		59,020		19,816
2020		80,984		59,647		21,337
2021		82,941		60,136		22,805
Thereafter		487,957		388,411		99,546
Total	$	882,028	$	683,404	$	198,624

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 27 years. Costs incurred under these contracts are included in operating expenses in the Statements of Income and were approximately $216.8 million and $241.6 million for the years ended December 31, 2016 and 2015, respectively. As of December 31, 2016, our commitments under these contracts are $206.1 million in 2017, $155.9 million in 2018, $156.2 million in 2019, $122.8 million in 2020, $107.0 million in 2021, and $1.3 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the Hydro Transaction, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $22.0 million between 2017 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, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us and is estimated to range between $27.9 million to $32.6 million. As of December 31, 2016, we have a reserve of approximately $31.5 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 $24.7 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, 2016, the reserve for remediation costs at this site is approximately $10.8 million, and we estimate that approximately $6.2 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 MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. In August 2016, the MDEQ sent us a letter of Notice of Potential Liability and Request for Remedial Action regarding the Helena site. An initial scoping meeting with MDEQ regarding this letter has not yet been scheduled. At MDEQ's direction, a Soil Vapor Analysis Plan for the two buildings located on the Helena site was submitted to confirm whether vapors are present in the soil that could seep into the two buildings. 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 and Helena sites.

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. The additional investigation work began in December 2015 and has continued in 2016. Analytical results from an October 2016 sampling exceeded the Montana Maximum Contaminant Level (MCL) for benzene and/or total cyanide in certain monitoring wells. These results were forwarded to MVWQD which shared the same with the MDEQ. In a December 21, 2016 letter to MVWQD, MDEQ requested that MVWQD file a formal complaint with MDEQ's Enforcement Division regarding groundwater contamination of the site. If MVWQD files a formal complaint, we expect it will prompt MDEQ to reevaluate its position concerning listing the Missoula site on the State's superfund list. 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 emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide (CO_2). These actions include legislative proposals, Executive and 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. There is uncertainty associated with the new EPA Administration and the timeframe for actions that may be taken with regard to the existing and pending GHG-related regulations.

On August 3, 2015, the EPA released for publication in the Federal Register, the final standards of performance to limit GHG emissions from new, modified and reconstructed fossil fuel generating units and from newly constructed and reconstructed natural gas combined cycle (NGCC) units. The standards reflect the degree of emission limitations achievable through the application of the best system of emission reduction that the EPA determined has been demonstrated for each type of unit.

In a separate action that also affects power plants, on August 3, 2015, the EPA released its final rule establishing GHG performance standards for existing power plants under Clean Air Act Section 111(d) (the Clean Power Plan, or CPP). The CPP establishes CO_2 emission performance standards for existing electric utility steam generating units and NGCC units. States may develop implementation plans for affected units to meet the individual state targets established in the CPP or may adopt a federal plan. The EPA has given states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour (MWH)) or mass-based tonnage limits for CO_2. The 2030 rate-based requirement for all existing affected generating units in South Dakota and Montana is 1,167 and 1,305 pounds per MWH, respectively. The rate-based approach requires a 38.4 percent reduction in South Dakota and a 47.4 percent reduction in Montana from 2012 levels by 2030. The mass-based approach for existing units in South Dakota requires a 30.9 percent decrease by 2030, while in Montana the mass-based approach requires a 41 percent decrease by 2030. States were required to submit initial plans for achieving GHG emission standards to EPA by September 2016, and could seek additional time to finalize State plans by September 2018. Due to the stay of the rule, discussed below, South Dakota and Montana have not submitted implementation plans. The initial performance period for compliance under the CPP would commence in 2022, with full implementation by 2030. The EPA also indicated that states may establish emission trading programs to facilitate compliance with the CPP and provides three options: an emission rate trading program that would allow the trading of emission reduction credits equal to one MWH of emission free generation; a mass-based program that would allow trading of allowances with an allowance equal to one short ton of CO_2; and a state measures program that would allow intra-state trading to achieve the state-wide average emission rate.

On August 3, 2015, the EPA also proposed a federal plan that would be imposed if a state fails to submit a satisfactory plan under the CPP. The federal plan proposal included a "model trading rule" that described how the EPA would establish an emission trading program as part of the federal plan to allow affected units to comply with the emission rate requirements. On December 19, 2016, the EPA withdrew the final model emissions trading rule and posted a draft model rule and supporting documents to "guide" states that elect to move forward in complying with the CPP.

The CPP reduction of 47.4 percent in carbon dioxide emissions in Montana by 2030 is the greatest reduction target among the lower 48 states, according to a nationwide analysis. Our Montana generation portfolio emits less carbon on average than the EPA's 2030 target due to investments we made prior to 2013 in carbon-free generation resources. However, under the CPP, investments made in renewable energy prior to 2012 are not counted for compliance with the CPP's requirements. We asked the University of Montana's Bureau of Business and Economic Research (BBER) to study the potential impacts of the CPP across Montana. The BBER study looked at the implications of closing all four of the generating units that comprise the Colstrip facility in southeast Montana as a scenario for complying with the federal rule. The study's conclusions describe the likely loss of jobs and population, the decline in the local and state tax base, the impact on businesses statewide, and the closure's impact on electric reliability and affordability. The electricity produced at Colstrip Unit 4 represents approximately 25 percent of our customer needs. Closing all four Colstrip units would lead to higher utility rates in order to replace the base-load generation that currently is provided by Colstrip. Closing all four Colstrip units would also create significant issues with the transmission grid that serves Montana, and we would lose transmission revenues that are credited to and lower electric customer bills.

On October 23, 2015, the same date the CPP was published in the Federal Register, we along with other utilities, trade groups, coal producers, and labor and business organizations, filed Petitions for Review of the CPP with the United States Court of Appeals for the District of Columbia Circuit. Accompanying these Petitions for Review were Motions to Stay the implementation of the CPP. On January 21, 2016, the U.S. Court of Appeals for the District of Columbia denied the requests for stay but ordered expedited briefing on the merits. On January 26, 2016, 29 states and state agencies asked the U.S. Supreme Court to issue an immediate stay of the CPP. On January 27, 2016, 60 utilities and allied petitioners also requested the U.S. Supreme Court to immediately stay the CPP, and we were among the utilities seeking a stay. On February 9, 2016, the U.S. Supreme Court entered an order staying the CPP. The stay of the CPP will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals' decision on the substantive challenges to the CPP, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. On May 16, 2016, the U.S. Court of Appeals for the District of Columbia entered an order declaring the challenge to the CPP would be reviewed en banc, and on September 27, 2016, the Court held oral argument in the matter. We expect a ruling this year from the U.S. Court of Appeals, and that ruling will likely be followed by a U.S. Supreme Court decision on challenges to the CPP, unless the new EPA administration withdraws, or significantly changes, the rule.

On December 22, 2015 we also filed an administrative Petition for Reconsideration with the EPA, requesting that it reconsider the CPP, on the grounds that the CO2 reductions in the CPP were substantially greater in Montana than in the proposed rule. We also requested EPA stay the CPP while it considered our Petition for Reconsideration. On January 11, 2017, the Petition for Reconsideration was denied. We have 60 days in which to file a Petition for Review in the U.S. Court of Appeals for the District of Columbia.

On June 23, 2014, the U.S. Supreme Court struck down the EPA's Tailoring Rule, which limited the sources subject to GHG permitting requirements to the largest fossil-fueled power plants, indicating that EPA had exceeded its authority under the Clean Air Act by "rewriting unambiguous statutory terms." However, the decision affirmed EPA's ability to regulate GHG emissions from sources already subject to regulation under the prevention of significant deterioration program, which includes most electric generating units.

Requirements to reduce GHG emissions could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Although there continues to be proposed legislation and regulations that affect GHG emissions from power plants, technology to efficiently capture, remove and/or sequester such emissions may not be available within a timeframe consistent with the implementation of such requirements. In addition, physical impacts of climate change may present potential risks for severe weather, such as droughts, floods and tornadoes, in the locations where we operate or have interests.

We are evaluating the implications of these rules and technology available to achieve the CO_2 emission performance standards. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from the final rules that, in our view, disproportionately impact customers in our region, and to seek relief from the final compliance requirements. We cannot predict the ultimate outcome of these matters or what our obligations might be under the state compliance plans with any degree of certainty until they are finalized; however, complying with the carbon emission standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

Water Intakes and Discharges - Section 316(b) of the Federal Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best technology available (BTA)" for minimizing environmental impacts. In May 2014, the EPA issued a final rule applicable to facilities that withdraw at least 2 million gallons per day of cooling water from waters of the US and use at least 25 percent of the water exclusively for cooling purposes. The final rule, which became effective in October 2014, gives options for meeting BTA, and provides a flexible compliance approach. Under the rule, permits required for existing facilities will be developed by the individual states and additional capital and/or increased operating costs may be required to comply with future water permit requirements. Challenges to the final cooling water intake rule filed by industry and environmental groups are under review in the Second Circuit Court of Appeals.

In November 2015, the EPA published final regulations on effluent limitations for power plant wastewater discharges, including mercury, arsenic, lead and selenium. The rule became effective in January 2016. Some of the new requirements for existing power plants would be phased in starting in 2018 with full implementation of the rule by 2023. The EPA rule estimates that 12 percent of the steam electric power plants in the U.S. will have to make new investments to meet the requirements of the new effluent limitation regulations. Challenges to the final rule have been filed in the Fifth Circuit Court of Appeals, indicating that the EPA underestimated compliance costs. It is too early to determine whether the impacts of these rules will be material.

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.

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS). Among other things, the MATS set stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. The rule was challenged by industry groups and states, and was upheld by the D.C. Circuit Court in April 2014. The decision was appealed to the Supreme Court and in June 2015, the Supreme Court issued an opinion that the EPA did not properly consider the costs to industry when making the requisite "appropriate and necessary" determination as part of its analysis in connection with the issuance of the MATS rule. The Supreme Court remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit, and the D.C. Circuit remanded, without vacatur, the MATS rule to the EPA, leaving the rule in place. In April 2016, the EPA published its final supplemental finding that it is "appropriate and necessary" to regulate coal and oil-fired units under Section 112 of the Clean Air Act. Although industry and trade associations have filed a lawsuit in the D.C. Circuit challenging the EPA's supplemental finding, installation or upgrading of relevant environmental controls at our affected plants is complete and we are controlling emissions of mercury under the state and Federal MATS rules.

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) were to be required in certain states beginning in 2012. In April 2014 the Supreme Court reversed and remanded the 2012 decision of the U.S. Court of Appeals for the D.C. Circuit that had vacated the CSAPR. EPA has published proposed updates to the CSAPR rule and litigation of the remaining CSAPR lawsuits is pending.

In October 2013, the Supreme Court denied certiorari in *Luminant Generation Co v. EPA*, which challenged the EPA's current approach to regulating air emissions during startup, shutdown and malfunction (SSM) events. As a result, fossil fuel power plants may need to address SSM in their permits to reduce the risk of enforcement or citizen actions.

The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze in national parks and wilderness areas across the United States. The Clean Air Visibility Rule requires the installation and operation of Best Available Retrofit Technology (BART) to achieve emissions reductions from designated sources (including certain electric generating units) that are deemed to cause or contribute to visibility impairment in 'Class I' areas.

In September 2012, a final Federal Implementation Plan for Montana was published in the Federal Register to address regional haze. As finalized, Colstrip Units 3 and 4 do not have to improve removal efficiency for pollutants that contribute to regional haze. On January 10, 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility, extending the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021. Thus, 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 November 2012, PPL Montana (now Talen Montana), the operator of Colstrip, as well as environmental groups (National Parks Conservation Association, Montana

Environmental Information Center (MEIC), and Sierra Club) jointly filed a petition for review of the Federal Implementation Plan in the U.S. Court of Appeals for the Ninth Circuit. MEIC and Sierra Club challenged the EPA's decision not to require any emissions reductions from Colstrip Units 3 and 4. In June 2015, the U.S. Court of Appeals for the Ninth Circuit rejected the challengers' contention that the EPA should have required additional pollution-reduction technologies on Unit 4 beyond those in the regulations and the matter is back in EPA Region 8 for action.

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to the various regulations discussed above that have been issued or proposed.

Regarding the CPP, as discussed above, we cannot predict the impact of the CPP on NorthWestern until there is a definitive judicial decision on the issue or other action is taken to withdraw or significantly change the CPP.

Compliance with the final rule on Water Intakes and Discharges discussed above, which became effective in January 2016, did not have a significant impact at any of our jointly owned facilities.

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, in which we have 10% ownership, to reduce its NOx emissions by July 2018. In 2016, Coyote completed installation of control equipment to maintain compliance with the lower NOx emissions of 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown. The cost of the control equipment was not significant.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is subject to EPA's coal combustion residual rule. A compliance plan has been developed and is in the initial stages of implementation. The current estimate of the total project cost is approximately $90.0 million (our share is 30%) over the remaining life of the facility.

See 'Legal Proceedings - Colstrip Litigation' below for discussion of Sierra Club litigation.

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

Billings, Montana Refinery Outage Claim

In August 2014, we received a letter from the ExxonMobil refinery in Billings, Montana claiming that it had sustained approximately $48.5 million in damages as a result of a January 2014 electrical outage. In December 2015, ExxonMobil increased the estimated losses related to that incident to approximately $61.7 million. On January 13, 2016, a second electrical outage shut down the ExxonMobil refinery. On January 22, 2016, ExxonMobil filed suit against NorthWestern in U.S. District Court in Billings, Montana, seeking unspecified compensatory and punitive damages arising from both outages. ExxonMobil currently claims property damages and economic losses of at least $108.0 million. We dispute ExxonMobil's claims and intend to vigorously defend this lawsuit. We have reported the refinery's claims and lawsuit to our liability insurance carriers under our liability insurance coverage, which has a $2.0 million per occurrence retention. We also have brought third-party complaints against the City of Billings and General Electric International, Inc. alleging that they are responsible in whole or in part for the outages. We are not currently able to predict an outcome or estimate the amount or range of loss that would be associated with an adverse result.

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is an Oregon solar QF developer with which we began negotiating in early 2016 to purchase capacity and energy at our avoided cost under the QF-1 option 1(a) tariff standard rates in accordance with the requirements of the Public Utility Regulatory Policies Act (PURPA) as implemented by the FERC and the MPSC.

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

On August 30, 2016, PNWS sent us a demand letter demanding that we enter into power purchase agreements for 21 solar projects and threatening to sue us for $106 million if we did not accede to its demand. We declined to do so, and on November 16, 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and other relief, including a judicial declaration that some or all of the proposed power purchase agreements were in effect. We removed the state lawsuit to the United States District Court for the District of Montana. The federal case has been stayed for six months while the MPSC considers related issues that may affect determination of issues raised in PNWS's lawsuit.

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

State of Montana - Riverbed Rents

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

Prior to our acquisition of the facilities, Talen litigated this issue against the State in State District Court, the Montana Supreme Court and in the United States Supreme Court. In August 2007, the State District Court determined that the 10 hydroelectric facilities were located on rivers which were navigable and that the State held title to the riverbeds. Subsequently, in June 2008, the State District Court awarded the State compensation with respect to all 10 facilities of approximately $34 million for the 2000-2006 period and approximately $6 million for 2007. The District Court deferred the determination of compensation for 2008 and future years to the Montana State Land Board.

Talen appealed the issue of navigability to the Montana Supreme Court, which in March 2010 affirmed the State District Court decision. In June 2011, the United States Supreme Court granted Talen's petition to review the Montana Supreme Court decision. The United States Supreme Court issued an opinion in February 2012, overturning the Montana Supreme Court and holding that the Montana courts erred first by not considering the navigability of the rivers on a segment-by-segment basis and second in relying on present day recreational use of the rivers. The United States Supreme Court also considered the navigability of what it referred to as the Great Falls Reach and concluded, at least from the head of the first waterfall to the foot of the last, that the Great Falls Reach 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 filed its complaint on remand with the State District Court. The complaint on remand renews all of the State's claims that the rivers on which the 10 hydroelectric facilities are located are navigable (including the Great Falls Reach), and that because they were navigable the riverbeds became State lands upon Montana's statehood in 1889 and that the State is entitled to rent for their use. The State's complaint on remand does not claim any specific rental amount. Pursuant to the terms of our acquisition of the hydroelectric facilities, Talen and NorthWestern will share jointly the expense of this litigation, and Talen is responsible for any rents applicable to the periods of time prior to the acquisition (i.e., before November 18, 2014), while we are responsible for periods thereafter.

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), and Talen consented to our removal. On April 27, 2016, we and Talen filed motions with the Federal District Court seeking to dismiss the portion of the litigation dealing with the Great Falls Reach in light of the United States Supreme Court's decision that the Great Falls Reach was not navigable for title purposes, and thus the State did not own the riverbeds in that segment.

On May 19, 2016, the State asked the Federal District Court to remand the case back to the State District Court and to dismiss Talen's consent to removal. The parties briefed the remand issue and oral argument was held on

January 17, 2017. On January 23, 2017 the Magistrate issued his Findings and Recommendation. The Magistrate recommended the Federal District Court remand the case to State District Court. On February 20, 2017, we filed objections to the Magistrate's Findings and Recommendation, arguing that the Federal District Court should retain jurisdiction. The following day Talen filed its objections to the Federal Magistrate's Findings and Recommendation, which we joined in on February 23, 2017. On March 21, 2017, the State filed its response to the objections. On March 24, 2017, in separate motions, both we and Talen filed motions asking the Federal District Court to hear oral argument on our respective objections. The motions for oral argument, objections along with Talen's and our motions to dismiss the State's claim regarding the Great Falls Reach remain pending before the Federal District Court, though it will not address the motions to dismiss unless it retains jurisdiction. If the case is remanded to State District Court, we will file new motions to dismiss regarding the Great Falls Reach.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is in the initial stages, and we cannot predict an outcome. If the Federal District Court (or the State District Court if the case is remanded to it) determines the riverbeds under all 10 of the hydroelectric facilities are navigable (including the five hydroelectric facilities on the Great Falls Reach) and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $7.0 million commencing in November 2014, when we acquired the facilities. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

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	23,292	21,084	10.47%
17				
18				
19	**TOTAL PROPANE PLANT**	$ 1,542,856	$ 1,540,648	0.14%
20				
21				
22	**CONSOLIDATED**	December 31,		
23	**PLANT IN SERVICE**	2016	2015	
24				
25	Montana Electric	$ 3,298,847,873	$ 3,172,088,756	
26	Yellowstone National Park	19,414,223	18,971,069	
27	Montana Natural Gas (Includes CMP)	763,632,169	728,443,945	
28	Common	123,877,637	121,487,443	
29	Townsend Propane	1,519,564	1,519,564	
30	South Dakota Electric	860,324,872	836,490,812	
31	South Dakota Natural Gas	175,034,946	170,070,949	
32	South Dakota Common	53,553,212	54,801,858	
33	Asset Retirement Obligation	31,407,853	29,338,772	
34	**TOTAL PLANT**	$ 5,327,612,349	$ 5,133,213,168	

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE				
	Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Local Storage Plant	$ 385,262	$251,375	$ 243,362	2.08%
4					
5	Distribution	1,069,348	600,406	567,520	3.08%
6					
7					
8	**Total Accumulated Depreciation**	$ 1,454,610	$851,781	$ 810,882	3.00%
9					
10					
11					
12					

13	**Consolidated**	December 31,	
14	**Accumulated Depreciation**	2016	2015
15			
16	Montana Electric	$1,130,680,436	$1,064,235,710
17	Yellowstone National Park	9,754,156	9,769,643
18	Montana Natural Gas (Includes CMP)	303,627,188	285,051,237
19	Common	28,020,639	36,076,855
20	Townsend Propane	851,781	810,882
21	South Dakota Electric	285,819,969	270,409,898
22	South Dakota Natural Gas	85,162,714	80,514,996
23	South Dakota Common	15,875,159	15,759,748
24	Acquisition Writedown	54,094,598	56,799,088
25	Basin Creek Capital Lease	21,109,982	19,099,502
26	FIN 47	3,750,578	2,653,230
27	CWIP-Capital Retirement Clearing	-7,538,353	-9,313,858
28	**Total Consolidated Accum Depreciation**	$ 1,931,208,847	$ 1,831,866,931

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
	Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
	Docket Number: 2012.9.94			
	Order Number : 7249e			
	Effective Date : June 1, 2013			
	Common Equity	47.65%	9.80%	4.67%
	Long Term Debt	52.35%	5.37%	2.81%
	TOTAL	100.00%		7.48%

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	$ 164,171,857	$ 151,208,862	8.57%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	140,114,080	125,834,295	11.35%
6	Amortization, Net	18,958,796	18,614,228	1.85%
7	Other Noncash Charges to Net Income, Net	14,018,040	12,638,644	10.91%
8	Deferred Income Taxes, Net	(6,771,384)	35,501,079	-119.07%
9	Investment Tax Credit Adjustments, Net	(196,376)	(232,401)	15.50%
10	Change in Operating Receivables, Net	860,619	13,822,901	-93.77%
11	Change in Materials, Supplies & Inventories, Net	3,365,478	1,348,472	149.58%
12	Change in Operating Payables & Accrued Liabilities, Net	16,004,227	(35,847,807)	144.64%
13	Allowance for Funds Used During Construction (AFUDC)	(4,581,196)	(8,676,344)	47.20%
14	Change in Other Assets & Liabilities, Net	(36,351,861)	34,977,392	-203.93%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,297,510)	(3,500,544)	34.37%
17	Change in Regulatory Assets	(15,485,060)	(11,042,720)	-40.23%
18	Change in Regulatory Liabilities	(411,739)	3,051,344	-113.49%
19	**Net Cash Provided by Operating Activities**	291,397,972	337,697,401	-13.71%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(287,062,468)	(428,647,576)	33.03%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	1,354,211	30,209,495	-95.52%
24	Other Investing activities	-	16,108,464	-100.00%
25	**Net Cash Used in Investing Activities**	(285,708,257)	(382,329,617)	25.27%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	249,660,000	270,000,000	-7.53%
29	Issuance of Short Term Borrowings, Net	70,936,129	-	100.00%
30	Proceeds From Issuance of Common Stock, Net	-	56,650,930	-100.00%
31	Payments for Retirement of:			
32	Capital Lease Obligations, Net	-	(24,683)	100.00%
33	Repayments of Short Term Borrowings, Net	-	(37,965,635)	100.00%
34	Long-term Debt	(225,205,000)	(150,000,000)	-50.14%
35	Dividends on Common Stock	(95,765,571)	(90,057,412)	-6.34%
36	Other Financing Activities:			
37	Debt Financing Costs	(8,430,186)	(12,082,800)	30.23%
38	Treasury Stock Activity	(560,077)	(663,706)	15.61%
39	**Net Cash (Used in)/Provided by Financing Activities**	(9,364,705)	35,856,694	-126.12%
40	**Net (Decrease)/Increase in Cash and Cash Equivalents**	(3,674,990)	(8,775,522)	58.12%
41	**Cash and Cash Equivalents at Beginning of Year**	4,108,132	12,883,654	-68.11%
42	**Cash and Cash Equivalents at End of Year**	$ 433,142	$ 4,108,132	-89.46%
43				
44	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
45	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
46	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
47	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
48				

Sch. 24	MONTANA LONG TERM DEBT 1/							
Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
6.34% Series ($250M), Due 2019	03/26/09	04/01/19	$ 250,000,000	$ 247,657,313	$ 249,962,312	6.34%	$ 16,514,170	6.61%
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	07/01/2025	75,000,000	74,563,893	75,000,000	3.11%	2,760,973	3.68%
4.11% Series($125M), Due 2045	06/23/15	07/01/2045	125,000,000	124,273,156	125,000,000	4.11%	5,367,425	4.29%
Total First Mortgage Bonds			$ 1,266,000,000	$ 1,255,902,235	$ 1,265,962,312		$ 62,326,382	4.92%
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%	$ 3,627,281	2.51%
Total Pollution Control Bonds			$ 144,660,000	$ 138,906,956	$ 144,660,000		$ 3,627,281	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%	$ 342,830	1.27%
Total Other Long Term Debt			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 342,830	1.27%
TOTAL LONG TERM DEBT			$ 1,437,636,900	$ 1,421,101,538	$ 1,437,599,212		$ 66,296,492	4.61%

This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is $24,346,170

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

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	48,178,591	$33.64				$55.84	$52.47	
February	48,284,740	33.89				60.40	56.18	
March	48,306,885	33.43	$0.83	$0.50		61.79	59.46	
April	48,307,647	33.62				62.44	56.28	
May	48,309,540	33.99				58.79	55.88	
June	48,311,079	33.69	0.74	0.50		63.07	58.31	
July	48,311,759	33.89				63.33	60.48	
August	48,313,720	34.21				61.24	57.45	
September	48,327,642	34.12	0.92	0.50		60.10	56.43	
October	48,328,436	34.31				57.55	54.09	
November	48,330,126	34.55				58.78	55.53	
December	48,331,675	34.68	0.91	0.50		57.53	54.59	
TOTAL Year End	48,298,896	$34.68	$3.40	$2.00	41.18%	$56.87		16.7

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2016.

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	(831,331)	(790,432)	-5.17%
4				
5	**Net Plant in Service**	$688,233	$729,132	-5.61%
6	Additions:			
7	Propane on Hand	$26,216	$34,066	-23.04%
8				
9	**Total Additions**	$26,216	$34,066	-23.04%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	$57,827	$70,075	-17.48%
12				
13	**Total Deductions**	$57,827	$70,075	-17.48%
14	**Total Rate Base**	$656,621	$693,123	-5.27%
15	**Net Earnings**	$ (21,890)	$ (12,928)	-69.32%
16	**Rate of Return on Average Rate Base**	-3.334%	-1.865%	-78.73%
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	23,292
7	108, 111	Depreciation & Amortization Reserves	851,781
8			
9	**NET BOOK COSTS**		691,075
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	495,329
14			
15	**Total Operating Revenues**		495,329
16			
17	401-402	Operation & Maintenance Expenses	428,633
18	403-407	Depreciation Expense	40,899
19	408.1	Taxes Other than Income Taxes	59,788
20	409-411	Federal & State Income Taxes	(12,101)
21			
22	**Total Operating Expenses**		517,219
23	**Net Operating Income**		(21,890)
24			
25	415-421.1	Other Income	-
26	421.2-426.5	Other Deductions	-
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ (21,890)
28			
29		**Average Customers**	
30		Residential	508
31		Commercial / Industrial	69
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		577
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	45.9
37		Average Annual Residential Cost per (Dkt)	$12.65
38		Average Residential Monthly Bill	$48.34
39			
40		Plant in Service (Gross) per Customer	$2,634

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,878	508	69	-	577
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,878	508	69	-	577
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/16 through 12/31/16.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	156	150	153
5	Finance	149	151	150
6	Regulatory Affairs	28	28	28
7	Distribution	455	449	452
8	Transmission	327	309	318
9	Supply	122	114	118
10	Legal	22	20	21
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,261	1,223	1,242

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2017 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Distribution - Elec Distribution Infrastructure Plan	$32,514,627	$32,514,627
4	MT Elec Trans - Columbus-Rapelje to Chrome Jct 100kv line	15,142,632	15,142,632
5	MT Elec Dist - Livingston Westside City Sub rebuild and removal	10,500,000	10,500,000
6	MT Elec Dist - Great Falls Eastside Sub upgrade	7,841,425	7,841,425
7	MT Elec Dist - Big Sky Lone Mountain Sub Bank upgrade	7,200,000	7,200,000
8	MT Elec Trans - NERC Facility Rating 115/100	5,100,000	5,100,000
9	SD Electric - Aberdeen City Sub clearance corrections	4,669,030	-
10	MT Elec Dist - Substation infrastructure improvements	2,500,000	2,500,000
11	MT Elec Trans - TFalls Burke A&B 115 kV NERC	2,500,000	2,500,000
12	MT Elec Trans - Crooked Falls Switchyard expansion	2,197,709	2,197,709
13	MT Elec Trans - Fort Benton-Kershaw substation switchyard	2,741,848	2,741,848
14	MT Elec Trans - Fort Benton to Assiniboine poles and clearances	2,002,289	2,002,289
15	MT Elec Dist - Bozeman-Big Sky Midway Sub	2,000,000	2,000,000
16	MT Elec Trans - Drummond City substation	1,927,000	1,927,000
17	MT Elec Trans - Holter - Drummond 100kv NERC	1,500,000	1,500,000
18	MT Elec Trans - Lower Duck to Columbus poles and clearances	1,205,000	1,205,000
19	MT Elec Trans - Assiniboine to Chester line rehab	1,074,969	1,074,969
20	MT Elec - Community Sustainability development	1,000,000	1,000,000
21	MT Elec Trans - Ennis161kv terminal	1,000,000	1,000,000
22			
23	All Other Projects < $1 Million Each	81,769,513	62,278,301
24			
25	**Total Electric Utility Construction Budget**	**186,386,042**	**162,225,800**
26			
27	**Natural Gas Operations**		
28	MT Gas Trans - Meriwether-Kalispell Horse Power	7,245,577	7,245,577
29	MT Gas Retail - Gas Distribution Infrastructure Plan	5,985,373	5,985,373
30			
31	All Other Projects < $1 Million Each	27,267,848	22,417,224
32			
33	**Total Natural Gas Utility Construction Budget**	**40,498,797**	**35,648,173**
34			
35	**Common**		
36	SD AMI Metering	11,865,924	-
37	MT and SD Fleet and Equipment upgrades	7,281,848	5,252,209
38	MT DSIP - Distribution Management System (DMS)	2,215,626	2,215,626
39	Business Tech - PowerPlan capital budget module implementation	1,204,087	1,015,324
40	MT Facilities - Bozeman facility expansion land and study	1,000,000	1,000,000
41	MT Facilities - Mitchell SD office	2,558,351	-
42			
43	All Other Projects < $1 Million Each	11,236,753	8,704,797
44	(Includes BT, Communications, Facilities, Customer Service)		
45			
46	**Total Common Utility Construction Budget**	**37,362,589**	**18,187,956**
47			
48	MT CU4 capital additions - PPL invoice	12,555,000	12,555,000
49	MT - Hydro Generation upgrades	11,347,508	11,347,508
50	MT - DGGS 25k hour overhauls and other	5,522,038	5,522,038
51	SD Big Stone, Neal 4, Coyote partner capital, internal	3,028,027	-
52			
53	All Other Projects < $1 Million Each	100,000	100,000
54			
55	**Total MT/SD Generation**	**32,552,572**	**29,524,545**
56	**TOTAL CONSTRUCTION BUDGET**	**$296,800,000**	**$245,586,474**

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2016 Year	2015 Year	2016 Year	2015 Year
1	**Name of Supplier**				
2					
3	AmeriGas	21,674	23,005	$6.1838	$15.0150
4	Gibson Energy, LLC	23,089	21,082	$7.1105	$7.1576
5					
6	**Total Propane Supply Volumes**	44,763	44,087	$6.6618	$11.2576

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2016 Year	2015 Year	2016 Year	2015 Year	2016 Year	2015 Year
1	**Sales of Propane**						
2							
3	Residential	$294,653	$441,052	23,298	23,831	508	509
4	Commercial / Industrial	200,676	303,726	16,742	17,224	69	71
5							
6							
7	**TOTAL SALES**	$495,329	$744,778	40,040	41,055	577	580