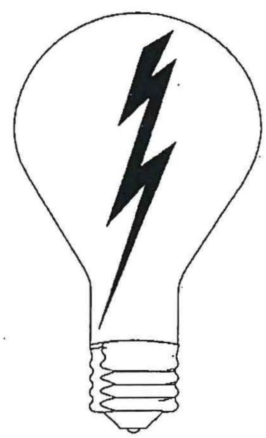
YEAR ENDING 2018

ANNUAL REPORT
OF

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC UTILITY



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

IDENTIFICATION

Year: 2018

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Tamie A. Aberle
5a.	Telephone Number:	(701) 222-7856

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors 1/ 2/

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	David L. Goodin (Chairman), Bismarck, ND	-
2	Daniel S. Kuntz, Bismarck, ND	-
3	Nicole A. Kivisto, Bismarck, ND	-
4	Jason L. Vollmer, Bismarck, ND	-
5		
6		
7		
8	1/ At December 31, 2018, Montana-Dakota Utilities Co. was a Division of MDU	
9	Resources Group, Inc., and had no Board of Directors. The affairs of the	
10	Company were managed by a Managing Committee, the members of which	
11	are provided herein rather than the directors of MDU Resources Group, Inc.	
12		
13	2/ On January 1, 2019, Montana-Dakota Utilities Co. became a subsidiary of	
14	MDU Resources Group, Inc. with its own Board of Directors, the names of	
15	which are provided above.	
16		
17		
18		

Officers Year: 2018

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief Executive Officer	Executive	Nicole A. Kivisto
2			
3	Vice President	Electric Supply	Jay W. Skabo
4			
5	Vice President	Operations & Engineering Services	Patrick C. Darras
6			
7	Executive Vice President	Business Development & Gas Supply	Scott W. Madison
8			
9	Executive Vice President	Regulatory Affairs, Customer Service	Garret Senger
10		& Administration	
11			
12	Vice President	Regulatory Affairs & Customer Service	Mark A. Chiles
13			
14	Vice President	Safety Process Improvement &	Hart Gilchrist
15		Operations Systems	
16			
17	Vice President	Field Operations	Eric P. Martuscelli
18			
19	Controller	Accounting	Tammy J. Nygard
20			
21			
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Company Name: Montana-Dakota Utilities Co. **SCHEDULE 4**

CORPORATE STRUCTURE Year: 2018

	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co./	Electric and Natural Gas	$84,732	31.12%
2	Great Plains Natural Gas Co.	Distribution		
3	(Divisions of MDU Resources			
4	Group, Inc.)/Cascade			
5	Natural Gas Corp. and			
6	Intermountain Gas Company			
7				
8	WBI Holdings, Inc.	Pipeline and Midstream	29,993	11.01%
9				
10				
11	Knife River Corporation	Construction Materials and	92,647	34.02%
12		Contracting		
13				
14	MDU Construction Services	Construction Services	64,309	23.62%
15	Group, Inc.			
16				
17	Centennial Energy Resources LLC/	Other	637	0.23%
18	Centennial Holdings Capital LLC			
19				
20				
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50	**TOTAL**		$272,318	100.00%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - ELECTRIC Year: 2018

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$15,236	4.59%	$316,675
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or	7,473	4.59%	155,211
4			Actual Costs Incurred			
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,652	3.78%	67,522
7			Studies, and/or Actual Costs Incurred			
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time	753	4.25%	16,969
10			Studies, and/or Actual Costs Incurred			
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	11,379	4.59%	236,536
13			Actual Costs Incurred			
14						
15	Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time	103	4.37%	2,256
16			Studies, and/or Actual Costs Incurred			
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	36,563	3.79%	926,987
19			Actual Costs Incurred			
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	65,906	2.95%	2,166,507
22			Actual Costs Incurred			
23						
24	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time	4,068	4.44%	87,487
25			Studies, and/or Actual Costs Incurred			
26						
27	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor	111,736	4.59%	2,324,868
28						
29	Employee Benefits	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,812	4.62%	58,036
30			Studies, and/or Actual Costs Incurred			

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2018

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or	12	4.71%	243
2			Actual Costs Incurred			
3						
4	Employee Reimbursable	Administrative & General	Various Corporate Overhead Allocation Factors, Time	5,969	4.05%	141,518
5	Expenses		Studies, and/or Actual Costs Incurred			
6						
7	Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time	12	4.62%	248
8			Studies, and/or Actual Costs Incurred			
9						
10	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	11,956	4.60%	248,133
11			Actual Costs Incurred			
12						
13	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	25	4.27%	560
14			Studies, and/or Actual Costs Incurred			
15						
16	Meals	Administrative & General	Various Corporate Overhead Allocation Factors, Time	5,431	4.43%	117,276
17			Studies, and/or Actual Costs Incurred			
18						
19	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time	4,740	4.35%	104,218
20			Studies, and/or Actual Costs Incurred			
21						
22	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or	4,111	3.45%	114,891
23			Actual Costs Incurred			
24						
25	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and	41,342	13.19%	271,993
26			Allocation Factors Based on Actual Experience			
27						
28	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	1,673	4.58%	34,821
29			Actual Costs Incurred			

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - ELECTRIC Year: 2018

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Postage & Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or	(209)	4.58%	(4,354)
2			Actual Costs Incurred			
3						
4	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,249,695	4.45%	26,864,469
5			Studies, and/or Actual Costs Incurred			
6						
7	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	83	5.41%	1,450
8			Actual Costs Incurred			
9						
10	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	8,415	4.63%	173,276
11			Actual Costs Incurred			
12						
13	Reimbursements	Administrative & General	Various Corporate Overhead Allocation Factors and/or	(42)	2.18%	(1,886)
14			Actual Costs Incurred			
15						
16	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	7,077	4.37%	154,775
17	Registrations		Studies, and/or Actual Costs Incurred			
18						
19						
20	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	87,183	4.21%	1,983,256
21			Studies, and/or Actual Costs Incurred			
22						
23	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or	16,810	4.10%	393,302
24			Actual Costs Incurred			
25						
26	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,373	5.54%	57,489
27			Studies, and/or Actual Costs Incurred			
28						
29	Uniforms	Administrative & General	Various Corporate Overhead Allocation Factors, Time	60	8.58%	639
30			Studies, and/or Actual Costs Incurred			
31	**TOTAL**			$1,706,397	4.41%	$37,015,371

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Materials		$11,085		$2,634
3						
4						
5		Capital	Actual Costs Incurred			
6		Materials		1,164		0
7						
8						
9		Other Transactions/Reimbursements				
10		Balance Sheet Acct		1,010,994		0
11		Resources Cost Ctrs		11,842		0
12						
13		Total Knife River Corporation Operating Revenues for the Year 2018			$1,925,854,000	
14		Excludes Intersegment Eliminations				
15	**TOTAL**	**Grand Total Affiliate Transactions**		$1,035,085	0.0537%	$2,634

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC.**	Expense	Actual Costs Incurred			
2		Contract Services		$75,064		$22,603
3		Fuel		78,044		20,915
4		Employee Benefits		3,767		830
5		Miscellaneous		38,272		10,189
6						
7		Capital	Actual Costs Incurred			
8		Contract Services		2,387		426
9		Miscellaneous		3,564		135
10						
11						
12		Other Transactions/Reimbursements				
13						
14		Balance sheet accounts		1,056,890		0
15		Resources Cost Centers		23,849		0
16						
17		Total WBI Operating Revenues for the Year 2018			$128,923,000	
18		Excludes Intersegment Eliminations				
19	**TOTAL**	**Grand Total Affiliate Transactions**		$1,281,837	0.9943%	$55,098

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU CONSTRUCTION**	Expense	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Miscellaneous		$974		$215
3						
4		Other Transactions/Reimbursements				
5		Resources Cost Centers		16,887		0
6		Balance Sheet Accounts		7,709		0
7						
8						
9						
10						
11						
12						
13						
14		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2018			$1,371,453,000	
15		Excludes Intersegment Eliminations				
16	**TOTAL**	**Grand Total Affiliate Transactions**		$25,570	0.0019%	$215

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	* Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$280,296		$61,741
3		Corporate Aircraft	Actual Costs Incurred	27,910		9,079
4		Office Expense		503,319		110,866
5		Miscellaneous		705,343		155,366
6						
7		Capital	Actual Costs Incurred			
8		Corporate Aircraft		11,819		2,632
9						
10						
11		Other Transactions/Reimbursements				
12		Resources Cost Centers		138,263		0
13		Balance Sheet Accounts		4,521,213		0
14						
15		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2018			$11,259,000	
16		Excludes Intersegment Eliminations				
17	**TOTAL**	**Grand Total Affiliate Transactions**		$6,188,163	54.9619%	$339,684

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU ENERGY CAPITAL**	Expense	Actual Costs Incurred			
2		Contract Services		$197		$47
3		Cost of Service		154,383		34,224
4		Office Expenses		8,622		1,541
5		Payroll/Employee Benefits		116,790		25,485
6		Miscellaneous		14,283		3,185
7						
8		Capital	Actual Costs Incurred			
9		Contract Services		29,999		6,253
10		Payroll/Employee Benefits		85,662		17,857
11		Miscellaneous		3,658		735
12						
13						
14		Other Transactions/Reimbursements	Actual Costs Incurred			
15		Clearing		(2,546)		0
16		Balance Sheet Accounts		2,185		0
17						
18						
19		Total MDU Energy Capital Operating Revenues for the Year 2018			$530,038,000	
20						
21	**TOTAL**	**Grand Total Affiliate Transactions**		$413,233	0.0780%	$89,327

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER	MDU RESOURCES GROUP, INC.				
2	CORPORATION	Corporate Overhead	1/ Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$70,189		
4		Advertising	Costs Incurred	36,029		
5		Air Service		13,818		
6		Automobile		4,965		
7		Bank Services		54,945		
8		Corporate Aircraft		18,708		
9		Consultant Fees		201,762		
10		Contract Services		928,329		
11		Computer Rental		537		
12		Directors Expenses		540,476		
13		Employee Benefits		13,112		
14		Employee Meeting		52		
15		Employee Reimbursable Expense		31,136		
16		Entertainment		57		
17		Non-Qualified Defined Contributions		23,914		
18		Legal Retainers & Fees		57,098		
19		Meal Allowance		140		
20		Cash Donations		9,118		
21		Meals & Entertainment		25,246		
22		Industry Dues & Licenses		23,805		
23		Office Expenses		30,969		
24		Supplemental Insurance		482,514		
25		Permits & Filing Fees		8,005		
26		Postage		(1,013)		
27		Payroll		5,642,276		
28		Reimbursements		(537)		
29		Reference Materials		39,840		
30		Rental		315		
31		Seminars & Meeting Registrations		31,072		
32		Software Maintenance		517,098		
33		Telephone/Cell Expenses		122,167		
34		Training		11,699		
35		Uniforms		88		
36		**Total MDU Resources Group, Inc.**		$8,937,929	0.5009%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER	MONTANA-DAKOTA UTILITIES CO.				
2	CORPORATION	Other Direct Charges	Actual Costs Incurred			
3		Contract Services		$88,313		
4		Communications		344,720		
5		Employee Discounts		17,418		
6		Dues, Permits, and Filing Fees		22,410		
7		Legal		26,160		
8		Sponsorship		44,200		
9		Electric Consumption		167,884		
10		Gas Consumption		166,258		$61,419
11		Bank Fees		32,653		
12		Computer/Software Support		987,338		
13		Office Expense		29,772		
14		Cost of Service		653,742		145,061
15		Audit Costs		752,914		
16		Auto		265		
17		Travel		9,908		
18		Employee Benefits		12,011		
19		Marketing		1,000		
20		Training Registration		2,000		
21		Balance Sheet		1,314,059		
22						
23		**Total Montana-Dakota Utilities Co.**		$4,673,025	0.2619%	$206,480
24						
25		OTHER TRANSACTIONS/REIMBURSEMENT	Actual Costs Incurred			
26						
27		Federal & State Tax Liability Payments		$3,101,274		
28		Miscellaneous Reimbursements		(876,867)		
29						
30		**Total Other Transactions/Reimbursements**		$2,224,407	0.1247%	
31						
32		**Grand Total Affiliate Transactions**		$15,835,361	0.8874%	$206,480
33						
34		**Total Knife River Corporation Operating Expenses for 2018-Excludes Intersegment Eliminations**			$1,784,428,000	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2018

KNIFE RIVER CORPORATION

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$27,509		
4		Advertising	Studies and/or Actual Costs	14,044		
5		Air Service	Incurred	9,666		
6		Automobile		1,498		
7		Bank Services		21,605		
8		Corporate Aircraft		9,968		
9		Consultant Fees		119,702		
10		Contract Services		190,296		
11		Computer Rental		216		
12		Directors Expenses		214,609		
13		Employee Benefits		6,167		
14		Employee Meeting		33		
15		Employee Reimbursable Expense		16,790		
16		Entertainment		22		
17		Non-Qualified Defined Contributions		9,094		
18		Legal Retainers & Fees		22,236		
19		Meal Allowance		81		
20		Cash Donations		3,470		
21		Meals		13,314		
22		Industry Dues & Licenses		9,845		
23		Office Expenses		10,517		
24		Supplemental Insurance		182,625		
25		Permits & Filing Fees		3,256		
26		Postage		(406)		
27		Payroll		3,196,805		
28		Reimbursements		(115)		
29		Reference Materials		15,979		
30		Rental		133		
31		Seminars & Meeting Registrations		19,461		
32		Software Maintenance		208,478		
33		Telephone/Cell Expenses		51,389		
34		Training		5,645		
35		Uniforms		55		
36		**Total MDU Resources Group, Inc.**		$4,383,987	4.7202%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Other Direct Charges	Actual Costs Incurred			
3		Audit Costs		$210,939		
4		Auto		1,726		
5		Bank Fees		9,687		
6		Communication Services		44,978		
7		Computer/Software Support		315,575		
8		Contract Services		393,896		
9		Utility/Merchandise Discounts		26,080		
10		Dues, Permits, and Filing Fees		13,845		
11		Interest		12,382		
12		Misc Employee Benefits		305,612		
13		Electric Consumption		699,220		$487,893
14		Gas Consumption		40,450		27,392
15		Cost of Service		84,776		18,811
16		Legal Fees		2,151		
17		Office Expense		101,088		
18		Sponsorship		18,000		
19		Training Registration		7,868		
20		Travel		21,546		
21		Payroll		184,450		
22		Balance Sheet		297,779		
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33		**Total Montana-Dakota Utilities Co.**		$2,792,048	3.0061%	$534,096

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.					
2						
3		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
4						
5		Federal & State Tax Liability Payments		$12,578,096		
6		Miscellaneous Reimbursements		(131,280)		
7		**Total Other Transactions/Reimbursements**		$12,446,816	13.4013%	
8						
9		**Grand Total Affiliate Transactions**		$19,622,851	21.1276%	$534,096
10						
11						
12						
13		**Total WBI Energy Operating Expenses for 2018 - Excludes Intersegment Eliminations**			$92,878,000	

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION	MDU RESOURCES GROUP, INC.				
2	SERVICES GROUP INC	Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$37,921		
4		Advertising	Studies and/or Actual Costs	14,902		
5		Air Service	Incurred	10,805		
6		Automobile		1,920		
7		Bank Services		22,588		
8		Corporate Aircraft		8,622		
9		Consultant Fees		91,615		
10		Contract Services		210,789		
11		Computer Rental		219		
12		Directors Expenses		220,644		
13		Employee Benefits		6,358		
14		Employee Meeting		33		
15		Employee Reimbursable Expense		19,457		
16		Entertainment		24		
17		Non-Qualified Defined Contributions		10,060		
18		Legal Retainers & Fees		23,636		
19		Meal Allowance		65		
20		Cash Donations		3,833		
21		Meals		12,051		
22		Industry Dues & Licenses		10,296		
23		Office Expenses		19,242		
24		Supplemental Insurance		203,622		
25		Permits & Filing Fees		3,264		
26		Postage		(411)		
27		Payroll		2,776,643		
28		Reimbursements		(419)		
29		Reference Materials		16,911		
30		Rental		140		
31		Seminars & Meeting Registrations		15,092		
32		Software Maintenance		248,483		
33		Telephone/Cell Expenses		50,477		
34		Training		5,021		
35		Uniforms		27		
36		**Total MDU Resources Group, Inc.**		$4,043,930	0.3148%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION	Intercompany Settlements	Actual Costs Incurred			
2	SERVICES GROUP INC	Audit Costs		$512,778		
3		Bank Fees		76,977		
4		Communication Services		171,696		
5		Computer/Software Support		1,001,109		
6		Contract Services		141,192		
7		Cost of Service		251,759		$55,863
8		Dues, Permits, and Filing Fees		51,146		
9		Gas Consumption		5,119		5,119
10		Legal		5,876		
11		Marketing		642		
12		Misc Employee Benefits		22,863		
13		Office Expense		26,433		
14		Payflex		(872)		
15		Payroll		3,022		
16		Sponsorship		17,800		
17		Travel		9,786		
18		Training Registration		21,773		
19		Balance Sheet		815,145		
20		**Total Montana-Dakota Utilities Co.**		$3,134,244	0.2440%	$60,982
21						
22		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
23		Federal & State Tax Liability Payments		$15,266,074		
24		Miscellaneous Reimbursements		(571,508)		
25						
26		**Total Other Transactions/Reimbursements**		$14,694,566	1.1438%	
27						
28		**Grand Total Affiliate Transactions**		$21,872,740	1.7026%	$60,982
29						
30		**Total MDU Construction Services Group, Inc. Operating Expenses for 2018**			$1,284,689,000	
31		**Excludes Intersegment Eliminations**				

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	RESOURCES INT					
3		Other Direct Charges	Actual costs incurred			
4		Dues, Permits, and Filing Fees		$550		
5		Bank Fees		2,604		
6						
8						
9		Intercompany Settlements	Actual costs incurred			
10		Dues, Permits, and Filing Fees		300		
11						
12		**Total Montana-Dakota Utilities Co.**		$3,454	4.0635%	$0
13						
14		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
15		Federal & State Tax Liability Payments		($66,722)		
16						
17		**Total Other Transactions/Reimbursements**		($66,722)	-78.4965%	$0
18						
19		**Grand Total Affiliate Transactions**		($63,268)	-74.4329%	$0
20						
21		**Total Centennial Energy Resources International Operating Expenses for 2018**			$85,000	
22		**Excludes Intersegment Eliminations**				

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL CORP. AND	Direct and Intercompany Charges	Actual costs incurred			
3	FUTURESOURCE	Auto		$1,404		
4		Bank Fees		1,311		
5		Contract Services		769,582		
6		Materials		332,923		
7		Office Expense		156,702		
8		Travel		2,410		
9		Electric Consumption		188,578		
10		Gas Consumption		14,016		
11		Payroll		517,412		
12		Legal		135		
13		Dues, Permits and Filing Fees		408		
14		Other		245		
15		Rent		139,382		
16		**Total Montana-Dakota Utilities Co.**		$2,124,508	19.0198%	$0
17		OTHER TRANSACTIONS/REIMBURSEMENTS				
18		Miscellaneous Reimbursements		($58,821)		
19		Federal & State Tax Liability Payments		8,516,485		
20		**Total Other Transactions/Reimbursements**		$8,457,664	75.7177%	$0
21						
22		**Grand Total Affiliate Transactions**		$10,582,172	94.7374%	$0
23						
24		**Total CHCC Operating Expenses for 2018**			$11,170,000	
25		**Excludes Intersegment Eliminations**				

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MDU RESOURCES GROUP, INC.				
2	CAPITAL 2/	Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$80,845		
4		Advertising	Studies and/or Actual Costs	41,083		
5		Air Service	Incurred	15,785		
6		Automobile		3,634		
7		Bank Services		62,566		
8		Corporate Aircraft		23,434		
9		Consultant Fees		161,434		
10		Contract Services		403,659		
11		Computer Rental		606		
12		Directors Expenses		614,474		
13		Employee Benefits		13,903		
14		Employee Meeting		43		
15		Employee Reimbursable Expense		34,865		
16		Entertainment		66		
17		Non-Qualified Defined Contributions		27,374		
18		Legal Retainers & Fees		66,513		
19		Meal Allowance		113		
20		Cash Donations		10,436		
21		Meals		30,940		
22		Industry Dues & Licenses		27,231		
23		Office Expenses		27,120		
24		Supplemental Insurance		552,740		
25		Permits & Filing Fees		9,300		
26		Postage		(1,150)		
27		Payroll		7,028,066		
28		Reimbursements		(539)		
29		Reference Materials		45,187		
30		Rental		318		
31		Seminars & Meeting Registrations		42,590		
32		Software Maintenance		435,834		
33		Telephone/Cell Expenses		58,700		
34		Training		12,942		
35		Uniforms		76		
36		**Total MDU Resources Group, Inc.**		$9,830,188	2.0447%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL 2/	Payroll & HR				
3		Employee Benefits	1/ Various Corporate Overhead			
4		Payroll	Allocation Factors, Cost of			
5		Travel	Service Factors, Time Studies			
6		Office Expenses	and/or Actual Costs Incurred			
7		Automobile				
8						
9		Other Direct Charges	Actual costs incurred			
10		Bank Fees		$3,422		
11		Computer Equip/Software		13,700		
12		Contract Services		557,399		
13		Employee Benefits		6,791		
14		Filing Fees		42,059		
15		Training		11,700		
16		Legal		1,779		
17		Balance Sheet		674,432		
18						
19		Intercompany Settlements	Actual costs incurred			
20		O&M				
21		Auto		79		
22		Bank Fees		27,521		
23		Communicationa		336,148		
24		Contract Services		542,708		
25		Cost of Service		2,025,240		$449,386
26		Employee Benefits		84,539		
27		Marketing		15,400		
28		Material		16,877		
29		Miscellaneous		318,700		
30		Office Expenses		179,301		
31		Payroll		10,491,410		
32		SISP		119,708		
33		Software Maintenance		2,208,877		
34		Sponsorship		50,000		
35		Travel		251,538		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL 2/	Other	Actual costs incurred			
3		Audit		$441,737		
4		LTIP		640,924		
5		MII		4,211		
6		Payflex		(14,702)		
7		Prepaid		255,718		
8		Miscellaneous		139,106		
9						
10		Capital	Actual costs incurred			
11		Auto		136		
12		Company Consumption-Electric		476		
13		Company Consumption-Gas		311		
14		Contract Services		5,451		
15		Material		391,884		
16		Misc Employee Benefit		1,923		
17		Misc Other		148,119		
18		Office Expense		544		
19		Payroll		1,591,784		
20		Travel		27,090		
21		Utility Group Project Allocation		1,882,356		
22		**Total Montana-Dakota Utilities Co.**		$23,496,396	4.8873%	$449,386
23						
24		OTHER TRANSACTIONS/REIMBURSEMENTS				
25		Federal & State Tax Liability Payments		$11,407,633		
26		Miscellaneous Reimbursements		(916,490)		
27		**Total Other Transactions/Reimbursements**		$10,491,143	2.1822%	$0
28						
29		**Grand Total Affiliate Transactions**		$43,817,727	9.1143%	$449,386
30						
31		**Total MDU Energy Capital Operating Expenses for 2018**			$480,760,000	
32		**Excludes Intersegment Eliminations**				

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2/ MDU Energy Capital is the parent company for Cascade Natural Gas Company and Intermountain Gas Company.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	HOLDING INC					
3		Other Direct Charges	Actual costs incurred			
4		Audit Costs		$138,616		
5		Bank Fees		2,797		
6		Contract Services		220,228		
7		Dues, Permits, and Filing Fees		250		
8		Legal		4,378		
9		Miscellaneous		713		
10		**Total Montana-Dakota Utilities Co.**		$366,982		
11						
12		**Grand Total Affiliate Transactions**		$366,982		
13						
14						
15						

MONTANA UTILITY INCOME STATEMENT

Year: 2018

		Account Number & Title	Last Year	This Year	% Change
1	400	Total Operating Revenues	$68,385,291	$68,263,779	-0.18%
2					
3		Operating Expenses			
4	401	Operation Expenses	$39,936,861	$41,231,538	3.24%
5	402	Maintenance Expense	5,075,972	5,120,604	0.88%
6		Total O & M Expenses	45,012,833	46,352,142	2.98%
7					
8	403	Depreciation Expense	8,717,908	9,195,759	5.48%
9	404-405	Amortization of Electric Plant	360,746	493,931	36.92%
10	406	Amort. of Plant Acquisition Adjustments	0	0	0.00%
11	407	Amort. of Property Losses, Unrecovered Plant			
12		& Regulatory Study Costs			
13	408.1	Taxes Other Than Income Taxes	5,308,128	5,813,051	9.51%
14	409.1	Income Taxes - Federal	(7,386,285)	(7,446,633)	-0.82%
15		- Other	(283,857)	191,228	167.37%
16	410.1	Provision for Deferred Income Taxes	33,229,272	13,207,993	-60.25%
17	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	27,145,531	8,385,449	-69.11%
18	411.4	Investment Tax Credit Adjustments			
19	411.6	(Less) Gains from Disposition of Utility Plant			
20	411.7	Losses from Disposition of Utility Plant			
21					
22		**Total Utility Operating Expenses**	$57,813,214	$59,422,022	2.78%
23		**NET UTILITY OPERATING INCOME**	$10,572,077	$8,841,757	-16.37%

MONTANA UTILITY REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2					
3	440	Residential	$17,273,829	$17,803,560	3.07%
4	442	Commercial & Industrial - Small	10,534,307	10,722,457	1.79%
5		Commercial & Industrial - Large	31,391,247	32,699,963	4.17%
6	444	Public Street & Highway Lighting	990,311	786,039	-20.63%
7	445	Other Sales to Public Authorities	507,988	449,348	-11.54%
8	446	Sales to Railroads & Railways			
9	448	Interdepartmental Sales			
10		Net Unbilled Revenue	878,519	737,607	-16.04%
11					
12		**Total Sales to Ultimate Consumers**	$61,576,201	$63,198,974	2.64%
13	447	Sales for Resale	226,695	278,641	22.91%
14					
15		**Total Sales of Electricity**	$61,802,896	$63,477,615	2.71%
16	449.1	(Less) Provision for Rate Refunds		(1,000,000)	
17					
18		**Total Revenue Net of Provision for Refunds**	$61,802,896	$62,477,615	1.09%
19		Other Operating Revenues			
20	450	Forfeited Discounts & Late Payment Revenues	$62,844	$67,906	8.05%
21	451	Miscellaneous Service Revenues	26,479	34,190	29.12%
22	453	Sales of Water & Water Power			
23	454	Rent From Electric Property	1,063,435	1,201,848	13.02%
24	455	Interdepartmental Rents			
25	456	Other Electric Revenues	5,429,637	4,482,220	-17.45%
26					
27		**Total Other Operating Revenues**	$6,582,395	$5,786,164	-12.10%
28		**TOTAL OPERATING REVENUES**	$68,385,291	$68,263,779	-0.18%

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	$494,130	$440,665	-10.82%
6	501 Fuel	13,058,252	14,181,071	8.60%
7	502 Steam Expenses	1,591,353	1,753,935	10.22%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	437,831	459,641	4.98%
11	506 Miscellaneous Steam Power Expenses	834,313	946,347	13.43%
12	507 Rents	2,123	1,863	-12.25%
13				
14	TOTAL Operation - Steam	16,418,002	17,783,522	8.32%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	281,092	273,109	-2.84%
18	511 Maintenance of Structures	174,899	154,973	-11.39%
19	512 Maintenance of Boiler Plant	1,447,042	1,605,421	10.95%
20	513 Maintenance of Electric Plant	368,371	477,940	29.74%
21	514 Maintenance of Miscellaneous Steam Plant	436,009	431,977	-0.92%
22				
23	TOTAL Maintenance - Steam	2,707,413	2,943,420	8.72%
24	**TOTAL Steam Power Production Expenses**	$19,125,415	$20,726,942	8.37%
25				
26	Nuclear Power Generation			
27	Operation			
28	517 Operation Supervision & Engineering			
29	518 Nuclear Fuel Expense			
30	519 Coolants & Water			
31	520 Steam Expenses			
32	521 Steam from Other Sources	NOT	NOT	
33	522 (Less) Steam Transferred - Cr.	APPLICABLE	APPLICABLE	
34	523 Electric Expenses			
35	524 Miscellaneous Nuclear Power Expenses			
36	525 Rents			
37				
38	TOTAL Operation - Nuclear			
39				
40	Maintenance			
41	528 Maintenance Supervision & Engineering			
42	529 Maintenance of Structures			
43	530 Maintenance of Reactor Plant Equipment	NOT	NOT	
44	531 Maintenance of Electric Plant	APPLICABLE	APPLICABLE	
45	532 Maintenance of Miscellaneous Nuclear Plant			
46				
47	TOTAL Maintenance - Nuclear			
48	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		Power Production Expenses -continued			
2	Hydraulic Power Generation				
3	Operation				
4	535	Operation Supervision & Engineering			
5	536	Water for Power			
6	537	Hydraulic Expenses	NOT	NOT	
7	538	Electric Expenses	APPLICABLE	APPLICABLE	
8	539	Miscellaneous Hydraulic Power Gen. Expenses			
9	540	Rents			
10					
11		TOTAL Operation - Hydraulic			
12					
13	Maintenance				
14	541	Maintenance Supervision & Engineering			
15	542	Maintenance of Structures	NOT	NOT	
16	543	Maint. of Reservoirs, Dams & Waterways	APPLICABLE	APPLICABLE	
17	544	Maintenance of Electric Plant			
18	545	Maintenance of Miscellaneous Hydro Plant			
19					
20		TOTAL Maintenance - Hydraulic			
21		**TOTAL Hydraulic Power Production Expenses**			
22					
23	Other Power Generation				
24	Operation				
25	546	Operation Supervision & Engineering	$72,561	$70,997	-2.16%
26	547	Fuel	904,174	926,294	2.45%
27	548	Generation Expenses	613,320	886,082	44.47%
28	549	Miscellaneous Other Power Gen. Expenses	142,481	208,998	46.68%
29	550	Rents	156,602	166,449	6.29%
30					
31		TOTAL Operation - Other	1,889,138	2,258,820	19.57%
32					
33	Maintenance				
34	551	Maintenance Supervision & Engineering	24,897	30,984	24.45%
35	552	Maintenance of Structures	6,200	4,881	-21.27%
36	553	Maintenance of Generating & Electric Plant	333,369	153,714	-53.89%
37	554	Maintenance of Misc. Other Power Gen. Plant	22,933	18,900	-17.59%
38					
39		TOTAL Maintenance - Other	387,399	208,479	-46.18%
40		**TOTAL Other Power Production Expenses**	$2,276,537	$2,467,299	8.38%
41					
42	Other Power Supply Expenses				
43	555	Purchased Power	$4,799,864	$4,549,762	-5.21%
44	556	System Control & Load Dispatching	445,123	434,476	-2.39%
45	557	Other Expenses			
46					
47		TOTAL Other Power Supply Expenses	$5,244,987	$4,984,238	-4.97%
48		**TOTAL Power Production Expenses**	$26,646,939	$28,178,479	5.75%

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	$806,190	$831,266	3.11%
4	561	Load Dispatching	461,934	469,108	1.55%
5	562	Station Expenses	124,690	97,243	-22.01%
6	563	Overhead Line Expenses	52,794	41,186	-21.99%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	6,210,824	5,894,270	-5.10%
9	566	Miscellaneous Transmission Expenses	11,165	24,818	122.28%
10	567	Rents	203,393	42,569	-79.07%
11	575	Day-Ahead and Real-Time Market Administration	125,093	146,017	16.73%
12					
13		TOTAL Operation - Transmission	7,996,083	7,546,477	-5.62%
14	Maintenance				
15	568	Maintenance Supervision & Engineering	14,698	23,468	59.67%
16	569	Maintenance of Structures			
17	570	Maintenance of Station Equipment	202,619	176,205	-13.04%
18	571	Maintenance of Overhead Lines	338,687	150,314	-55.62%
19	572	Maintenance of Underground Lines			
20	573	Maintenance of Misc. Transmission Plant			
21					
22		TOTAL Maintenance - Transmission	556,004	349,987	-37.05%
23		**TOTAL Transmission Expenses**	$8,552,087	$7,896,464	-7.67%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	$422,400	$421,721	-0.16%
28	581	Load Dispatching			
29	582	Station Expenses	121,101	107,849	-10.94%
30	583	Overhead Line Expenses	238,696	227,801	-4.56%
31	584	Underground Line Expenses	191,179	205,277	7.37%
32	585	Street Lighting & Signal System Expenses	31,947	5,943	-81.40%
33	586	Meter Expenses	286,953	306,183	6.70%
34	587	Customer Installations Expenses	52,341	82,347	57.33%
35	588	Miscellaneous Distribution Expenses	688,811	740,707	7.53%
36	589	Rents	45,404	43,517	-4.16%
37					
38		TOTAL Operation - Distribution	2,078,832	2,141,345	3.01%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	116,256	180,731	55.46%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	52,341	46,811	-10.57%
43	593	Maintenance of Overhead Lines	648,198	777,460	19.94%
44	594	Maintenance of Underground Lines	184,767	176,279	-4.59%
45	595	Maintenance of Line Transformers	43,581	80,013	83.60%
46	596	Maintenance of Street Lighting, Signal Systems	43,625	27,389	-37.22%
47	597	Maintenance of Meters	3,043	8,079	165.49%
48	598	Maintenance of Miscellaneous Dist. Plant	226,905	226,002	-0.40%
49					
50		TOTAL Maintenance - Distribution	1,318,716	1,522,764	15.47%
51		**TOTAL Distribution Expenses**	$3,397,548	$3,664,109	7.85%

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	$27,459	$20,324	-25.98%
4	902	Meter Reading Expenses	83,819	82,979	-1.00%
5	903	Customer Records & Collection Expenses	511,731	448,706	-12.32%
6	904	Uncollectible Accounts Expenses	144,799	170,757	17.93%
7	905	Miscellaneous Customer Accounts Expenses	60,364	66,741	10.56%
8					
9		TOTAL Customer Accounts Expenses	$828,172	$789,507	-4.67%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	$8,912	$5,347	-40.00%
14	908	Customer Assistance Expenses	8,129	13,166	61.96%
15	909	Informational & Instructional Adv. Expenses	28,479	32,420	13.84%
16	910	Miscellaneous Customer Service & Info. Exp.	0	0	0.00%
17					
18		TOTAL Customer Service & Info Expenses	$45,520	$50,933	11.89%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision	$301	($213)	-170.76%
23	912	Demonstrating & Selling Expenses	22,699	11,480	-49.43%
24	913	Advertising Expenses	1,731	2,375	37.20%
25	916	Miscellaneous Sales Expenses	2,821	3,019	7.02%
26					
27		TOTAL Sales Expenses	$27,552	$16,661	-39.53%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	$1,680,309	$1,866,462	11.08%
32	921	Office Supplies & Expenses	542,440	777,079	43.26%
33	922	(Less) Administrative Expenses Transferred - Cr.			
34	923	Outside Services Employed	82,725	158,513	91.61%
35	924	Property Insurance	219,122	225,583	2.95%
36	925	Injuries & Damages	469,253	490,276	4.48%
37	926	Employee Pensions & Benefits	1,776,550	1,577,663	-11.20%
38	927	Franchise Requirements			
39	928	Regulatory Commission Expenses	239,975	179,543	-25.18%
40	929	(Less) Duplicate Charges - Cr.			
41	930	Miscellaneous General Expenses	145,617	195,465	34.23%
42	931	Rents	252,584	189,451	-24.99%
43					
44		TOTAL Operation - Admin. & General	5,408,575	5,660,035	4.65%
45	Maintenance				
46	935	Maintenance of General Plant	106,440	95,954	-9.85%
47					
48		**TOTAL Administrative & General Expenses**	$5,515,015	$5,755,989	4.37%
49		**TOTAL Operation & Maintenance Expenses**	$45,012,833	$46,352,142	2.98%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 11**

MONTANA TAXES OTHER THAN INCOME Year: 2018

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$601,800	$593,048	-1.45%
2	Secretary of State	339	335	-1.18%
3	Highway Use Tax	936	1,139	21.69%
4	Montana Consumer Counsel	87,732	78,924	-10.04%
5	Montana PSC	230,641	210,590	-8.69%
6	Montana Electric	50,547	50,487	-0.12%
7	Coal Conversion	249,591	258,690	3.65%
8	Delaware Franchise	32,180	32,916	2.29%
9	Property Taxes	3,926,280	4,459,130	13.57%
10	Wind Generation Tax	128,082	127,792	-0.23%
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50	**TOTAL MT Taxes Other Than Income**	$5,308,128	$5,813,051	9.51%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	AGRI INDUSTRIES, INC.	Pipeline Install, Underground Construction	$220,365	$124,311	56.41%
2					
3	ALLIANCE PIPELINE LP	Contract Services - Milnor-Gwinner Pipeline	1,502,073	0	0.00%
4					
5	AMERICAN GAS ASSOCIATION	Industrial Membership	295,040	0	0.00%
6					
7	ANCHOR QEA	Erosion Control	97,014	17,687	18.23%
8					
9	APPLIED CONTROL (MT & WY)	Automation and Constrol Solutions	81,488	10,129	12.43%
10					
11	APPTIO INC	IT Planning, Budgeting and Forecasting	183,461	8,406	4.58%
12					
13	ARBOR SOLUTIONS TREE SERVICE LLC	Vegetation Removal	198,810	0	0.00%
14					
15	ARVIG CONSTRUCTION	Construction Services	1,848,128	0	-0.01%
16					
17	ASSOCTIATED BUILDERS	Service Center Roof Reinforcement	485,129	64,009	13.19%
18					
19	AUTOMOTIVE RENTALS, INC	Contract Services	322,657	0	0.00%
20					
21	AVERY TECHNICAL RESOURCES	Contract Services	83,556	0	0.00%
22					
23	B & B EXCAVATING INC	Contract Services	130,424	0	0.00%
24					
25	B&H UTILITY SERVICES, INC	Contract Services	320,511	0	0.00%
26					
27	BARR ENGINEERING COMPANY	Engineering Services - Power Plants	947,659	222,601	23.49%
28					
29	BARTLETT & WEST INC	Contract Services	423,390	0	0.00%
30					
31	BESLER INC	Contract Services - Equipment	316,854	62,815	19.82%
32					
33	BIG HORN ASPHALT & MORE	Contract Services	112,551	0	0.00%
34					
35	BLUE HERON CONSULTING CORPORATION	Consulting Services	106,640	13,184	12.36%
36					
37	BOWERS EXCAVATING LLC	Contract Services - Service Center	139,700	6,622	4.74%
38					
39	BOYCE LAW FIRM LLP	Legal Services	97,767	0	0.00%
40					
41	BRAHMA INDUSTRIAL SERVICES INC (BISI)	Subcontract Labor - Power Plants	167,307	39,750	23.76%
42					
43	BROADRIDGE ICS	Investing Services	166,913	7,647	4.58%
44					
45	BULLINGER TREE SERVICE	Vegetation Removal	260,708	2,986	1.15%
46					
47	BURNS & MCDONNELL ENGINEERING CO, INC	Engineering Services	726,463	76,912	10.59%
48					
49	CA CONTRACTING INC	Contract Services	137,275	0	0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	CA INC	Constructions Services	$84,656	$4,074	4.81%
2					
3	CBB COLLECTIONS INC	Collection Services	81,768	23,574	28.83%
4					
5	CENTRAL MECHANICAL INC	Underground Construction	115,650	5,451	4.71%
6					
7	CENTRAL TRENCHING INC	Contract Services	347,057	0	0.00%
8					
9	CGI TECHNOLOGIES AND SOLUTIONS INC	Consulting Services	282,355	13,564	4.80%
10					
11	CHAPMAN AND CUTLER LLP	Contract Services	141,660	0	0.00%
12					
13	CHIEF CONSTRUCTION INC	Contract Services	1,091,067	0	0.00%
14					
15	CISCO SYSTEMS CAPITAL CORP	Software Maintenance	230,795	4,322	1.87%
16					
17	CITRIX SYSTEMS, INC	Software Maintenance	76,857	2,651	3.45%
18					
19	CITY OF BILLINGS	Multiple Permits	82,657	0	0.00%
20					
21	COFFMAN ENGINEERS	Contract Services	174,252	0	0.00%
22					
23	COMPLETE CONTRACTING SOLUTIONS	Contract Services	514,431	0	0.00%
24					
25	CONCRETE ENERG ADVISORS INC	Consulting Services	305,530	13,566	4.44%
26					
27	CONDUCTOR POWER LLC	Contract Services - Power Plants	3,161,932	751,226	23.76%
28					
29	COP CONTRSTRUCTION LLC	Construction Services	264,529	0	0.00%
30					
31	CROWLEY FLECK PLLP	Legal Services	371,915	17,561	4.72%
32					
33	CYBER ADVISORS, INC	Software Maintenance	94,413	2,485	2.63%
34					
35	DAKOTA FENCE COMPANY	Fence Maintenance & Installation	81,355	1,912	2.35%
36					
37	DAVEY RESOURCE GROUP INC	Consulting Services	662,206	136,679	20.64%
38					
39	DELOITTE & TOUCHE LLP	Auditing & Consulting Services	2,205,484	43,691	1.98%
40					
41	DIS TECHNOLOGIES	GIS Data Conversion	82,030	10,142	12.36%
42					
43	DNV-GL	SL Essentials	227,953	4,039	1.77%
44					
45	E ON ENERGY SERVICES LLC	Energy Servies & Maintenance	88,425	23,159	26.19%
46					
47	EDISON ELECTRIC INSTITUTE	Industrial Membership	136,513	29,642	21.71%
48					
49	EDLING ELECTRIC INC	Contract Servies - Fiber-Interduct Work	143,999	2,768	1.92%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ELECTRIC COMPANY OF SOUTH DAKOTA	Underground Construction	$507,095	$0	0.00%
2					
3	EMERSON PROCESS MGMT POWER & WATER	Contract Services - Power Plants	846,266	201,060	23.76%
4					
5	ENVIRONMENTAL CONSULTING & TECHNOLOGY	Consulting Services	80,054	19,020	23.76%
6					
7	ENVIROSYSTEMS USA INC-FORMERLY VISTEC	Contract Services - Power Plants	67,858	16,122	23.76%
8					
9	EQUINITI TRUST COMPANY	Bank Service Fees	173,843	7,979	4.59%
10					
11	ESRI	Consulting Services	191,458	3,967	2.07%
12					
13	ETSYSTEMS, INC	Engineering Services	211,259	40,521	19.18%
14					
15	EVERIST, THOMAS S	Director Fees	80,000	3,674	4.59%
16					
17	EXTREME UNDERGROUND HDD LLC	Underground Construction	606,789	0	0.00%
18					
19	FAGG, KAREN B	Director Fees	83,061	3,814	4.59%
20					
21	FIS ENERGY SYSTEMS, INC	Software Maintenance	87,775	0	0.00%
22					
23	FISCHER CONTRACTING	Construction Services	300,689	0	0.00%
24					
25	FITCH RATINGS	Credit Rating Services	176,500	6,375	3.61%
26					
27	FORRESTER, GARY	Lobbying & Promotion	119,986	5,512	4.59%
28					
29	FOSTER CONSTRUCTION SERVICE LLC	Contract Services	135,981	0	0.00%
30					
31	FRANZ CONSTRUCTION INC	Contract Services - Power Plant	4,305,088	1,086,406	25.24%
32					
33	GARTNER INC	Consulting Services	75,409	3,472	4.60%
34					
35	GE ENERGY - BRETT HANSON	Subcontract Labor - Heskett	173,911	41,318	23.76%
36					
37	GE PACKAGED POWER LLC	Subcontract Labor	85,296	20,265	23.76%
38					
39	GE PROLEC TRANSFORMERS INC	Contract Services	100,600	0	0.00%
40					
41	HDR INC	Engineering Services	702,317	207,297	29.52%
42					
43	HEITKAMP CONSTRUCTION SERVICES, INC	Contract Services	157,742	0	0.00%
44					
45	HIGH VOLTAGE, INC	Contract Services-Preventative Maintenance	2,075,380	365,698	17.62%
46					
47	HIGHMARK ERECTORS INC	Contract Services	3,657,478	0	0.00%
48					
49	HONEYWELL	SE & SP Support Renewal	90,324	21,460	23.76%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	HPI LLC	Contract Services - Miles City Turbine	$218,772	$51,977	23.76%
2					
3	IBA DRILLING CO INC	Contract Services	89,540	0	0.00%
4					
5	INDOOR SERVICES, INC	Janitorial Services	125,579	16,097	12.82%
6					
7	INDUSTRIAL CONTRACTORS, INC	Contractor Services - Maintenance	682,923	162,252	23.76%
8					
9	INFRASOURCE	Construction Services	1,258,245	0	0.00%
10					
11	INFRASOURCE CONST LLC	Contract Services	3,983,366	0	0.00%
12					
13	INSIGHT	Software Maintenance	621,816	19,034	3.06%
14					
15	ITRON INC	Software Maintenance	363,775	13,363	3.67%
16					
17	J.B. CONSTRUCTION INC	Construction Services	484,499	21,529	4.44%
18					
19	J2 STUDIO ARCHITECTURE & DESIGN	Architectural Services	264,246	32,669	12.36%
20					
21	JACKSON UTILITIES LLC	Gas & Electric Line Installation	1,862,027	0	0.00%
22					
23	JACOBSEN TREE EXPERTS	Vegetation Removal	927,540	264,256	28.49%
24					
25	JOHN HANCOCK LIFE INSURANCE CO USA	Retirement Plan Services	21,457,128	1,279	0.01%
26					
27	JOHNSON, DENNIS	Director Fees	86,632	3,979	4.59%
28					
29	KADRMAS LEE & JACKSON	Engineering Services	345,899	75,982	21.97%
30					
31	KEY CONTRACTING INC	Contract Services - Transmission Line	1,670,487	52,211	3.13%
32					
33	L & S ELECTRIC INC	Lewis & Clark Repair Exiter System	336,492	79,945	23.76%
34					
35	LANDWORKS INC	Data Entry & Mapping	1,236,580	255,229	20.64%
36					
37	LIGNITE ENERGY COUNCIL	Membership Dues	106,992	23,567	22.03%
38					
39	MANAGED DESIGN, INC	Software Design	101,823	82	0.08%
40					
41	MARCO INC	Software Maintenance	221,093	6,915	3.13%
42					
43	MARCO TECHNOLOGIES LLC	Software Maintenance	350,565	25,437	7.26%
44					
45	MAULER CONTRACTING LLC	Contract Services - Cable Installation	110,862	110,863	100.00%
46					
47	MAVIRO INC	Pur Payment Processing Software	52,064	12,369	23.76%
48					
49	MCCRACKEN, WILLIAM E	Director Fees	75,034	3,447	4.59%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	MCM GENERAL CONTRACTORS, INC	Construction Services	$462,353	$0	0.00%
2					
3	MERIDIAN COMPENSATION PARTNERS LLC	Consulting Services	108,272	4,983	4.60%
4					
5	MG MEDIA STRATEGIES	Radio Advertising	101,145	15,825	15.65%
6					
7	MICROSOFT CORPORATION	Software Maintenance	1,738,981	40,013	2.30%
8					
9	MINNESOTA DEPARTMENT OF COMMERCE	Permits & Filing Fees	127,151	0	0.00%
10					
11	MINNESOTA VALLEY TESTING	Fuel Sampling & Testing	122,657	30,830	25.14%
12					
13	MOBILE SOLUTIONS SERVICES INC	Phone Services	260,310	0	0.00%
14					
15	MOORHEAD ELECTRIC INC (MEI)	Equipment Rental	431,587	15,259	3.54%
16					
17	NERC	Contract Services - Quarterly Assessment	123,417	29,322	23.76%
18					
19	NORDEX USA INC	Thunder Spirit - Service Contract	911,370	238,693	26.19%
20					
21	NYSE MARKET INC	Financial Services	211,511	9,691	4.58%
22					
23	ONE CALL LOCATORS LTD (ELM)	Line Locating Services	2,423,435	109,260	4.51%
24					
25	ONSHARP	Software Maintenance	94,057	4,325	4.60%
26					
27	OPEN SYSTEMS INTERNATIONAL, INC	Software Maintenance	411,266	84,895	20.64%
28					
29	OPTIV SECURITY, INC	Software Maintenance	248,761	10,007	4.02%
30					
31	ORACLE AMERICA, INC	Software Maintenance	1,103,886	34,348	3.11%
32					
33	ORACLE CORP	Software Maintenance	222,432	5,952	2.68%
34					
35	ORMAT NEVEDA INC	Energy Converter Maintenance	492,259	116,953	23.76%
36					
37	OSMOSE UTILITIES SERVICES, INC	Contract Services	354,698	77,053	21.72%
38					
39	PEARCE, HARRY J	Director Fees	160,000	7,348	4.59%
40					
41	PEARL MEYER & PARTNERS	Consulting Services	91,162	4,626	5.07%
42					
43	PERKINS COIE LLP	Legal Services	266,902	11,864	4.45%
44					
45	PHIFER OILFIELD CONSTRUCTION	Contract Services	309,074	0	0.00%
46					
47	PINKE LUMBER COMPANY	Contract Services	86,253	0	0.00%
48					
49	PLURALSIGHT	Software Maintenance	97,167	2,874	2.96%
50					

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	POWERCOSTS INC	Software Maintenance	$194,154	$44,582	22.96%
2					
3	POWERPLAN, INC	Consulting Services - Software	888,031	72,792	8.20%
4					
5	POWERTECH LABS INC	Software License	76,123	18,086	23.76%
6					
7	PPI GROUP	Professional Organization Dues	390,800	6,274	1.61%
8					
9	PRESORT PLUS LLC	Mail Delivery & Pickup	79,009	7,520	9.52%
10					
11	PRICEWATERHOUSE COOPERS LLP	Consulting Services	263,934	2,630	1.00%
12					
13	PROSOURCE TECHNOLOGIES LLC	Consulting Services	96,228	4,696	4.88%
14					
15	Q3 CONTRACTING	Contract Services	3,965,103	0	0.00%
16					
17	R & L CONTRACTING INC	Contract Services	106,925	28,004	26.19%
18					
19	REMOTE ADMIN INC	Software Maintenance	79,800	3,674	4.60%
20					
21	ROCKY MOUNTAIN CONTRACTORS, INC	Construction Services	1,472,585	0	0.00%
22					
23	ROCKY MOUNTAIN LINE SYSTEMS, INC	Construction Services	1,512,516	213	0.01%
24					
25	SCHERBENSKE INC.	Contract Services	333,912	0	0.00%
26					
27	SCHULTE TA INC	Contract Services	374,351	0	0.00%
28					
29	SEAWAY PAINTING LLC	Subcontract Labor	153,306	0	0.00%
30					
31	SIBLEY ELECTRIC	Contract Services	91,755	0	0.00%
32					
33	SOUTHERN CROSS CORP	Contract Services-Preventative Maintenance	726,221	0	0.00%
34					
35	SPHERION STAFFING LLC	Temp Services	172,707	19,471	11.27%
36					
37	STATE-LINE CONTRACTORS INC	Underground Construction	145,480	0	0.00%
38					
39	STINSON LEONARD STREET LLP	Legal Services	179,251	15,863	8.85%
40					
41	SUBURAN CONSULTING ENGINEERS INC	Consulting Services	699,982	34,651	4.95%
42					
43	SWANSON & YOUNGDALE INC.	Subcontract Labor - Heskett	184,806	43,907	23.76%
44					
45	TRC ENVIRONMENTAL CORPORATION	Testing Pollution Control Equipment	282,138	67,031	23.76%
46					
47	TREASURY MANAGEMENT SERVICES	Banking Services	117,030	8,502	7.26%
48					
49	TRU PIPE INC	Underground Maintenance	146,447	0	0.00%
50					

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	TRUE NORTH CONTRACTING LLC	Construction Services	$173,437	$0	0.00%
2					
3	TURBINEPROS	Subcontract Labor - Heskett	762,740	181,215	23.76%
4					
5	UBISENSE, INC	Underground CPS Based Leak Survey	80,750	0	0.00%
6					
7	UNITED ACCOUNTS INC	Credit Collections	84,842	0	0.00%
8					
9	UPPER MISSOURI POWER COOP	Construction Services	278,873	66,256	23.76%
10					
11	US DEPARTMENT OF ENERGY	Transmission Charges	1,314,427	163,177	12.41%
12					
13	USIC LOCATING SERVICES, INC	Line Locating Services	141,038	0	0.00%
14					
15	UTILITY SHAREHOLDERS OF NORTH DAKOTA	Organizational Dues	84,481	69	0.08%
16					
17	VERIZON WIRELESS	Phone Services	131,111	2	0.00%
18					
19	WEED WARRIORS	Subcontract Labor	99,211	0	0.00%
20					
21	WELLS FARGO BANK AGENCY SERVICES CLEARING	Banking Services	553,903	0	0.00%
22					
23	WESTERN HORIZON	Vegetation Removal	109,988	17,124	15.57%
24					
25	WESTMORELAND SAVAGE CORPORATION	Equipment Rental	154,548	39,615	25.63%
26					
27	WINN CONSTRUCTION INC	Contract Services	90,885	0	0.00%
28					
29	WOOD MACKENZIE INC	Contract Services	80,500	0	0.00%
30					
31	WORKFORCE SERVICES, INC	Vehicle Maintenance	292,197	0	0.00%
32					
33	WORKIVA INC	Cloud Based Subscription for FCC Filing	62,631	4,029	6.43%
34					
35	XEROX CORPORATION	Copier Leases	126,299	15,526	12.29%
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	Total Payments for Services		$100,862,071	$6,753,037	6.70%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 13**

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2018

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$125,675	$9,000	7.16%
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
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41				
42				
43	**TOTAL Contributions**	$125,675	$9,000	7.16%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 14**

PENSION COSTS Year: 2018

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Traditional Unit Credit	IRS Code: 1A		
4	Annual Contribution by Employer: 0	Is the Plan Over Funded? No		
5				
6	Item	Current Year	Last Year	% Change
7	**Change in Benefit Obligation**	(000's)	(000's)	
8	Benefit obligation at beginning of year	$250,888	$245,858	2.05%
9	Service cost	-	-	0.00%
10	Interest cost	8,183	9,090	-9.98%
11	Plan participants' contributions	-	-	0.00%
12	Amendments	-	-	0.00%
13	Actuarial (Gain) Loss	(17,943)	10,543	-270.19%
14	Curtailment gain	-	-	0.00%
15	Benefits paid	(21,159)	(14,603)	-44.89%
16	Benefit obligation at end of year	$219,969	$250,888	-12.32%
17	**Change in Plan Assets**			
18	Fair value of plan assets at beginning of year	$192,712	$182,213	5.76%
19	Actual return on plan assets	(11,423)	24,679	-146.29%
20	Employer contribution	7,201	423	1602.36%
21	Plan participants' contributions	-	-	0.00%
22	Benefits paid	(21,159)	(14,603)	-44.89%
23	Fair value of plan assets at end of year	$167,331	$192,712	-13.17%
24	**Funded Status**	($52,638)	($58,176)	9.52%
25	Unrecognized net actuarial loss	103,455	102,514	0.92%
26	Unrecognized prior service cost	-	-	0.00%
27	Unrecognized net transition obligation	-	-	0.00%
28	Accrued benefit cost	$50,817	$44,338	14.61%
29	**Weighted-Average Assumptions as of Year End**			
30	Discount rate	4.03	3.38	19.23%
31	Expected return on plan assets	6.75	6.75	0.00%
32	Rate of compensation increase	-	-	0.00%
33	**Components of Net Periodic Benefit Costs**			
34	Service cost	-	-	0.00%
35	Interest cost	8,182	9,090	-9.99%
36	Expected return on plan assets	(11,352)	(11,222)	-1.16%
37	Amortization of prior service cost	-	-	0.00%
38	Recognized net actuarial loss	3,890	3,554	9.45%
39	Curtailment loss	-	-	0.00%
40	Net periodic benefit cost	$720	$1,422	-49.37%
41	**Montana Intrastate Costs:**			
42	Pension costs	$720	$1,422	-49.37%
43	Pension costs capitalized	-	294	-100.00%
44	Accumulated pension asset (liability) at year end	($52,638)	($57,927)	9.13%
45	**Number of Company Employees:**			
46	Covered by the plan	1,460	1,503	-2.86%
47	Not covered by the plan	809	708	14.27%
48	Active	411	440	-6.59%
49	Retired	931	941	-1.06%
50	Deferred vested terminated	118	122	-3.28%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 15**

OTHER POST EMPLOYMENT BENEFITS (OPEBS) Year: 2018

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	**Weighted-Average Assumptions as of Year End**			
7	Discount rate	4.03	3.38	19.23%
8	Expected return on plan assets	5.75	5.75	0.00%
9	Medical cost inflation rate	4.50	4.50	0.00%
10	Actuarial cost method	Projected unit credit	Projected unit credit	
11	Rate of compensation increase	N/A	N/A	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15	**TOTAL COMPANY**			
16	**Change in Benefit Obligation**	(000's)	(000's)	
17	Benefit obligation at beginning of year	$40,128	$40,267	-0.35%
18	Service cost	621	616	0.81%
19	Interest cost	1,257	1,443	-12.89%
20	Plan participants' contributions	731	804	-9.08%
21	Amendments	-	-	0.00%
22	Actuarial (Gain) Loss	(4,389)	260	1788.08%
23	Acquisition	-	-	0.00%
24	Benefits paid	(2,749)	(3,262)	-15.73%
25	Benefit obligation at end of year	$35,599	$40,128	-11.29%
26	**Change in Plan Assets**			
27	Fair value of plan assets at beginning of year	$50,531	$47,253	6.94%
28	Actual return on plan assets	(1,551)	5,645	-127.48%
29	Acquisition	-	-	0.00%
30	Employer contribution	70	91	-23.08%
31	Plan participants' contributions	731	804	-9.08%
32	Benefits paid	(2,749)	(3,262)	-15.73%
33	Fair value of plan assets at end of year	$47,032	$50,531	-6.92%
34	**Funded Status**	$11,433	$10,403	9.90%
35	Unrecognized net actuarial loss	-	-	0.00%
36	Unrecognized prior service cost	-	-	0.00%
37	Unrecognized transition obligation	-	-	0.00%
38	Accrued benefit cost	$11,433	$10,403	9.90%
39	**Components of Net Periodic Benefit Costs**			
40	Service cost	$621	$616	0.81%
41	Interest cost	1,257	1,443	-12.89%
42	Expected return on plan assets	(2,754)	(2,651)	-3.89%
43	Amortization of prior service cost	(976)	(976)	0.00%
44	Recognized net acturial gain	-	-	0.00%
45	Transition amount amortization	-	-	0.00%
46	Net periodic benefit cost	($1,852)	($1,568)	18.11%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount funded through VEBA	$801	$895	-10.50%
49	Amount funded through 401(h)	-	-	0.00%
50	Amount funded through Other ___________________	-	-	0.00%
51	TOTAL	$801	$895	-10.50%
52	Amount that was tax deductible - VEBA (1)	$70	$91	-23.08%
53	Amount that was tax deductible - 401(h)	-	-	0.00%
54	Amount that was tax deductible - Other ___________	-	-	0.00%
55	TOTAL	$70	$91	-23.08%

(1) Estimated

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 15**

Other Post Employment Benefits (OPEBS) Continued Year: 2018

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the plan	1,231	1,271	-3.15%
3	Not covered by the plan	39	39	0.00%
4	Active	535	557	-3.95%
5	Retired	517	544	-4.96%
6	Spouses/dependants covered by the plan	179	170	5.29%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition	NOT APPLICABLE		
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss	NOT APPLICABLE		
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	NOT APPLICABLE		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount funded through VEBA			
39	Amount funded through 401(h)	NOT APPLICABLE		
40	Amount funded through other _______________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension costs	($1,852)	($1,568)	18.11%
48	Pension costs capitalized	119	0	100.00%
49	Accumulated pension asset (liability) at year end	11,433	10,403	9.90%
50	**Number of Montana Employees:**			
51	Covered by the plan			
52	Not covered by the plan	NOT APPLICABLE		
53	Active			
54	Retired			
55	Spouses/dependants covered by the plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5	The requested information will be provided after the entry of a protective order which maintains the confidentiality of the information being provided. Montana-Dakota, submitted a Motion for Protective Order on April 21, 2015 in Docket No. N2015.2.17.						
6							
7							
8							
9							
10							

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 17**

Year: 2018

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION 1/

Line No.	Name/Title	Base Salary	Bonuses	Other 2/	Total Compensation	Total Compensation Last Year 2/	% Increase Total Compensation
1	David L. Goodin President & CEO	$824,460	$807,971	$2,491,636	$4,124,067	$4,058,001	2%
2	Jason L. Vollmer Vice President, CFO & Treasurer	$350,000	$222,950	$559,075	$1,132,025	$634,551	78%
3	David C. Barney President & CEO of Knife River Corporation	$455,000	$384,589	$1,192,325	$2,031,914	$1,502,240	35%
4	Jeffrey S. Thiede President & CEO of MDU Construction Services Group	$455,000	$437,141	$1,081,995	$1,974,136	$1,636,860	21%
5	Nicole A. Kivisto President & CEO of Montana-Dakota Utilities Co.	$430,000	$225,277	$643,901	$1,299,178	$1,228,841	6%

1/ See Schedule 17A for Total Compensation detail.

2/ Amounts represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 - Share Based Payment.

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table for 2018

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)[1]	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)[2]	All Other Compensation ($) (i)[3]	Total ($) (j)
David L. Goodin	2018	824,460	2,433,437	807,971	16,503	41,696	4,124,067
President and CEO	2017	792,750	1,504,546	1,377,007	342,727	40,971	4,058,001
	2016	755,000	1,441,954	1,055,490	218,301	40,246	3,510,991
Jason L. Vollmer[4]	2018	350,000	495,840	222,950	—	63,235	1,132,025
Vice President, CFO and Treasurer	2017	256,625	95,101	230,988	3,681	48,156	634,551
David C. Barney	2018	455,000	958,410	384,589	—	233,915	2,031,914
President and CEO of	2017	427,140	324,247	483,736	93,786	173,331	1,502,240
Knife River Corporation	2016	406,800	276,232	593,114	77,565	22,905	1,376,616
Jeffrey S. Thiede	2018	455,000	958,410	437,141	—	123,585	1,974,136
President and CEO of	2017	437,750	332,318	743,629	—	123,163	1,636,860
MDU Construction Services Group, Inc.	2016	425,000	288,598	489,600	—	122,708	1,325,906
Nicole A. Kivisto[5]	2018	430,000	609,197	225,277	210	34,494	1,299,178
President and CEO of Montana-Dakota Utilities Co.	2017	378,000	286,955	433,906	96,931	33,049	1,228,841

[1] Amounts in this column represent the aggregate grant date fair value of performance share award opportunities at target calculated in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts were calculated as described in Note 12 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2018. For 2018, the total aggregate grant date fair value of performance share award opportunities assuming the highest level of payout would be as follows:

Name	Aggregate grant date fair value at highest payout ($)
David L. Goodin	4,866,874
Jason L. Vollmer	991,681
David C. Barney	1,603,026
Jeffrey S. Thiede	1,603,026
Nicole A. Kivisto	1,218,393

[2] Amounts shown for 2018 represent the change in the actuarial present value for the named executive officers' accumulated benefits under the pension plan, SISP, and Excess SISP, collectively referred to as the "accumulated pension change," plus above-market earnings on deferred annual incentives as of December 31, 2018.

Name	Accumulated Pension Change ($)	Above Market Interest ($)
David L. Goodin	(230,602)	16,503
Jason L. Vollmer	(3,594)	—
David C. Barney	(28,196)	—
Jeffrey S. Thiede	—	—
Nicole A. Kivisto	(98,726)	210

[3] All Other Compensation is comprised of:

Name	401(k) ($)[a]	Nonqualified Defined Contribution Plan ($)	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Moving Stipend ($)[b]	Total ($)
David L. Goodin	39,875	—	621	1,200	—	41,696
Jason L. Vollmer	27,500	35,000	435	300	—	63,235
David C. Barney	22,000	150,000	565	1,200	60,150	233,915
Jeffrey S. Thiede	22,000	100,000	565	1,020	—	123,585
Nicole A. Kivisto	33,000	—	534	960	—	34,494

[a] Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions made after the pension plans were frozen at December 31, 2009.

[b] Represents stipend for moving household goods as approved in Mr. Barney's 2012 relocation proposal.

[4] Mr. Vollmer was promoted to vice president, chief financial officer and treasurer effective September 30, 2017. He appeared as a named executive officer for the first time in 2017.

[5] Ms. Kivisto was promoted to president and chief executive officer of the electric and natural gas distribution segments effective January 9, 2015. She appeared as a named executive officer for the first time in 2017.

Grants of Plan-Based Awards in 2018

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All other stock awards: Number of shares of stock or units	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	# (i)	($) (l)
David L. Goodin	2/15/2018 [1]	303,707	824,460	1,648,920					
	2/15/2018 [2]				15,692	78,460	156,920		2,433,437
Jason L. Vollmer	2/15/2018 [1]	83,804	227,500	455,000					
	2/15/2018 [2]				3,197	15,987	31,974		495,840
David C. Barney	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Jeffrey S. Thiede	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Nicole A. Kivisto	2/15/2018 [1]	125,775	279,500	559,000					
	2/15/2018 [2]				3,928	19,642	39,284		609,197

1 Annual incentive for 2018 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

2 Performance shares for the 2018-2020 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

3 Time-vesting restricted stock units granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2018 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 15, 2018. The award opportunities at threshold, target, and maximum are reflected in columns (c), (d), and (e), respectively, of the Grants of Plan-Based Awards Table. The actual amount paid with respect to 2018 performance is reflected in column (g) of the Summary Compensation Table.

As described in the "Annual Incentives" section of the "Compensation Discussion and Analysis," payment of annual award opportunities is dependent upon achievement of performance measures; actual payout may range from 0% to 200% of the target except for the construction materials and contracting and construction services segments which may range from 0% to 240%.

All our named executive officers were awarded their annual incentive opportunities pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan. Under the Executive Incentive Compensation Plan, executives who retire during the year at or after age 65 remain eligible to receive an award, but executives who terminate employment for other reasons are not eligible for an award. The compensation committee generally does not modify the performance measures; however, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance measures, the compensation committee, in consultation with the CEO, may modify the performance measures. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether to adjust payment of awards downward based upon individual performance. For further discussion of the specific 2018 incentive plan performance measures and results, see the "Annual Incentives" section in the "Compensation Discussion and Analysis."

Long-Term Incentive

The compensation committee recommended long-term incentive award opportunities for the named executive officers in the form of performance shares, and the board approved the award opportunities at its meeting on February 15, 2018. The long-term incentive opportunities are presented as the number of performance shares at threshold, target, and maximum in columns (f), (g), and (h) of the

Grants of Plan-Based Awards Table. The value of the long-term performance-based incentive opportunities is based on the aggregate grant date fair value and is reflected in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

Depending on the achievement of the performance measures associated with our 2018-2020 performance period, executives will receive from 0% to 200% of the target awards in February 2021. We also will pay dividend equivalents in cash on the number of shares actually vested for the performance period. The dividend equivalents will be paid in 2021 at the same time as the performance share awards are issued.

The compensation committee also awarded Messrs. Barney and Thiede each 11,419 restricted stock units on February 15, 2018, which will vest on December 31, 2020 if the officers remain employees of the company through the vesting date as reflected in column (i) of the Grants of Plan-Based Awards Table. The compensation committee believes the restricted stock unit awards will incentivize Messrs. Barney and Thiede to continue their employment with the company for the next three years and grow their respective business segments during that time. For further discussion of the specific long-term incentive plan, see the "Long-Term Incentives" section in the "Compensation Discussion and Analysis."

Nonqualified Defined Contribution Plan

The CEO recommends participants and contribution amounts to the Nonqualified Defined Contribution Plan which are approved by the compensation committee of the board of directors. The purpose of the plan is to recognize outstanding performance coupled with enhanced retention as the Nonqualified Defined Contribution Plan requires a vesting period. The amount shown in column (i) - All Other Compensation of the Summary Compensation Table includes contributions of $35,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. For further information, see the section entitled "Nonqualified Deferred Compensation for 2018."

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation:

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
David L. Goodin	824,460	—	4,124,067	20.0%
Jason L. Vollmer	350,000	—	1,132,025	30.9%
David C. Barney	455,000	—	2,031,914	22.4%
Jeffrey S. Thiede	455,000	—	1,974,136	23.0%
Nicole A. Kivisto	430,000	—	1,299,178	33.1%

Outstanding Equity Awards at Fiscal Year-End 2018

	Stock Awards	
Name (a)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[1]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	337,878	8,055,012
Jason L. Vollmer	29,433	701,683
David C. Barney	83,381	1,987,803
Jeffrey S. Thiede	85,407	2,036,103
Nicole A. Kivisto	64,934	1,548,027

1 Below is a breakdown by year of the outstanding performance share plan awards:

	2016 Award	2017 Award	2018 Award	
Performance Period End	12/31/2018	12/31/2019	12/31/2020	Total
David L. Goodin	197,528	61,890	78,460	337,878
Jason L. Vollmer	9,534	3,912	15,987	29,433
David C. Barney	37,840	13,338	32,203	83,381
Jeffrey S. Thiede	39,534	13,670	32,203	85,407
Nicole A. Kivisto	33,488	11,804	19,642	64,934

Shares for the 2016 award are shown at the maximum level (200%) based on results for the 2016-2018 performance cycle above target.

Shares for the 2017 award are shown at the target level (100%) based on results for the first two years of the 2017-2019 performance cycle between threshold and target.

Shares for the 2018 award are shown at the target level (100%) based on results for the first year of the 2018-2020 performance cycle between threshold and target. The number of shares under the 2018 award also includes 11,419 time-vesting restricted stock units granted to Messrs. Barney and Thiede.

2 Value based on the number of performance shares and restricted stock units reflected in column (i) multiplied by $23.84, the year-end per share closing stock price for 2018.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2018 Table, the number of shares and value shown for the 2016-2018 performance cycle is at 200% of target, the actual results for the performance period certified by the compensation committee and settled on February 14, 2019, was 140% of target. For further information, see the "Long-Term Incentives" section of the "Compensation Discussion and Analysis."

Option Exercises and Stock Vested During 2018

Name (a)	Stock Awards: Number of Shares Acquired on Vesting (#) (d)[1]	Stock Awards: Value Realized on Vesting ($) (e)[2]
David L. Goodin	103,916	3,090,981
Jason L. Vollmer	2,751	81,829
David C. Barney	16,912	503,047
Jeffrey S. Thiede	18,198	541,300
Nicole A. Kivisto	17,616	523,988

1 Reflects performance shares for the 2015-2017 performance period ended December 31, 2017, which were settled February 15, 2018.

2 Reflects the value of vested performance shares based on the closing stock price of $27.48 per share on February 15, 2018, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2018

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)
David L. Goodin	Pension	26	1,146,362
	Basic SISP [2]	10	2,343,866
	Excess SISP [3]	26	38,870
Jason L. Vollmer	Pension	4	20,857
	Basic SISP [3]	n/a	—
	Excess SISP [3]	n/a	—
David C. Barney	Pension [3]	n/a	—
	Basic SISP [2]	10	1,449,287
	Excess SISP [3]	n/a	—
Jeffrey S. Thiede	Pension [3]	n/a	—
	Basic SISP [3]	n/a	—
	Excess SISP [3]	n/a	—
Nicole A. Kivisto	Pension	14	220,945
	Basic SISP [2]	8	424,883
	Excess SISP [3]	n/a	—

1 Years of credited service related to the pension plan reflects the years of participation in the plan as of December 31, 2009, when the pension plan was frozen. Years of credited service related to the Basic SISP reflects the years toward full vesting of the benefit which is 10 years. Years of credited service related to Excess SISP reflects the same number of credited years of services as the pension plan.

2 The present value of accumulated benefits for the Basic SISP assumes the named executive officer would be fully vested in the benefit on the benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

3 Messrs. Barney and Thiede are not eligible to participate in the pension plans. Messrs. Vollmer and Thiede do not participate in the SISP. Mr. Goodin is the only named executive officer eligible to participate in the Excess SISP.

The amounts shown for the pension plan, Basic SISP, and Excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2018, calculated using:

- a 3.85% discount rate for the Basic SISP and Excess SISP;
- a 4.01% discount rate for the pension plan;
- the Society of Actuaries RP-2014 Mortality Table with scale MP-2018 for post-retirement mortality; and
- no recognition of future salary increases or pre-retirement mortality.

The actuary assumed a retirement age of 60 for the pension, Basic SISP, and Excess SISP benefits and assumed retirement benefits commence at age 60 for the pension and Excess SISP and age 65 for Basic SISP benefits.

Pension Plan

The MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (pension plan) applies to employees hired before 2006 and was amended to cease benefit accruals as of December 31, 2009. The benefits under the pension plan are based on a participant's average annual salary over the 60 consecutive month period where the participant received the highest annual salary between 1999 and 2009. Benefits are paid as straight life annuities for single participants and as actuarially reduced annuities with a survivor benefit for married participants unless they choose otherwise.

Supplemental Income Security Plan

The Supplemental Income Security Plan (SISP), a defined benefit nonqualified retirement plan, is offered to select key managers and executives. SISP benefits are determined by reference to levels defined within the plan. Our compensation committee, after receiving recommendations from our CEO, determined each participant's level within the plan. On February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants.

Basic SISP Benefits

Basic SISP is a supplemental retirement benefit intended to augment the retirement income provided under the pension plans. The Basic SISP benefits are subject to the following ten-year vesting schedule:

- 0% vesting for less than three years of participation;
- 20% vesting for three years of participation;
- 40% vesting for four years of participation; and
- an additional 10% vesting for each additional year of participation up to 100% vesting for ten years of participation.

Participants can elect to receive the Basic SISP as:

- monthly retirement benefits only;
- monthly death benefits paid to a beneficiary only; or
- a combination of retirement and death benefits, where each benefit is reduced proportionately.

Regardless of the election, if the participant dies before the SISP retirement benefit commences, only the SISP death benefit is provided.

Excess SISP Benefits

Excess SISP is an additional retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans. Excess SISP benefits are equal to the difference between the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and the actual benefits payable to the participant under the pension plans. Participants are only eligible for the Excess SISP benefits if the participant is fully vested under the pension plan, their employment terminates prior to age 65, and benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation.

In 2009, the SISP was amended to limit eligibility for the Excess SISP benefit. Mr. Goodin is the only named executive officer eligible for the Excess SISP benefit and must remain employed with the company until age 60 in order to receive the benefit. Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65.

Both Basic and Excess SISP benefits are forfeited if the participant's employment is terminated for cause.

Nonqualified Deferred Compensation for 2018

Deferred Annual Incentive Compensation

Executives participating in the annual incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2018 was 4.28% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" rated companies. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was earned. The amounts are paid in accordance with the participant's election in either a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts deferred would immediately become payable. For purposes of deferred annual incentive compensation, a change of control is defined as:

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock;
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock;
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors; or
- acquisition of our assets having a gross fair market value at least equal to 40% of the gross fair market value of all of our assets.

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, effective January 1, 2012, to provide deferred compensation for a select group of employees. The compensation committee approves the amount of employer contributions under the Nonqualified Defined Contribution Plan and the obligations under the plan constitute an unsecured promise of the company to make such payments. The company credits contributions to plan accounts which capture the hypothetical investment experience based on the participant's elections. Contributions made prior to 2017 vest four years after each contribution in accordance with the terms of the plan. Contributions made in 2017 vest rateably over a three-year period with 1/3 vesting after the first year, an additional 1/3 after the second year, and the final 1/3 after the third year. Amounts shown as aggregate earnings in the table below for Messrs. Vollmer, Barney, and Thiede reflect the change in investment value at market rates for the hypothetical investments selected by the participants. Participants may elect to receive their vested contributions and investment earnings either in a lump sum upon separation from service with the company or in annual installments over a period of years upon the later of (i) separation from service and (ii) age 65. Plan benefits become fully vested if the participant dies while actively employed. Benefits are forfeited if the participant's employment is terminated for cause.

The table below includes individual contributions from deferrals of annual incentive compensation and company contributions under the Nonqualified Defined Contribution Plan:

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
David L. Goodin	688,504	—	58,102	—	1,498,658 [1]
Jason L. Vollmer	—	35,000	(6,425)	—	56,250 [2]
David C. Barney	—	150,000	(19,556)	—	303,785 [3]
Jeffrey S. Thiede	—	100,000	(52,812)	—	627,169 [4]
Nicole A. Kivisto	—	—	740	—	17,685

[1] Mr. Goodin deferred 50% of his 2017 annual incentive compensation which was $1,377,007 as reported in the Summary Compensation Table for 2017.

[2] Mr. Vollmer received $35,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Vollmer's balance also includes a contribution of $22,550 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

[3] Mr. Barney received $150,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Barney's balance also includes a contribution of $150,000 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year.

[4] Mr. Thiede received $100,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Thiede's balance also includes contributions of $100,000 for 2017, $100,000 for 2016, $150,000 for 2015, $75,000 for 2014, and $33,000 for 2013. Each of these amounts is reported in column (i) of the Summary Compensation Table in the Proxy Statement for its respective year, where applicable.

Potential Payments upon Termination or Change of Control

The Potential Payments upon Termination or Change of Control Table shows the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios or upon a change of control. The scenarios include:

- Voluntary Termination
- Not for Cause Termination
- Death
- Disability
- Change of Control with Termination
- Change of Control without Termination.

For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2018.

The table excludes compensation and benefits our named executive officers would earn during their employment with us whether or not a termination or change of control event had occurred. The tables also do not include benefits under plans or arrangements generally available to all salaried employees and that do not discriminate in favor of the named executive officers, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include Nonqualified Defined Contribution Plan or deferred annual compensation amounts which are shown and explained in the Nonqualified Deferred Compensation for 2018 Table.

Compensation

None of our named executive officers have employment or severance agreements entitling them to their base salary, some multiple of base salary or severance upon termination or change of control. Our compensation committee generally considers providing severance benefits on a case-by-case basis. Because severance payments are discretionary, no amounts are presented in the tables.

All our named executive officers were granted their 2018 annual incentive award under the Executive Incentive Compensation Plan (EICP) which has no change of control provision in regards to annual incentive compensation other than for deferred compensation. The EICP requires participants to remain employed with the company through the service year to be eligible for a payout unless otherwise determined by the compensation committee for named executive officers, or employment termination after age 65. As all our scenarios assume a termination or change in control event on December 31st, the named executives officers would be considered employed for the entire performance period; therefore, no amounts are shown for annual incentives in the tables for our named executive officers, as they would be eligible to receive their annual incentive award based on the level that performance measures were achieved for the performance period regardless of termination or change of control occurring on December 31, 2018.

All named executive officers received their performance share awards under the Long-Term Performance-Based Incentive Plan (LTIP). Upon a change of control (with or without termination), performance share awards would be deemed fully earned and vest at their target levels for the named executive officers. For this purpose, the term "change of control" is defined in the LTIP as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock;
- a majority of our board of directors whose election or nomination was not approved by a majority of the incumbent board members;
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors; or
- stockholder approval of our liquidation or dissolution.

For termination scenarios other than a change of control, our award agreements provide that performance share awards are forfeited if the participant's employment terminates before the participant has reached age 55 and completed 10 years of service. If a participant's employment is terminated other than for cause after reaching age 55 and completing 10 years of service, performance shares are prorated as follows:

- termination of employment during the first year of the performance period = shares are forfeited;
- termination of employment during the second year of the performance period = performance shares earned are prorated based on the number of months employed during the performance period; and
- termination of employment during the third year of the performance period = full amount of any performance shares earned are received.

Under the termination scenarios, Messrs. Goodin, Barney, and Thiede would receive performance shares as they have each reached age 55 and have 10 or more years of service. The number of performance shares received would be based on the following:

- 2016-2018 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2018, which was 140%;
- 2017-2019 performance shares would be prorated at 24 out of 36 months (2/3) of the performance period and vest based on the achievement of the performance measure for the period ended December 31, 2019. For purposes of the Potential Payments upon Termination or Change of Control Table, the vesting is shown at 100%; and
- 2018-2020 performance shares would be forfeited.

For purposes of calculating the performance share value shown in the Potential Payments upon Termination or Change of Control Table, the number of vesting shares was multiplied by the average of the high and low stock price for the last market day of the year, which was December 31, 2018. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Neither Ms. Kivisto nor Mr. Vollmer have reached age 55; therefore, they are not eligible for vesting of performance shares in the event of their termination.

Messrs. Barney and Thiede were granted 11,419 restricted stock units in February 2018. The restricted stock units will vest on December 31, 2020 provided that Messrs. Barney and Thiede remain continuously employed by the company through December 31, 2020, except for termination due to death or disability or a change in control as defined in the LTIP. In the case of a voluntary or not for cause termination on December 31, 2018, Messrs Barney and Thiede would forfeit the restricted stock units. In the case of death or disability, the restricted stock units would vest based on the number of full months of employment completed during the grant period to the date of death or disability divided by the total number of months in the grant period. In the case of death or disability occurring on December 31, 2018, one-third of Messrs. Barney and Thiede's restricted stock units plus dividend equivalents would vest. In the case of a change of control (with or without termination) occurring on December 31, 2018, the restricted stock units plus dividend equivalents would fully vest.

Benefits and Perquisites

Supplemental Income Security Plan

As described in the "Pension Benefits for 2018" section, the Basis SISP provides a benefit of payments commencing at age 65 and payable for 15 years. Of the named executive officers, only Messrs. Goodin, Barney, and Ms. Kivisto participate in the Basic SISP benefits. While Messrs. Goodin and Barney are 100% vested in their SISP benefit, Ms. Kivisto entered the plan in 2011 and is only 80% vested in her SISP benefit at December 31, 2018. Ms. Kivisto received a benefit level upgrade in 2014, which cliff vests on January 1, 2021. This means that if her employment terminates for any reason other than death before January 1, 2021, her benefit upgrade is forfeited.

Under all scenarios except death and change of control without termination, the payment represents the present value of the vested Basic SISP benefit as of December 31, 2018 using the monthly retirement benefit shown in the table below and a discount rate of 3.85%. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto's beneficiaries would receive monthly death benefit payments for 15 years. The Potential Payments upon Termination or Change of Control Tableshows the present value calculations of the monthly death benefit using the 3.85% discount rate.

	Monthly SISP Retirement Payment ($)	Monthly SISP Death Payment ($)
David L. Goodin	23,040	46,080
David C. Barney	10,936	21,872
Nicole A. Kivisto	5,000 *	10,000 *

* Ms. Kivisto's calculations are based on 80% of the value shown above for voluntary, not for cause and change of control with termination scenarios. The disability scenario allows for two additional years of vesting and is calculated using 100% of the value shown above. Ms. Kivisto's death benefit scenario is calculated using her 2014 benefit upgrade level with a monthly death benefit of $13,144.

Because the plan requires a participant to be no longer actively employed by the company in order to be eligible for payments, we do not show benefits for the change of control without termination scenario.

Disability

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a salary limit of $200,000 for officers and $100,000 for other salaried employees when calculating benefits. For all eligible employees, disability payments continue until age 65 if disability occurs at or before age 60 and for five years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The disability payments in the Potential Payments upon Termination or Change of Control Table reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. For Messrs. Goodin and Vollmer and Ms. Kivisto, who participate in the pension plan, the amount represents the present value of the disability benefit after reduction for retirement benefits using a discount rate of 4.01%. Because Mr. Goodin's retirement benefit is greater than the disability benefit, the amount shown is zero. For Messrs. Barney and Thiede, who do not participate in the pension plan, the amount represents the present value of the disability benefit without reduction for retirement benefits using the discount rate of 3.85%, which is considered a reasonable rate for purposes of the calculation.

Potential Payments upon Termination or Change of Control Table

Executive Benefits and Payments upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
David L. Goodin						
Compensation:						
Performance Shares	4,615,957	4,615,957	4,615,957	4,615,957	6,067,414	6,067,414
Benefits and Perquisites:						
Basic SISP	2,343,541	2,343,541	—	2,343,541	2,343,541	—
SISP Death Benefits	—	—	6,313,609	—	—	—
Disability Benefits	—	—	—	—	—	—
Total	**6,959,498**	**6,959,498**	**10,929,566**	**6,959,498**	**8,410,955**	**6,067,414**
Jason L. Vollmer						
Compensation:						
Performance Shares	—	—	—	—	611,066	611,066
Benefits and Perquisites:						
Disability Benefits	—	—	—	893,360	—	—
Total	**—**	**—**	**—**	**893,360**	**611,066**	**611,066**
David C. Barney						
Compensation:						
Performance Shares	909,098	909,098	909,098	909,098	1,333,967	1,333,967
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Basic SISP	1,432,676	1,432,676	—	1,432,676	1,432,676	—
SISP Death Benefits	—	—	2,996,772	—	—	—
Disability Benefits	—	—	—	273,370	—	—
Total	**2,341,774**	**2,341,774**	**3,998,565**	**2,707,839**	**3,044,753**	**1,612,077**
Jeffrey S. Thiede						
Compensation:						
Performance Shares	945,326	945,326	945,326	945,326	1,361,390	1,361,390
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Disability Benefits	—	—	—	413,878	—	—
Total	**945,326**	**945,326**	**1,038,021**	**1,451,899**	**1,639,500**	**1,639,500**
Nicole A. Kivisto						
Compensation:						
Performance Shares	—	—	—	—	1,209,958	1,209,958
Benefits and Perquisites:						
Basic SISP	258,172	258,172	—	322,715	258,172	—
SISP Death Benefits	—	—	1,800,913	—	—	—
Disability Benefits	—	—	—	708,366	—	—
Total	**258,172**	**258,172**	**1,800,913**	**1,031,081**	**1,468,130**	**1,209,958**

CEO Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, we are providing information regarding the relationship of the annual total compensation of David L. Goodin, our president and chief executive officer, to the annual total compensation of our median employee.

Our employee workforce fluctuates during the year largely depending on the seasonality, number, and size of construction project activity conducted by our businesses. Approximately 49.6% of our employee workforce is employed under union bargained labor contracts which define compensation and benefits for participants which may include payments made by the company associated with employee participation in union benefit and pension plans.

We identified the median employee by examining the 2018 taxable wage information for all individuals on the company's payroll records as of December 31, 2018, excluding Mr. Goodin and the employees of Sweetman Construction Company which was acquired by our Construction Materials and Contracting segment during the fourth quarter. Because of the timing of this acquisition and its integration, payroll records were not available to include in the pay ratio analysis. Sweetman Construction Company reported 232 employees which represents less than 2% of the company's employee population. All of the company's employees are located in the United States. We made no adjustments to annualize compensation for individuals employed for only part of the year. We selected taxable wages as reported to the Internal Revenue Service on Form W-2 for 2018 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and economic manner for the identification of the median employee. Our median employee works for our corporate office with annual compensation consisting of wages, annual incentive and company matching, retirement replacement and profit sharing 401(k) contributions. Our median employee does not participate in the company's pension plan since our median employee joined the company in 2017, after the plan was frozen. Our median employee receives an additional 5% company match to his 401(k) plan in lieu of pension contributions.

Once identified, we categorized the median employee's compensation to correspond to the compensation components as reported in the Summary Compensation Table. For 2018, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was $4,124,067, and the total annual compensation of our median employee was $77,268. Based on this information, the 2018 ratio of annual total compensation of Mr. Goodin to the median employee was 53 to 1.

Company Name: Montana-Dakota Utilities Co.

BALANCE SHEET

Year: 2018

	Account Number	& Title	Last Year	This Year	% Change
1		**Assets and Other Debits**			
2					
3	**Utility Plant**				
4	101	Electric Plant in Service	$1,352,039,065	$1,691,798,611	25.13%
5	101.1	Property Under Capital Leases			
6	102	Electric Plant Purchased or Sold			
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use			
9	106	Completed Constr. Not Classified - Electric	420,967,343	201,385,454	-52.16%
10	107	Construction Work in Progress - Electric	116,083,188	157,910,408	36.03%
11	108	(Less) Accumulated Depreciation	(596,868,751)	(623,443,481)	4.45%
12	111	(Less) Accumulated Amortization	(2,416,052)	(3,086,461)	27.75%
13	114	Electric Plant Acquisition Adjustments	10,387,643	10,468,339	0.78%
14	115	(Less) Accum. Amort. Electric Plant Acq. Adj.	(10,387,643)	(10,399,534)	0.11%
15	120	Nuclear Fuel (Net)			
16		Other Utility Plant	717,749,025	769,939,776	7.27%
17		Accum. Depr. and Amort. - Other Utl. Plant	(312,188,468)	(330,703,391)	5.93%
18					
19		**Total Utility Plant**	$1,695,365,350	$1,863,869,721	9.94%
20					
21	**Other Property & Investments**				
22	121	Nonutility Property	$16,449,813	$16,931,362	2.93%
23	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(5,380,673)	(6,199,490)	15.22%
24	123	Investments in Associated Companies			
25	123.1	Investments in Subsidiary Companies	1,704,908,136	1,790,885,738	5.04%
26	124	Other Investments	76,779,282	76,201,921	-0.75%
27	125	Sinking Funds			
28					
29		**Total Other Property & Investments**	$1,792,756,558	$1,877,819,531	4.74%
30					
31	**Current & Accrued Assets**				
32	131	Cash	$619,085	($273,799)	-144.23%
33	132-134	Special Deposits	4,603,012	617,411	-86.59%
34	135	Working Funds	150,750	312,522	107.31%
35	136	Temporary Cash Investments	0	1,178,164	100.00%
36	141	Notes Receivable			
37	142	Customer Accounts Receivable	25,259,589	27,283,245	8.01%
38	143	Other Accounts Receivable	4,110,686	14,756,480	258.98%
39	144	(Less) Accum. Provision for Uncollectible Accts.	(561,438)	(779,796)	38.89%
40	145	Notes Receivable - Associated Companies			
41	146	Accounts Receivable - Associated Companies	34,029,187	36,014,729	5.83%
42	151	Fuel Stock	4,684,911	4,784,694	2.13%
43	152	Fuel Stock Expenses Undistributed			
44	153	Residuals and Extracted Products			
45	154	Plant Materials and Operating Supplies	16,837,763	21,026,434	24.88%
46	155	Merchandise			
47	156	Other Material & Supplies			
48	163	Stores Expense Undistributed			
49	164.1	Gas Stored Underground - Current	9,179,608	8,508,246	-7.31%
50	165	Prepayments	5,865,158	5,480,655	-6.56%
51	166	Advances for Gas Explor., Devl. & Production			
52	171	Interest & Dividends Receivable			
53	172	Rents Receivable			
54	173	Accrued Utility Revenues	50,091,799	47,151,553	-5.87%
55	174	Miscellaneous Current & Accrued Assets			
56					
57		**Total Current & Accrued Assets**	$154,870,110	$166,060,538	7.23%

BALANCE SHEET

Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits (cont.)**			
2					
3	**Deferred Debits**				
4	181	Unamortized Debt Expense	$2,353,114	$2,581,364	9.70%
5	182.1	Extraordinary Property Losses			
6	182.2	Unrecovered Plant & Regulatory Study Costs	2,959,651	2,508,004	-15.26%
7	182.3	Other Regulatory Assets	206,776,202	214,409,347	3.69%
8	183	Prelim. Electric Survey & Investigation Chrg.	1,678,581	1,112,510	-33.72%
9	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.	7,900	11,624	47.14%
10	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.	24,835	57,531	131.65%
11	184	Clearing Accounts	(52,274)	(31,304)	-40.12%
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	29,033,605	28,836,015	-0.68%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	4,726,100	4,154,385	-12.10%
17	190	Accumulated Deferred Income Taxes	59,350,651	51,529,326	-13.18%
18	191	Unrecovered Purchased Gas Costs	2,175,012	(2,576,502)	-218.46%
19	192.1	Unrecovered Incremental Gas Costs			
20	192.2	Unrecovered Incremental Surcharges			
21					
22		**Total Deferred Debits**	$309,033,377	$302,592,300	-2.08%
23					
24	**TOTAL ASSETS & OTHER DEBITS**		$3,952,025,395	$4,210,342,090	6.54%
25		**Liabilities and Other Credits**			
26					
27	**Proprietary Capital**				
28	201	Common Stock Issued	$195,843,297	$196,564,907	0.37%
29	202	Common Stock Subscribed			
30	204	Preferred Stock Issued			
31	205	Preferred Stock Subscribed			
32	207	Premium on Capital Stock	1,239,981,494	1,255,155,546	1.22%
33	211	Miscellaneous Paid-In Capital			
34	213	(Less) Discount on Capital Stock			
35	214	(Less) Capital Stock Expense	(6,569,697)	(6,579,697)	0.15%
36	216	Appropriated Retained Earnings	620,946,628	642,942,878	3.54%
37	216.1	Unappropriated Retained Earnings	419,801,251	520,659,042	24.03%
38	217	(Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
39	219	Accumulated Other Comprehensive Income	(37,333,718)	(38,342,046)	-2.70%
40					
41		**Total Proprietary Capital**	$2,429,043,442	$2,566,774,817	5.67%
42					
43	**Long Term Debt**				
44	221	Bonds			
45	222	(Less) Reacquired Bonds			
46	223	Advances from Associated Companies			
47	224	Other Long Term Debt	714,686,250	788,725,495	10.36%
48	225	Unamortized Premium on Long Term Debt			
49	226	(Less) Unamort. Discount on Long Term Debt-Dr.			
50					
51		**Total Long Term Debt**	$714,686,250	$788,725,495	10.36%

BALANCE SHEET

	Account Number & Title		Last Year	This Year	% Change
1		**Total Liabilities and Other Credits (cont.)**			
2					
3	**Other Noncurrent Liabilities**				
4	227	Obligations Under Cap. Leases - Noncurrent			
5	228.1	Accumulated Provision for Property Insurance			
6	228.2	Accumulated Provision for Injuries & Damages	$283,024	$190,410	-32.72%
7	228.3	Accumulated Provision for Pensions & Benefits	45,731,295	41,383,945	-9.51%
8	228.4	Accumulated Misc. Operating Provisions			
9	229	Accumulated Provision for Rate Refunds	0	15,514,270	100.00%
10	230	Asset Retirement Obligations	127,809,107	142,922,575	11.83%
11					
12		**TOTAL Other Noncurrent Liabilities**	$173,823,426	$200,011,200	15.07%
13					
14	**Current & Accrued Liabilities**				
15	231	Notes Payable			
16	232	Accounts Payable	$45,904,554	$48,869,177	6.46%
17	233	Notes Payable to Associated Companies			
18	234	Accounts Payable to Associated Companies	7,233,715	12,438,043	71.95%
19	235	Customer Deposits	1,361,897	1,443,059	5.96%
20	236	Taxes Accrued	3,296,066	24,703,900	649.50%
21	237	Interest Accrued	8,191,173	6,739,759	-17.72%
22	238	Dividends Declared	38,572,614	39,695,262	2.91%
23	239	Matured Long Term Debt			
24	240	Matured Interest			
25	241	Tax Collections Payable	1,095,165	1,181,720	7.90%
26	242	Miscellaneous Current & Accrued Liabilities	35,763,020	31,208,839	-12.73%
27	243	Obligations Under Capital Leases - Current			
28					
29		**TOTAL Current & Accrued Liabilities**	$141,418,204	$166,279,759	17.58%
30					
31	**Deferred Credits**				
32	252	Customer Advances for Construction	$23,674,715	$20,525,735	-13.30%
33	253	Other Deferred Credits	87,716,626	83,378,564	-4.95%
34	254	Other Regulatory Liabilities	172,633,655	164,617,567	-4.64%
35	255	Accumulated Deferred Investment Tax Credits	1,830,976	3,377,889	84.49%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	207,198,101	216,651,064	4.56%
39					
40		**TOTAL Deferred Credits**	$493,054,073	$488,550,819	-0.91%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$3,952,025,395	$4,210,342,090	6.54%

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Definitions

The following abbreviations and acronyms used in the Notes are defined below:

AFUDC	Allowance for funds used during construction
ARAM	Average Rate Assumption Method
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019.
Coyote Station	427-MW coal fired electric generating facility near Beulah, North Dakota (25 percent ownership)
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock on Montana-Dakota
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
K-Plan	Company’s 401(k) Retirement Plan
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana-Dakota in the Holding Company Reorganization
MISO	Midcontinent Independent System Operator, Inc.

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
SEC	United States Securities and Exchange Commission
SDPUC	South Dakota Public Utilities Commission
SSIP	System Safety and Integrity Program
TCJA	Tax Cuts and Jobs Act
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Montana-Dakota and Great Plains are public utility divisions of the Company.

Montana-Dakota generates, transmits, and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota, and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services. The Company provides service to approximately 143,000 electric and 299,000 natural gas residential, commercial, industrial and municipal customers in 285 communities and adjacent rural areas as of December 31, 2018.

Montana-Dakota is subject to regulation by the FERC, NDPSC, MTPSC, SDPUC, and WYPSC. Great Plains is subject to regulation by the MNPUC and the NDPSC.

The Company owns two wholly owned subsidiaries, Centennial and MDU Energy Capital, as well as ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. These requirements differ from GAAP related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs. As required by the FERC for Form 1 report purposes, the Company reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $975.6 million; current and accrued assets would increase by $1.0 billion; deferred debits would increase by $784.1 million; long-term debt would increase by $1.1 billion; other noncurrent liabilities and current and accrued liabilities would increase by $619.8 million; and deferred credits would increase by $1.1 billion as of December 31, 2018. Furthermore, operating revenues would increase by $3.9 billion and operating expenses, excluding income taxes, would increase by $3.6 billion for the twelve months ended December 31, 2018. In addition, net cash provided by operating activities would increase by $202.4 million; net cash used in investing activities would increase by $498.1 million; net cash used in financing activities would decrease by $314.6 million; the effect of exchange rate changes on cash would decrease by $1,000; and the net change in cash and cash equivalents would be an increase of $18.9 million for the twelve months ended December 31, 2018. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Notes to Financial Statements accompanying this FERC Form No. 1 relate to the nonconsolidated parent company and its two public utility divisions. For information on disclosures of the subsidiary companies, refer to the Company's Form 10-K.

Montana-Dakota and Great Plains are regulated businesses which account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 5 for more information regarding the nature and amounts of these regulatory deferrals.

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's corporate structure prior to the Holding Company Reorganization.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Due to the enactment of the TCJA, the jurisdictions in which the Company provides service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company's rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or passed back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 16.

Management has also evaluated the impact of events occurring after December 31, 2018, up to the date of issuance of these financial statements.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of

three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount. The total balance of receivables past due 90 days or more was $640,000 and $690,000 at December 31, 2018 and 2017, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2018 and 2017 was $780,000 and $561,000, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota was $47.2 million and $50.1 million at December 31, 2018 and 2017, respectively.

Inventories and natural gas in storage

Natural gas in storage is carried at cost using the last-in, first-out method. All other inventories are stated at the lower of cost or net realizable value. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2018	2017
	(In thousands)	
Plant materials and operating supplies	**$ 21,026**	$ 16,838
Gas stored underground-current	**8,508**	9,179
Fuel stock	**4,785**	4,685
Total	**$ 34,319**	$ 30,702

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was $1.7 million and $2.5 million at December 31, 2018 and 2017, respectively.

Investments

The Company's investments include its investment in subsidiary companies, the cash surrender value of life insurance policies, an insurance contract, and other miscellaneous investments. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Statement of Income. The Company has not elected the fair value option for its other investments. For more information, see Notes 6 and 14.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. The amount of AFUDC capitalized for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
AFUDC - borrowed	**$ 1,283**	$ 503
AFUDC - equity	**$ 1,027**	$ 401

Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets. The Company collects removal costs for plant assets in regulated utility rates. These amounts are included in accumulated provision for depreciation, amortization and depletion.

Property, plant and equipment at December 31 was as follows:

	2018	2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Electric:			
Generation	**$ 1,131,484**	$ 1,034,765	49
Distribution	**430,750**	415,543	46
Transmission	**302,315**	296,941	64
Construction in progress	**161,742**	117,922	-
Other	**117,133**	112,301	13
Natural gas distribution:			
Distribution	**547,788**	506,539	46
Construction in progress	**4,122**	6,998	-
Other	**134,450**	123,702	12
Less accumulated depreciation, depletion and amortization	**967,633**	921,861	
Net utility plant	**$ 1,862,151**	$ 1,692,850	
Nonutility property	**$ 16,931**	$ 16,450	
Less accumulated depreciation, depletion and amortization	**6,199**	5,381	
Net nonutility property	**$ 10,732**	$ 11,069	

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No impairment losses were recorded in 2018 and 2017. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2018 and 2017, there were no impairment losses recorded. At December 31, 2018, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value. For more information on goodwill, see Note 4.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, risk adjusted cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital of 5.0 percent, and a long-term growth rate projection of 3.5 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Under the market approach, the Company estimates fair value using multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

Revenue recognition
Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The Company generates revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. The Company establishes a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company’s utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state’s tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the Company has no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered. For more information on revenue from contracts with customers, see Note 2.

Asset retirement obligations
The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a regulatory asset or liability. For more information on asset retirement obligations, see Note 8.

Legal costs
The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Natural gas costs recoverable (refundable) through rate adjustments were ($2.6) million and $2.2 million at December 31, 2018 and 2017, respectively, and included in unrecovered purchased gas costs.

Stock-based compensation
The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also preforms an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

Income taxes
The Company and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by the Company, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. The Company makes a similar allocation for state income taxes paid in connection with combined state filings. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities by using enacted tax rates in effect for

the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Taxes recoverable from customers have been recorded as regulatory assets. Taxes refundable to customers and excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as regulatory liabilities. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in interest and penalties, respectively.

Use of estimates
The preparation of financial statements in conformity with GAAP requires the Company 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, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the valuation of stock-based compensation. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

New accounting standards
Recently adopted accounting standards
ASU 2014-09 - Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was effective for the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company elected the practical expedient to not disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, along with an explanation of when such revenue would be expected to be recognized. This practical expedient was used since the performance obligations are part of contracts with an original duration of one year or less. The Company also elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is one year or less. Upon completion of the Company's evaluation of contracts and methods of revenue recognition under the previous accounting guidance, the Company did not identify any material cumulative effect adjustments to be made to retained earnings. In addition, the Company has expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, as discussed in Note 2. The Company reviewed its revenue streams to evaluate the impact of this guidance and did not identify a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacted certain business processes and controls. As such, the Company developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant. Results for reporting periods beginning after December 31, 2017, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting for revenue recognition.

For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance.

ASU 2016-15 - Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company adopted the guidance on January 1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's statement of cash flows.

ASU 2017-01 - Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company adopted the guidance on January 1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

ASU 2017-07 - Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension and net periodic postretirement benefit costs. The guidance required the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net periodic benefit cost shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also only allows the service cost component to be capitalized.

In December 2017, the FERC issued guidance to provide clarification of whether and how to apply this ASU for purposes of regulatory accounting and reporting. The FERC concluded that pension and postretirement benefit cost, in its entirety without separation of the various components, be recorded in operating expenses. Regarding capitalization, companies may continue to capitalize the service cost component and non-service cost component or elect to capitalize only the service cost component as prescribed by ASU No. 2017-07.

The Company has elected to capitalize only the service cost component as prescribed by ASU No. 2017-07 as of January 1, 2018. This change in accounting practice will not have a material effect on the Company's results of operations, cash flows or disclosures, nor will it have a material effect on rates, rate base or current period expenses.

ASU 2018-02 - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss).

In November 2018, the FERC issued an Order granting blanket approval for certain public utilities to reclassify the stranded tax effects caused by the reduction in corporate tax rate by the TCJA, from Account 219 to Account 439, in keeping with FASB's guidance for public utilities that include both accumulated other comprehensive income and retained earnings in their capital structures for ratemaking purposes. The approval was granted provided the transfer from accumulated other comprehensive income to retained earnings will not affect rates.

The Company early adopted the guidance on January 1, 2018, for its GAAP financial statements and elected to reclassify the stranded income taxes at the beginning of the period. During the first quarter of 2018, the Company reclassified $7.9 million of stranded tax expense from accumulated other comprehensive loss to retained earnings, including $6.9 million related to the stranded tax expense of subsidiaries. As the Company's capital structure for ratemaking purposes would not be impacted, following the FERC's Order, the Company reclassified the stranded income taxes in its FERC financial statements from Account 219 to Account 439 as of December 31, 2018. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

Recently issued accounting standards not yet adopted

ASU 2016-02 - Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company adopted the standard for its GAAP financial statements on January 1, 2019.

In December 2018, the FERC issued guidance to provide clarity on how regulated entities can implement the lease accounting guidance within the framework and regulatory intent of the FERC's existing requirements for lease accounting. The FERC guidance permits entities to record operating leases that may be capitalized under ASU No. 2016-02 in the FERC balance sheet accounts that have already been established for capital lease assets and liabilities. All other provisions of lease accounting are not affected by this accounting guidance, and the accounting guidance is intended to have no impact on the existing ratemaking treatment or practices. For entities that elect this option, additional disclosures would be required within their FERC filings. The Company has elected to not record operating leases on its FERC financial statements. Therefore, this standard will not have an impact on the Company's FERC financial statements or disclosures.

ASU 2017-04 - Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be effective for the Company on January 1, 2020, and must be applied on a prospective basis with early adoption permitted. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August 2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January 1, 2020, including interim periods, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August 2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be effective for the Company on January 1, 2021, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The guidance will be effective for the Company on January 1, 2020, including interim periods, and may be applied on a retrospective or a prospective basis with early adoption permitted. The Company adopted the guidance for its GAAP financial statements effective January 1, 2019, on a prospective basis. For FERC financial statements, the Company will functionalize these costs within the FERC plant accounts or in miscellaneous intangible plant, if appropriate. Additionally, the amortization of these costs will be reported as depreciation and amortization. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from postretirement liability adjustments and other comprehensive income (loss) recorded by its subsidiaries.

The postretirement liability adjustment in other comprehensive income was $1.0 million and $(517,000), net of tax of $(323,000) and $315,000, for the years ended December 31, 2018 and 2017, respectively.

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31, 2018	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2017	$ (4,803)	$ (32,531)	$ (37,334)
Other comprehensive income before reclassifications	903	3,333	4,236
Amounts reclassified from accumulated other comprehensive loss	99	2,616	2,715
Net current-period other comprehensive income	1,002	5,949	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(1,045)	(6,914)	(7,959)
Balance at December 31, 2018	**$ (4,846)**	**$ (33,496)**	**$ (38,342)**

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NOTES TO FINANCIAL STATEMENTS (Continued)

Twelve Months Ended December 31, 2017	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2016	$ (4,287)	$ (31,446)	$ (35,733)
Other comprehensive loss before reclassifications	(599)	(1,358)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	83	1,416	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	---	(1,143)	(1,143)
Net current-period other comprehensive income loss	(516)	(1,085)	(1,601)
Balance at December 31, 2017	**$ (4,803)**	**$ (32,531)**	**$ (37,334)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Statement of Income. The reclassifications were as follows:

Twelve Months Ended December 31,	**2018**	2017	Location on Statement of Income
	(In thousands)		
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**$ (131)**	$ (133)	(a)
	32	50	Income taxes
	(99)	(83)	
Subsidiary reclassifications out of accumulated other comprehensive loss	**(2,616)**	(1,416)	Equity in earnings of Subsidiary Companies
Total reclassifications	**$ (2,715)**	$ (1,499)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14.

Note 2 – Revenue from contracts with customers

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments.

Year Ended December 31, 2018	Electric	Natural Gas Distribution	Total
		(In thousands)	
Residential utility sales	$ 121,477	$ 160,022	$ 281,499
Commercial utility sales	136,236	109,631	245,867
Industrial utility sales	34,353	5,672	40,025
Other utility sales	7,556	---	7,556
Natural gas transportation	---	6,423	6,423
Other	31,568	9,431	40,999
Revenues from contracts with customers	331,190	291,179	622,369
Revenues out of scope	3,933	1,475	5,408
Total external operating revenues	$ 335,123	$ 292,654	$ 627,777

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Note 3 - Acquisitions

During 2018, a subsidiary of the Company completed four acquisitions of construction materials and contracting businesses in Oregon, Minnesota, and South Dakota. As of December 31, 2018, the gross aggregate consideration for these acquisitions, which were all accounted for as business combinations was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. The acquisitions are subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the businesses as of the closing dates.

The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

Note 4 - Goodwill and Other Intangible Assets

The carrying amount of goodwill, which is related to the natural gas distribution business, remained unchanged at $4.8 million for the years ended December 31, 2018 and 2017. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 5 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period*	**2018**	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(h)	**$ 96,595**	$ 95,806
Asset retirement obligations (a) (b)	Over plant lives	**13,763**	12,036
Taxes recoverable from customers (a)	Over plant lives	**8,179**	8,253
Unamortized loss on required debt	Up to 8 years	**4,154**	4,726
Costs related to identifying generation development (c)	Up to 8 years	**2,508**	2,960
Unrecovered purchased gas costs	Up to 1 year	**(2,577)**	2,175
Other (a) (d) (e)	Up to 20 years	**13,832**	14,283
Total regulatory assets		**136,454**	140,239
Regulatory liabilities:			
Taxes refundable to customers (f)		**148,015**	155,329
Plant removal and decommissioning costs (b) (f)		**56,095**	55,519
Accumulated provision for rate refunds		**15,514**	---
Pension and postretirement benefits (f)		**10,309**	11,056
Other (f) (g)		**6,209**	3,214
Total regulatory liabilities		**236,142**	225,118
Net regulatory position		**$ (99,688)**	$ (84,879)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.

(a) Included in other regulatory assets on the Comparative Balance Sheet.

(b) Included in accumulated provision for depreciation, amortization and depletion on the Comparative Balance Sheet.

(c) Included in unrecovered plant and regulatory study costs on the Comparative Balance Sheet.

(d) Included in prepayments on the Comparative Balance Sheet.
(e) Included in miscellaneous deferred debits on the Comparative Balance Sheet.
(f) Included in other regulatory liabilities on the Comparative Balance Sheet.
(g) Included in accumulated deferred investment tax credits on the Comparative Balance Sheet.
(h) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2018 and 2017, approximately $119.4 million and $118.5 million respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $7.4 million in taxes recoverable from customers and an increase of $149.8 million in taxes refundable to customers. The revaluation of the Company’s regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019, TCJA filings are pending in Wyoming. For more information on the various rate cases, see Note 16. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

If, for any reason, the Company's regulated business ceases to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 6 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plan for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $49.2 million and $51.6 million as of December 31, 2018 and 2017, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized loss on these investments for the year ended December 31, 2018, was $2.4 million. The net unrealized gain on these investments for the year ended December 31, 2017, was $6.5 million. The change in fair value, which is considered part of the cost of the plan, is classified in Other Income and Deductions as Life Insurance on the Statement of Income.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach. The Company’s Level 2 money market funds are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known sources including pricing from outside sources. The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

The Company's assets measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
		(In thousands)		
Assets:				
Money market funds	$ —	$ 5,045	$ —	$ 5,045
Insurance contract*	—	49,213	—	49,213
Total assets measured at fair value	$ —	$ 54,258	$ —	$ 54,258

*The insurance contract invests approximately 53 percent in fixed-income investments, 21 percent in common stock of large-cap companies, 11 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 2 percent in cash equivalents.

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
		(In thousands)		
Assets:				
Money market funds	$ —	$ 3,762	$ —	$ 3,762
Insurance contract*	—	51,578	—	51,578
Total assets measured at fair value	$ —	$ 55,340	$ —	$ 55,340

*The insurance contract invests approximately 49 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 14 percent in common stock of mid-cap companies, 11 percent in common stock of small-cap companies, 2 percent in target date investments and 1 percent in cash equivalents.

The Company's long-term debt is not measured at fair value on the Comparative Balance Sheet and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2018		2017	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 788,725**	**$ 795,113**	$ 714,686	$ 752,311

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 7 - Debt

Certain debt instruments of the Company, including those discussed later, contain restrictive covenants and provisions. In order to borrow under the respective credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. At December 31, 2018, the Company complied with all applicable financial covenants and restrictions. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding revolving credit facilities of the Company:

Company	Facility		Facility Limit	Amount Outstanding at December 31, 2018	Amount Outstanding at December 31, 2017	Letters of Credit at December 31, 2018	Expiration Date
				(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0	$ 48.5 (b)	$ 73.8 (b)	$ —	6/8/23

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program included in other long-term debt on the Comparative Balance Sheet.

The Company's commercial paper program is supported by a revolving credit agreement. While the amount of commercial paper outstanding does not reduce available capacity under the revolving credit agreement, the Company does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

The following includes information related to the preceding table.

Long-term debt

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. The Company’s ratio of funded debt to total capitalization at December 31, 2018, was 45 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

On January 1, 2019, the Company’s revolving credit agreement and commercial paper program became Montana-Dakota’s revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

		2018		2017
		(In thousands)		
Senior Notes at a weighted average rate of 4.12%, due on dates ranging from October 17, 2019 to November 21, 2046	**$**	**739,800**	$	640,500
Commercial paper at an interest rate of 2.83%, supported by revolving credit agreement		**48,500**		73,750
Other note at a rate of 6.0%, due on November 30, 2038		**425**		436
Total long-term debt	**$**	**788,725**	$	714,686

Schedule of Debt Maturities Long-term debt maturities for the five years and thereafter following December 31, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	$200,711	$712	$713	$714	$49,214	$536,661

Note 8 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, decommissioning of certain electric generating facilities, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

A reconciliation of the Company's liability for the years ended December 31 was as follows:

		2018		2017
		(In thousands)		
Balance at beginning of year	**$**	**127,809**	$	119,521
Liabilities incurred		**6,293**		4,559
Liabilities settled		**(1,006)**		(2,509)
Accretion expense *		**6,690**		6,277
Revisions in estimates		**3,137**		(39)
Balance at end of year	**$**	**142,923**	$	127,809

* Includes $6.7 million and $6.3 million in 2018 and 2017, respectively, related to regulatory assets.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

Note 9 - Preferred Stocks

The Company currently has 500,000 shares of preferred stock authorized to be issued with a $100 par value; 1,000,000 shares of preferred stock A authorized to be issued with no par value; and 500,000 shares of preference stock authorized to be issued with no par value. At December 31, 2018, there were no shares outstanding. At December 31, 2017, there were no shares outstanding. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at $105 per share and $102 per share, respectively, for a repurchase price of approximately $15.6 million and $300,000 of redeemable preferred stock classified as long-term debt.

Note 10 - Common Stock

For the years 2018 and 2017, dividends declared on common stock were $.7950 and $.7750 per common share, respectively.

The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2018 and 2017, the K-Plan purchased shares of common stock on the open market. At December 31, 2018, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only declare or pay distributions if as of the last day of any fiscal quarter, the ratio of Centennial’s average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial’s Consolidated EBITDA does not exceed 3 to 1. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately $1.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2018. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $424 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders’ equity including retained earnings, would be restricted from use for dividend payments at December 31, 2018. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 11 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2018, there were 5.0 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock based awards.

Total stock-based compensation expense (after tax), excluding the amount recognized by the Company’s subsidiaries, was $1.2 million and $805,000 in 2018 and 2017, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company’s subsidiaries, related to stock-based compensation was approximately $2.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 38,605 shares with a fair value of $1.0 million and 40,572 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2018 and 2017, respectively.

Restricted stock awards

In February 2018, the Company began granting restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. At December 31, 2018, the total nonvested shares were 22,838 with a weighted average grant-date fair value of $27.48 per share.

Performance share awards

Since 2003, key employees of the Company and its subsidiaries have been granted performance share awards each year under the long-term performance-based incentive plan. Entitlement to performance shares is established by either the market condition or the performance metrics and service condition relative to the designated award.

Target grants of performance shares outstanding at December 31, 2018, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	255,773
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558
February 2018	2018-2020	246,309

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants applicable to the market condition for certain performance shares issued in 2018 and 2017 were:

	2018	2017	2016
Weighted average grant-date fair value	**$34.55**	$24.31	$14.60
Blended volatility range	**17.87 % – 22.14 %**	22.70% – 25.56%	29.25 % – 32.51 %
Risk-free interest rate range	**1.86 % – 2.46 %**	.69% – 1.61%	.47 % – .92 %
Weighted average discounted dividends per share	**$2.46**	$1.70	$1.56

Under the performance conditions for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The performance shares applicable to these performance conditions have a weighted average grant-date fair value of $27.48 per share.

There were no performance shares that vested in 2018. The fair value of the performance shares that vested during the year ended December 31, 2017, was $9.6 million.

A summary of the status of the performance share awards for the year ended December 31, 2018, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	425,534	$	18.35
Granted	246,309		31.02
Less:			
Forfeited	3,052		14.60
Nonvested at end of period	668,791	$	23.03

Note 12 - Income Taxes

Income before income taxes for the years ended December 31, 2018 and 2017, respectively was $57.0 million and $76.5 million.

Income tax expense (benefit) for the years ended December 31 was as follows:

		2018		2017
		(In thousands)		
Current:				
Federal	**$**	**(15,223)**	$	(19,922)
State		**(295)**		(1,380)
		(15,518)		(21,302)
Deferred:				
Income taxes:				
Federal		**8,835**		32,335
State		**877**		2,590
Investment tax credit - net		**1,547**		191
		11,259		35,116
Total income tax expense (benefit)	**$**	**(4,259)**	$	13,814

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NOTES TO FINANCIAL STATEMENTS (Continued)

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes associated with the non-regulated operations were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax expense of $2.9 million for the year ended December 31, 2017. Included in the tax expense was $1.0 million related to amounts in accumulated other comprehensive loss.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators to plan for amounts expected to be returned to customers, as discussed in Notes 5 and 16. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $157.2 million in the fourth quarter of 2017. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

The changes included in the TCJA were broad and complex. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company has reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

Based on the Company’s estimate of the amount of excess deferred income taxes that would be used to reduce future customer rates, the Company recorded an increase in regulatory liabilities of approximately $149.8 million and a reduction in regulatory assets of $7.4 million, including gross ups, to reflect the future revenue reduction required to return previously collected income taxes to customers.

The accounts that increased and (decreased) in the 2017 remeasurement of deferred income taxes are reflected below (in millions):

FERC Account	**254**	**182.3**	**190**	**281**	**282**	**283**
Excess Deferred Income Taxes:						
Electric*	$122.5		$(1.7)	$(0.5)	$(120.3)	$(3.4)
Gas	27.3		(3.1)		(26.3)	(4.1)
Regulatory Asset and Deferred Taxes associated with AFUDC:						
Electric*		$(6.8)			(3.2)	(3.6)
Gas		(0.6)			(0.3)	(0.3)
Total	$149.8	$(7.4)	$(4.8)	$(0.5)	$(150.1)	$(11.4)

*Deferred income taxes for the Company’s electric integrated system, including excess deferred income taxes and those associated with AFUDC, are included in the MISO attachment O formula rate template based on an allocation percentage of transmission-related assets to total integrated system-related assets for each given year. For the years ended

December 31, 2018 and 2017, the allocation percentage for transmission-related assets to total integrated-system related assets was 18.92% and 15.83%, respectively.

Total plant-related excess deferred taxes, those originating in FERC accounts 281 or 282, as of December 31, 2017, were $147.1 million, and were largely considered protected. The Company has proposed in all of its state jurisdictions to amortize both protected and non-protected plant-related excess deferred taxes on an ARAM basis which is based on plant lives. See Note 1 for more information on the Company's weighted average depreciable lives. All state jurisdictions which have approved rates related to TCJA have approved this treatment and the Company is awaiting final orders in the remaining jurisdictions.

Net non-plant-related excess deferred taxes, those originating in FERC accounts 190 and 283, as of December 31, 2017 were $2.7 million. These excess deferred taxes are being amortized on a straight-line basis over periods ranging from 1-10 years as approved by the respective state jurisdictions which have approved rates related to TCJA.

Deferred taxes associated with AFUDC, recorded in FERC account 282 and 283, and the related regulatory asset, recorded in FERC account 182.3 were reduced by $7.4 million as of December 31, 2017 reflecting the reduction in future revenue requirement required to be collected from customers.

Amortization of the excess deferred taxes are being recorded to FERC Accounts 410.1 and 411.1 as appropriate. For the year ended December 31, 2018, the amortization of excess deferred taxes, including gross ups, has reduced the related regulatory liabilities by $7.3 million.

In November 2018, MISO submitted revisions to the generic rate template in attachment O of its Open Access Transmission, Energy and Operating Reserve Markets Tariff and to company-specific formula rate templates of several MISO transmission owners, including the Company's (FERC Docket No. ER19-249-000). The revisions add two income tax items to the generic rate template and the company-specific formula rates regarding the allowance for funds used during construction and a provision to return (or recover) excess (or deficient) accumulated deferred income taxes resulting from tax law or rate changes. In December 2018, the submittal was approved by the FERC for filing effective January 1, 2019.

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2018	2017
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 23,695	$ 26,021
Production Tax Credits	8,015	19,367
Compensation-related	7,903	5,294
Customer advances	4,988	5,762
Other	6,928	2,907
Total deferred tax assets	51,529	59,351
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	183,229	173,782
Postretirement	26,206	25,745
Cost recovery mechanisms	1,688	2,285
Other	5,528	5,386
Total deferred tax liabilities	216,651	207,198
Net deferred income tax liability	$ (165,122)	$ (147,847)

As of December 31, 2018 and 2017, the Company had a federal income tax credit carryforward of $8.0 million and $19.4 million, respectively. The federal income tax credit carryforwards will expire in 2037 and 2038 if not utilized. As of December 31, 2018 and 2017, no valuation allowances have been recorded associated with previously identified deferred tax assets. Changes in tax regulations or assumptions regarding current and future taxable income could require valuation allowances in the future.

The following table reconciles the change in the net deferred income tax liability from December 31, 2017, to December 31, 2018, to deferred income tax expense:

	2018
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 17,275
Deferred taxes associated with TCJA enactment for regulated activities	(5,364)
Deferred taxes associated with other comprehensive income (loss)	(323)
Other	(329)
Deferred income tax expense for the period	$ 11,259

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2018 Amount	2018 %	2017 Amount	2017 %
	(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 11,959**	**21.0**	$ 26,781	35.0
Increases (reductions) resulting from:				
Production tax credit	**(11,759)**	**(20.6)**	(13,958)	(18.2)
Excess deferred income tax amortization	**(5,364)**	**(9.4)**	---	---
Amortization and deferral of investment tax credit	**(120)**	**(0.2)**	(171)	(0.2)
R&D tax credit	**(669)**	**(1.2)**	---	---
Deductible K-Plan dividends	**(644)**	**(1.1)**	(1,092)	(1.4)
AFUDC equity	**(215)**	**(0.4)**	(140)	(0.2)
State income taxes, net of federal income tax	**2,163**	**3.8**	1,923	2.5
Nonqualified benefit plan TCJA	**182**	**0.3**	(2,342)	(3.1)
revaluation	---	---	1,890	2.5
TCJA revaluation related to accumulated other comprehensive income	---	---	1,045	1.4
Other	**208**	**0.3**	(122)	(0.2)
Total income tax expense (benefit)	**$ (4,259)**	**(7.5)**	$ 13,814	18.1

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The Company is no longer subject to U.S. federal income tax examinations by tax authorities for years ending prior to 2015. With few exceptions, as of December 31, 2018, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2014.

A reconciliation of unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ ---**	$ ---
Additions based on tax positions related to current year	**39**	---
Additions for tax positions of prior years	**100**	---
Balance at end of year	**$ 139**	---

For the years ended December 31, 2018 and 2017, the Company recognized approximately $59,000 and $14,000, respectively, of interest income, related to income taxes. At December 31, 2018 and 2017, the Company had no accrued receivables for interest.

Note 13 – Cash Flow Information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

		2018		2017
		(In thousands)		
Interest, net of AFUDC – borrowed of $1,283 and $503 in 2018 and 2017, respectively	**$**	**32,841**	$	30,101
Income taxes refunded, net	**$**	**(36,926)**	$	(7,885)

Noncash investing transactions at December 31 were as follows:

		2018		2017
		(In thousands)		
Property, plant and equipment additions in accounts payable	**$**	**12,907**	$	12,324
Issuance of common stock in connection with acquisition by a subsidiary	**$**	**18,186**	$	---

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. Other postretirement plans presented here include certain of the Company’s subsidiaries.

Prior to 2017, all of the Company’s defined benefit pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits to an annuity company. The transfer of the benefit payments for these participants reduces the Company’s liability and future premiums.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who had attained age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage was replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Changes in benefit obligation and plan assets for the years ended December 31, 2018 and 2017, and amounts recognized in the Comparative Balance Sheet at December 31, 2018 and 2017, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 250,889**	$ 245,858	**$ 40,128**	$ 40,267
Service cost	**---**	---	**621**	616
Interest cost	**8,183**	9,090	**1,257**	1,443
Plan participants' contributions	**---**	---	**731**	804
Actuarial (gain) loss	**(17,944)**	10,543	**(4,389)**	260
Benefits paid	**(21,159)**	(14,602)	**(2,749)**	(3,262)
Benefit obligation at end of year	**219,969**	250,889	**35,599**	40,128
Change in net plan assets:				
Fair value of plan assets at beginning of year	**192,712**	182,213	**50,531**	47,253
Actual gain (loss) on plan assets	**(11,422)**	24,679	**(1,551)**	5,645
Employer contribution	**7,200**	422	**70**	91
Plan participants' contributions	**---**	---	**731**	804
Benefits paid	**(21,159)**	(14,602)	**(2,749)**	(3,262)
Fair value of net plan assets at end of year	**167,331**	192,712	**47,032**	50,531
Funded status – over (under)	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Net amount recognized	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 103,455**	$ 102,514	**$ 599**	$ 683
Prior service credit	**---**	---	**(7,253)**	(8,228)
Total	**$ 103,455**	$ 102,514	**$ (6,654)**	$ (7,545)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. The table above includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 5.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets.

The pension plans all have accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2018	2017
	(In thousands)	
Projected benefit obligation	$ **219,969**	$ 250,889
Accumulated benefit obligation	$ **219,969**	$ 250,889
Fair value of plan assets	$ **167,331**	$ 192,712

Components of net periodic benefit cost (credit) for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	$ **---**	$ ---	$ **621**	$ 616
Interest cost	**8,183**	9,090	**1,257**	1,443
Expected return on assets	**(11,352)**	(11,222)	**(2,754)**	(2,651)
Amortization of prior service credit	**---**	---	**(976)**	(976)
Recognized net actuarial loss	**3,890**	3,554	**---**	---
Net periodic benefit cost (credit), including amount capitalized	**721**	1,422	**(1,852)**	(1,568)
Less amount capitalized	**---**	294	**119**	(360)
Net periodic benefit cost (credit)	**721**	1,128	**(1,971)**	(1,208)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities):				
Net (gain) loss	**4,831**	(2,915)	**(84)**	(2,733)
Amortization of actuarial loss	**(3,890)**	(3,554)	**---**	---
Amortization of prior service credit	**---**	---	**976**	976
Total recognized in accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**941**	(6,469)	**892**	(1,757)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss and regulatory assets (liabilities)	$ **1,662**	$ (5,341)	$ **(1,079)**	$ (2,965)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2019 is $3.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost (credit) in 2019 are $0 and $976,000, respectively. Prior service cost is amortized on a straight-line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**4.02%**	3.37%	**4.03%**	3.38%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%

Weighted average assumptions used to determine net periodic benefit cost (credit) for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**3.38 %**	3.82%	**3.38%**	3.83%
Expected return on plan assets	**6.75 %**	6.75%	**5.75%**	5.75%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2018, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 25 percent to 30 percent equity securities and 70 percent to 75 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2018	2017
Health care trend rate assumed for next year	**8.0%**	7.5 %
Health care cost trend rate - ultimate	**4.5%**	4.5 %
Year in which ultimate trend rate achieved	**2024**	2024

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2018:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 42	$ (36)
Effect on postretirement benefit obligation	$ 925	$ (806)

Outside investment managers manage the Company's pension and postretirement assets. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's pension plans’ assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded. The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data. The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plans’ assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2018, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,680	$ —	$ 2,680
Equity securities:				
U.S. companies	6,000	—	—	6,000
International companies	---	526	—	526
Collective and mutual funds *	79,347	28,051	—	107,398
Corporate bonds	—	39,744	—	39,744
Municipal bonds	—	5,775	—	5,775
U.S. Government securities	261	3,205	—	3,466
Total assets measured at fair value	$ 85,608	$ 79,981	$ —	$ 165,589

*Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents and 19 percent in other investments.

	Fair Value Measurements at December 31, 2017, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,074	$ —	$ 2,074
Equity securities:				
U.S. companies	7,257	—	—	7,257
International companies	960	—	—	960
Collective and mutual funds *	93,436	36,842	—	130,278
Corporate bonds	—	40,761	—	40,761
Municipal bonds	—	4,647	—	4,647
U.S. Government securities	564	4,510	—	5,074
Total assets measured at fair value	$ 102,217	$ 88,834	$ —	$ 191,051

*Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities and 14 percent in other investments.

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources.

The estimated fair value of the other postretirement benefit plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plans' Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,187	$ —	$ 2,187
Equity securities:				
U.S. companies	841	—	—	841
Insurance contract*	—	44,004	—	44,004
Total assets measured at fair value	$ 841	$ 46,191	$ —	$ 47,032

*The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,738	$ —	$ 2,738
Equity securities:				
U.S. companies	1,074	—	—	1,074
Insurance contract*	—	46,719	—	46,719
Total assets measured at fair value	$ 1,074	$ 49,457	$ —	$ 50,531

*The insurance contract invests approximately 38 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 21 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 9 percent in other investments.

The Company expects to contribute approximately $2.8 million to its defined benefit pension plans in 2019. The Company does not expect to contribute to its postretirement benefit plans in 2019.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2018, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2019	$ 13,893	$ 2,653	$ 91
2020	13,992	2,544	87
2021	14,138	2,486	82
2022	14,305	2,476	76
2023	14,377	2,445	70
2024– 2028	70,899	11,592	249

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

The projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 47,176**	$ 51,388
Accumulated benefit obligation	**$ 47,176**	$ 51,388

Components of net periodic benefit cost for the Company's nonqualified benefit plans for the years ended December 31 were as follows:

		2018		2017
		(In thousands)		
Components of net periodic benefit cost:				
Service cost	**$**	**185**	$	221
Interest cost		**1,586**		1,769
Recognized net actuarial loss		**290**		214
Net periodic benefit cost	**$**	**2,061**	$	2,204

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	**3.85%**	3.18%
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.18%**	3.54%
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified benefit plans at December 31, 2018, are expected to aggregate as follows:

		2019		2020		2021		2022		2023		Thereafter
						(In thousands)						
Nonqualified benefits	$	4,263	$	4,525	$	4,620	$	3,914	$	4,035	$	18,272

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018 and 2017 were $96,000 and $167,000, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2018	2017
	(In thousands)	
Investments		
Insurance contract*	$ 49,213	$ 51,578
Life insurance**	19,122	19,399
Other	5,054	3,765
Total investments	$ 73,389	$ 74,742

* For more information on the insurance contract, see Note 6.
**Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees, and costs incurred under these plans were $10.6 million in 2018 and $11.1 million in 2017.

Note 15 - Jointly Owned Facilities
The financial statements include the Company's ownership interests in the assets, liabilities and expenses of Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities. The Company has an ownership interest of 22.7 percent in Big Stone Station, 25 percent in Coyote Station, and 25 percent in Wygen III.

The Company's share of the stations’ operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power, operation and maintenance, and taxes, other than income) in the Statement of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2018	2017
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 156,534**	$ 158,084
Less accumulated depreciation	**49,345**	51,740
	$ 107,189	$ 106,344
Coyote Station:		
Utility plant in service	**$ 155,236**	$ 155,287
Less accumulated depreciation	**105,565**	103,897
	$ 49,671	$ 51,390
Wygen III:		
Utility plant in service	**$ 65,382**	$ 65,065
Less accumulated depreciation	**9,174**	7,652
	$ 56,208	$ 57,413

Note 16 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details and statuses of each open request.

MNPUC

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Pursuant to the notice, Great Plains provided preliminary impacts of the TCJA on January 30, 2018. On March 2, 2018, Great Plains submitted its initial filing addressing the impacts of the TCJA advocating existing rates are reasonable and a reduction in rates is not warranted. On August 9, 2018, the MNPUC ruled that Great Plains reduce rates to reflect TCJA impacts and to also provide a one-time refund that captures the TCJA impacts from January 1, 2018 through the implementation date of new rates. On December 5, 2018, the MNPUC issued an order requiring Great Plains reduce its rates by $400,000 on an annual basis and provide a one-time refund of approximately $400,000, as previously mentioned, within 90 days after the rates are implemented through credits to customers' bills. The required compliance filing was submitted to the MNPUC on January 4, 2019. The MNPUC is scheduled to address the compliance filing on April 18, 2019.

MTPSC

On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA and to file a proposal for the impacts on the electric segment by March 31, 2018. On April 2, 2018, Montana-Dakota submitted its plan requesting the MTPSC recognize the identified need for additional rate relief and to consider the effects of the TCJA in a general electric rate case to be submitted by September 30, 2018. Montana-Dakota submitted the general electric rate case on September 28, 2018, as discussed below. On November 30, 2018, Montana-Dakota and interveners of the case submitted a stipulation and settlement agreement reflecting a one-time refund of approximately $1.5 million to account for all TCJA related impacts from January 1, 2018 through the date new rates are effective in the rate case noted below. A hearing was held on December 4, 2018, and the MTPSC issued an order accepting the stipulation and settlement agreement on December 21, 2018, requiring a one-time bill credit to occur in April 2019. The TCJA refund was issued to customers on March 29, 2019.

On September 28, 2018, Montana-Dakota filed an application with the MTPSC for an electric rate increase of approximately $11.9 million annually or approximately 18.9 percent above current rates. The requested increase is primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. The increase was offset by tax savings related to the TCJA. On March 7, 2019, the MTPSC issued an interim order authorizing an interim increase of $7.9 million or 12.8% to be effective April 1, 2019. The interim increase is subject to refund depending on the final outcome of the rate case. This matter is pending before the MTPSC.

NDPSC

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately $5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota also introduced a SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately $4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately $2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. On March 1, 2018, the updated interim rates were implemented. The impact of the TCJA was submitted as part of a rebuttal testimony identifying a reduction of the adjusted revenue requirement to approximately $3.6 million. On July 19, 2018, a settlement was filed reflecting a revised annual revenue increase of approximately $2.5 million or approximately 2.3 percent. The proposed adjustment mechanism to fund the SSIP was not included in the settlement and will be decided on separately by the NDPSC. On September 26, 2018, the NDPSC issued an order approving the settlement as filed but did not approve the SSIP recovery mechanism. On October 5, 2018, Montana-Dakota submitted a compliance filing, which included a plan for the one-time refund to be available March 1, 2019, for the interim amount to be refunded to customers. The NDPSC approved the compliance rates and were effective with service rendered on and after December 1, 2018. The interim refund was issued to customers on March 1, 2019.

On January 10, 2018, the NDPSC issued a general order initiating the investigation into the effects of the TCJA. The order required regulatory deferral accounting on the impacts of the TCJA and for companies to file comments and the expected impacts. On February 15, 2018, Montana-Dakota filed a summary of the primary impacts of the TCJA on the electric and natural gas utilities. On March 9, 2018, Montana-Dakota submitted a request to decrease its electric rates by $7.2 million or 3.9 percent annually. On August 10, 2018, a settlement agreement was filed requesting a decrease in rates of approximately $8.4 million. On September 26, 2018, the NDPSC issued an order approving the settlement along with requiring an additional adjustment to the rates to return 100 percent of the tax-effective 2018 excess deferred income taxes. On October 10, 2018, Montana-Dakota submitted a compliance filing, which included a refund plan for the interim amount to be refunded to customers. On November 20, 2018, the NDPSC approved the compliance rates which were effective with service rendered on and after December 1, 2018. The NDPSC also approved a one-time refund of approximately $7.9 million to be credited to customers' bills by March 15, 2019, based on 4.7 percent of the revenues collected between January 1, 2018, through November 30, 2018. The TCJA refund was issued to customers on March 12, 2019.

On October 19, 2018, Great Plains and the NDPSC advocacy staff filed a settlement agreement to resolve all outstanding issues in the NDPSC's investigation into the TCJA and a revenue neutral tariff filing submitted by Great Plains. The settlement agreement provides for miscellaneous tariff changes and a reduction in annual revenues of $168,000. On January 9, 2019, the NDPSC issued an order approving the settlement agreement and a refund requirement for the period from January 1, 2018 through the month preceding the effective date of the rate change. On January 23, 2019, the NDPSC approved the compliance rates to be effective February 1, 2019, along with the refund plan that provides for approximately $200,000 in refunds to be credited to customers' bills by April 15, 2019. New rates were implemented on February 1, 2019. The refund is scheduled to be issued to customers on April 12, 2019.

SDPUC

On December 29, 2017, the SDPUC issued an order initiating the investigation into the effects of the TCJA. The order required Montana-Dakota to provide comments by February 1, 2018, regarding the general effects of the TCJA on the cost of service in South Dakota and possible mechanisms for adjusting rates. The order also stated that all rates impacted by the federal income tax shall be adjusted effective January 1, 2018, subject to refund. On May 4, 2018 and June 2, 2018, Montana-Dakota submitted detailed plans to address the TCJA impacts on the natural gas and electric utilities, respectively, to the SDPUC staff. On September 28, 2018, a settlement agreement was submitted to the SDPUC reflecting a proposal to refund approximately $600,000 to electric customers and approximately $1.3 million to natural gas customers. These refunds reflect the impact of the TCJA on 2018. On October 23, 2018, an order was issued by the SDPUC approving the settlement agreement with the refunds being credited to customers' bills beginning on February 15, 2019. On December 3, 2018, Montana-Dakota submitted proposed rate changes to reflect 2018 pro forma results and the TCJA impacts. On December 28, 2018, the SDPUC approved an annual decrease in revenues of approximately $300,000 for the natural gas operations and approximately $100,000 for the electric operations. The decrease in revenues was effective January 1, 2019. The TCJA refund was issued to customers on February 15, 2019.

WYPSC

On December 29, 2017, the WYPSC issued a general order requiring regulatory deferral accounting on the impacts of the TCJA. A technical conference was held on February 6, 2018, to discuss the implications of the TCJA. On March 23, 2018, the WYPSC issued an order requiring all public utilities to submit an initial assessment of the overall effects on the TCJA on their rates by March 30, 2018. On March 30, 2018, Montana-Dakota submitted its initial assessment indicating a rate reduction for its electric rates in the amount of approximately $1.1 million annually or approximately 4.2 percent. Revised electric rates reflecting this reduction were submitted to the WYPSC on June 13, 2018. Montana-Dakota reported its natural gas earnings do not support a decrease in rates and requested the WYPSC allow the impacts of the TCJA be addressed in a natural gas rate case to be submitted by June 1, 2019. On March 19, 2019, the WYPSC ruled to approve Montana-Dakota’s requested decrease in electric rates and required a refund to customers for the period of January 1, 2018, through the date prior to the implementation of rates within 90 days of the effective date of new rates. Compliance electric rates were submitted to the WYPSC on April 4, 2019. Both matters are pending before the WYPSC.

FERC

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. On March 15, 2018, the FERC approved the waiver request and new rates reflecting the effects of the TCJA were implemented by MISO on March 1, 2018. MISO also retroactively re-billed the January and February 2018 services to reflect the new rates. On September 4, 2018, Montana-Dakota filed an update to its transmission formula rate under the MISO tariff for the multivalue project for $12.5 million, which is effective January 1, 2019.

Note 17 - Commitments and Contingencies

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of $190,000 and $283,000 which have not been discounted, for contingencies related to litigation as of December 31, 2018 and 2017, respectively. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Legal costs are expensed as they are incurred.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
				(In thousands)		
Operating leases	$1,802	$1,738	$1,610	$1,386	$1,340	$27,122

Rent expense was $1.9 million and $2.7 million for the years ended December 31, 2018 and 2017, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 22 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
				(In thousands)		
Purchase commitments	$167,413	$89,378	$61,099	$20,883	$18,401	$22,298

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2018 and 2017, were $292.6 million and $256.7 million, respectively.

Note 18 - Subsequent Event

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 in Sidney, Montana, and in late 2021 in Mandan, North Dakota. A plan is in place to maintain staff until the plant retirements. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Intangible Plant**			
4	301	Organization			
5	302	Franchises & Consents			
6	303	Miscellaneous Intangible Plant	$6,485,092	$6,964,462	7.39%
7					
8		**Total Intangible Plant**	$6,485,092	$6,964,462	7.39%
9					
10		**Production Plant**			
12	**Steam Production**				
14	310	Land & Land Rights	$233,855	$241,163	3.13%
15	311	Structures & Improvements	18,028,026	24,329,514	34.95%
16	312	Boiler Plant Equipment	75,022,188	68,703,235	-8.42%
17	313	Engines & Engine Driven Generators			
18	314	Turbogenerator Units	12,972,506	13,406,461	3.35%
19	315	Accessory Electric Equipment	3,972,901	5,262,075	32.45%
20	316	Miscellaneous Power Plant Equipment	4,488,551	5,212,839	16.14%
21					
22		**Total Steam Production Plant**	$114,718,027	$117,155,287	2.12%
23					
24	**Nuclear Production**				
26	320	Land & Land Rights			
27	321	Structures & Improvements			
28	322	Reactor Plant Equipment	NOT	NOT	
29	323	Turbogenerator Units	APPLICABLE	APPLICABLE	
30	324	Accessory Electric Equipment			
31	325	Miscellaneous Power Plant Equipment			
32					
33		**Total Nuclear Production Plant**			
34					
35	**Hydraulic Production**				
37	330	Land & Land Rights			
38	331	Structures & Improvements			
39	332	Reservoirs, Dams & Waterways	NOT	NOT	
40	333	Water Wheels, Turbines & Generators	APPLICABLE	APPLICABLE	
41	334	Accessory Electric Equipment			
42	335	Miscellaneous Power Plant Equipment			
43	336	Roads, Railroads & Bridges			
44					
45		**Total Hydraulic Production Plant**			

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 19**

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Production Plant (cont.)**			
4	**Other Production**				
6	340	Land & Land Rights	$9,038	$9,155	1.29%
7	341	Structures & Improvements	2,157,251	9,534,947	342.00%
8	342	Fuel Holders, Producers & Accessories	496,371	470,034	-5.31%
9	343	Prime Movers			
10	344	Generators	108,867,254	114,244,023	4.94%
11	345	Accessory Electric Equipment	4,316,445	13,988,864	224.08%
12	346	Miscellaneous Power Plant Equipment	435,602	449,678	3.23%
13					
14		**Total Other Production Plant**	$116,281,961	$138,696,701	19.28%
15					
16		**Total Production Plant**	$230,999,988	$255,851,988	10.76%
17					
18		**Transmission Plant**			
20	350	Land & Land Rights	$831,860	$831,675	-0.02%
21	352	Structures & Improvements	420	425	1.19%
22	353	Station Equipment	27,344,201	27,890,127	2.00%
23	354	Towers & Fixtures	1,112,330	1,126,630	1.29%
24	355	Poles & Fixtures	15,938,818	15,022,987	-5.75%
25	356	Overhead Conductors & Devices	9,620,475	10,898,266	13.28%
26	357	Underground Conduit	283,929	287,593	1.29%
27	358	Underground Conductors & Devices	541,254	548,239	1.29%
28	359	Roads & Trails			
29					
30		**Total Transmission Plant**	$55,673,287	$56,605,942	1.68%
31					
32		**Distribution Plant**			
34	360	Land & Land Rights	$285,059	$285,059	0.00%
35	361	Structures & Improvements			
36	362	Station Equipment	11,116,040	11,638,448	4.70%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	9,155,326	10,186,446	11.26%
39	365	Overhead Conductors & Devices	6,993,458	7,189,073	2.80%
40	366	Underground Conduit	12,967	12,967	0.00%
41	367	Underground Conductors & Devices	12,917,717	13,539,262	4.81%
42	368	Line Transformers	13,082,417	13,511,602	3.28%
43	369	Services	6,254,145	6,428,615	2.79%
44	370	Meters	3,327,228	3,340,686	0.40%
45	371	Installations on Customers' Premises	1,037,341	1,093,526	5.42%
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems	2,104,648	2,696,068	28.10%
48					
49		**Total Distribution Plant**	$66,286,346	$69,921,752	5.48%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1					
2		**General Plant**			
4	389	Land & Land Rights	$8,334	$8,399	0.78%
5	390	Structures & Improvements	290,239	293,148	1.00%
6	391	Office Furniture & Equipment	66,771	48,863	-26.82%
7	392	Transportation Equipment	1,878,052	1,969,159	4.85%
8	393	Stores Equipment			
9	394	Tools, Shop & Garage Equipment	1,010,577	1,213,674	20.10%
10	395	Laboratory Equipment	69,809	48,045	-31.18%
11	396	Power Operated Equipment	3,498,128	3,264,420	-6.68%
12	397	Communication Equipment	233,776	361,743	54.74%
13	398	Miscellaneous Equipment	11,495	11,550	0.48%
14	399	Other Tangible Property			
15					
16	**Total General Plant**		$7,067,181	$7,219,001	2.15%
17					
18		**Common Plant**			
20	389	Land & Land Rights	$216,046	$334,418	54.79%
21	390	Structures & Improvements	4,675,645	4,873,699	4.24%
22	391	Office Furniture & Equipment	657,058	683,369	4.00%
23	392	Transportation Equipment	1,630,518	1,677,188	2.86%
24	393	Stores Equipment	24,115	32,876	36.33%
25	394	Tools, Shop & Garage Equipment	124,813	124,393	-0.34%
26	395	Laboratory Equipment			
27	396	Power Operated Equipment			
28	397	Communication Equipment	524,025	500,713	-4.45%
29	398	Miscellaneous Equipment	149,133	151,704	1.72%
30	399	Other Tangible Property			
31					
32	**Total Common Plant**		$8,001,353	$8,378,360	4.71%
34					
35	**Total Electric Plant in Service**		$374,513,247	$404,941,505	8.12%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 20**

MONTANA DEPRECIATION SUMMARY

Year: 2018

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production 1/	$119,623,229	$59,845,432	$61,300,828	2.58%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	138,696,701	23,594,016	27,595,959	3.24%
6	Transmission	56,605,942	22,930,336	23,598,038	1.70%
7	Distribution	69,921,752	27,661,453	27,207,133	0.50%
8	General	8,535,558	2,500,855	2,619,132	2.72%
9	Common	14,026,265	6,326,124	6,820,709	4.00%
10	**Total**	$407,409,447	$142,858,216	$149,141,799	2.38%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	$1,218,821	$1,272,348	4.39%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	710,022	725,141	2.13%
9	Transmission Plant (Estimated)	544,279	1,376,409	152.89%
10	Distribution Plant (Estimated)	1,311,120	1,398,511	6.67%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16	**Total Materials & Supplies**	$3,784,242	$4,772,409	26.11%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	2007.7.79			
2	Order Number	6846f			
3					
4	Common Equity		50.67%	10.25%	5.19%
5	Preferred Stock		3.58%	4.61%	0.17%
6	Long Term Debt		38.18%	7.22%	2.76%
7	Short Term Debt		7.57%	6.11%	0.46%
8	**TOTAL**		100.00%		8.58%
9					
10	Actual at Year End				
11					
12	Common Equity		49.258%	10.250%	5.049%
13	Long Term Debt		46.371%	4.921%	2.282%
14	Short Term Debt		4.371%	2.906%	0.127%
15	**TOTAL**		100.000%		7.458%

1/ Includes acquisition adjustment.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 23**

STATEMENT OF CASH FLOWS

Year: 2018

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$281,202,988	$272,318,357	-3.16%
5	Depreciation	67,700,375	72,312,708	6.81%
6	Amortization	495,300	343,465	-30.66%
7	Deferred Income Taxes - Net	34,925,280	9,711,851	-72.19%
8	Investment Tax Credit Adjustments - Net	190,592	1,546,913	711.64%
9	Change in Operating Receivables - Net	(426,114)	(14,436,634)	-3287.97%
10	Change in Materials, Supplies & Inventories - Net	4,163,158	(2,820,729)	-167.75%
11	Change in Operating Payables & Accrued Liabilities - Net	2,207,920	23,281,803	954.47%
12	Change in Other Regulatory Assets	5,923,937	8,688,521	46.67%
13	Change in Other Regulatory Liabilities	(1,212,357)	563	100.05%
14	Allowance for Other Funds Used During Construction (AFUDC)	(400,908)	(1,026,572)	-156.06%
15	Change in Other Assets & Liabilities - Net	(15,841,825)	22,778,222	243.79%
16	Less Undistributed Earnings from Subsidiary Companies	(102,928,921)	(95,210,157)	7.50%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$275,999,425	$297,488,311	7.79%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($145,516,664)	($243,141,453)	-67.09%
23	Acquisition of Other Noncurrent Assets	(468,090)	(527,466)	-12.68%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(40,000,000)	30,000,000	175.00%
26	Contributions and Advances from Affiliates	40,000,000	0	-100.00%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	1,064,862	811,995	-23.75%
29	**Net Cash Provided by/(Used in) Investing Activities**	($144,919,892)	($212,856,924)	-46.88%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$70,500,000	$200,000,000	183.69%
34	Preferred Stock			
35	Common Stock		(10,000)	100.00%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Repurchase of Common Stock	(564,642)	(1,920,095)	-240.06%
39	Other: Tax Withholding on Stock-Based Compensation	(508,519)	(1,720,999)	-238.43%
40	Payment for Retirement of:			
41	Long-Term Debt	(37,568,736)	(125,960,755)	-235.28%
42	Preferred Stock	(15,600,000)	0	100.00%
43	Common Stock			
44	Other: Adjustment to Retained Earnings			
45	Net Decrease in Short-Term Debt			
46	Dividends on Preferred Stock	(342,501)	0	100.00%
47	Dividends on Common Stock	(150,384,383)	(154,572,486)	-2.78%
48	Other Financing Activities (related to IGC acquisition)			
49	**Net Cash Provided by (Used in) Financing Activities**	($134,468,781)	($84,184,335)	37.39%
50				
51	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($3,389,248)	$447,052	113.19%
52	**Cash and Cash Equivalents at Beginning of Year**	$4,159,083	$769,835	-81.49%
53	**Cash and Cash Equivalents at End of Year**	$769,835	$1,216,887	58.07%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 24**

LONG TERM DEBT Year: 2018

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	5.98% Senior Notes	12/03	12/33	$30,000,000	$29,375,535	$30,000,000	5.98%	$1,863,000	6.21%
2	6.33% Senior Notes	08/06	08/26	100,000,000	89,123,930	100,000,000	6.33%	7,514,000	7.51%
3	5.18% Senior Notes	04/14	04/44	50,000,000	49,760,822	50,000,000	5.18%	2,640,000	5.28%
4	4.24% Senior Notes	07/14	07/24	60,000,000	59,708,737	60,000,000	4.24%	2,607,600	4.35%
5	4.34% Senior Notes	07/14	07/26	40,000,000	39,802,958	40,000,000	4.34%	1,776,800	4.44%
6	3.78% Senior Notes	10/15	10/25	87,000,000	86,528,003	87,000,000	3.78%	3,378,210	3.88%
7	4.03% Senior Notes	12/15	12/30	52,000,000	51,713,645	52,000,000	4.03%	2,143,440	4.12%
8	4.87% Senior Notes	10/15	10/45	11,000,000	10,940,539	11,000,000	4.87%	546,040	4.96%
9	4.15% Senior Notes	11/16	11/46	40,000,000	39,773,916	40,000,000	4.15%	1,691,200	4.23%
10	3.73% Senior Notes	03/17	03/37	40,000,000	39,826,363	40,000,000	3.73%	1,518,800	3.80%
11	3.36% Senior Notes	03/17	03/32	20,000,000	19,913,929	20,000,000	3.36%	685,000	3.43%
12	2.00% Senior Notes	09/17	09/32	10,500,000	10,500,000	9,800,000	2.00%	196,000	2.00%
13	Minot Air Force Base Payable	09/08	11/38	509,197		425,495	6.00%	25,530	6.00%
14	LIBOR Floating Rate Note	09/18	10/19	100,000,000	99,600,000	100,000,000	Variable	4,755,000	4.76%
15	LIBOR Floating Rate Note	10/18	11/19	100,000,000	99,600,000	100,000,000	Variable	4,755,000	4.76%
16	Revolving Credit Facility	06/18	06/23			48,500,000	Variable		
17	Amortization of Loss on Reacquired Debt							43,469	
18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$741,009,197	$726,168,377	$788,725,495		$36,139,089	4.58%

1/ Yield to maturity based upon the life, net proceeds and semiannual compunding of stated interest rate.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 25**

PREFERRED STOCK Year: 2018

	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										
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26										
27										
28										
29										
30										
31										
32	**TOTAL**					$0		$0	$0	0.00%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 26**

COMMON STOCK

Year: 2018

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 3/
1	January								
2									
3	February								
4									
5	March	195,304,376	$12.42	$0.22	$0.1975	10.23%	$28.23	$24.29	18.9
6									
7	April								
8									
9	May								
10									
11	June	195,524,052	12.50	0.22	0.1975	10.23%	29.28	27.05	19.2
12									
13	July								
14									
15	August								
16									
17	September	196,018,324	12.86	0.55	0.1975	64.09%	29.62	25.33	16.3
18									
19	October								
20									
21	November								
22									
23	December	196,022,905	13.09	0.40	0.2025	49.38%	26.96	22.73	17.3
24									
25	TOTAL Year End	196,022,905	$13.09	$1.39	$0.7950	42.81%			

1/ Basic shares
2/ Basic earnings per share.
3/ Calculated on 12 months ended using closing stock price.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 27**

MONTANA EARNED RATE OF RETURN Year: 2018

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service 1/	$374,513,247	$404,941,505	8.12%
3	108	(Less) Accumulated Depreciation 2/	140,421,716	146,673,857	4.45%
4					
5		**Net Plant in Service**	$234,091,531	$258,267,648	10.33%
6					
7		Additions			
8	151	Fuel Stocks	$1,218,821	$1,272,348	4.39%
9	154, 156	Materials & Supplies	2,565,421	3,500,061	36.43%
10	165	Prepayments	56,379	50,239	-10.89%
11	189	Unamortized Loss on Debt	733,689	648,892	-11.56%
12	254	Other Regulatory Liability	(4,685,674)	(3,241,668)	30.82%
13		Provision for Pension & Benefits	4,167,013	4,859,012	16.61%
14		Provision for Injuries & Damages	(40,559)	(29,624)	26.96%
15					
16		**Total Additions**	$4,015,090	$7,059,260	75.82%
17		Deductions			
18	282	Accumulated Deferred Income Taxes	$44,395,222	$50,722,286	14.25%
19	252	Customer Advances for Construction	1,023,510	766,775	-25.08%
20	255	Accumulated Def. Investment Tax Credits			
21		Other Deductions			
22		DIT Related to Pension	1,607,261	1,200,803	-25.29%
23		DIT Related to Injuries & Damages	(15,371)	(7,226)	52.99%
24					
25		**Total Deductions**	$47,010,622	$52,682,638	12.07%
26		**Total Rate Base**	$191,095,999	$212,644,270	11.28%
27					
28		**Net Earnings**	$10,572,077	$8,841,757	-16.37%
29					
30		**Rate of Return on Average Rate Base**	5.54%	4.38%	-20.94%
31					
32		**Rate of Return on Average Equity**	6.06%	3.92%	-35.31%
33		Major Normalizing Adjustments & Commission			
34		Ratemaking Adjustments to Utility Operations			
35		Adjustments to Operating Revenues 3/			
36		Gain (Loss) from Disposition of Property 4/	(13,189)	(16,088)	-21.98%
37					
38		Adjustments to Operating Expenses 3/			
39		Elimination of Promotional & Institutional Advertising	(6,909)	(9,570)	-38.51%
40					
41		Other Adjustments to Federal & State Income Taxes			
42		Federal & State Out of Period & Closing/Filing	260,288	(588,161)	-325.97%
43		Deferred Federal & State Out of Period & Closing/Filing	(257,629)	608,395	336.15%
44		Total Adjustments to Operating Income	($8,939)	($26,752)	199.27%
45					
46		**Adjusted Rate of Return on Average Rate Base**	5.54%	4.37%	-21.12%
47					
48		**Adjusted Rate of Return on Average Equity**	6.06%	3.90%	-35.64%

1/ Excludes Acquisition Adjustment of $2,436,500 for 2017 and $2,467,942 for 2018.
2/ Excludes Acquisition Adjustment of $2,436,500 for 2017 and $2,467,942 for 2018.
3/ Updated amounts, net of taxes.
4/ Amortized over 5 years.

MONTANA COMPOSITE STATISTICS

Year: 2018

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$345,621
5	107	Construction Work in Progress	5,473
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	3,500
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	146,674
11	252	Contributions in Aid of Construction	767
12			
13		**NET BOOK COSTS**	$207,153
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	$68,264
18			
19	403 - 407	Depreciation & Amortization Expenses	$9,690
20		Federal & State Income Taxes	(2,433)
21		Other Taxes	5,813
22		Other Operating Expenses	46,352
23		Total Operating Expenses	$59,422
24			
25		Net Operating Income	$8,842
26			
27		Other Income	251
28		Other Deductions	4,504
29			
30		**NET INCOME**	$4,589
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	19,679
36		Small General	5,616
37		Large General	252
38		Other	161
39			
40		**TOTAL NUMBER OF CUSTOMERS**	25,708
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	9,601
45		Average Annual Residential Cost per (Kwh) *	$0.095
46		* Avg annual cost = [(cost per Kwh x annual use) +	
47		(mo. svc chrg x 12)]/annual use	
48		Average Residential Monthly Bill	$76.01
49		Gross Plant per Customer	$13,444

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 29**

MONTANA CUSTOMER INFORMATION

Year: 2018

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	51	67	19	2	88
2	Bainville	208	156	48	4	208
3	Baker	1,741	973	360	24	1,357
4	Brockton	255	101	23	1	125
5	Carlyle	Not Available	2	5		7
6	Culbertson	714	398	149	5	552
7	Fallon	164	195	132		327
8	Fairview	840	435	112	3	550
9	Flaxville	71	59	28	2	89
10	Forsyth	1,777	1,011	295	12	1,318
11	Froid	185	150	51	2	203
12	Glendive	4,935	3,404	877	48	4,329
13	Homestead	Not Available	23	10	1	34
14	Ismay	19	26	23		49
15	Kinsey	Not Available	117	72		189
16	Medicine Lake	225	185	60	2	247
17	Miles City	8,410	4,612	1,138	58	5,808
18	Outlook	47	55	40	9	104
19	Plentywood	1,734	990	258	5	1,253
20	Plevna	162	99	36	1	136
21	Poplar	810	904	180	12	1,096
22	Poplar Oil Field	Not Available		5	8	13
23	Redstone	Not Available	15	21		36
24	Reserve	23	23	11	2	36
25	Rosebud	111	68	71	3	142
26	Savage	Not Available	143	33	1	177
27	Scobey	1,017	592	172	4	768
28	Sidney	5,191	2,948	555	34	3,537
29	Terry	605	361	117	6	484
30	Whitetail	Not Available	27	22		49
31	Wibaux	589	290	105	12	407
32	Wolf Point	2,621	1,481	304	17	1,802
33	MT Oil Fields	Not Available	8	72	73	153
34	**TOTAL Montana Customers**	32,505	19,918	5,404	351	25,673

1/ 2010 Census.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 30**

MONTANA EMPLOYEE COUNTS Year: 2018

	Department	Year Beginning	Year End	Average
1	Electric	26	24	25
2	Gas	38	36	37
3	Accounting	4	4	4
4	Management	4	6	5
5	Service	36	39	38
6	Training	0	0	0
7	Power Production	38	38	38
8				
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43				
44	**TOTAL Montana Employees**	146	147	147

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2018

	Project Description	Total Company	Total Montana	
1	**Projects>$1,000,000**			
2				
3	**Common-General**			
4	Renovate purchased Substation and Communications building in Bismarck	$4,031,935	$884,357	1/
5				
6	**Common-Intangible**			
7	Purchase Workforce Asset Management software for the Company	2,841,596	623,270	1/
8				
9	**Total Common**	$6,873,531	$1,507,627	
10				
11	**Electric-Distribution**			
12	Construct 115/6.9kV substation for Keystone Pipeline	$2,852,640	$2,852,640	2/
13	Replace street lighting with LED lighting in ND	2,497,695	0	
14				
15	**Electric-Steam Production**			
16	Install bank erosion improvements at Lewis & Clark Station	3,792,881	901,129	1/
17	Construct ash disposal cells at Heskett Station	1,705,513	405,203	1/
18	Install slag pond liner for Coal Combustion Residuals Compliance at Coyote	1,286,420	305,633	1/
19				
20	**Electric-Other Production**			
21	Replace gearboxes at Diamond Willow wind farm	1,288,213	337,391	1/
22				
23	**Electric-Transmission**			
24	Install 115kV breakers in N junction substation in Dickinson, ND	3,587,124	0	
25	Construct 115kV line from Ellendale, ND to Leola, SD (ND portion)	3,429,178	814,719	1/
26	Construct 115KV line from Ellendale, ND to Leola, SD (SD portion)	3,113,764	739,782	1/
27	Construct 345KV line-Big Stone to Ellendale, ND	2,458,796	0	
28	Construct 115kV loop line in Dickinson, ND	2,381,173	0	
29	Construct 34.5KV line from WAPA sub to NW Watford City, ND	2,305,965	0	
30	Install 115kV oilfield line tap from Glendive to Baker, MT	2,157,920	2,157,920	2/
31	Rebuild 60kV line from Glendive to Baker, MT	2,099,156	2,099,156	2/
32	Install 60kV loop line from Rosebud to Forsyth, MT	1,907,446	1,907,446	2/
33	Reconductor 115kV double circuit from Lewis & Clark to Richland substations	1,370,723	325,662	1/
34	Add 115KV bay for junction substation in Ellendale, ND	1,058,924	225,614	1/
35				
36	**Total Electric**	$39,293,531	$13,072,295	
37				
38	**Gas-Distribution**			
39	Construct main to serve new facilities in Menoken, ND	$1,002,668	0	
40				
41	**Gas-General**			
42	Construct office/shop in Glasgow, MT	1,013,953	$1,013,953	2/
43				
44	**Total Gas**	$2,016,621	$1,013,953	
45	**Total Projects >$1,000,000**	$48,183,683	$15,593,875	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) **Year: 2018**

	Project Description	Total Company	Total Montana	
1	**Other Projects<$1,000,000**			
2				
3	**Electric**			
4	Production	$13,003,490	$2,554,243	1/
5	Integrated Transmission	2,507,053	449,508	1/
6	Direct Transmission	4,873,996	686,712	2/
7	Distribution	27,678,021	5,684,346	3/
8	General	6,222,682	1,200,805	3/
9	Intangible	2,021,622	451,707	1/
10	Common:			
11	General Office	4,475,932	923,828	1/
12	Other Direct	744,460	180,491	3/
13				
14	**Total Other Electric**	$61,527,256	$12,131,640	
15				
16	**Gas**			
17	Distribution	$35,428,428	$10,984,748	3/
18	General	4,787,178	1,199,735	3/
19	Intangible	439,718	82,752	1/
20	Common:			
21	General Office	2,730,019	657,494	1/
22	Other Direct	391,711	133,545	3/
23				
24	**Total Other Gas**	$43,777,054	$13,058,274	
25	**Total Other Projects <$1,000,000**	$105,304,310	$25,189,914	
26				
27	**Total Projects**	$153,487,993	$40,783,789	

1/ Allocated to Montana.
2/ Directly assigned to Montana.
3/ Combination of allocated and directly assigned to Montana.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 32**

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 2018

Integrated System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	16	900	565.1	331,591	938
2	Feb.	12	1000	540.8	315,240	337
3	Mar.	8	900	467.2	291,743	4,234
4	Apr.	6	900	470.5	252,718	690
5	May	26	1800	463.8	250,024	3,658
6	Jun.	28	1700	532.9	264,175	6,447
7	Jul.	10	1700	572.4	288,403	3,059
8	Aug.	10	1800	566.8	285,152	958
9	Sep.	7	1700	453.1	244,532	3,199
10	Oct.	15	900	412.3	255,385	2,314
11	Nov.	9	900	478.2	296,599	3,483
12	Dec.	31	1900	506.0	324,989	16,657
13	**TOTAL**				3,400,551	45,974

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	16	900	125.7		
15	Feb.	12	1000	135.5		
16	Mar.	8	900	114.5		
17	Apr.	6	900	108.2		
18	May	26	1800	102.4		
19	Jun.	28	1700	119.3		
20	Jul.	10	1700	132.6	Not Available	Not Available
21	Aug.	10	1800	145.8		
22	Sep.	7	1700	113.6		
23	Oct.	15	900	95.8		
24	Nov.	9	900	117.7		
25	Dec.	31	1900	122.7		
26	**TOTAL**					

TOTAL SYSTEM SOURCES & DISPOSITION OF ENERGY

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,235,939	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	3,354,401
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	604,414	for Resale	
7	(Less) Energy for Pumping			
8	**NET Generation**	2,840,353	Non-Requirements Sales	
9	Purchases	831,039	for Resale	45,974
10	Power Exchanges			
11	Received		Energy Furnished	
12	Delivered		Without Charge	
13	**NET Exchanges**			
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	1,173,621	Electric Utility	
16	Delivered	1,150,810		
17	**NET Transmission Wheeling**	22,811	Total Energy Losses	293,828
18	Transmission by Others Losses			
19	**TOTAL**	3,694,203	**TOTAL**	3,694,203

Montana-Dakota's annual peak occurred during HE1700 July 10, 2018. All generation units were available for operation during the peak hour. The following units were on line and providing energy:

Big Stone	92.4
Cedar Hills	7.4
Coyote	106.7
Diamond Willow	16.7
Glendive Turbine	0.0
Glen Ullin Ormat	4.6
Heskett #1	21.3
Heskett #2	65.1
Heskett #3	0.0
Lewis & Clark	40.4
Lewis & Clark 2	11.0
Miles City	0.0
Thunder Spirit	25.0

Montana-Dakota also purchased 174.624 MW from MISO to meet energy requirements at the time of the system peak.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 34**

SOURCES OF ELECTRIC SUPPLY - INTEGRATED SYSTEM

Year: 2018

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Big Stone Station 1/	Milbank, SD	108.09	521,187
2	Wind	Cedar Hills	Rhame, ND	19.50	49,933
3	Thermal	Coyote Station 1/	Beulah, ND	106.98	765,233
4	Wind	Diamond Willow	Baker, MT	30.20	86,103
5	Heat Recovery	Glen Ullin Ormat Sub	Glen Ullin, ND	7.70	44,940
6	Combustion Turbine	Glendive Turbine	Glendive, MT	76.28	2,734
7	Combustion Turbine	Heskett Station	Mandan, ND	101.53	3,981
8	Thermal	Heskett Station	Mandan, ND	99.00	504,357
9	Combustion Turbine	Lewis & Clark Station	Sidney, MT	19.00	8,497
10	Thermal	Lewis & Clark Station	Sidney, MT	51.08	235,882
11	Combustion Turbine	Miles City Turbine	Miles City, MT	26.00	273
12	Oil	Portable Generators	Ray/Alexander,ND	6.00	6
13	Wind	Thunder Spirit	Hettinger, ND	144.00	407,947
14	Purchased Power				746,667
15					
16					
17					
18					
19					
20					
21					
22					
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38					
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40					
41	**Total 2/**			795.36	3,377,740

1/ Reflects Montana-Dakota Utilities' share.
2/ Excludes Wyoming generation of 209,280 Mwh and purchased power of 84,372 Mwh.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 34A**

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		Big Stone Plant
03/04/2018 23:05	03/05/2018 01:16	A ID Fan VFD Fault
04/13/2018 16:50	04/29/2018 02:30	Planned Outage
04/29/2018 02:30	04/29/2018 23:56	Extraction Steam Valves Leaking
05/01/2018 18:05	05/03/2018 01:28	Valve 512 - #11 FWH Inlet Packing Failed
06/20/2018 21:00	06/21/2018 17:45	Main Steam Line Vent Valve Packing Failure
06/21/2018 17:45	06/23/2018 01:50	Boiler Waterwall Leak
08/31/2018 19:04	09/01/2018 22:56	Baghouse Repairs
09/04/2018 19:13	09/07/2018 00:20	Train 2 Scrubber Cleaning
09/15/2018 16:57	10/01/2018 00:00	Planned Outage
10/01/2018 00:00	11/01/2018 00:00	Planned Outage
11/01/2018 00:00	11/12/2018 00:00	Planned Outage
11/12/2018 00:00	11/12/2018 16:04	Stator Windings Issues
11/12/2018 16:04	11/14/2018 18:46	Tube Leak
11/15/2018 08:10	11/15/2018 09:19	Maintenance Procedure Issure
11/15/2018 20:00	11/17/2018 00:24	Tube Leak
		Coyote Station
03/01/2018 22:08	03/04/2018 18:00	Boiler Wash Outage
03/04/2018 18:00	03/05/2018 06:20	Extended Wash Outage
03/21/2018 12:42	03/24/2018 01:01	Waterwall Tube Leak
04/07/2018 02:12	04/07/2018 17:34	Turbine Rotor "A" Thrust Probe Failure
05/02/2018 19:14	05/04/2018 11:23	Boiler Plugged Up - Vadikin Wash
05/04/2018 15:47	05/05/2018 17:07	#4 Cyclone Tube Leak
05/31/2018 04:03	06/06/2018 18:00	Boiler Wash Outage
06/06/2018 18:00	06/07/2018 22:36	Extended Wash Outage
06/14/2018 15:37	06/14/2018 17:20	"A" Circulating Water Pump Motor Lead Blew
07/31/2018 20:02	08/03/2018 08:36	Boiler Plugged Up - Vadikin Wash
10/05/2018 22:02	10/08/2018 18:00	Boiler Wash Outage
10/08/2018 18:00	10/10/2018 00:11	Extended Wash Outage
10/24/2018 18:50	10/26/2018 16:53	Rear Lower Wall Arch Tube Leak
10/30/2018 05:55	11/04/2018 15:46	Screen Tube Leak
11/05/2018 21:45	11/09/2018 03:10	6th Floor Waterwall Tube Leak
12/16/2018 21:57	12/20/2018 08:59	Boiler Wash Outage

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 34A**

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
		Lewis & Clark Station Unit 1
01/01/2018 00:00	01/10/2018 08:06	Generator Rotor Ground Issue
02/24/2018 09:31	02/24/2018 13:46	Ground Fault While Testing Online DCS
02/27/2018 03:20	02/27/2018 19:10	Deluge Spray Nozzle Broken, Repaired
03/30/2018 19:42	05/14/2018 00:00	Turbine Major/Exciter Replacement
05/14/2018 00:00	05/19/2018 08:36	Turbine Major/Exciter Replacement
05/19/2018 10:00	05/19/2018 13:35	Turbine Governor, Main Steam Header Transmitter Left Valved Out
05/19/2018 21:41	05/21/2018 07:10	Exciter Calibration
05/27/2018 20:59	06/02/2018 09:56	Lube Oil #5 Bearing Leak
06/16/2018 19:39	06/20/2018 07:49	Lube Oil #5 Bearing Leak
08/25/2018 00:07	09/10/2018 11:51	Boiler Inspection Scheduled/Routine - Cleaning
11/19/2018 20:29	11/21/2018 16:28	Wet Scrubber Inspection and Cleaning
11/27/2018 22:16	11/28/2018 21:17	Generator Brushes Arching/Inspection and Repair
12/06/2018 09:31	12/06/2018 11:26	Generator Trip Due to Brush Rigging Short Circuit
		R.M. Heskett Unit 1
04/07/2018 21:36	04/16/2018 14:38	Spring Outage (Cleaned Boiler, Including Grit Blasting)
10/20/2018 20:16	10/28/2018 05:05	Fall Outage
10/31/2018 14:01	11/01/2018 21:35	Stop Valve Test Not Working
		R.M. Heskett Unit II
03/31/2018 20:22	04/13/2018 02:00	Spring Outage (Cleaned Boiler, Including Grit Blasting)
04/13/2018 02:00	04/14/2018 10:36	Cleaning Took Longer Than Expected
05/05/2018 12:34	05/17/2018 05:13	Loss of Hydraulic Pressure. Checked for Internal Leakage.
10/06/2018 22:36	10/17/2018 09:10	Fall Outage

1/ Outages longer than 1 hour, other than reserve shutdowns for economic dispatch.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 35**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2018

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2	MT Conservation & DSM Program	$215,027	$89,309	140.77%	760.4	2,031.5	1,271
3	(As Detailed on Schedule 35B)						
4							
5							
6							
7							
8							
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28							
29							
30							
31							
32	**TOTAL**	$215,027	$89,309	140.77%	760.4	2,031.5	1,271

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 35A**

ELECTRIC UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2018

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	Commercial Lighting	$215,027	$0	$215,027	760.4 MWh	2018
3						
4						
5						
6						
7	Market Transformation					
8						
9						
10						
11						
12	Renewable Resources					
13						
14						
15						
16						
17	Research & Development					
18						
19						
20						
21						
22	Low Income					
23	Discounts	$281,054	$0	$281,054		2018
24						
25	Bill Assistance		90,000	90,000		2018
26						
27	Weatherization		45,000	45,000		2018
28						
29	Furnace Safety		50,000	50,000		2018
30						
31	Education	4,878	0	4,878		2018
32						
33	Energy Audits		10,000	10,000		2018
34	Large Customer Self Directed					
35	Customer A	$242,866	$0	$242,866		
36	Customer B	15,988		15,988		
37	Customer C	14,407		14,407		
38						
39						
40	Total	$774,220	$195,000	$969,220	760.4 MWh	
41	Number of customers that received low income rate discounts			(Average)	1,262	
42	Average monthly bill discount amount ($/mo)				$18.56	
43	Average LIEAP-eligible household income				N/A	
44	Number of customers that received weatherization assistance				N/A	
45	Expected average annual bill savings from weatherization				N/A	
46	Number of residential audits performed				N/A	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 35B**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2018

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	LED Lighting	$215,027	$0	$215,027	760.4 MWh	2018
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46	Total	$215,027	$0	$215,027	760.4 MWh	2018

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 36**

MONTANA CONSUMPTION AND REVENUES Year: 2018

	Sales of Electricity	**Operating Revenues** Current Year	Previous Year	**MegaWatt Hours Sold** Current Year	Previous Year	**Avg. No. of Customers** Current Year	Previous Year
1	Residential	$17,803,560	$17,273,829	188,930	185,466	19,679	19,744
2	Small General	10,722,457	10,534,307	119,830	121,219	5,616	5,601
3	Large General	32,699,963	31,391,247	489,012	482,329	252	265
4	Lighting	786,039	990,311	7,447	10,015	63	63
5	Municipal Pumping	449,348	507,988	5,753	6,890	98	99
6	Sales to Other Utilities			Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	**TOTAL**	$62,461,367	$60,697,682	810,972	805,919	25,708	25,772