

PRELIMINARY DRAFT – SUBJECT TO REVISION

DIRECT TESTIMONY AND SCHEDULES

JOEL F. JEANSON

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

MONTANA-DAKOTA UTILITIES CO.

CASE NO. PU-20-379

NATURAL GAS RATE CASE

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1 **I. Introduction and Qualifications**

2 **Q. Would you please state your name, affiliation, and address?**

3 **A.** My name is Joel F. Jeanson. I am a Principal Consultant at PA Consulting Group
4 (PA). My business address is 143 South Street, 6th Floor, Boston, MA 02111.

5
6 **Q. On whose behalf are you filing this testimony?**

7 **A.** I am filing this testimony on behalf of the Advocacy Staff of the North Dakota
8 Public Service Commission (Commission or NDPSC).

9
10 **Q. Please summarize your qualifications and experience.**

11 **A.** I have worked in the utility industry for over 40 years, primarily specializing in
12 regulatory finance and accounting issues. I started my professional career in the
13 audit division for a Big Eight accounting firm, working primarily with investor-
14 owned utility clients. After leaving public accounting I went to work for a large
15 Midwest utility in a variety of accounting, planning/budgeting, corporate
16 performance, and auditing roles. Since 2001, I have worked as a consultant to
17 clients in the utility and energy industry, including regulators, utility
18 management, and investors. My academic background includes a B.S. in
19 Business (with distinction) from Indiana University. I am a Certified Public
20 Accountant (inactive). My CV is provided in Exhibit JFJ-1.

21
22 **Q. Have you testified before the North Dakota Public Service Commission
23 previously?**

24 **A.** Yes. I testified on behalf of the Advocacy Staff of the Commission in the following
25 two cases:

- 26 • Northern States Power Company Advance Prudence – Biomass PPAs
27 Application for Deferred Accounting Case Nos. PU-17-322, PU-17-270, and
28 PU-17-271

- Montana-Dakota Utilities Application for Deferred Accounting Treatment
Case No. PU-19-317

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with an assessment of the reasonableness of the Montana-Dakota Utilities Co. (Montana-Dakota or the Company) requested revenue requirements in its natural gas rate case.

I have reviewed the Company’s Application including the direct testimony of Company witnesses and responses to data requests in order to develop conclusions and recommendations regarding the reasonableness of the Company’s requested revenue requirements. My review focused on those components of revenue requirements and related business drivers deemed significant based on my review of the Company’s Application and discussions with Commission Advocacy Staff.

Revenue requirements associated with the return on rate base is the subject of my colleague Aaron Rothschild’s testimony.

In addition, delivered natural gas costs are also excluded from my review.

Q. Would you please summarize the organization of your testimony?

A. Yes. My testimony is organized as follows:

- Overview of the Montana-Dakota Request
- Review of Rate Base excluding the Company’s request for the inclusion of provisions for pension and benefits and post retirement costs
- Review of Operating Expenses
- Review of request for the inclusion of provisions for pension and benefits and post retirement costs, net of accumulated deferred income taxes, in rate base

1 **Q. Are you sponsoring any exhibits to your testimony?**

2 **A.** Yes. I am sponsoring the following exhibit:

- 3
 - Exhibit JFJ-1: CV of Joel F. Jeanson
- 4

5 **II. Overview of Montana-Dakota Request**

6 **Q. Please describe the request for an increase in natural gas rates made by**
7 **Montana-Dakota in Case No. PU-20-379.**

8 **A.** In its Application and Notice of Change in Natural Gas Rates, Montana-Dakota
9 Utilities Co. in Case No. PU-20-379 requests authorization of an increase in
10 revenues which will provide Montana-Dakota a reasonable opportunity to earn a
11 fair rate of return for its North Dakota natural gas operations. Montana-Dakota
12 proposes a total increase of \$8,972,496 or 7.8 percent above current rates, based
13 on a 2021 test year. Only distribution costs, the cost of distributing the gas from
14 the town border station to the end use customer, are the subject of this application
15 for a general rate increase.

16 Company witness Kivisto represents the following as the primary drivers of the
17 requested increase:

- 18
 - Investments of approximately \$11.0 million between 2017 and 2019 to
19 improve the safety and reliability of its distribution system in North
20 Dakota.
 - Projected future investments of more than \$43.1 million to ensure system
21 safety and reliability between 2020 and 2024.
 - In total, Gross Plant in Service at the end of the 2021 projected test period
22 is expected to be \$336 million or nearly 22 percent greater than the gross
23 investment from the 2018 test year used in the last rate case.
 - Increases in labor and personnel costs and general cost increases across
24 its business line.
- 25
- 26
- 27

- The requested inclusion of the provision for pension and post-retirement benefits, net of the associated deferred taxes, to be added to rate base.

III. Review of Other O&M

Q. How do projected 2021 test year Other O&M Costs compare to historical levels?

A. The following tables compare test year costs to historical costs by a) FERC Uniform System of Accounts cost category and b) expense types as used by the Company. Compound annual growth rates (CAGR) are color coded to provide focus on those cost categories and expense types which have changed significantly among period examined going from dark red which signifies the highest rates of increase to dark green which signify the highest rates of decrease.

Non-Gas O&M Trends by Cost Category:

Cost Category	Historical Expenses					Projected Expenses	
	2015	2016	2017	2018	2019	2020	2021
Cost of Gas (COG)	\$75,354,753	\$54,268,701	\$70,600,163	\$75,245,401	\$77,820,648	\$72,535,424	\$73,319,285
Other Gas Supply	302,318	370,755	332,927	294,870	334,284	351,572	363,936
Transmission	13,598	6,930	12,751	6,695	10,215	10,322	10,523
Distribution	9,218,811	9,182,538	9,798,612	9,878,192	10,261,369	10,298,708	10,575,591
Customer Accounting	2,582,405	2,831,570	2,670,392	2,618,418	2,584,082	2,698,815	2,773,671
Customer Service & Info.	263,912	253,969	234,055	224,919	260,399	261,913	269,021
Sales	228,648	138,984	153,190	185,028	180,699	145,544	149,928
Administrative and General	7,360,867	8,138,083	8,707,440	8,397,054	9,107,793	9,323,160	9,826,032
Total O&M	\$95,325,312	\$75,191,530	\$92,509,530	\$96,850,577	\$100,559,489	\$95,625,458	\$97,287,987
Total O&M (excl. COG)	\$19,970,559	\$20,922,829	\$21,909,367	\$21,605,176	\$22,738,841	\$23,090,034	\$23,968,702

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Projected CAGR Analysis
(anchored off historical)

Cost Category	6-Year CAGR (2015-2021)	5-Year CAGR (2016-2021)	4-Year CAGR (2017-2021)	3-Year CAGR (2018-2021)	2-Year CAGR (2019-2021)
Cost of Gas (COG)	0%	6%	1%	-1%	-3%
Other Gas Supply	3%	0%	2%	7%	4%
Transmission	-4%	9%	-5%	16%	1%
Distribution	2%	3%	2%	2%	2%
Customer Accounting	1%	0%	1%	2%	4%
Customer Service & Info.	0%	1%	4%	6%	2%
Sales	-7%	2%	-1%	-7%	-9%
Administrative and General	5%	4%	3%	5%	4%
Total O&M	0%	5%	1%	0%	-2%
Total O&M (excl. COG)	3%	3%	2%	4%	3%

Non-Gas O&M Trends by Expense Type:

Expense Type	Historical Expenses					Projected Expenses	
	2015	2016	2017	2018	2019	2020	2021
Cost of Gas (COG)	\$75,354,753	\$54,268,701	\$70,600,163	\$75,245,401	\$77,820,648	\$72,535,424	\$73,319,285
Labor	10,093,759	11,190,721	11,639,814	11,561,732	12,706,971	12,926,451	13,342,105
Benefits	2,325,729	2,544,589	2,713,616	2,292,798	2,540,632	2,760,940	2,925,082
Subcontract Labor	1,967,309	1,704,158	1,722,782	2,022,194	1,945,282	1,953,838	1,991,743
Materials	762,041	607,753	805,831	748,257	727,482	731,590	745,783
Vehicles & Work Equip.	594,928	611,108	724,069	705,821	808,758	789,182	784,421
Company Consumption	267,637	176,913	212,313	243,578	302,897	240,938	240,938
Uncollectible Accounts	343,208	268,559	284,204	359,605	305,665	386,444	390,145
Postage	472,825	421,751	423,422	420,581	384,062	382,016	389,427
Software Maintenance	344,368	414,908	543,231	658,248	640,345	764,168	907,828
Building Rental	409,861	446,475	434,333	345,927	565,325	514,769	524,756
Advertising	237,236	186,160	136,482	166,657	166,858	126,396	128,848
Industry Dues	111,297	103,909	102,771	143,448	114,675	97,608	97,608
Insurance	587,748	567,329	676,116	687,278	846,612	708,518	729,774
Commission Expense	96,755	155,943	168,394	67,955	125,441	138,518	190,555
All Other O&M	1,355,858	1,522,553	1,321,989	1,181,097	557,836	568,657	579,689
Total O&M	\$95,325,312	\$75,191,530	\$92,509,530	\$96,850,577	\$100,559,489	\$95,625,458	\$97,287,987
Total O&M (excl. COG)	\$19,970,559	\$20,922,829	\$21,909,367	\$21,605,176	\$22,738,841	\$23,090,034	\$23,968,702

Projected CAGR Analysis
 (anchored off historical)

Expense Type	6-Year CAGR (2015-2021)	5-Year CAGR (2016-2021)	4-Year CAGR (2017-2021)	3-Year CAGR (2018-2021)	2-Year CAGR (2019-2021)
Cost of Gas (COG)	0%	6%	1%	-1%	-3%
Labor	5%	4%	3%	5%	2%
Benefits	4%	3%	2%	8%	7%
Subcontract Labor	0%	3%	4%	-1%	1%
Materials	0%	4%	-2%	0%	1%
Vehicles & Work Equip.	5%	5%	2%	4%	-2%
Company Consumption	-2%	6%	3%	0%	-11%
Uncollectible Accounts	2%	8%	8%	3%	13%
Postage	-3%	-2%	-2%	-3%	1%
Software Maintenance	18%	17%	14%	11%	19%
Building Rental	4%	3%	5%	15%	-4%
Advertising	-10%	-7%	-1%	-8%	-12%
Industry Dues	-2%	-1%	-1%	-12%	-8%
Insurance	4%	5%	2%	2%	-7%
Commission Expense	12%	4%	3%	41%	23%
All Other O&M	-13%	-18%	-19%	-21%	2%
Total O&M	0%	5%	1%	0%	-2%
Total O&M (excl. COG)	3%	3%	2%	4%	3%

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Q. Are there any projected costs that appear inconsistent with historical trends?

A. Yes. For Uncollectible Accounts expense, the projections for 2020 and 2021 average \$388k compared to 2015 through 2019 which average \$312k. Based on Response No. 10.8, bad debt expense for 2020 through November 2020 totals \$256,843, which appears more in line with the historical averages than the average of the projected costs.

In addition, test year software maintenance costs have increased significantly from prior years. This is consistent with trends I have noticed in the industry as a result of the increase in the number of software applications commonly being used and the changes in the pricing structures for that software, for example Microsoft Office moving to an annual subscription service rather than a one-time purchase cost.

1 **Q. Did you compare the Company’s O&M costs to other Natural Gas Local**
2 **Distribution Companies (LDCs)?**

3 A. Yes. I performed two comparisons. First, I compared rates of growth (i.e.,
4 CAGRs) in non-gas O&M expenses. Second, I compared non-gas O&M costs
5 per customer for 2019 in total and by FERC cost category. A peer panel
6 comprised of ten other natural gas LDCs with customer counts ranging from
7 50,000 to 250,000 (“the peer group”) was used to make this comparison.
8

9 **Q. What were the results of this comparison?**

10 A. First, I compared the average compound annual growth rate (CAGR) of non-gas
11 O&M costs for the period 2015 - 2019.¹ The CAGR for peer group’s non-gas
12 O&M costs for this period was 2.1% compared to the Company’s CAGR of
13 3.3% over this same time period. I performed a similar analysis for non-gas
14 O&M costs on a per customer basis. The CAGR for non-gas O&M costs for the
15 Company for this period was 2.6%, which was also higher than the peer group’s
16 CAGR of 0.8% for the same period.²
17

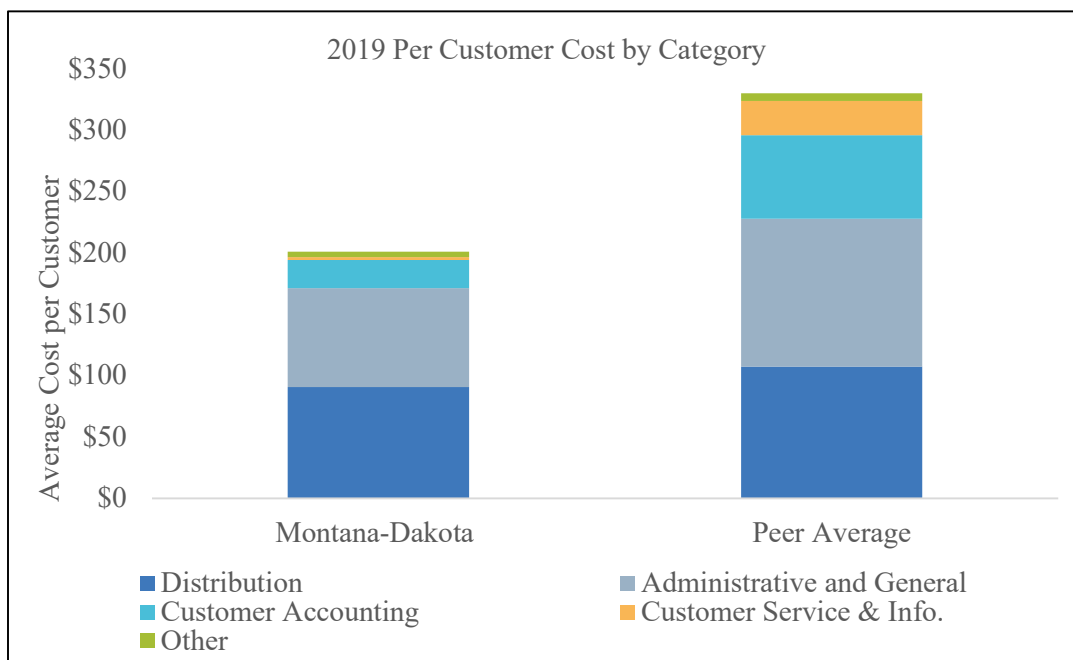
18 **Q. And how does the Company’s annual per customer non-gas O&M costs**
19 **compare to the peer group’s average?**

20 A. Based on 2019 data, the Company’s annual non-gas O&M costs on a per
21 customer basis are significantly lower than that of their peers. The highest per
22 customer costs for the Company and the peer group are distribution expenses and

¹ 2019 is the most recent year for which financial results are available.

² Data source: S&P Global. Montana-Dakota provided data was used for missing values.

1 administrative & general (A&G) expenses.

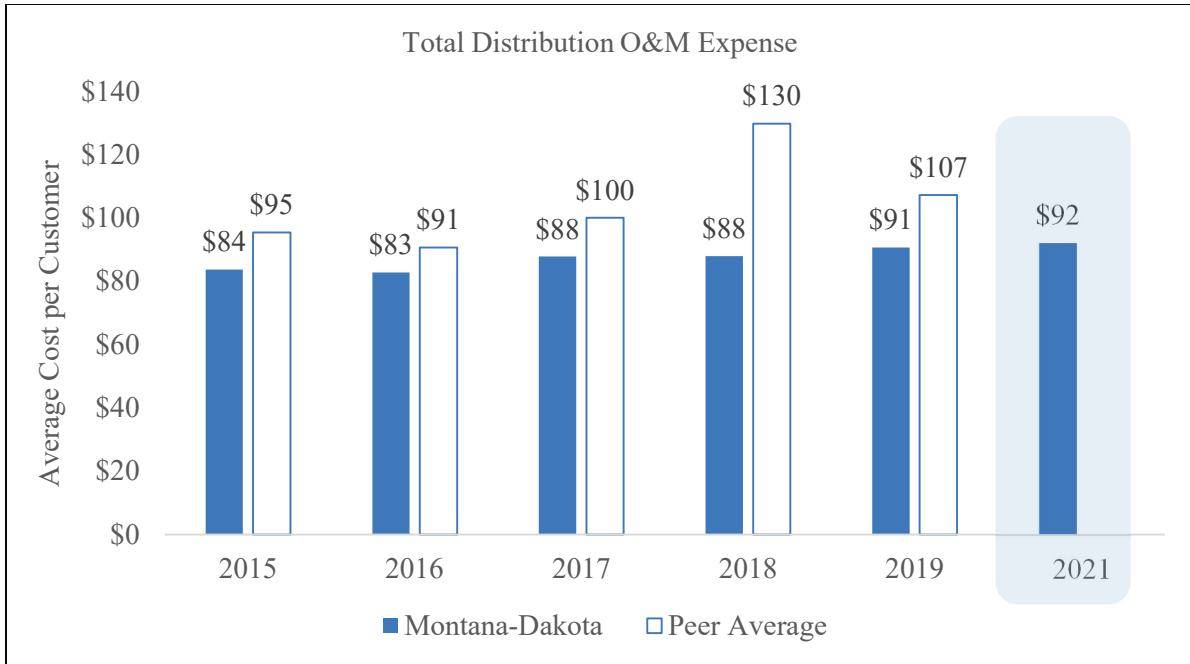


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Q. Did you analyze how the Company’s per customer distribution and A&G expenses are trending compared to the peer group?

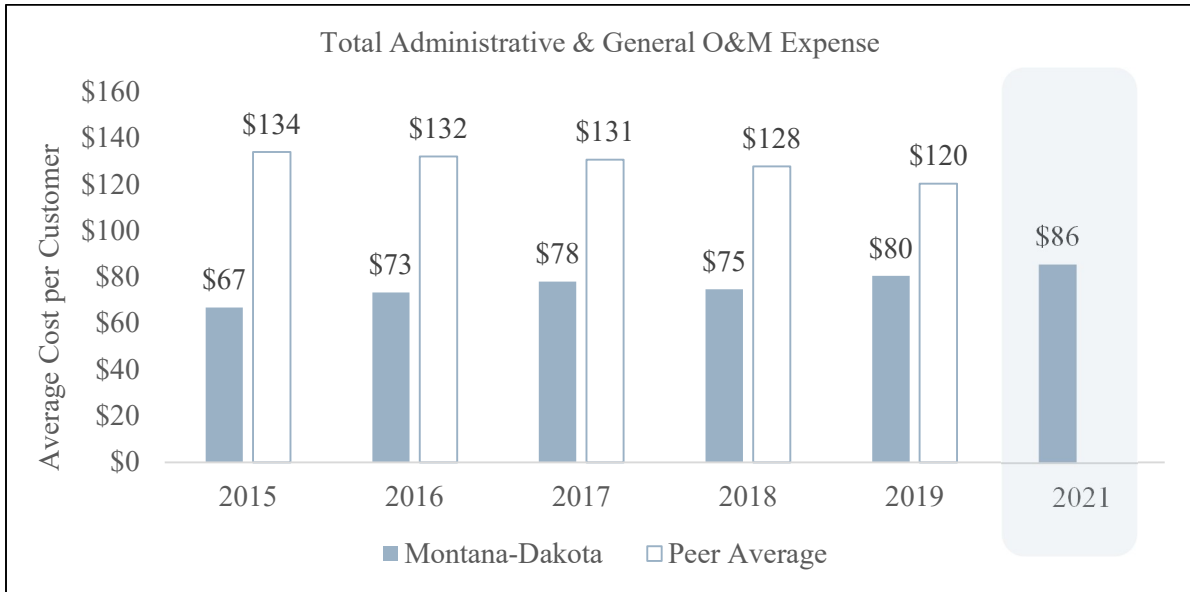
A. Yes. The Company’s “per customer” distribution and A&G expenses rate of growth were below the average of the peer group over the 2015 – 2019 study period. In 2021, the Company’s projected per customer distribution and A&G expenses continue to remain lower than the 2019 peer group distribution and A&G expenses per customer average.³

³ Customers used in this analysis represent total natural gas customers, including transportation. Data source: S&P Global / LDC State Filings. The Company’s 2021 year-end customers used in this analysis were forecasted based on the customer forecast methodology outlined in Mr. Shoemake’s testimony, page 10, line 1-12.



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Note: A single peer company drove the spike in 2018's high peer average distribution expense.



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Q. What do you conclude based on the peer group comparison?

1 A. Based on the above comparisons of non-gas O&M costs to the peer group, we
2 conclude that the Company's costs are reasonable. However, this does not imply
3 that all non-gas O&M costs are then by definition reasonably recoverable from
4 ratepayers (see executive compensation discussion below).

5
6 **Q. How do the compounded annual growth rates in non-gas O&M costs
7 compare to CPI?**

8 A. Using 2015 as the base, the compound annual growth rate (CAGR) for O&M
9 costs excluding cost of gas is 3.1% through 2021. This compares to average CPI
10 increases of 2.0% during this same period. The largest components of non-gas
11 O&M are labor and benefits, which increased by 5% and 4%, respectively, on a
12 CAGR-basis. If the Company's forecasted 2021 non-gas O&M expenses
13 reflected a 2.0% CAGR based on the CPI rather than the calculated 3.1% CAGR,
14 2021 non-gas O&M expenses would be \$22,466,339, or \$1,502,363 less than the
15 amounts requested. This difference decreases to \$319,544 based on a 2019
16 starting point.

17
18 **Q. What has the Company included in the revenue requirement for Labor
19 expense?**

20 A. The revenue requirement consists of \$13.3M of labor related expenses. These
21 expenses include straight time, premium time, bonuses & stock compensations,
22 incentive compensation, meals and vacation. The cost associated with straight
23 time and premium time, totaling \$11.6M in the test year, is projected to increase
24 at a rate of 3.63% and 3.31% in 2020 and 2021. I find that these growth rates are
25 in line with the growth experienced in 2018 and 2019 of 3.7% and 3.6%
26 respectively.

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<i>\$ in millions</i>	Historical			Projected	
	2017	2018	2019	2020	2021
5110 Straight Time	\$9.5	\$9.9	\$10.1	\$10.5	\$10.9
5120 Premium Time	\$0.6	\$0.6	\$0.7	\$0.7	\$0.7
5130 Bonuses & Comm.	\$0.3	\$0.4	\$0.4	\$0.4	\$0.4
5131 Incentive Comp.	\$1.2	\$0.6	\$1.4	\$1.2	\$1.3
5150 Meals	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
5193 Vacation	\$0.1	\$0.1	\$0.1	\$0.1	\$0.1
Total	\$11.6	\$11.6	\$12.7	\$12.9	\$13.3

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3

Q. Should the full amount of Bonuses and Commissions be included in the revenue requirement?

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5

A. No. Bonuses and Commissions, including stock compensation and miscellaneous bonuses, totaling \$366,616 are included in the revenue requirement. Bonuses and Commissions includes executive stock compensation of \$291,492. I do not recommend including executive stock compensation in the revenue requirement. The shareholders benefit from increased stock price appreciation; therefore, shareholders should pay for stock compensation expense as supposed to the ratepayers.

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Q. Is the full amount of Incentive Compensation reasonable to include in the revenue requirement?

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A. No. The Company included \$1,254,324 of incentive compensation in the revenue requirement. This amount is based on an average target payout level of 11.41% of straight time and vacation. The average target payout level of 11.41% is a

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function of the target payout amount and salary amount of all employee classes (including executive) and represents all MDU Resources employees⁴.

	Historical				Projected	
Salary (\$ in millions)	2016	2017	2018	2019	2020	2021
IBEW	\$30.8	\$28.3	\$29.3	\$29.4	\$29.0	\$29.0
Non-Exempt	\$8.5	\$12.4	\$12.2	\$16.1	\$13.1	\$13.1
Exempt	\$44.5	\$45.1	\$47.8	\$53.5	\$56.0	\$56.0
Executive	\$4.7	\$3.9	\$3.6	\$5.1	\$5.6	\$5.6
Total Salary	\$88.5	\$89.7	\$92.8	\$104.1	\$103.7	\$103.7
Payout (\$ in millions)	2016	2017	2018	2019	2020	2021
IBEW	\$1.4	\$1.3	\$1.3	\$1.3	\$1.3	\$1.3
Non-Exempt	\$0.4	\$0.8	\$0.7	\$1.0	\$0.8	\$0.8
Exempt	\$4.1	\$5.0	\$5.4	\$6.2	\$6.4	\$6.4
Executive	\$2.8	\$2.4	\$2.3	\$3.0	\$3.3	\$3.3
Total Payout	\$8.8	\$9.4	\$9.8	\$11.5	\$11.8	\$11.8
Target Payout	2016	2017	2018	2019	2020	2021
IBEW	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Non-Exempt	5.08%	6.14%	6.15%	6.12%	6.12%	6.12%
Exempt	9.21%	11.11%	11.36%	11.57%	11.49%	11.49%
Executive	60.31%	61.13%	64.44%	58.54%	59.00%	59.00%
Total Target Payout	9.89%	10.49%	10.56%	11.05%	11.41%	11.41%

⁴ The Company noted that all employees of MDU Resources provide support to Montana-Dakota Utilities and Great Plains Natural Gas.

1
2 However, the Company noted in the 2019 Proxy statement that 20% of the
3 executives' annual incentives are tied to Corporate Earnings Per Share (EPS) with
4 the remaining 80% tied to business segment earnings.

5
6 *"EPS is a generally accepted accounting principle (GAAP) measurement
7 and is a key driver of stockholder return. This is the basis on which we provide
8 annual performance expectations and consistent with how we report results to the
9 financial community."*⁵

10
11 Similar to stock compensation, I recommend that the 20% of executive
12 compensation tied to Corporate EPS performance be excluded from revenue
13 requirement. This results in a change to the 2021 average target payout level from
14 11.41% to 10.78% and the 2021 incentive compensation from \$1,254,324 to
15 \$1,184,658, a \$69,666 difference.

16
17 For the non-executive employees, it is common for companies to offer incentive
18 compensation as part of their overall compensation. Incentive compensation
19 provides an opportunity to both reward employees for the achievement of specific
20 goals and objectives as well as share in the achievement of business unit and
21 corporate objectives. The overall weighting tends toward individual and business
22 unit performance rather than corporate performance. Non-executive incentive
23 compensation typically includes metrics related to customer satisfaction and
24 safety as well as financial performance and does not typically include metrics
25 associated with share price.

⁵ MDU Resource Group, Inc. Annual Report, Form 10-K, Proxy Statement. 2019. Page 42-43.

1 Offering employee bonuses can also help with employee retention which can
2 result in decreased costs related to employee turnover. As a result, I agree with the
3 inclusion of non-executive incentive compensation
4

5 **Q. What is the total labor cost adjustment that you are recommending?**

6 A. I recommend that the total labor expense in the revenue requirement be reduced
7 from \$13,342,105 to \$12,980,947, a \$361,158 adjustment.
8
9

10 **IV. Review of Rate Base**

11 **Q. Based on your analysis, what are the primary drivers of increases in rate base?**

12 A. The tables below show trends in rate base by component for the historical periods
13 2015 through 2019 and projected period 2020 and 2021. As can be seen, a
14 significant portion of the projected increase in rate base from 2019 to 2021 is due
15 to the inclusion of the provision for pensions and benefits in working capital
16 which is discussed in more detail in Section V of my testimony.
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MONTANA DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.								
HISTORY OF RATE BASE - AVERAGE								
2015-2019								
	2015	2016	2017	2018	2019	Projected		
						2020	2021	
Rate Base								
Gas Plant in Service	\$233,194,370	\$251,016,848	\$263,002,254	\$283,843,113	\$305,656,931	\$308,074,611	\$325,928,741	
Accumulated Reserve	(85,380,387)	(91,073,274)	(96,372,634)	(102,491,066)	(109,560,560)	(116,841,322)	(124,807,754)	
Net Gas Plant in Service	147,813,983	159,943,574	166,629,619	181,352,047	196,096,371	191,233,289	201,120,987	
CWIP in Service								
Total Gas Plant in Service	147,813,983	159,943,574	166,629,619	181,352,047	196,096,371	191,233,289	201,120,987	
Additions								
Materials and Supplies	2,263,531	1,987,743	1,912,002	1,802,764	2,082,281	2,538,800	2,538,800	
Fuel Stocks	110,061	137,392	142,069	103,529	38,773	35,198	35,198	
Prepayments	50,467	56,509	57,394	49,732	48,543	278,648	276,676	
Gas in Underground Storage	0	0	0	24,517	43,645	25,259	0	
Prepaid Demand/Commodity	0	0	0	3,182	7,589	5,689	0	
Unamortized Loss on Debt	699,324	648,690	532,830	467,490	410,422	356,501	298,810	
Unamort. Redemption of Pref. Stock	0	0	0	28,676	55,363	51,385	47,407	
Gain/Loss on Sale	(335,782)	(316,643)	100,991	516,959	512,853	490,410	467,967	
Provision for Pension & Benefits						7,873,218	16,296,452	
Provision for Post Retirement						271,249	542,497	
Total Additions	2,787,602	2,513,691	2,745,285	2,996,849	3,199,468	11,926,357	20,503,807	
Total Before Deductions	150,601,585	162,457,265	169,374,904	184,348,896	199,295,839	203,159,646	221,624,794	
Deductions								
Acc. Deferred Income Taxes	(21,199,065)	(20,943,511)	(21,240,450)	(22,278,376)	(23,357,955)	(26,130,493)	(28,172,298)	
Acc. Investment Tax Credits	0	0	0	0	0	0	0	
Customer Advances	(12,949,560)	(13,784,793)	(14,291,120)	(13,288,413)	(10,581,859)	(8,811,421)	(8,786,871)	
Total Deductions	(34,148,625)	(34,728,304)	(35,531,570)	(35,566,789)	(33,939,814)	(34,941,914)	(36,959,169)	
Total Rate Base	\$116,452,959	\$127,728,961	\$133,843,335	\$148,782,107	\$165,356,024	\$168,217,732	\$184,665,625	

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PRELIMINARY DRAFT – SUBJECT TO REVISION

Non-Public Document
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MONTANA-DAKOTA UTILITIES CO. & GREAT PLAINS NATURAL GAS CO.				
AVERAGE RATE BASE				
GAS UTILITY - NORTH DAKOTA				
TWELVE MONTHS ENDED DECEMBER 31, 2019				
PROJECTED 2020-2021				
	Per Books	Projected		
	Average	2020	2021	Reference
Gas Plant in Service	\$305,656,931	\$308,074,611	\$325,928,741	Statement B
Accumulated Reserve for Depreciation	109,560,560	116,841,322	124,807,754	Statement C
Net Gas Plant in Service	\$196,096,371	\$191,233,289	\$201,120,987	
Additions:				
Materials and Supplies	\$2,082,281	\$2,538,800	\$2,538,800	Statement D
Fuel Stock	38,773	35,198	35,198	Statement D
Prepayments	48,543	278,648	276,676	Statement D
Gas in Underground Storage	43,645	25,259	0	Statement D
Prepaid Demand/Commodity	7,589	5,689		Statement D
Unamortized Loss on Debt	410,422	356,501	298,810	Statement D
Unamort. Redemption Cost of Pref. Stock	55,363	51,385	47,407	Statement D
Gain/Loss on Sale	512,853	490,410	467,967	Statement D
Provision for Pension & Benefits		7,873,218	16,296,452	Statement D
Provision for Post Retirement		271,249	542,497	Statement D
Total Additions	\$3,199,468	\$11,926,357	\$20,503,807	
Total Before Deductions	\$199,295,839	\$203,159,646	\$221,624,794	
Deductions:				
Accumulated Deferred Income Taxes	\$23,357,955	\$26,130,493	\$28,172,298	Statement J
Customer Advances	\$10,581,859	8,811,421	8,786,871	Statement D
Total Deductions	\$33,939,814	\$34,941,914	\$36,959,169	
Total Rate Base	\$165,356,024	\$168,217,732	\$184,665,625	

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Q. Please explain your understanding of the Company’s projected plant additions included in Rate Base.

A. The total projected plant additions for 2020 and 2021 are \$20.2M and \$22.7M respectively which is in-line with the total historical 5-year average plant additions from 2015-2019 of \$21.8M. The largest plant additions component is distribution plant, comprising 75% and 80% of total plant additions in 2020 and 2021 respectively. The proportion of distribution CapEx to total plant additions is in-line with the historical 5-year average of 76% from 2015-2019.

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Q. What are the primary drivers of the additions to distribution plant?

A. The majority of distribution capital spend is for replacement projects. Pipeline replacement projects are typically for safety reasons and to reduce system risk. Replacement projects comprise approximately 60% of the 2021 total distribution CapEx spend. The remaining portion of the 2021 total distribution CapEx spend is primarily made up of pipeline extensions that account for approximately 30% and capacity expansions.

Q. Are replacement projects typically a large component of distribution capital expenditures?

A. Yes, however projected replacement spend in 2020 and 2021 is more than 30% greater than actual replacement spend in 2018 and 2019. Replacement projects spend was approximately 33% and 53% of distribution CapEx spend in 2018 and 2019 respectively. The Company is projecting replacement projects spend to be 73% and 62% of distribution CapEx spend in 2020 and 2021 respectively.

	Historical		Projected	
	2018	2019	2020	2021
Distribution CapEx	\$24,805,373	\$15,278,834	\$15,170,405	\$18,308,192
Replacements CapEx	\$8,308,460	\$8,081,275	\$11,007,925	\$11,267,981
Replacements CapEx % of Distribution CapEx	33%	53%	73%	62%

Q. How do distribution and replacement capital expenditures compare to distribution plant depreciation expense?

A. As shown in the table below, in 2019 replacement capital expenditures were entirely funded by distribution plant depreciation expense. For 2020 and 2021,

1 distribution replacement capital expenditures exceeded distribution plant
 2 depreciation capital expenditures.

Distribution Plant	Actual	Projected	
	2019	2020	2021
Total Distribution CapEx	\$15,278,834	\$15,170,405	\$18,308,192
Replacements CapEx	\$8,081,275	\$11,007,925	\$11,267,981
Distribution Depreciation ⁶	\$8,332,557	\$8,629,524	\$9,163,072
Replacements CapEx as a Percent of Distribution Depreciation	97%	127%	123%
Distribution CapEx as a Percent of Distribution Depreciation	183%	176%	200%

3
 4 Absent significant safety and reliability concerns, limiting distribution plant
 5 replacement spend to distribution depreciation is a reasonable management
 6 practice.

7
 8 **Q. What is the reason for the large increase in replacement project spend?**

9 A. Needs for replacement CapEx are increasing due to the Company’s large
 10 replacement capital projects undertaken since 2018. The Company undertook
 11 these major capital projects in an effort to replace early vintage plastic and steel
 12 pipe. The total replacement in-service capital spend associated with the major
 13 replacement capital projects increased from \$1.3M in 2018 to \$4.0M in 2019 and
 14 at least \$5.0M for 2020⁷. The Company’s System Safety and Integrity Program
 15 (SSIP) identified the Dickinson project, which started in 2019, as a high risk early
 16 vintage steel pipe system. This project is a multi-year project which is expected to
 17 continue until the system’s early vintage plastic and steel pipes are replaced or

⁶ Schedule H, Page 1 of 1

⁷ Possibly more depending on how much of the approved budget the Company spent and placed in service, as well as the estimated remaining costs associated with the other projects.

1 replacement is determined to be no longer needed. The Company spent \$4.0M in
 2 2019 and budgeted to spend \$7.3M in 2020 for the Dickinson project.⁸
 3

Project Name	Completion Year	Project Cost	Estimated Remaining / Ongoing Cost
Barlow, ND	2018	\$112,380	-
Cleveland, ND	2018	\$63,507	-
Eldridge, ND	2018	\$166,279	-
Taylor, ND	2018	\$448,417	-
Gladstone, ND	2018	\$508,473	-
Dickinson, ND	Started in 2019, multi-year project	\$3,969,647	Approved 2020 Budget: \$7,339,300
Fairview, ND	2020	\$578,501	Less than \$30,000
Glen Ullin, ND	2020	\$1,904,586	\$20,000
New Salem, ND	2020	\$2,517,012	\$40,000

4
 5 **Q. Are utility plant retirements related to replacements in 2020 and 2021**
 6 **reflected in rate base?**

7 A. Yes, however, projected retirements for 2020 and 2021 are based on a three-year
 8 average of retirements.⁹ Given the significant projected increase in replacement
 9 spend in 2020 and 2021 compared to 2018 and 2019 as shown above, projected
 10 retirements may be understated in 2020 and 2021. While this does not impact the
 11 net utility plant component of rate base as accumulated depreciation is reduced by
 12 the dollar amount of the retirements, it could result in an overstatement of

⁸ Direct Testimony of Patrick C. Darras. Page 9-30.

⁹ Statement B, Schedule B-1, Page 1 of 4.

1 depreciation expense and ad valorem taxes. I have not estimated the potential
2 overstatement.

3
4 **Q. Are capital expenditures and related expenses related to providing service to**
5 **the Town of Bobcat via the Gwinner Pipeline driving the increase in Utility**
6 **Plant in rate base?**

7 A. No. As summarized in the Company's response to Advocacy Staff DR 10.6, and
8 confirmed through review of the Statements referenced in that response, the
9 Company has removed the following rate base items from the case:

- 10 • Plant in Service
- 11 • Accumulated Reserve for Depreciation
- 12 • Accumulated deferred Income Taxes

13 In addition, the Company removed the related revenue and cost of service items
14 from the case:

- 15 • Depreciation expense
- 16 • Revenues and associated taxes
- 17 • Ad Valorem Taxes

18 The Company did not indicate whether any incremental operating expenses
19 associated with the pipeline were also removed from the case.

20
21 **Q. Are you aware of any delays in projected capital expenditures in 2020 or 2021**
22 **which should impact forecasted test year rate base?**

23 A. Yes. The Company included \$1.2M of CapEx spend related to capacity
24 expansion in 2021 for the Jamestown Town Border Station (TBS). This project is
25 now delayed and currently has no scheduled construction date. The Company is
26 planning to uprate the Jamestown system pressure instead. In addition to the TBS
27 project, other projects were identified in 2020 and 2021 that were either canceled
28 or delayed.

1

Canceled or Delayed Total Plant CapEx	2020	2021
Canceled Distribution Projects	\$501,282	\$0
Delayed Distribution Projects (to 2021)	\$347,881	\$0
Delayed Distribution Projects (post 2021)	\$0	\$0
Delayed Distribution Projects (no date set)	\$0	\$1,200,000
Canceled Other Plant Projects	\$53,478	\$268,490
Delayed Other Plant Projects (to 2021)	\$111,821	\$0
Delayed Distribution Projects (post 2021)	\$0	\$86,923
Delayed Distribution Projects (no date set)	\$0	\$0

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In addition, as noted in the Company’s response to Advocacy Staff DR 10.3, 2020 projected spend for System Safety & Integrity Main Replacements and Service Replacements may be overstated and should be adjusted to actual spend.

7

Q. Please describe the impact on rates of the Company’s Service Extension Policy.

8

A. The Company’s Service Extension Policy including the maximum allowable investment is provided in Rate Schedule 120 as excerpted below.

9

Non-Public Document
Not for Public Disclosure - Contains Trade Secret Data

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
1st Revised Sheet No. 62
Canaling Original Sheet No. 62

FIRM GAS SERVICE EXTENSION POLICY Rate 120

Page 1 of 6

The policy of Montana-Dakota Utilities Co. for gas extensions necessary to provide firm sales service to customers is as follows:

(A) General Rules and Regulations Applicable to all Firm Service Extensions

1. An extension will be constructed without a contribution if the estimated capital expenditure is cost justified as defined in ¶A.3.
2. The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified.
3. The extension will be considered cost justified if the calculated maximum allowable investment equals or exceeds the estimated capital expenditure using the following formula:

Maximum Allowable Investment =

Annual Basic Service Charge + (Project Estimated 3rd Year Annual Dk x
Distribution Delivery Charge)/LARR

where: LARR = Levelized Annual Revenue Requirement Factor of 13.807%

4. Cost of the extension shall include the gas main extension(s), valves, service line(s), any required payments made by the Company to the transmission pipeline company to accommodate the extension(s), and other costs up to, and including, the riser.

The service line is that portion of the gas service extending from the gas main to the connection at the house regulator and/or meter

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For an average customer using 191 Dk a year, the maximum allowable investment approximates \$1,142. My review of Response No. 3.2 Attachment A suggests that the Company is executing this policy as intended.

Through the use of a levelized annual revenue requirement factor, the extension policy is designed to ensure that existing customers do not subsidize new customers over the life of the asset. However, in early years as the facilities remain largely undepreciated, this policy will have upward pressure on rates. In addition, in instances in which the Company decides to install mains sized at a capacity greater than that needed to provide gas service to only those customers requesting service (for example, installing a 6” main rather than a 2” main), the cost of those distribution improvements is not considered in the calculation of the maximum allowed investment. This also has the impact of upward pressure on rates especially in the early years.

I also note that the extension policy does not consider the cost of house regulators and meters in determining the maximum allowable investment. The inclusion of the

1 cost of house regulators and meters will significantly impact advances required
2 while reducing the cost of facility extensions borne by existing customers.

3
4 **Q. Are there capital projects made which accommodate future growth which are**
5 **not subject to the Company’s Gas Service Extension Policy related to maximum**
6 **allowable investments?**

7 A. Yes. The Company may extend or replace facilities to accommodate future growth
8 without developer or customer advances or contributions for extensions or system
9 enhancements made at the Company’s discretion and not in direct response to a
10 customer or developer request for service. For example, as described in the
11 Company’s response to Advocacy Staff DR 10.4, a customer advance / contribution
12 was not required for Funding Projects FP-315285 (\$1.8M) and FP-316375 (\$0.7M)
13 related to facilities to serve Menoken. The cost of these extensions and
14 enhancements are borne by customers generally through the inclusion of these costs
15 in revenue requirements. The Company has not requested advance determination of
16 prudence for these specific projects.

17 On the other hand, the Rate 120 Firm Gas Service Extension Policy does provide an
18 option for an Incremental Expansion Surcharge. The largest (by far) single pipeline
19 extension project was the Gwinner pipeline project. In this instance, the cost of the
20 project is being recovered through an incremental pipeline surcharge.

21 Rate 120 does not provide specificity as to which pipeline extensions require the use
22 of a surcharge mechanism and which do not. The Rate 120 policy indicates that the
23 use of the surcharge is solely at the discretion of the Company.

24 While not suggesting the Commission micromanage management decision-making, I
25 recommend that the Commission consider modifying this section of the firm gas
26 service extension policy to provide further direction regarding the appropriate use of
27 the surcharge.

1 **Q. Do you believe the Company’s calculation of customer advances for**
 2 **construction in rate base is reasonable?**

3 A. No. As shown in Statement D, Schedule D-1, Page 11 of 11, the amount of
 4 customer advances remains unchanged from May 2020 onward. According to the
 5 Company’s response to Advocacy Staff DR 12.5, the Company has not included any
 6 projects for which an advance is required in the test year. In my opinion, it is
 7 unlikely that the Company’s projected growth for 2020 and 2021 can be achieved
 8 absent the extension of facilities thus potentially understating test year rate base.
 9

10 **Q. What are the rate base adjustments that you recommend?**

11 A. I recommend that the total plant additions in 2020 be reduced by \$1,014,462 due
 12 to canceled projects and delayed projects. I also recommend reducing 2021 total
 13 plant additions by \$754,711. The recommend 2021 reduction comprises
 14 \$1,555,413 of canceled and delayed projects partially offset by \$459,702 of 2020
 15 project delays which moved into 2021 and the additional \$341,000 cost to uprate
 16 the Jamestown system pressure.
 17

Total Plant CapEx Adjustments	2020	2021
Canceled and Delayed Projects	\$1,014,462	\$1,555,413
2020 Delayed Projects moved to 2021	\$0	\$459,702
Jamestown Distribution System Pressure Uprate	\$0	\$341,000
Total Plant CapEx Reduction	\$1,014,462	\$754,711

18
 19 **Q. Are there any other recommended changes to rate base?**

20 A. Yes. Based on the following analysis, I believe the forecasted amounts of Meter
 21 Plant additions are unreasonable. To assess the reasonableness of the amounts
 22 forecasted, I compared the “costs per meter” forecasted for 2020 and 2021 to

1 actual costs for the prior five years based on Company-reported Meter Plant
 2 Additions and PA-calculated numbers of meters needed. The “number of meters
 3 needed” was based on the sum of the number of customers added and the number
 4 of meters replaced. The number of customers added was provided by the
 5 company; the number of meters replaced was estimated by PA based on the
 6 forecasted value of meter retirements divided by the embedded cost per unit as of
 7 the end of 2014 (\$251).

	Year	Residential & Firm General Customers	Number of Meters Replaced (PA Calculation)	Total Number of Meters Needed	Meter Plant Additions	Cost per Meter (Meter Plant Additions / Meters Needed)
Actual	2015	2,489	607	3,096	\$1,617,359	\$522
Actual	2016	821	735	1,556	\$1,062,321	\$683
Actual	2017	673	1,378	2,051	\$1,107,332	\$540
Actual	2018	681	1,129	1,810	\$1,801,544	\$995
Actual	2019	895	2,926	3,821	\$2,239,113	\$586
Projection	2020	761	1,100	1,861	\$1,896,737	\$1,019
Projection	2021	767	1,291	2,058	\$2,353,304	\$1,143

8
 9 Using the calculated cost per meter for 2019 of \$586, the meter plant additions cost
 10 for 2020 and 2021 would be \$2,296,534. This compares to forecasted meter plant
 11 additions of \$4,250,041, or a difference of \$1,953,507. Based on this analysis, it
 12 appears that the Company has likely increased meter inventory levels beyond those
 13 needed to provide service to new customers and replace existing meters. As a
 14 result, I recommend that Meter Utility Plant be reduced by \$1,000,000.

15
 16 **Q. Do you have any other recommendations related to rate base?**

17 A. Yes. Based on the Company’s revised response to Advocacy Staff DR 6.22,
 18 capitalized administrative and general costs are projected to be \$130,564 and
 19 \$435,517 in 2020 and 2021, respectively. This represents 0.9% and 2.4% of
 20 Distribution Plant Additions in 2020 and 2021, respectively. In my opinion, these
 21 percentages suggest that the company has taken a very conservative position
 22 related to identifying corporate and shared services resources supporting
 23 construction activities. This potentially results in overstated A&G expenses and
 24 understated capital expenditures. I recommend that the Company complete an

1 A&G capitalization study to reassess its identification of general administrative
2 costs in support of construction activities.

5 **V. Inclusion of Net Pension Regulatory Asset in Rate** 6 **Base**

7 **Q. Please describe Montana-Dakota's request to include the Company's net**
8 **pension regulatory asset in rate base as a component of working capital.**

9 A. The Company is requesting the inclusion of the provision for pension and post-
10 retirement benefits, net of the associated deferred taxes, to be added to rate base.
11 The amounts representing the prepaid asset as a component of working capital¹⁰
12 and the associated amounts of deferred taxes in accumulated deferred income
13 taxes.^{11 12 13}

Average Working Capital Component	2020	2021
Provision for Pension & Benefits	\$7,873,218	\$16,296,452
Provision for Post Retirement	\$271,249	\$542,497
Total	\$8,144,467	\$16,838,949
Average Accumulated Deferred Income Taxes	2020	2021
Provision for Pension & Benefits	(\$2,085,979)	(\$4,306,162)
Provision for Post Retirement	(\$66,165)	(\$132,330)
Total	(\$2,152,144)	(\$4,438,492)

¹⁰ Statement D, Page 1 of 1

¹¹ Statement J, Schedule J-2, Page 1 of 5

¹² Kivisto Direct, Page 10, Lines 1-3. Jacobson Direct, Page 4, Lines 13-19 and Page 5

¹³ Table based on excerpts from Average Rate Base, Statement A, Page 3 of 3

1
2 The Company’s decision to include these assets and liabilities in rate base at this
3 time is driven by cash contributions, including recent contributions to the
4 Company’s pension trust fund, which have significantly exceeded pension
5 expense in revenue requirements. This difference has resulted in a significant
6 prepaid asset related to the Company’s pension plan.¹⁴ From 2004 through the
7 year ended December 31, 2019, Montana-Dakota represents that it has made cash
8 contributions in the amount of \$81.5 million but has recovered only \$29.4 million
9 through the inclusion of pension expense in the revenue requirement. North
10 Dakota gas operations’ share of the total net pension regulatory asset of \$59.8
11 million as of December 31, 2019 is \$14.8 million.¹⁵
12

13 **Q. Do you have any concerns regarding the Company’s calculation of its prepaid**
14 **pension asset?**

15 A. Yes. First, Montana-Dakota appears to have double-counted the \$12.4 million in
16 2019 prefunded pension contributions. The \$81.5 million in total cash contributions
17 as of December 31, 2019 includes the amounts prefunded according to the
18 Company’s response to Advocacy Staff DR (hereafter referred to as “DR”) 4.13.
19 Statement D-1, Pages 1-2 provides detail on the Net Pension Regulatory Asset. This
20 statement clearly shows the prefunded amount of \$12.8 million being included in the
21 calculation of the December 31, 2019 Net Pension Asset and then also shows the
22 projected 2020 and 2021 contributions, which equal the prefunded amount paid in
23 2019, in the calculation of the deferred pension component of net pension assets in
24 2020 and 2021. Thus overstating the amounts requested in working capital. The

¹⁴ Kivisto Direct, Page 10, Lines 6-8.

¹⁵ Jacobson Direct, Page 5, Lines 11-16

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Company’s response to DR 4.6 clearly confirms that no contributions will be made to the pension plan and OPEB plans in 2020 and 2021.

Second, the table below shows pension plan contributions and expenses by year from 2004 through 2019. As can be seen, there is significant variability in the pension expense amounts recovered from year-to-year.¹⁶ I would reasonably have expected that the amounts paid by ratepayers would have significantly less variability, especially in between general rate cases. Of course, black box rate case settlements make it difficult to determine with certainty the nature and amount of specific costs allowed for recovery.

MONTANA-DAKOTA UTILITIES CO.			
PENSION BALANCE SUMMARY			
ENDING DECEMBER 31, 2019			
	Cash	Pension	Pension Balance
	Contributions 1/	Expense 2/	Debit (Credit)
Beginning Balance - 12/31/2004			\$7,777,266
Activity - 2005	\$0	\$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj. 3/	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Total Funding	\$81,544,704	\$29,564,490	
Ending Balance - 12/31/2019			\$ 59,757,480
1/ Actuarially determined cash payments to the pension trust fund.			
2/ Actuarially determined pension expense use in the development of the revenue requirement through rate cases.			
3/ Adjustment to reflect the removal of MDU Resources pension funding - cash received by Montana-Dakota due to the 1/1/2019 corporate reorganization in Case No. PU-18-075.			

¹⁶ Kivisto Direct, Page 10; Jacobson Direct, Page 6

1
2 **Q. Please define “working capital”?**

3 A. According to The Process of Ratemaking by Leonard Saul Goodman published by
4 Public Utilities Reports, Inc. in 1998, “The Ohio commission has given us this
5 useful definition of the ‘working capital’ allowance in rate base:

6 the average amount of capital provided by investors in the
7 company, over and above the investments in plant and other
8 specifically identified rate base items, to bridge the gap between
9 the time that expenditures are required to provide service and the
10 time collections are received for that service.”

11
12 According to the University of Pennsylvania Law Review, Volume 102, 1954
13 (p495), of working capital is defined as.

DEFINITIONS AND CONCEPTS OF WORKING CAPITAL

14 The generic term “working capital” encompasses two items: working
15 cash, and materials and supplies. Working cash is required to bridge the
16 gap between expenditures for the production of service and the receipt of
17 payments from consumers. It represents the amount needed to pay for
18 salaries, services, current bills, and to maintain a sound financial position.²²

19 This definition is virtually identical to that provided by Mr. Goodman. The
20 implication is that working capital reflects “current” cash needs to fund current
21 expenses until recovered from ratepayers.

22 **Q. Do you believe that Montana-Dakota’s request to include the Company’s net
23 pension regulatory asset in rate base as a component of working capital is
24 reasonable?**

A. No. While the Company represents that the calculation of the requested net
pension regulatory asset is based on cash flows – that is, contributions paid
compared to expenses recovered from ratepayers – which, as noted above, is

1 fundamental to the definition of working capital, the amounts requested would be
 2 more appropriately treated as a regulatory asset rather than as a working capital
 3 component. In fact, the Company describes this request as the inclusion of the net
 4 pension regulatory asset in rate base. While this is consistent with how the
 5 Company seeks recovery of a return on the pension regulatory asset in other
 6 jurisdictions, this is not the case for Montana-Dakota gas operations. Given the
 7 long-term nature of a net pension regulatory asset, I believe the Company should
 8 request approval for a similar regulatory asset from the North Dakota
 9 Commission rather than seek treatment as a component of working capital as the
 10 amounts requested do not reflect “current” working capital needs.¹⁷
 11 In addition, as noted above, I have several issues associated with the calculation
 12 of the pension-related amounts requested for recovery in rate base.

14 **Q. Please describe the funded status of the Montana-Dakota Pension and Post
 15 Retirement (OPEB) Plans.**

16 A. As presented in the Company’s Response to Advocacy Staff DR 4.12, as of
 17 December 31, 2019, the funded status of the MDU plans is as follows. I calculated
 18 the MDU ND Gas allocated share based on the factors provided by the Company in
 19 Response No. 3.1, Statement Workpapers D-1 Pg 1-2.

MDU (\$ Millions)				MDU Gas North Dakota
Plan	Plan Assets	Plan Obligations	Funded Status	Funded Status
Pension	\$176.5	\$206.7	(\$30.2)	(\$7.4)
Post Retirement	\$48.1	\$32.6	\$15.4	\$3.9
Total	\$224.6	\$239.3	(\$14.8)	(\$3.5)

¹⁷ Kivisto Direct, Page 10, provides a schedule showing the calculation of the prepaid pension asset dating back to 2004.

1 Between 2015 and 2019, Plan Obligations for the total Company pension plan
2 decreased by \$44.9 M, or 18%, and for the post retirement plan by \$14.1M, or
3 30%.¹⁸ Based on these trends, I would expect the Funded Status gap to continue to
4 narrow. The OPEB plan has not required funding since 2013.¹⁹

5
6 **Q. Is it a common practice for utilities to seek regulatory asset / liability approval
7 for pension plans?**

8 A. Yes. While not a common practice in North Dakota, in our experience it is
9 common in other jurisdictions for companies to request and receive regulatory
10 approval for the establishment of pension-related regulatory assets and liabilities.
11 In many cases, these net regulatory assets earn a return as a rate base component.

12
13 **Q. Are there other options available to the Company?**

14 A. Yes. First, the Company could have elected not to pre-pay two years of pension
15 plan contributions. Second, the Company could request an increase in the annual
16 pension expense beyond that currently included in Benefits Expense in revenue
17 requirements. As noted in Statement G, Schedule G-1, Page 9 of 23, the pension
18 expense included in benefits for 2021 is \$331,258, which when netted against the
19 post retirement expense credit of (\$378,720) results in a net credit of \$47,462 in
20 2021.

21
22 **Q. Does the Company currently earn a return on any pension expenses?**

23 A. Yes. Until a relatively recent change in generally accepted accounting principles,
24 pension plan expenses were allowed as an overhead/burden on labor charged to
25 construction. Consequently, historically the Company has been earning a return
26 on capitalized pension costs.

¹⁸ Company Response to Advocacy Staff DR No, 4.12.

¹⁹ Company Response to Advocacy Staff DR No. 4.5.

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Q. Does this conclude your pre-filed testimony?

A. Yes.

 Joel Jeanson
Principal Consultant



Joel F. Jeanson is a Principal Consultant in the PA Consulting Group Energy & Utility Markets practice. He has extensive experience in utility finance and accounting, financial and operational auditing, internal control review and assessment, corporate performance, benchmarking, budgeting and management reporting, customer service and utility ratemaking.

While in consulting, Mr. Jeanson has performed numerous independent assessments of utility performance on behalf of both utility management and regulators, has completed a number of technical accounting studies for utility clients, and has provided due diligence services to a number of investors in connection with utility mergers and acquisitions. He has testified before several utility regulatory commissions. During his business career, Mr. Jeanson directed the accounting, budgeting, corporate performance and auditing departments at a major investor-owned utility headquartered in Indiana. He began his career with Arthur Andersen & Co.

Mr. Jeanson received a Bachelor of Science degree in Accounting, with distinction, from Indiana University. He has continued his studies with course work at the Indiana University Graduate School of Business and is also a graduate of the Wabash Executive Program.

Primary expertise	Related experience	Qualifications	Client list
<ul style="list-style-type: none"> • Regulatory accounting • Utility ratemaking • Corporate performance management • Performance improvement • Management audits 	<ul style="list-style-type: none"> • Utility management • Independent audit 	<ul style="list-style-type: none"> • CPA (inactive) • Bachelor of Science in Business (Accounting Major) 	<ul style="list-style-type: none"> • Vermont DPS • Liberty Utilities • NYS DPS • National Grid • ND PSC • Public Service New Mexico • LIPA

Primary expertise

Regulatory accounting – helping clients improve cost allocation practices to mitigate regulatory risks; completing specialized cost studies to support regulatory accounting and compliance activities

Utility ratemaking – helping clients develop and support revenue requirements; performing special studies of technical accounting issues

Corporate performance management – assisting clients improve performance by improving processes whereby strategic plans are aligned with business unit, functional and individual performance including performance measurement and management reporting processes

Performance Improvement – helping clients improve business processes through benchmarking and focus on value-adding activities

Management Audits – performing compliance, efficiency, and effectiveness audits of utilities on behalf of utility regulatory agencies and management, and assisting utility clients prepare for upcoming management audits

Key client achievements

Confidential client – Project manager for sell-side support in connection with the proposed sale of a holding company with six gas LDCs located throughout the United States.

Confidential client – Project manager associated with due diligence performed for a major US electric utility in connection with the acquisition of an on-site non-potable reclaimed water service provider.

North Dakota PSC - Testified on behalf of the Advocacy Staff of the Commission in Montana-Dakota Utilities Co. Application for Deferred Accounting Treatment, Case No. PU-19-317.



North Dakota PSC - Testified on behalf of the Advocacy Staff of the Commission in Northern States Power Company Advance Prudence – Biomass PPAs Application for Deferred Accounting Case Nos. PU-17-322, PU-17-270, and PU-17-271.

New York State Department of Public Service / New York American Water – Project manager for independent monitor activities in connection with billing and property tax issues. The Billing study was completed in 2019 with our expert report filed with the NYS PSC. The property tax work remains underway.

National Grid USA - Project manager for several technical accounting studies including 1) an engagement in which PA developed new accounting and cost allocation practices for the Service Company in connection with the client's implementation of SAP and provided regulatory support associated with new practices; 2) A&G capitalization study; and 3) cost of removal study.

Liberty Utilities – Technical accounting services related to the Company's updated indirect overhead capitalization study. PA reports filed in connection with several rate proceedings as well as provided testimony in an Arizona rate case related to the work performed.

Frontier Communications – Technical advisor in connection with the validation of the success of Frontier's systems replication actions required for the approval of the sale of Frontier's operations in the Northwest states of Montana (MT), Oregon (OR), and Washington (WA). Specifically, prior to Frontier going into production mode of the replicated systems, a third-party review must confirm that any severity level 1 failures (defined as full-service denials) that occurred during pre-production functionality tests on the customer-affecting systems that serve retail telecommunications customers have been fully resolved.

NYSDPS/ NYSERDA – Lead consultant in connection with a confidential study.

Financial and Strategic Investors – Provided due diligence services related to technical utility accounting issues, financial projections and regulatory assessments for several independent investors considering substantial investments in or acquisitions of utility assets and operations.

City of Baltimore DPW – Lead consultant in connection with an independent review of the City's water and wastewater treatment plants.

Hawaii Gas - Lead consultant responsible for assessing technical accounting issues including cost allocations and clearing account processes in connection with the Company's upcoming rate case.

Vermont DPS – Lead consultant responsible providing an assessment of the financial capabilities of the combined entity in connection with a telecommunications industry merger and acquisition. Provided expert testimony.

LIPA – Project manager / lead consultant on two independent assessments of PSEG-LI's performance related to the Operating Service Agreement. Project manager for subsequent engagement assessing the performance benchmarks and metrics used as part of the incentive framework for the independent operator of the LIPA electric T&D system on Long Island.

Consolidated Edison – Led the development of a comprehensive cost allocation manual in response to New York PSC management audit finding.

SUEZ Water – Project manager for the independent assessment of the Company's cost allocation practices. This review was requested by the New York Public Service Commission. The PA Report was provided to the NY PSC.

PNM Resources - Project manager responsible for completing a series of A&G capitalization studies as well as A&G studies required by the operating agreement for a large, jointly-owned power plant. Required developing an understanding of the Company's accounting system code block and cost charging / allocation practices.

FairPoint Communications – Provided audit preparation services in connection with a service quality audit required by the New Hampshire PUC.

Confidential Client – Lead consultant assessing the regulatory environment and potential regulatory risks in connection with the review of the Company's long-term financial forecast. This work was performed in connection with the potential sale of the Company as part of a bankruptcy proceeding.

Frontier Corporation – Lead consultant responsible for assessing the robustness of the financial forecast and reasonableness of assumptions used to project financial results in connection with a telecommunication industry acquisition valued at \$8 billion

Hawaiian Electric – Directed the development of a long-term financial forecast model. This model was initially used to identify rate impacts by customer class associated with the proposed long-term power supply implementation plan.

PSE&G - Provided support to the Company in preparing for an upcoming management audit. This included performing a diagnostic assessment of potential audit risks and employee training. Lead consultant for the review of

cost allocations and related controls to ensure the utility was not subsidizing non-regulated operations for a large, east coast gas & electric utility in advance of a state regulatory commission-mandated management audit.

HECO – Corporate accounting performance improvement initiative and benchmarking; completed specialized regulatory accounting studies; performed financial modeling to support business design changes.

Washington Gas – Provided assistance in identifying potential merger synergies for support services functions.

EPCOR – Completed special study filed with the Alberta regulatory commission related to cost allocation practices and shared services.

LADWP – Developed cost management processes designed to support the Department's new tariff and regulatory framework. Directed the completion of water system revenue requirements, cost of service and rate design studies.

FirstEnergy-Pennsylvania – Assessed the effectiveness of the corporate management process and suggested changes to the process to better ensure the transparency of the process and linkages to operational plans and budgets.

NiSource - Provided a framework for assessing the value of corporate and shared services to the operating companies in connection with a NIPSCO rate case. Included a review and assessment of the Company's cost allocation practices.

Vectren - Performed a detailed assessment of cost charging and allocation practices to the individual affiliate operating companies post-merger and acquisition of the DPL gas properties. Assessed the effectiveness of the corporate management process and suggested changes to the process to better ensure the transparency of the process and linkages to operational plans and budgets.

New Jersey American Water - Provided assistance by performing a diagnostic assessment of utility performance in connection with an upcoming management audit and rate case.

City of Baltimore DPW - Lead consultant responsible for benchmarking water and wastewater treatment plant performance. Also lead development of performance / financial management-related recommendation.

Anaheim Public Utilities PUC - Project manager responsible for completing a comprehensive review of water and power meter reading and billing operations and controls.

City of Kansas City Water Department - Lead consultant on a comprehensive review of the water utility's finance and accounting function.

Arizona Corporation Commission - Project manager and lead consultant for the review of the meter reading, billing and usage estimation practices of Arizona American Water Company. Testified before the ACC related to the work performed.

The Metropolitan District (MDC) - Lead consultant for the restructuring of the financial organization of the MDC, a municipal water and sewer utility headquartered in Hartford, CT. Also, lead consultant for the review of financial, human resources, information technology and customer service in connection with a comprehensive management review of the District.

Washington State Auditor's Office – Project manager for the performance audit of the three mid-Columbia Public Utility Districts. This performance audit was performed under Washing Legislative Initiative 900. The project team identified numerous opportunities for cost savings including the increased use of shared support services

Unitil Corporation – Reviewed cost allocation, management and control, and customer service processes for an east coast gas and electric utility in advance of a state regulatory commission-mandated management audit

Anaheim Public Utilities – Project manager for a meter reading and billing process improvement initiative, controls assessment, and billing integrity audit for a large, west coast municipal electric and water utility

City of LA – Water System project manager for two revenue requirements studies of the Los Angeles Department of Water and Power

CA PUC – Lead Consultant for the program evaluation of SBX1 5 energy efficiency and low-income assistance funds performed for the CPUC. Audited SDG&E and Southern California Gas's program and administrative costs for compliance with CPUC and Legislative requirements.

South Jersey Industries – Lead consultant for the review of cost allocations in preparation for an upcoming management audit. Provided a comprehensive re-write of the Company's cost allocation manual.

Direct Utility Industry Experience

- Head of Internal Audit – responsible for developing the internal audit plan, directing the completion of the planned work, and reporting results to the Audit Committee and senior management. Activities included compliance, operational and financial audits.
- Financial lead in merger integration – responsible for developing an overall assessment of financial impact of the merger as well as the identification of staffing levels, structure, systems and processes, and cost savings opportunities for the company's financial organization.
- Member of the management team – responsible for the implementation of shared services including establishing a separate shared services organization. Developed cost assignment and allocation processes for shared services.
- Project director for activity-based management – initiative focused on internal products and services. ABM used to assess performance against other service providers, measure performance, and improve performance.
- Directed the corporate business planning and budgeting process – responsible for integrating the strategic and operational planning processes so that departmental plans, capital and O&M budgets and performance measures would be focused on both continuous improvement and the achievement of corporate financial and non-financial objectives.
- Led customer service business process – improvement initiative that assessed performance and made recommendations for improvement of all customer service processes, leading to improved customer service and reduced costs. Facilitated the development of customer service standards and measurement processes.
- Key member of project team – that completed a study to identify the services, and levels of service, that customers are willing to pay for. This study resulted in significant changes in how the company delivered services to its customers.

Testimony Experience

North Dakota PSC - Testified on behalf of the Advocacy Staff of the Commission in Northern States Power Company Advance Prudence – Biomass PPAs Application for Deferred Accounting Case Nos. PU-17-322, PU-17-270, and PU-17-271.

SUEZ Water NA – Prepared expert report related to the cost allocation practices and cost of corporate and shared services of SUEZ Water NA. This report was filed by the Company with the New York PSC in connection with New York operating company's general rate case.

National Grid US – Worked with the Company to develop a new cost allocation manual (and associated cost allocation practices). Expert report prepared related to the work performed was filed by the Company in its Niagara-Mohawk general rate case.

Vermont DPS – Testified in connection with the proposed purchase of Verizon's northern New England properties by FairPoint Communications. Subsequently testified in connection with the proposed purchase of the assets of FairPoint Communications by Consolidated Communications.

Arizona Corporation Commission – Prepared expert report and testified on behalf of the Arizona Corporation Commission's Utilities Division in connection with the meter reading and billing practices of Arizona Public Service

Arizona Corporation Commission – Prepared expert report and testified on behalf of the Arizona Corporation Commission's Utilities Division in connection with the meter reading and billing practices of Arizona American Water Company

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2020 Natural Gas Rate Increase
Application

Case No. PU-20-379

VERIFICATION

STATE OF WISCONSIN)
) ss.
COUNTY OF WAUKESHA _____)

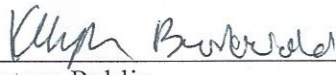
Joel F. Jeanson, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.



Joel F. Jeanson

Subscribed and sworn to before me this 14th day of January 2021.





Notary Public
My Commission Expires: 9/27/2022