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January 31, 2023

**SENT VIA EMAIL (NDPSC@ND.GOV) AND
U.S. MAIL CERTIFIED MAIL**

Steve Kahl, Executive Secretary
North Dakota Public Service Commission
600 E. Boulevard Avenue, Dept. 408
Bismarck, ND 58505-0480

**RE: PUBLIC Direct Testimony and Exhibits of Kavita Maini
Montana-Dakota Utilities Co. 2022 Electric Rate Increase Application
PSC Case No. PU-22-194**

Dear Mr. Kahl:

Enclosed please find the **PUBLIC** Direct Testimony and Exhibits of Kavita Maini in the above-referenced matter on behalf of Marathon Petroleum Company LP, as well as the Certificate of Service.

Thank you for your attention to this matter. Please let me know if you have any questions.

Sincerely,

CLARK HILL PLC

**Stephen A.
Campbell**

Stephen A. Campbell

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SAC/lkd

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86 PU-22-194 Filed 01/31/2023 Pages: 56
Prefiled Direct Testimony of Kavita Maini - redacted
Marathon Petroleum Company LP
Stephen Campbell, Clark Hill, PLC

Direct Testimony of
Kavita Maini

Before the
North Dakota Public Service Commission

In the Matter of Montana-Dakota Utilities Co. for Authority
To Establish Increased Rates for Electric Service

CASE NO.: PU-22-194
**PUBLIC DOCUMENT – NOT PUBLIC CONFIDENTIAL (OR PRIVILEGED)
DATA AND INFORMATION HAS BEEN EXCISED**

Exhibit __

January 31, 2023

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ATTACHMENTS

- (Exhibit ___ (KM-1), Attachment 1): Exhibit B of the Electric Sales Agreement (NOT PUBLIC)**
- (Exhibit ___ (KM-1), Attachment 2): Calculation of the margin (NOT PUBLIC)**
- (Exhibit ___ (KM-1), Attachment 3): Discovery Response MDU DR MPC-MDU-II-10 (NOT PUBLIC)**
- (Exhibit ___ (KM-1), Attachment 4): Discovery Response MPC-MDU-IV-1**
- (Exhibit ___ (KM-1), Attachment 5): Discovery Response MPC-MDU-V-8**
- (Exhibit ___ (KM-1), Attachment 6): Discovery Response MPC-MDU-V-5**
- (Exhibit ___ (KM-1), Attachment 7): COSS results using 4-CP**

1 **I. INTRODUCTION**

2 **Q. Please state your name and occupation.**

3 A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting,
4 LLC.

5 **Q. Please state your business address.**

6 A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

7 **Q. On whose behalf are you testifying in this proceeding?**

8 A. I am testifying on behalf of Marathon Petroleum Company LP (“MPC”). MPC employs
9 310 employees at its North Dakota facilities and contributes significant tax revenues to the
10 State. In addition, MPC contributed more than \$2.7 million to various community-related
11 initiatives, several of which focus on strengthening youth education and promoting career
12 development. In 2022 it received an award for community engagement.

13 MPC has two facilities served at the primary voltage service level by Montana-Dakota
14 Utilities (“MDU” or “Company”).

15 **Q. Please state your educational and professional background.**

16 A. My educational background includes a Master’s degree in Business Administration
17 (“MBA”) and a Master’s degree in Applied Economics. Prior to becoming an independent
18 consultant in 2002, I worked as a research analyst at Wisconsin Power and Light (“WPL”),
19 Alliant Energy’s regulated subsidiary, and conducted process and impact evaluations of
20 the energy efficiency programs, forward price curve, and asset valuation analyses. I also
21 worked as a Senior Economist at Alliant Energy Integrated Services’ Energy Consulting
22 Division. In this role, I was responsible for providing energy consulting services to

23 commercial and industrial customers in the area of electric and natural gas procurement,
24 contract negotiations, forward price curve analysis, rate design, and on site generation
25 feasibility analysis. I was also involved in strategic planning and due diligence on
26 acquisitions.

27 Since 2002, I have been an independent consultant. In this role, I have provided
28 consulting services in the areas of class cost of service studies, rate design, resource
29 planning and revenue requirement related issues, Midcontinent Independent System
30 Operator (“MISO”) related matters, and various policy matters. I also represent industrial
31 trade associations at MISO’s various task forces and committees and am the End Use
32 Sector representative at MISO’s Advisory and Planning Advisory Committees.

33 **Q. Have you ever participated in other utility proceedings?**

34 A. Yes, I have testified before a number of state regulatory commissions, including
35 Wisconsin, Minnesota, Missouri, Iowa, North Dakota, and South Dakota. I have submitted
36 technical comments on a variety of issues related to energy policy, cost recovery, revenue
37 allocations and rate design in transmission and renewable rider proceedings. I have also
38 provided technical comments in Federal Energy Regulatory Commission (“FERC”)
39 proceedings, several of which have involved MISO-related activities.

40 **Q. What is the purpose of your direct testimony?**

41 A. The purpose of my direct testimony is to address and make recommendations regarding
42 issues related to revenue requirement and revenue allocation to the rate classes. I also
43 provide recommendations regarding allocation of fuel and purchased power costs to the
44 rate classes.

45 **II. REVENUE REQUIREMENT ISSUES**

46 **Q. What is the Company’s proposed increase?**

47 A. As stated by MDU witness Ms. Nicole Kvisto, the Company proposes to increase the
48 revenue requirement by \$25,365,558, which represents a 12.3% increase, based on a
49 projected 2023 test year.¹ The 12.3% increase includes the effect on the base electric rates
50 and the Generation Resource Recovery Rider (“GRRR”). MDU’s proposal consists of
51 \$17,536,702 increase in base rate related revenue requirements and recovery of \$7,828,856
52 from the GRRR.

53 **Q. Which revenue requirement issues do you address?**

54 A. I address the following three issues:

55 A. Applied Blockchain Load Addition;

56 B. Depreciation expense; and

57 C. Potential impacts of the Inflation Reduction Act

58 **A. New Load Addition: Applied Blockchain**

59 **Q. Describe the Applied Blockchain load addition.**

60 A. On September 21, 2022, MDU filed an Application in Docket No. PU-22-371 seeking
61 approval of an Electric Service Agreement (“ESA”) with a new customer called Applied
62 Blockchain, which sought to take service from MDU under Rate 45 and to energize a
63 facility in the first quarter of 2023 near MDU’s Ellendale 345 kV substation near Ellendale,
64 North Dakota.

¹ See Ms. Nicole Kvisto’s Direct Testimony on page 7.

65 Applied Blockchain’s load is anticipated to be 180 MW with a load factor of 95% and
66 projected 1,477,440,000 kWh on an annual basis.² To provide context of the magnitude of
67 this load addition, the class cost of service study shows that the total kWh sales associated
68 with the North Dakota jurisdiction for the test year is 2,265,660,133 kWh. Thus, the
69 expected load is anticipated to add 65% of incremental energy consumption. It is my
70 understanding that the new load addition is expected to take service in the first quarter of
71 2023 and therefore, will be operational in the Company’s test year in this rate case.

72 **Q. What is MDU’s proposed rate for this new load addition?**

73 A. As noted earlier, the Applied Blockchain load would be served under Schedule Rate 45.
74 According to Rate 45, an eligible customer must be at least 10 Megawatts (“MWs”) with
75 an expected minimum load factor of 85% and the ability to be interrupted up to 200 hours.
76 The rate schedule does not provide any specific charges but rather offers the general
77 guiding principle that “customers on this rate shall be billed at any and all incremental costs
78 required to provide electric service to customers each month.”³

79 [REDACTED]

80 (Exhibit ___ (KM-1), Attachment 1), [REDACTED]

81 [REDACTED]

82 [REDACTED]

83 [REDACTED]

84 [REDACTED]

² See Case No. PU-22-370, Exhibit MDU-12 (redacted copy).

³ See Rate Schedule 45 under “Billing”

85 [REDACTED]

86 [REDACTED]

87 [REDACTED]

88 [REDACTED]

89 [REDACTED]

90 [REDACTED]

91 [REDACTED]

92 [REDACTED]

93 [REDACTED]

94 [REDACTED]

95 [REDACTED]

96 [REDACTED] (Exhibit ___ (KM-1), Attachment 2), [REDACTED]

97 [REDACTED]

98 [REDACTED]

99 [REDACTED]

100 [REDACTED]

101 [REDACTED]

102 [REDACTED]

103 [REDACTED]

104 [REDACTED]
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152 [REDACTED]

⁴ For instance, in 2022, I calculated that the day ahead pricing at Ellendale (MDU.ELLNDL.MVP Hub) was negative over 44% of the time with an average negative pricing of (\$24.40/MWh). As a result, the average annual retail price in 2022 was under \$12/MWh.

153 [REDACTED]
154 [REDACTED]
155 [REDACTED]
156 [REDACTED]
157 [REDACTED]
158 [REDACTED]
159 [REDACTED]
160 [REDACTED]
161 [REDACTED]
162 [REDACTED]

163 **Q. Given the interrelatedness of the Blockchain ESA (addressed in Case No. PU-22-371)**
164 **and this rate case, should the Commission consider consolidation of the dockets?**

165 A. Yes. Because the rates, terms, and conditions in the ESA could materially impact the rates,
166 terms, and conditions for service MDU has requested the Commission approve in this rate
167 case, the Commission should account for the impact of the ESA on MDU’s revenues and
168 service in this proceeding by consolidating these cases. However, if the Commission finds
169 that there is an urgency to address the Blockchain ESA prior to resolving the rate case
170 related decisions and does not consolidate the two proceedings, I recommend the
171 Commission determine that the relevant rates, terms, and conditions approved in this rate
172 case proceeding are subject to the outcome of Case No. PU-22-371 and the ESA terms

⁵See Otter Tail Power Company’s Mandatory Riders – Applicability Matrix and related applicability to Super Large General Service Rate (North Dakota, Section 13 of Rate Book).

173 approved in that proceeding. Stated differently, given the material impact the net revenues
174 associated with the ESA will have on MDU's revenue requirement, these impacts must be
175 reflected and accounted for in this rate case proceeding.

176 **B. Depreciation Expense**

177 **Q. What is the Company's proposed depreciation expense?**

178 A. The Company proposes an increase of \$10 million related to depreciation expense. Of this
179 amount, \$4.6 million is associated with updating the depreciation rates for the various plant
180 types.⁶ Figure 1 shows the currently approved versus proposed depreciation rates by plant
181 with the composite rate increasing from 2.54% to 2.95%.⁷ Applying the increase in the
182 depreciation rate in each plant group category results in a revenue requirement increase of
183 approximately \$4.6 million in this rate case. If the proposed rates are approved, these
184 changes will also result in potentially increasing the revenue requirement in riders.

185 **Figure 1: Proposed v. Currently Approved Depreciation Rate**

Plant Group	Proposed Depreciation Rate	Currently Approved Depreciation Rate
Steam Plant	2.45%	1.93%
Other Production Plant	3.98%	3.76%
Transmission Plant	1.70%	1.61%
Distribution Plant	3.25%	2.40%
General Plant	7.34%	5.84%
Total Plant in Service	2.95%	2.54%

186
187 **Q. What are your observations regarding this increase?**

⁶ See Ms. Kvisto's Direct Testimony on page 13.

⁷ See Mr. Larry Kennedy's Direct Testimony on page 7.

188 A. From a policy perspective, the Company’s proposal to recover its investment through
189 depreciation more quickly than the current situation is substantial, at a time when the
190 proposed revenue requirement increase is in the double digits. I believe that efforts should
191 be made to mitigate the rate increase.

192 **Q. What is your recommendation?**

193 A. I recommend that MDU continue to utilize the existing depreciation rates and recover its
194 investment at the same pace as the current situation. I expect the reduction in revenue
195 requirement to be less than \$4.6 million due to the impact on rate base. I intend to issue a
196 discovery request in this regard and will provide an estimate in following rounds of
197 testimony.

198 **C. Inflation Reduction Act**

199 **Q. Did you investigate whether any adjustments were applicable in the rate case as a**
200 **result of MDU potentially utilizing credits or incentives associated with the Inflation**
201 **Reduction Act of 2022?**

202 A. Yes. I did. In response to MPC-MDU-IV-1 (**Exhibit ___ (KM-1), Attachment 4**), the
203 Company indicated the following:

204 At the current time, Montana-Dakota has not identified any credits or
205 incentives resulting from the Inflation Reduction Act of 2022 that would
206 apply to Case No. PU-22-194. Montana-Dakota has identified that the
207 Company will receive Production Tax Credits (PTCs) related to the
208 Diamond Willow Wind Repower at full valuation. Previously, the IRS
209 guidance identified the repowered turbines would qualify for PTCs at 80%
210 of the full value. However, PTCs are not included in Case No. PU-22-194,
211 but rather, are reflected in the Renewable Resources Cost Adjustment
212 (RRCA) Rate 55 tariff.

213 In a subsequent response (MPC-MDU-V-8), (**Exhibit ___ (KM-1), Attachment 5**) the
214 Company provided the impact of the full PTC credit, which will be passed through the
215 RRCA.

216 **Q. What do you recommend should the Company be able to utilize credits or incentives**
217 **on going forward basis?**

218 A. Should the utility use any credits or incentives in the future, I expect that these credits are
219 likely eligible to (and should) be offset and passed through to customers in the transmission
220 or renewable cost adjustment riders. However, to the extent that the Company receives
221 credits or incentives that are not eligible to be offset in any of the riders, these credits should
222 be deferred to be passed along to customers based on a future Commission decision. The
223 Commission Order in this proceeding should direct the Company to ensure these outcomes.

224 **III. NON REVENUE REQUIREMENT ISSUES**

225 **A. Class Cost of Service Study (CCOSS) Issues**

226 **Q What is the importance of a utility’s cost of service study?**

227 A. A utility’s cost of service study is the fundamental basis for establishing just and reasonable
228 rates in the ratemaking process. The cost of service study determines the total costs incurred
229 by a utility in providing service to its customers and the portions of the total costs that are
230 incurred to serve each customer class. The cost of service study: (a) helps identify the
231 degree to which the revenue collected from each class is covering the cost responsibility of
232 the class, (b) guides revenue allocation to classes, and (c) informs rate design.

233 **Q. What are the different steps involved in the cost of service process?**

234 A. A cost of service study generally follows three basic steps. First, the various costs are
235 identified as production, transmission, and distribution (functionalization step). Next, these
236 functionalized costs are classified as demand-related, energy-related, or customer-related
237 (classification step). Finally, these classified costs are allocated among the various rate
238 classes based upon factors which attempt to measure each customer class' contribution to
239 that total classified cost (allocation step).

240 **Functionalization:** Various costs are separated according to function such as generation,
241 transmission, distribution, customer service, and administration. To a large extent, this is
242 done in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform
243 System of Accounts.

244 **Classification:** The functionalized costs are classified based on the components of utility
245 service being provided and the underlying cost causative factors. As described by the
246 Electric Utility Cost Allocation Manual published by the National Association of
247 Regulatory Utility Commissioners ("NARUC Manual"), the three principal cost
248 classifications are: (1) demand-related costs (costs that vary with the kW demand imposed
249 by the customer), (2) energy-related costs (costs that vary with energy or kWh that the
250 utility provides), and (3) customer-related costs (costs that are directly related to the
251 number of customers served). See NARUC Manual page 20.

252 **Allocation:** Once the costs are classified as demand-related, energy-related, or customer-
253 related, they are then allocated to classes using the relevant demand, energy, or customer
254 allocators. Each of these allocators measures each class' contribution to the total system

255 cost. Cost causation principles are used to determine the relevant measures for demand
256 (e.g., number of coincident peaks) or energy (e.g., time differentiated).

257 **Q. Did you use the Company sponsored excel spreadsheet COSS model as a starting**
258 **point for your analysis?**

259 A Yes, I reviewed the Company’s sponsored excel spreadsheet model, provided in response
260 to MPC’s discovery request 103⁸ and evaluated an alternative demand allocator in lieu of
261 the MDU’s demand method for allocating fixed production and transmission plant related
262 costs.

263 *(i) COSS: Fixed Production Plant Cost Allocation*

264 **Q. What are fixed production plant-related costs?**

265 A. Fixed production plant-related costs are costs that are functionalized as production related
266 and incurred in acquiring or procuring generation resources. Utilities are required to build
267 or acquire sufficient generation capacity to ensure that they can reliably meet system peak
268 demands. Primarily, these costs consist of the fixed investment in power plants, but do not
269 include the variable cost (e.g., fuel) of generation. These costs include return on and of
270 investment and fixed operations and maintenance costs. Once the generation investment is
271 made, the costs are sunk costs, fixed in nature, and do not vary with energy usage.

272 **Q. What is the Company’s proposed method for allocating fixed production plant**
273 **related costs to retail customer classes?**

⁸ Company’s sponsored COSS is submitted as part of the initially filed workpapers (See Statement K).

274 A. The Company classifies fixed production (non-renewable) plant as demand related and
275 allocates these costs to classes using the class demand contribution to the twelve coincident
276 peaks (“12-CP”). MDU’s expert witness, Mr. Ronald Amen primarily relies on Federal
277 Energy Regulatory Commission’s (“FERC”) criteria for affirming the use of a 12-CP
278 demand allocator.⁹

279 **Q. Are there other factors that can also be considered in determining an appropriate**
280 **allocator?**

281 A. Yes, production plant must be sized to meet the maximum load or demand imposed on
282 these facilities. An alternative allocator can be used to reflect these cost causative
283 characteristics.

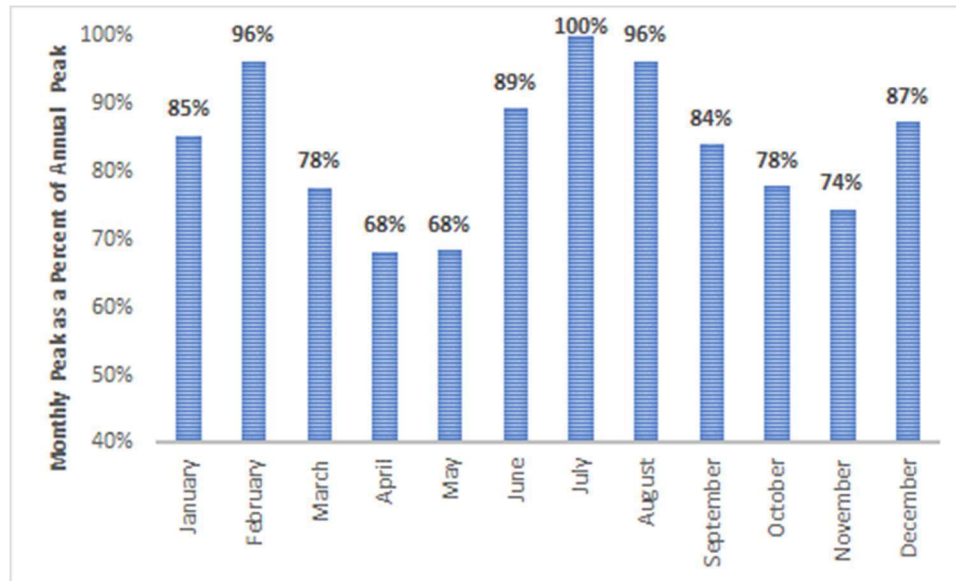
284 **Q. Did you analyze MDU’s system load?**

285 A. Yes, I did. Figure 2 shows the system monthly peak demands as a percent of overall annual
286 peak for the test year. I received this information in response to MPC-MDU-V-5, (**Exhibit**
287 **___ (KM-1), Attachment 6**). This chart shows that MDU’s system peak occurred in July.
288 MDU’s annual system peak is in July followed closely by August and February at 96% of
289 the annual system peak. Since generation capacity is sized to reliably meet the highest peak
290 demands, it would be appropriate to consider class contributions to monthly demands for
291 all months that are around 10% of the system peak. Using this metric, a reasonable cost
292 causation based demand allocator for the test year would be to take the class contribution
293 to the system peaks in the months of February, June, July, and August. I calculated the

⁹ See. Mr. Amen’s direct testimony, pages 8 through 10.

294 class contribution to these four months and replaced the Company’s 12-CP demand
295 allocator with the 4-CP demand allocator in the Company’s COSS model.¹⁰

296 **Figure 2: Test Year Metro Missouri’s Monthly Peak**
297 **Demands As a Percent of Annual Peak Demand**



- 298
- 299 **Q. How did you calculate the 4-CP allocator?**
- 300 **A.** While I would have preferred a more updated data set and direct way to calculate the class
301 contributions for the four highest peaks in the test year, in the absence of such data, I
302 utilized the same approach as used by the Company using 2019 data.¹¹
- 303 **Q. Is the 4-CP demand allocator also compatible with the Company’s resource**
304 **planning?**

¹⁰ The 4-CP allocator is also used to allocate transmission costs, which is appropriate for the same cost causative reasons as identified in my testimony for fixed production plant.

¹¹ See response to MPC-MDU-V-5. I replaced the class 12-CP demand by class with the 4-CP demand

305 A. Yes, MDU’s most recent Integrated Resource Plan (“IRP”) issued in 2021 and used to
306 make investment decisions,¹² places emphasis on its system peak demand forecast for
307 planning purposes (as opposed to a demand forecast that reflects an average of the monthly
308 peaks). For example, Table 2 on page 15 in Volume 1 of the Company’s 2021 IRP shows
309 the summer peak and the winter peak demand forecast, which would imply that even a 2-
310 CP method would be appropriate. By incorporating the predominant summer and winter
311 peaks, the 4-CP demand allocator reasonably captures the cost causative driver for
312 generation investment.

313 *(ii) COSS Results*

314 **Q. Aside from replacing the Company’s 12-CP allocator with your 4-CP allocator, did**
315 **you make any other changes to the allocators in the Company’s COSS model?**

316 A. No.

317 **Q. Please explain how the results of the COSS are shown.**

318 A. Upon completion of the class cost of service study, the net income for each class (revenues
319 less expenses) is divided by the rate base dedicated to serving that class to calculate the
320 rate of return earned. To the extent that a class rate of return (“ROR”) is greater than the
321 system return, then the revenues recovered from the class are more than the costs to serve
322 that class. To the extent that a class rate of return is lower than the system return but not
323 negative, the revenues recovered from the class are covering the expenses but not earning
324 the same rate of return as the system. Finally, if a class rate of return is negative, this means
325 that the particular class revenues are not sufficient enough to cover the costs allocated to

¹² See MDU Integrated Resource Plan, Vol. 1, available at [Electric Generation - Montana-Dakota Utilities Company](#)

326 it. Figure 3 shows a comparison of the class RORs resulting from the Company and my
327 cost of service studies at present rates.

328 **Q. Are the COSS results using MDU’s 12-CP method and your 4-CP method generally**
329 **consistent?**

330 A. Yes. I compared the earned rate of return (“ROR”) and the indexed rate of return derived
331 from my study as well as the Company’s COSS at present rates. The indexed rate of return
332 helps to provide a relative comparison between customer classes. As shown in Figure 3,
333 the results are directionally consistent although the magnitude varies. In particular, the
334 results show that at present rates, the primary class related RORs are significantly higher
335 under the 4-CP approach at 7.04% compared to the Company’s results at 5.53%. Similarly,
336 the ROR for Tesoro (now Marathon) is very close to the system ROR. **(Exhibit ___ (KM-**
337 **1), Attachment 7)** provides a summary of the 4-CP COSS results.

338 **Figure 3: Marathon v. MDU’s CCOSS Earned Rate of Return (“ROR”) and**
Indexed ROR by Class at Present Rates¹³

¹³ Tesoro in the Company’s COSS is Marathon Petroleum Company. MDU’s RORs can be found in Statement K.

	Marathon 4-CP COSS		MDU 12-CP COSS	
	Earned ROR	Indexed ROR	Earned ROR	Indexed ROR
Residential	2.21%	41	2.50%	47
Small General	4.14%	77	4.20%	79
Irrigation	-5.72%	-107	-4.06%	-76
Large General Primary	7.04%	132	5.53%	103
Large General Secondary	10.35%	193	10.45%	195
TOD Large General Primary	8.67%	162	6.87%	128
TOD Large General Secondary	11.22%	210	11.33%	212
Space Heating	6.16%	115	5.31%	99
Small Municipal	1.17%	22	0.90%	17
Municipal Lighting Primary	30.86%	577	14.82%	277
Municipal Lighting Secondary	11.55%	216	9.63%	180
Municipal Pumping Primary	1.10%	20	2.87%	54
Municipal Pumping Secondary	8.75%	164	7.93%	148
Outdoor Lighting	8.83%	165	7.60%	142
Interruptible Demand Response	18.43%	345	11.63%	217
Tesoro	4.96%	93	3.79%	71
Sabin	3.12%	58	1.95%	36
System	5.347%	100	5.347%	100

339 **Q. Do you have any other comments regarding the Company’s COSS at the present**
340 **time?**

341 A. Yes. MDU allocates fuel and purchased power energy costs using a flat kWh allocator.¹⁴
342 This allocator fails to recognize hourly energy cost and load variations. Fuel costs vary by
343 the hour and are typically higher in the week daytime hours compared to night time and
344 weekend hours. Otter Tail Power Company and Xcel Energy utilize an E8760 allocator to
345 allocate all costs classified as energy related. Figure 4 shows the Energy Adjustment Ratios
346 included in Otter Tail Power Company’s Energy Adjustment Rider. As can be noted in this
347 figure, the ratios vary by class and imply that classes with high load factors (such as Large
348 General Service that includes companies with 24X7 operations) have a ratio less than 1

¹⁴ See Factor 1 n Statement K. Energy allocator is calculated using class total energy consumption as a percent of total energy consumption.

349 due to consuming more energy in the off peak hours when the prices are lower. A ratio less
350 than 1 also means that below system average costs are to be allocated to this class.

351 **Figure 4: Otter Tail Power Company’s EAF Ratios**

Service Category	Section	EAF Ratio
Residential	9.01, 9.02, 9.04	1.025
Farms	9.03	0.969
General Service	10.01, 10.02, 10.03	1.016
Large General Service	10.04, 10.05, 10.06	0.967
Irrigation Services	11.01, 11.02	0.937
Outdoor Lighting	11.03, 11.04, 11.07	0.784
OPA	11.05	1.011
Controlled Service-Water Heating	14.01	1.035
Controlled Service- Interruptible	14.04, 14.05, 14.12	1.037
Controlled Service - Deferred	14.06, 14.07	0.963

352
353 Therefore, MDU’s flat energy allocator is likely over allocating energy costs to high load
354 factor classes such as the General Primary Class. I therefore recommend that the
355 Commission require the Company to develop and introduce an E8760 allocator to allocate
356 fuel costs recovered through the fuel and purchased power rider. This allocator should be
357 effective with final rates in this case.

358 ***B. Revenue Allocation***

359 **Q. Are you recommending any changes to the Company’s proposed revenue allocation**
360 **to the major classes such as residential, small general service, large general service,**
361 **municipal lighting, municipal pumping or lighting classes?**

362 **A.** No. While I could recommend an alternative revenue allocation to these classes based on
363 the 4-CP COSS results, in order to narrow the differences in the case, I am not

364 recommending revenue allocation changes to the major classes as proposed by the
 365 Company. MDU’s proposed increases are based on the Company’s revenue requirement
 366 increase of \$17.5 million.¹⁵ To maintain the Company’s proposed revenue allocation
 367 approach, I calculated the resulting percent class revenue responsibility share excluding
 368 fuel (Column E in Figure 5) after applying the proposed increase. These shares can be
 369 applied to the final total revenue requirement excluding fuel and the costs proposed to be
 370 recovered through the Generation Resource Recovery Rider.

371 **Figure 5: Class Revenue Responsibility Share Excluding Fuel Costs**

Column	A	B	C	D	E
	Total Present Revenues	Present Revenues Excluding Fuel	Company Proposed Increase	Resulting Revenue Responsibility Exc Fuel	% Rev. Resp Share Exc. Fuel
Residential Service	\$69,769,528	\$52,661,633	\$11,083,761	\$63,745,394	44.40%
Small General Service	\$10,414,218	\$8,284,943	\$1,813,125	\$10,098,068	7.03%
Large General Service	\$88,497,679	\$62,278,194	\$4,248,109	\$66,526,303	46.33%
Municipal Lighting	\$980,235	\$682,723	\$67,318	\$750,041	0.52%
Municipal Pumping	\$2,878,349	\$1,865,062	\$311,733	\$2,176,795	1.52%
Outdoor Lighting	\$362,968	\$273,524	\$12,656	\$286,180	0.20%
Total	\$172,902,977	\$126,046,079	\$17,536,702	\$143,582,781	100.00%

372
 373 As it relates to revenue allocation increases within the Large General Service class,
 374 however, I have recommended changes as discussed below.

375 **Q. What is your proposal for the sub classes within the Large General Service class?**

376 A. Figure 6 shows a comparison of my recommended allocation compared to the Company’s
 377 proposal found in Statement L. This figure shows MDU’s COSS (Columns E and F) and
 378 Marathon’s COSS (Columns I, J) respectively. The COSS results show the increases in
 379 dollar amounts and as a percent of total revenues including fuel. Columns G and H show

¹⁵ Note that an additional \$7.8 million is proposed to be recovered through the Generation Resource Recovery Rider. This revenue requirement is associated with the undepreciated plant value of the retired units.

380 MDU’s proposed increases in dollar amounts and as a percent of revenues excluding fuel,
 381 while Columns K and L show Marathon’s proposed increases.
 382 Compared to the Company’s proposal, my proposed approach generally assigns lower
 383 increases to primary level related classes. Factors considered in the reallocation include
 384 and are not limited to the 4-CP COSS results, number of customers served at the primary
 385 level (43 including contract customers) versus secondary level (over 4500) and gradualism.

386 **Figure 6: Comparison of Proposed Increases within the**
 387 **Large General Service Class: MDU v. Marathon**

COLUMN	A	B	C	D	E	F	G	H	I	J	K	L
					MDU COSS		MDU Proposed Increase		Marathon COSS		Marathon Proposed Increase	
Rate Class	No: of Customers	Fuel Rev	Total Present Revenues	Total Revenues Excluding Fuel	Increase	% Incr (Total Revenues)	\$ Amount	As a % of Revenues Exc. Fuel	Increase	% Incr (Total Revenues)	\$ Amount	As a % of Revenues Exc. Fuel
Large General Service												
Rate 30 Primary	40	4,935,088.00	\$14,563,657	\$9,628,569	\$1,274,750	8.8%	\$1,280,984	13.30%	\$279,852	1.9%	\$878,771	9.13%
Rate 30 Secondary	4,566	16,196,742.00	\$60,580,979	\$44,384,237	(\$6,454,832)	-10.7%	\$2,048,353	4.62%	(\$6,261,381)	-10.3%	\$2,665,563	6.01%
Rate 31 Primary	1	53,996.00	\$158,043	\$104,047	\$4,106	2.6%	\$6,691	6.43%	\$6,664	4.2%	\$6,691	6.43%
Rate 31 Secondary	52	310,452.00	\$1,173,919	\$863,467	(\$156,616)	-13.3%	\$38,077	4.41%	(\$152,906)	-13.0%	\$38,077	4.41%
Rate 32 Secondary	603	1,282,464	\$3,608,230	\$2,325,766	\$336,128	9.3%	\$336,200	14.46%	\$195,445	5.4%	\$259,301	11.15%
Subtotal	5,262	22,778,742	\$80,084,828	\$57,306,086	(\$4,996,464)	-6.2%	\$3,710,305	6.47%	(\$5,626,514)	-7.0%	\$3,848,403	6.72%
											\$0	
Contract Rate - Tesoro	1	2,151,779	\$4,874,206	\$2,722,427	\$780,410	16.0%	\$360,599	13.25%	\$495,313	10.2%	\$247,319	9.08%
Contract Rate - Sabin	1	591,987	\$1,438,878	\$846,891	\$418,060	29.1%	\$112,097	13.24%	\$301,606	21.0%	\$87,279	10.31%
Rate 38	4	696,977	\$2,099,767	\$1,402,790	(\$279,336)	-13.3%	\$65,108	4.64%	(\$566,288)	-27.0%	\$65,108	4.64%
Rate 39	0	-	\$0	\$0							\$0	
Total Large General	5,268	26,219,485	\$88,497,679	\$62,278,194	(\$4,077,330)	-4.6%	\$4,248,109	6.82%	(\$5,395,883)	-6.1%	\$4,248,109	6.82%

388
 389 **Q. What is your recommended approach for the final rate increase within the Large**
 390 **General Service class?**

391 A. In order to show an apples-to-apples comparison, I utilized the same revenue
 392 requirement increase as proposed by the Company. I recommend that the final revenue
 393 requirement increase be allocated within the Large General Service class using the
 394 revenue responsibility shares provided in Figure 7 below.

395

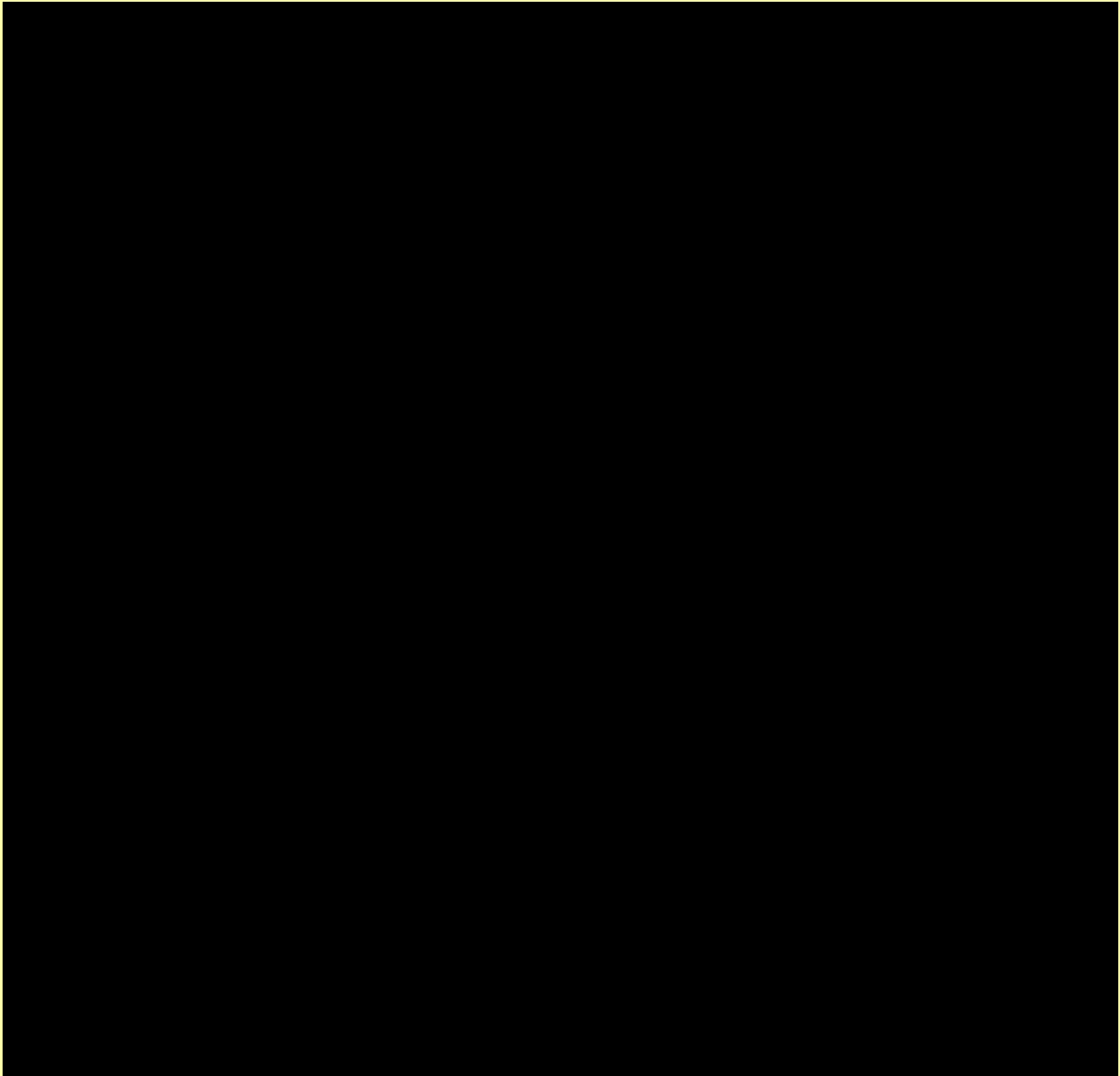
Figure 7: Revenue Responsibility Shares within the Large General Service Class

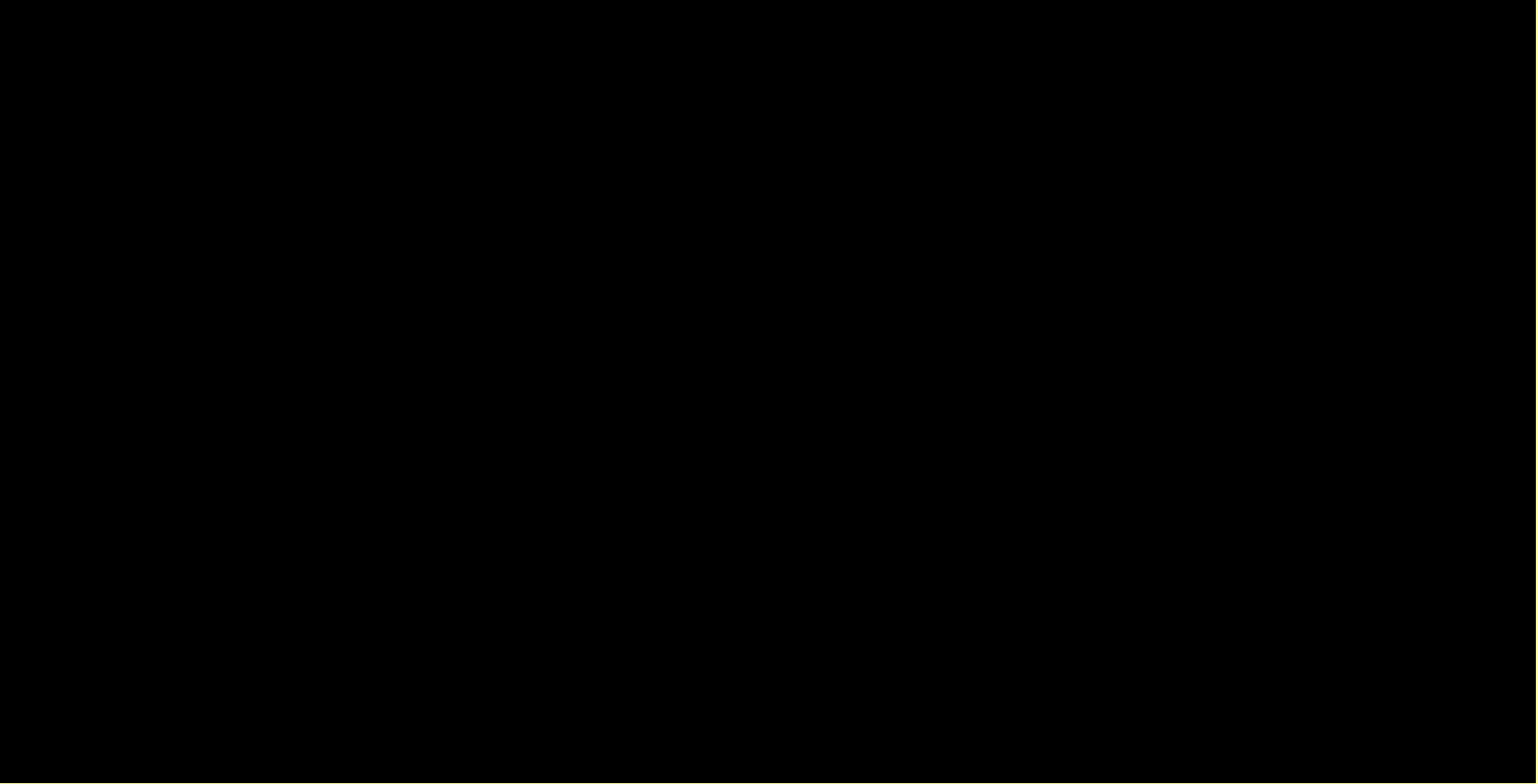
Rate Class	Total Revenues Exc Fuel	Revenue Responsibility after increase	Sub Class Revenue Responsibility % Shares
Large General Service			
Rate 30 Primary	\$9,628,569	\$10,507,340	15.79%
Rate 30 Secondary	\$44,384,237	\$47,049,800	70.72%
Rate 31 Primary	\$104,047	\$110,738	0.17%
Rate 31 Secondary	\$863,467	\$901,544	1.36%
Rate 32 Secondary	\$2,325,766	\$2,585,067	3.89%
Subtotal	\$57,306,086	\$61,154,489	91.93%
Contract Rate - Tesoro	\$2,722,427	\$2,969,746	4.46%
Contract Rate - Sabin	\$846,891	\$934,170	1.40%
Rate 38	\$1,402,790	\$1,467,898	2.21%
Rate 39	\$0	\$0	0.00%
Total Large General	\$62,278,194	\$66,526,303	100.00%

396

397 Q. **Does this conclude your direct testimony?**

398 A. Yes.





**MONTANA-DAKOTA UTILITIES CO.
MARATHON PETROLEUM COMPANY LP
INTERROGATORIES/INFORMATION REQUEST
TO MONTANA-DAKOTA UTILITIES CO.
DATA REQUEST SET 2 (MPC-MDU-II-1 – MPC-MDU-II-10)
ISSUED NOVEMBER 1, 2022
ND ELECTRIC RATE CASE NO. PU-22-194**

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

**MONTANA-DAKOTA UTILITIES CO.
MARATHON PETROLEUM COMPANY LP
INTERROGATORIES/INFORMATION REQUEST
TO MONTANA-DAKOTA UTILITIES CO.
DATA REQUEST SET 2 (MPC-MDU-II-1 – MPC-MDU-II-10)
ISSUED NOVEMBER 1, 2022
ND ELECTRIC RATE CASE NO. PU-22-194**

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

**MONTANA-DAKOTA UTILITIES CO.
MARATHON PETROLEUM COMPANY LP
INTERROGATORIES/INFORMATION REQUEST
TO MONTANA-DAKOTA UTILITIES CO.
DATA REQUEST SET 2 (MPC-MDU-II-1 – MPC-MDU-II-10)
ISSUED NOVEMBER 1, 2022
ND ELECTRIC RATE CASE NO. PU-22-194**

[REDACTED]

■ [REDACTED]

[REDACTED]

[REDACTED]

■ [REDACTED]

■ [REDACTED]

■ [REDACTED]

**MONTANA-DAKOTA UTILITIES CO.
MARATHON PETROLEUM COMPANY LP
INTERROGATORIES/INFORMATION REQUEST
TO MONTANA-DAKOTA UTILITIES CO.
DATA REQUEST SET 2 (MPC-MDU-II-1 – MPC-MDU-II-10)
ISSUED NOVEMBER 1, 2022
ND ELECTRIC RATE CASE NO. PU-22-194**

[REDACTED]

[REDACTED]

**MARATHON PETROLEUM COMPANY LP
INTERROGATORIES/INFORMATION REQUEST
SET IV
TO MONTANA-DAKOTA UTILITIES CO. (“MDU”)
ISSUED DECEMBER 16, 2022
ND ELECTRIC RATE CASE NO. PU-22-194**

Case No.: PU-22-194
OAH File No.: 20220225

Date of Request: December 16, 2022

Requested From: Marathon Petroleum Company, LP (“Marathon” or “MPC”)

Party Requesting Information: Kenneth R. Stark, Robert A. Weishaar, Jr., and Richard J. Savelkoul, Attorneys for Marathon

If your responses are trade secret or privileged, please indicate this on your response. If answers include Excel spreadsheet output, please include a copy of the spreadsheet with formulae intact.

MPC-MDU-IV-1. Has MDU identified any credits or incentives it plans to utilize as a result of the Inflation Reduction Act of 2022 ([Pub. L. 11-169](#))? If so, please provide a detailed explanation along with any and all adjustments to the 2023 revenue requirement.

Response:

At the current time, Montana-Dakota has not identified any credits or incentives resulting from the Inflation Reduction Act of 2022 that would apply to Case No. PU-22-194.

Montana-Dakota has identified that the Company will receive Production Tax Credits (PTCs) related to the Diamond Willow Wind Repower at full valuation. Previously, the IRS guidance identified the repowered turbines would qualify for PTCs at 80% of the full value. However, PTCs are not included in Case No. PU-22-194, but rather, are reflected in the Renewable Resources Cost Adjustment (RRCA) Rate 55 tariff.

MPC-MDU-V-8. Refer to MDU's response to MPC-MDU-IV-1.

- a. Please provide the impacts of receiving Production Tax Credits (PTCs) related to the Diamond Willow Wind Repower at full valuation. Also, at what time period would these savings be realized by customers? Please explain and provide all documents and analyses (including native Excel files) relied on in responding to this request.

Response:

As stated in the Company's response to MPC-MDU-IV-1, Production Tax Credits (PTCs) are recovered in the Company's Renewable Resource Cost Adjustment (RRCA) Rate 55 tariff and are not a component of the proposed rates in Case No. PU-22-194.

Please see the Excel file titled Response No. MPC-MDU-V-8 Attachment A for a comparison of the total estimated PTCs by year at the full value of \$0.026/kWh vs the estimated PTC's at 80% of the PTC value for the Diamond Willow Wind Repower.

In Case No. PU-21-420, the Company agreed to smooth out the effects of Diamond Willow's PTC expiration by creating a levelization adjustment which is reflected in the RRCA. Thus, customers will realize the savings of PTC's over the remaining life of the asset, which is until 2035 for Diamond Willow Wind.

**MONTANA-DAKOTA UTILITIES CO.
 ELECTRIC UTILITY - NORTH DAKOTA
 DIAMOND WILLOW ESTIMATED PRODUCTION TAX CREDITS**

Year	Diamond Willow Repower Generation 1/	PTC's @ \$.026/Kwh 2/	PTC's @ 80% Value 3/	Difference
2022	14,613,000	\$267,000	\$213,600	\$53,400
2023	66,226,000	1,210,041	968,033	242,008
2024	63,839,705	1,166,440	933,152	233,288
2025	63,839,705	1,166,440	933,152	233,288
2026	63,839,705	1,166,440	933,152	233,288
2027	63,839,705	1,166,440	933,152	233,288
2028	63,839,705	1,166,440	933,152	233,288
2029	63,839,705	1,166,440	933,152	233,288
2030	63,839,705	1,166,440	933,152	233,288
2031	63,839,705	1,166,440	933,152	233,288
2032	48,371,305	883,811	707,049	176,762
		<u>\$11,692,372</u>	<u>\$9,353,898</u>	<u>\$2,338,474</u>

- 1/ Diamond Willow Repower turbines were eligible for Production Tax Credits (PTC's) starting November 2022. Turbines will generate PTC's for 10 years. Generation reflects the estimated annual generation of the affected turbines.
- 2/ Annual PTC's at \$0.026/kWh of generation, allocated to North Dakota.
 ND Allocation - Factor #271 - 2022: 70.274582%
- 3/ Annual PTC's at 80% of \$0.026/kWh of generation, allocated to North Dakota.
 ND Allocation - Factor #271 - 2022: 70.274582%

- MPC-MDU-V-5.** Please provide the following in an Excel spreadsheet:
- a. Monthly system peaks for MDU's North Dakota jurisdiction for the test year.
 - b. Class contribution to the monthly system peaks for the North Dakota jurisdiction provided in response to subsection (a).
 - c. The class cost of service study provides 1CP and 12CP numbers but does not show the data to arrive at the 1CP and 12CP numbers. Please provide the derivation of the 1CP and 12CP in an excel spreadsheet format. Provide all documents, correspondence, and analyses (including native Excel files) relied on in responding to this request.

Response:

- a. Please see the attached Excel file titled Response No. MPC-MDU-V-5 Attachment A.
- b. As noted in response to MPC-MDU-II-3, Montana-Dakota used the results of its 2019 load research study to calculate the NCP by rate class in the class cost of service study. It was also used to calculate the 1CP and 12 CP. Please see part c below.
- c. Please see the amounts for the 1 CP and 12 CP in cells G4 and I4, respectively, of the tab titled "kWh and kW for E&D (load data)" in the "ND 2022 Electric Class Cost of Service - K" file provided in response to data request ND PSC 4.2 which comes from the results of the 2019 load research study provided as Excel file MPC-MDU-II-3 Attachment A in response to data request MPC-MDU-II-3. For example, for Rate 100, the 12CP of 138,536 is the average of the monthly amounts found on the "Total Coincident Peak" line (line 45) in tab "Stmt K page 26". The 1CP amount can be found in cell P45.

To calculate the 12 CP amount that was used for the allocation factors, the 2019 12 CP amount was brought into the "E&D Allocation" tab in the "ND 2022 Electric Class Cost of Service -K" Excel file in cell B44. To calculate the 2023 12 CP @ Secondary, the ratio of the projected 2023 Rate 10 kWh to the 2019 Actual kWh from cells H3 and B3, respectively, was applied to the 2019 12 CP in cell H44. This amount was then multiplied by the applicable peak losses found in cells H112 - H116 to arrive at the 12 CP @ Generation amount used for the 12 CP @ Gen allocation (Factor 2) in cell E15 on the "allocation factors worksheet" tab of the same Excel file. The same calculation was done for each rate class for Factor 2. The 1CP was not used in the cost of service study and therefore was not calculated for 2023.

**Montana-Dakota Utilities Co.
 2021 MONTHLY PEAKS BY STATE
 (INCLUDING LOSSES)**

	North Dakota		South Dakota		Montana		Total	
	KW	%	KW	%	KW	%	KW	%
JAN 26 HE 1000	362,617	71.06%	26,629	5.22%	121,053	23.72%	510,299	100%
FEB 12 HE 1100	408,914	71.40%	30,166	5.27%	133,623	23.33%	572,703	100%
MAR 30 HE 1000	329,718	72.77%	18,271	4.03%	105,101	23.20%	453,090	100%
APR 13 HE 1000	289,508	69.32%	23,550	5.64%	104,604	25.05%	417,662	100%
MAY 18 HE 1800	290,490	69.07%	17,749	4.22%	112,316	26.71%	420,555	100%
JUNE 10 HE 1600	379,380	68.99%	31,097	5.65%	139,430	25.36%	549,907	100%
JULY 19 HE 1700	424,592	70.33%	31,728	5.26%	147,406	24.42%	603,726	100%
AUG 16 HE 1700	408,935	70.24%	32,700	5.62%	140,579	24.15%	582,214	100%
SEPT 28 HE 1800	356,799	73.08%	27,244	5.58%	104,197	21.34%	488,240	100%
OCT 5 HE 1700	330,471	74.17%	18,656	4.19%	96,438	21.64%	445,565	100%
NOV 17 HE 1800	315,887	71.16%	18,429	4.15%	109,601	24.69%	443,917	100%
DEC 31 HE 1900	370,302	70.93%	22,724	4.35%	129,056	24.72%	522,082	100%
2021 Year End	4,267,613	71.01%	298,943	4.97%	1,443,404	24.02%	6,009,960	100%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
NORTH DAKOTA
Embedded Class Cost of Service Study
Projected 2023

Allocation Factor	Total North Dakota	Total Residential Rate 10	Total SG Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total LG TOD Primary Rate 31	Total LG TOD Secondary Rate 31	Total Space Heating Rate 32	
Rate Base										
Electric Plant in Service										
Production Plant	2	372,523,090	160,485,302	17,810,795	527,988	32,583,127	125,444,480	356,948	2,404,342	7,061,179
Wind Production Plant	3	0	0	0	0	0	0	0	0	0
Total Production Plant		372,523,090	160,485,302	17,810,795	527,988	32,583,127	125,444,480	356,948	2,404,342	7,061,179
Transmission Plant	2	235,301,764	101,369,487	11,250,071	333,500	20,580,918	79,236,182	225,464	1,518,687	4,460,147
Distribution Plant										
Land & Rights of Way	4	3,007,365	1,182,101	162,300	14,679	409,859	811,421	2,250	15,553	109,917
Station Equipment	4	72,632,242	28,549,460	3,919,780	354,518	9,898,687	19,597,007	54,352	375,623	2,654,655
Poles, OH & UG Conductors & Conduit										
Customer Related 83%	7	128,514,594	107,382,163	13,884,144	45,012	49,104	5,623,767	1,364	64,108	45,012
Demand Related 17%	4	25,579,643	10,054,557	1,380,469	124,854	3,486,122	6,901,679	19,142	132,287	934,917
Line Transformers										
Customer Related 64%	11	35,354,826	18,548,454	6,834,981	132,412	0	8,266,769	0	98,955	0
Demand Related 36%	5	19,766,511	9,912,555	1,360,973	123,091	0	6,804,206	0	130,419	921,713
Services	10	27,193,804	21,638,049	2,679,030	14,874	0	2,335,024	0	30,560	0
Meters	8	12,509,383	7,379,147	1,588,828	12,635	235,368	2,618,841	6,640	28,683	281,575
Installation on Customer Premise	Direct	1,609,949	0	0	0	0	0	0	0	0
Street Light & Signal System	Direct	4,950,417	0	0	0	0	0	0	0	0
Total Distribution Plant		331,118,734	204,646,486	31,810,505	822,075	14,079,140	52,958,714	83,748	876,188	4,947,789
General, Common & Intangible Plant	13	95,060,753	47,229,636	6,162,754	170,449	6,807,852	26,083,989	67,443	485,883	1,667,370
Common - Intangible - CC&B & PCAD	6	7,872,688	6,565,174	848,854	2,752	3,002	343,828	83	3,919	2,752
General, Common & Intangible Plant, incl. CC&B & PCAD		102,933,441	53,794,810	7,011,608	173,201	6,810,854	26,427,817	67,526	489,802	1,670,122
Acquisition Adjustment	29	7,381,702	3,180,084	352,928	10,462	645,648	2,485,735	7,073	47,643	139,920
Total Electric Plant in Service		1,049,258,731	523,476,169	68,235,907	1,867,226	74,699,687	286,552,928	740,759	5,336,662	18,279,157

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
NORTH DAKOTA
Embedded Class Cost of Service Study
Projected 2023

	Allocation Factor	Total North Dakota	Total Residential Rate 10	Total SG Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total LG TOD Primary Rate 31	Total LG TOD Secondary Rate 31	Total Space Heating Rate 32
Less: Accumulated Depreciation										
Production Plant	2	139,506,807	60,100,414	6,669,995	197,727	12,202,111	46,977,917	133,674	900,406	2,644,353
Wind Production Plant	3	0	0	0	0	0	0	0	0	0
Total Production Plant		139,506,807	60,100,414	6,669,995	197,727	12,202,111	46,977,917	133,674	900,406	2,644,353
Transmission Plant	2	61,384,598	26,444,873	2,934,874	87,002	5,369,069	20,670,823	58,818	396,189	1,163,546
Distribution Plant										
Rights of Way	4	143,560	56,429	7,748	701	19,565	38,734	107	742	5,247
Station Equipment	4	16,362,608	6,431,629	883,049	79,866	2,229,979	4,414,818	12,244	84,621	598,041
Poles, OH & UG Conductors & Conduit	15	46,085,142	35,121,936	4,565,205	50,802	1,057,283	3,745,999	6,133	58,736	293,069
Line Transformers	19	20,292,634	10,477,773	3,017,298	94,062	0	5,548,301	0	84,443	339,324
Services	10	15,950,026	12,691,400	1,571,336	8,724	0	1,369,565	0	17,925	0
Meters	8	4,667,223	2,753,143	592,788	4,714	87,815	977,084	2,478	10,702	105,055
Installation on Customer Premise	Direct	(339,370)	0	0	0	0	0	0	0	0
Street Light & Signal System	Direct	424,111	0	0	0	0	0	0	0	0
Total Distribution Plant		103,585,934	67,532,310	10,637,424	238,869	3,394,642	16,094,501	20,962	257,169	1,340,736
General, Common & Intangible Plant	13	35,694,527	17,734,338	2,314,063	64,002	2,556,292	9,794,323	25,324	182,445	626,083
Common - Intangible - CC&B & PCAD	6	5,166,437	4,308,383	557,059	1,806	1,970	225,637	55	2,572	1,806
General, Common & Intangible Plant, incl. CC&B & PCAD		40,860,964	22,042,721	2,871,122	65,808	2,558,262	10,019,960	25,379	185,017	627,889
Acquisition Adjustment	29	7,381,181	3,179,859	352,903	10,462	645,603	2,485,560	7,073	47,640	139,910
Amort. - Power Plant Decommissioning	2	309,542	133,353	14,800	439	27,074	104,236	297	1,998	5,867
Less: Total Accumulated Reserve for Depreciation		353,029,026	179,433,530	23,481,118	600,307	24,196,761	96,352,997	246,203	1,788,419	5,922,301
Net Electric Plant in Service		696,229,705	344,042,639	44,754,789	1,266,919	50,502,926	190,199,931	494,556	3,548,243	12,356,856
Additions										
Materials & Supplies	13	13,868,468	6,890,359	899,087	24,866	993,201	3,805,408	9,839	70,885	243,253
Prepayments	26	1,105,632	551,601	71,902	1,968	78,712	301,949	780	5,624	19,261
Fuel Stocks	1	1,960,046	713,472	84,269	1,474	209,694	675,473	2,294	12,947	53,484
Unamortized Loss on Debt	26	838,282	418,220	54,515	1,492	59,680	228,935	592	4,264	14,604
Gain/(Loss) on Sale of Building	13	875,617	435,038	56,766	1,570	62,707	240,262	621	4,475	15,359
Unamortized Redemption of Preferred Stock	26	207,687	103,615	13,506	370	14,786	56,720	147	1,057	3,618
Provision for Pension & Benefits	23	15,608,892	8,141,043	1,088,758	26,458	1,007,274	3,982,702	10,011	74,406	279,696
Provision for Post Retirement	23	3,678,752	1,918,706	256,601	6,236	237,397	938,656	2,359	17,536	65,920
Total Additions		38,143,376	19,172,054	2,525,404	64,434	2,663,451	10,230,105	26,643	191,194	695,195

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
NORTH DAKOTA
Embedded Class Cost of Service Study
Projected 2023

	Allocation Factor	Total North Dakota	Total Residential Rate 10	Total SG Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total LG TOD Primary Rate 31	Total LG TOD Secondary Rate 31	Total Space Heating Rate 32
Total Electric Retail Sales Revenues		172,902,977	69,769,528	10,032,962	100,003	14,563,657	60,580,979	158,043	1,173,919	3,608,230
Other Revenue										
Miscellaneous										
Reconnect Fees	7	45,720	38,203	4,940	16	17	2,001	0	23	16
NSF Check Fees	7	34,041	28,444	3,678	12	13	1,490	0	17	12
Other Miscellaneous Service Revenue	27	9,294	4,591	597	17	674	2,540	7	47	165
Rent from Electric Property										
Facilities Rental	27	1,250,571	617,972	80,390	2,276	90,714	341,638	888	6,374	22,196
Pole Attachments	15	77,937	59,396	7,720	86	1,788	6,335	11	99	496
Street Lights	Direct	903,186	0	0	0	0	0	0	0	0
Yard Lights	Direct	360,800	0	0	0	0	0	0	0	0
Joint Use Facilities	30	17,644	7,601	844	25	1,543	5,941	17	114	334
Miscellaneous	27	17,621	8,708	1,133	32	1,278	4,814	13	90	313
Other Electric Revenues										
Late Payment Revenue	92	178,090	178,090	0	0	0	0	0	0	0
2-Year Average KVAR Penalty	14	584,936	361,517	56,195	1,452	24,872	93,553	148	1,548	8,741
Sales of Construction & Sundry Junk Material	14	43,398	26,822	4,169	108	1,845	6,941	11	115	649
Patronage Dividends	23	15,145	7,900	1,056	25	978	3,864	9	72	271
Joint Use Agreements	8	82,144	48,456	10,433	83	1,546	17,197	44	188	1,849
Big Stone Miscellaneous	29	207,328	89,318	9,913	294	18,134	69,816	199	1,338	3,930
Miscellaneous	23	70,310	36,671	4,904	120	4,537	17,940	45	336	1,261
Total Other Revenues		3,898,165	1,513,689	185,972	4,546	147,939	574,070	1,392	10,361	40,233

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	Allocation Factor	Total North Dakota	Total Residential Rate 10	Total SG Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total LG TOD Primary Rate 31	Total LG TOD Secondary Rate 31	Total Space Heating Rate 32
Street Light & Signal Systems	Direct	160,497	0	0	0	0	0	0	0	0
Total Distribution Plant		10,628,911	6,589,192	1,024,901	26,173	443,493	1,690,105	2,644	27,898	156,881
General, Common & Intangible Plant & Amort of Gain/L	13	4,496,935	2,234,241	291,535	8,064	322,052	1,233,928	3,190	22,986	78,877
Common - Intangible - CC&B & PCAD	6	650,395	542,377	70,127	227	248	28,405	7	324	227
Total Plant		5,147,330	2,776,618	361,662	8,291	322,300	1,262,333	3,197	23,310	79,104
Amort. Of Decomm. Of Power Plants	29	647,584	278,983	30,962	918	56,642	218,069	621	4,180	12,275
Amort. Of Preferred Stock Redemption	26	20,943	10,449	1,362	38	1,490	5,721	15	106	365
Total Depreciation Expense		30,209,497	15,585,174	2,076,996	54,929	2,027,871	7,811,402	19,666	144,334	509,535
Taxes Other Than Income										
Ad Valorem Taxes										
Production Plant	29	2,347,268	1,011,218	112,226	3,327	205,306	790,426	2,249	15,150	44,492
Transmission Plant	30	1,221,216	526,108	58,388	1,731	106,815	411,236	1,170	7,882	23,148
Distribution Plant	14	1,519,173	938,919	145,946	3,771	64,595	242,974	385	4,020	22,700
General, Common & Intangible Plant	13	529,439	263,044	34,323	950	37,915	145,275	376	2,706	9,286
Total Ad Valorem Taxes		5,617,096	2,739,289	350,883	9,779	414,631	1,589,911	4,180	29,758	99,626
Other Taxes										
Other Taxes - Payroll, Franchise, Other	23	1,739,321	907,168	121,322	2,947	112,242	443,798	1,115	8,291	31,167
Total Taxes Other Than Income Taxes		7,356,417	3,646,457	472,205	12,726	526,873	2,033,709	5,295	38,049	130,793
Total Operating Expense		139,145,080	65,243,680	8,426,698	199,129	10,981,629	39,832,891	113,558	750,269	2,858,500
Income Taxes										
Interest Expense, AFUDC Equity & Other Adjustments	27	13,689,326	6,764,595	879,972	24,910	992,993	3,739,727	9,724	69,766	242,962
Taxable Income		23,966,736	(725,058)	912,264	(119,490)	2,736,974	17,582,431	36,153	364,245	547,001
Less: State Income Tax	44	1,032,966	(31,250)	39,319	(5,151)	117,964	757,802	1,558	15,698	23,576
Federal Taxable Income		22,933,770	(693,808)	872,945	(114,339)	2,619,010	16,824,629	34,595	348,547	523,425
Federal Income Tax										
@ Current Rate of 21%		4,816,092	(145,701)	183,318	(24,011)	549,992	3,533,173	7,264	73,195	109,919
State Income Taxes	44	1,032,966	(31,250)	39,319	(5,151)	117,964	757,802	1,558	15,698	23,576
Credits and Adjustments										
Plant Related Excess Deferred - ARAM	27	(926,911)	(458,034)	(59,583)	(1,687)	(67,236)	(253,219)	(659)	(4,723)	(16,451)
Federal and State Income Taxes		4,922,147	(634,985)	163,054	(30,849)	600,720	4,037,756	8,163	84,170	117,044
Total Operating Expenses		144,067,227	64,608,695	8,589,752	168,280	11,582,349	43,870,647	121,721	834,439	2,975,544
Total Operating Income		32,733,915	6,674,522	1,629,182	(63,731)	3,129,247	17,284,402	37,714	349,841	672,919

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Allocation Factor	Total North Dakota	Total Small Municipal Rate 40	Total Mun. Lighting Pri Rate 41	Total Mun. Lighting Sec Rate 41	Total Mun. Pumping Pri Rate 48	Total Mun. Pumping Sec Rate 48	Total Outdoor Lighting Rate 52	Total American Colloid Rate 39
Rate Base								
Electric Plant in Service								
Production Plant								
2	372,523,090	556,121	7,458	119,062	4,146,838	2,920,477	180,119	0
Wind Production Plant								
3	0	0	0	0	0	0	0	0
Total Production Plant	372,523,090	556,121	7,458	119,062	4,146,838	2,920,477	180,119	0
Transmission Plant								
2	235,301,764	351,270	4,711	75,205	2,619,323	1,844,700	113,771	0
Distribution Plant								
Land & Rights of Way								
4	3,007,365	9,371	2,050	17,827	37,166	23,869	10,263	0
Station Equipment								
4	72,632,242	226,313	49,506	430,541	897,603	576,473	247,855	0
Poles, OH & UG Conductors & Conduit								
Customer Related 83%								
7	128,514,594	317,811	58,651	665,631	4,092	365,552	0	0
Demand Related 17%								
4	25,579,643	79,703	17,435	151,628	316,118	203,022	87,290	0
Line Transformers								
Customer Related 64%								
11	35,354,826	290,504	0	359,773	0	648,393	174,585	0
Demand Related 36%								
5	19,766,511	78,577	0	149,487	0	200,155	85,335	0
Services								
10	27,193,804	74,102	0	209,595	0	139,279	73,291	0
Meters								
8	12,509,383	46,852	3,781	44,085	42,056	125,524	46,300	0
Installation on Customer Premise								
Direct	1,609,949	0	0	0	0	0	1,609,949	0
Street Light & Signal System								
Direct	4,950,417	0	0	4,950,417	0	0	0	0
Total Distribution Plant	331,118,734	1,123,233	131,423	6,978,984	1,297,035	2,282,267	2,334,868	0
General, Common & Intangible Plant								
13	95,060,753	205,586	14,538	726,236	816,336	713,498	266,141	0
Common - Intangible - CC&B & PCAD								
6	7,872,688	19,431	3,586	40,696	250	22,349	15,511	0
General, Common & Intangible Plant, incl. CC&B & PCAD								
102,933,441	225,017	18,124	766,932	816,586	735,847	281,652	0	
Acquisition Adjustment								
29	7,381,702	11,020	148	2,359	82,171	57,870	3,569	0
Total Electric Plant in Service	1,049,258,731	2,266,661	161,864	7,942,542	8,961,953	7,841,161	2,913,979	0

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Less: Accumulated Depreciation									
Production Plant	2	139,506,807	208,263	2,793	44,588	1,552,956	1,093,694	67,453	0
Wind Production Plant	3	0	0	0	0	0	0	0	0
Total Production Plant		139,506,807	208,263	2,793	44,588	1,552,956	1,093,694	67,453	0
Transmission Plant	2	61,384,598	91,638	1,229	19,619	683,319	481,238	29,680	0
Distribution Plant									
Rights of Way	4	143,560	447	98	851	1,774	1,139	490	0
Station Equipment	4	16,362,608	50,984	11,153	96,992	202,212	129,868	55,837	0
Poles, OH & UG Conductors & Conduit	15	46,085,142	118,885	22,756	244,419	95,766	170,044	26,106	0
Line Transformers	19	20,292,634	135,875	0	187,482	0	312,388	95,688	0
Services	10	15,950,026	43,463	0	122,934	0	81,692	42,987	0
Meters	8	4,667,223	17,480	1,411	16,448	15,691	46,833	17,274	0
Installation on Customer Premise	Direct	(339,370)	0	0	0	0	0	(339,370)	0
Street Light & Signal System	Direct	424,111	0	0	424,111	0	0	0	0
Total Distribution Plant		103,585,934	367,134	35,418	1,093,237	315,443	741,964	(100,988)	0
General, Common & Intangible Plant	13	35,694,527	77,196	5,459	272,696	306,527	267,912	99,933	0
Common - Intangible - CC&B & PCAD	6	5,166,437	12,751	2,353	26,706	164	14,667	10,179	0
General, Common & Intangible Plant, incl. CC&B & PCAD		40,860,964	89,947	7,812	299,402	306,691	282,579	110,112	0
Acquisition Adjustment	29	7,381,181	11,019	148	2,359	82,166	57,866	3,569	0
Amort. - Power Plant Decommissioning	2	309,542	462	6	99	3,446	2,427	150	0
Less: Total Accumulated Reserve for Depreciation		353,029,026	768,463	47,406	1,459,304	2,944,021	2,659,768	109,976	0
Net Electric Plant in Service		696,229,705	1,498,198	114,458	6,483,238	6,017,932	5,181,393	2,804,003	0
Additions									
Materials & Supplies	13	13,868,468	29,993	2,121	105,951	119,096	104,092	38,827	0
Prepayments	26	1,105,632	2,389	170	8,370	9,444	8,262	3,071	0
Fuel Stocks	1	1,960,046	3,057	1,087	11,340	21,777	20,884	3,731	0
Unamortized Loss on Debt	26	838,282	1,811	130	6,345	7,161	6,265	2,327	0
Gain/(Loss) on Sale of Building	13	875,617	1,893	133	6,689	7,520	6,573	2,452	0
Unamortized Redemption of Preferred Stock	26	207,687	449	32	1,572	1,774	1,552	577	0
Provision for Pension & Benefits	23	15,608,892	34,551	2,811	119,300	120,519	112,460	70,864	0
Provision for Post Retirement	23	3,678,752	8,143	663	28,117	28,404	26,505	16,701	0
Total Additions		38,143,376	82,286	7,147	287,684	315,695	286,593	138,550	0

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Total Before Deductions	734,373,081	1,580,484	121,605	6,770,922	6,333,627	5,467,986	2,942,553	0
Deductions								
26 Accumulated Deferred Income Tax	120,747,223	260,844	18,626	914,017	1,031,329	902,350	335,335	0
26 Accumulated Investment Tax Credit	0	0	0	0	0	0	0	0
26 Customer Advances For Construction	1,447,877	3,128	224	10,960	12,366	10,820	4,022	0
Total Deductions	122,195,100	263,972	18,850	924,977	1,043,695	913,170	339,357	0
Total Rate Base	612,177,981	1,316,512	102,755	5,845,945	5,289,932	4,554,816	2,603,196	0
Rate of Return - Per Books	5.347%	1.173%	30.864%	11.549%	1.096%	8.754%	8.826%	0.000%
Electric Operating Revenues								
Retail Sales								
Residential Direct	69,769,528	0	0	0	0	0	0	0
Small General Electric Service Direct	10,032,962	0	0	0	0	0	0	0
Irrigation Direct	100,003	0	0	0	0	0	0	0
Large General Service - Primary Direct	14,563,657	0	0	0	0	0	0	0
Large General Service - Secondary Direct	60,580,979	0	0	0	0	0	0	0
TOD Large General Service - Primary Direct	158,043	0	0	0	0	0	0	0
TOD Large General Service - Secondary Direct	1,173,919	0	0	0	0	0	0	0
Space Heating - Secondary Direct	3,608,230	0	0	0	0	0	0	0
Small Municipal Electric Service Direct	281,253	281,253	0	0	0	0	0	0
Municipal Lighting - Primary Direct	80,434	0	80,434	0	0	0	0	0
Municipal Lighting - Secondary Direct	899,801	0	0	899,801	0	0	0	0
Municipal Pumping - Primary Direct	1,254,219	0	0	0	1,254,219	0	0	0
Municipal Pumping - Secondary Direct	1,624,130	0	0	0	0	1,624,130	0	0
Outdoor Lighting Direct	362,968	0	0	0	0	0	362,968	0
Interruptible Demand Response Direct	2,099,767	0	0	0	0	0	0	0
Contract - Tesoro	4,874,206	0	0	0	0	0	0	0
Contract - Sabin Direct	1,438,878	0	0	0	0	0	0	0

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Total Electric Retail Sales Revenues	172,902,977	281,253	80,434	899,801	1,254,219	1,624,130	362,968	0
Other Revenue								
Miscellaneous								
Reconnect Fees	7	45,720	113	21	237	1	130	0
NSF Check Fees	7	34,041	84	16	176	1	97	0
Other Miscellaneous Service Revenue	27	9,294	20	2	87	80	70	38
Rent from Electric Property								
Facilities Rental	27	1,250,571	2,690	205	11,645	10,810	9,307	5,037
Pole Attachments	15	77,937	201	39	414	162	288	44
Street Lights	Direct	903,186	0	0	903,186	0	0	0
Yard Lights	Direct	360,800	0	0	0	0	360,800	0
Joint Use Facilities	30	17,644	26	0	6	196	138	9
Miscellaneous	27	17,621	38	2	164	152	131	71
Other Electric Revenues								
Late Payment Revenue	92	178,090	0	0	0	0	0	0
2-Year Average KVAR Penalty	14	584,936	1,984	232	12,329	2,292	4,032	4,125
Sales of Construction & Sundry Junk Material	14	43,398	148	17	914	170	300	306
Patronage Dividends	23	15,145	34	3	116	117	110	68
Joint Use Agreements	8	82,144	308	25	289	276	824	304
Big Stone Miscellaneous	29	207,328	310	4	66	2,308	1,625	100
Miscellaneous	23	70,310	156	13	537	543	506	320
Total Other Revenues		3,898,165	6,112	579	930,166	17,108	17,558	371,222

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	Allocation Factor	Total North Dakota	Total Small Municipal Rate 40	Total Mun. Lighting Pri Rate 41	Total Mun. Lighting Sec Rate 41	Total Mun. Pumping Pri Rate 48	Total Mun. Pumping Sec Rate 48	Total Outdoor Lighting Rate 52	Total American Colloid Rate 39
Total Operating Revenues		176,801,142	287,365	81,013	1,829,967	1,271,327	1,641,688	734,190	0
Operation & Maintenance Expenses									
Production Expense									
Fuel	1	18,235,994	28,441	10,118	105,507	202,610	194,305	34,710	0
Purchased Power - Energy	1	23,830,979	37,167	13,222	137,878	264,772	253,920	45,360	0
Purchased Power - Capacity	2	3,747,271	5,594	75	1,198	41,714	29,378	1,812	0
Other Production	2	13,324,439	19,891	267	4,259	148,324	104,460	6,442	0
Total Production Expense		59,138,683	91,093	23,682	248,842	657,420	582,063	88,324	0
Transmission Expense	2	6,495,412	9,697	130	2,076	72,305	50,922	3,141	0
Distribution Expense	14	11,249,462	38,161	4,465	237,105	44,066	77,538	79,325	0
Customer Accounts Expense	12	2,895,512	7,325	1,167	16,876	298	12,942	61,479	0
Customer Service & Info. Expense	12	256,354	649	103	1,494	26	1,146	5,443	0
Sales Expense	7	102,864	254	47	533	3	293	0	0
Administrative & General Expenses	24	21,440,879	47,459	3,860	163,875	165,549	154,479	97,341	0
Total Electric O&M Expenses		101,579,166	194,638	33,454	670,801	939,667	879,383	335,053	0
Total Operating Expenses									
Cost of Fuel & Purchased Power		45,814,244	71,202	23,415	244,583	509,096	477,603	81,882	0
Other O&M Expenses		55,764,922	123,436	10,039	426,218	430,571	401,780	253,171	0
Total Operation & Maintenance Expenses		101,579,166	194,638	33,454	670,801	939,667	879,383	335,053	0
Depreciation Expense									
Production Plant	2	9,835,190	14,682	197	3,143	109,483	77,105	4,755	0
Wind Production Plant	3	0	0	0	0	0	0	0	0
Total Production Plant + Amor + Def. Gen.		9,835,190	14,682	197	3,143	109,483	77,105	4,755	0
Transmission Plant	2	3,929,539	5,866	79	1,256	43,743	30,806	1,900	0
Distribution Plant									
Rights of Way	4	7,440	23	5	44	92	59	25	0
Station Equipment	4	2,351,115	7,326	1,603	13,937	29,056	18,660	8,023	0
Poles, OH & UG Conductors & Conduit	15	4,988,147	12,868	2,463	26,455	10,365	18,405	2,826	0
Line Transformers	19	1,784,594	11,949	0	16,488	0	27,472	8,415	0
Services	10	880,074	2,398	0	6,783	0	4,508	2,372	0
Meters	8	404,962	1,517	122	1,427	1,361	4,064	1,499	0
Installation on Cust. Premises	Direct	52,082	0	0	0	0	0	52,082	0

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Street Light & Signal Systems	Direct	160,497	0	0	160,497	0	0	0	0
Total Distribution Plant		10,628,911	36,081	4,193	225,631	40,874	73,168	75,242	0
General, Common & Intangible Plant & Amort of Gain/L	13	4,496,935	9,726	687	34,355	38,618	33,752	12,590	0
Common - Intangible - CC&B & PCAD	6	650,395	1,605	296	3,362	21	1,846	1,281	0
Total Plant		5,147,330	11,331	983	37,717	38,639	35,598	13,871	0
Amort. Of Decomm. Of Power Plants	29	647,584	967	13	207	7,209	5,077	313	0
Amort. Of Preferred Stock Redemption	26	20,943	45	3	158	178	157	58	0
Total Depreciation Expense		30,209,497	68,972	5,468	268,112	240,126	221,911	96,139	0
Taxes Other Than Income									
Ad Valorem Taxes									
Production Plant	29	2,347,268	3,504	47	750	26,129	18,402	1,135	0
Transmission Plant	30	1,221,216	1,823	24	390	13,594	9,574	590	0
Distribution Plant	14	1,519,173	5,154	603	32,020	5,951	10,471	10,712	0
General, Common & Intangible Plant	13	529,439	1,145	81	4,046	4,546	3,974	1,483	0
Total Ad Valorem Taxes		5,617,096	11,626	755	37,206	50,220	42,421	13,920	0
Other Taxes									
Other Taxes - Payroll, Franchise, Other	23	1,739,321	3,849	313	13,294	13,430	12,532	7,897	0
Total Taxes Other Than Income Taxes		7,356,417	15,475	1,068	50,500	63,650	54,953	21,817	0
Total Operating Expense		139,145,080	279,085	39,990	989,413	1,243,443	1,156,247	453,009	0
Income Taxes									
Interest Expense, AFUDC Equity & Other Adjustments	27	13,689,326	29,457	2,251	127,475	118,325	101,877	55,132	0
Taxable Income		23,966,736	(21,177)	38,772	713,079	(90,441)	383,564	226,049	0
Less: State Income Tax	44	1,032,966	(912)	1,671	30,734	(3,898)	16,531	9,743	0
Federal Taxable Income		22,933,770	(20,265)	37,101	682,345	(86,543)	367,033	216,306	0
Federal Income Tax									
@ Current Rate of 21%		4,816,092	(4,256)	7,791	143,292	(18,174)	77,077	45,424	0
State Income Taxes	44	1,032,966	(912)	1,671	30,734	(3,898)	16,531	9,743	0
Credits and Adjustments									
Plant Related Excess Deferred - ARAM	27	(926,911)	(1,995)	(153)	(8,631)	(8,012)	(6,898)	(3,732)	0
Federal and State Income Taxes		4,922,147	(7,163)	9,309	165,395	(30,084)	86,710	51,435	0
Total Operating Expenses		144,067,227	271,922	49,299	1,154,808	1,213,359	1,242,957	504,444	0
Total Operating Income		32,733,915	15,443	31,714	675,159	57,968	398,731	229,746	0

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Allocation Factor	Total North Dakota	Total IT Demand Response Rate 38	Total Contract Tesoro	Total Contract Sabin	
Rate Base					
Electric Plant in Service					
Production Plant	2	372,523,090	2,238,562	11,869,636	3,810,649
Wind Production Plant	3	0	0	0	
Total Production Plant		372,523,090	2,238,562	11,869,636	3,810,649
Transmission Plant	2	235,301,764	1,413,973	7,497,377	2,406,971
Distribution Plant					
Land & Rights of Way	4	3,007,365	62,407	88,397	47,935
Station Equipment	4	72,632,242	1,507,224	2,134,936	1,157,709
Poles, OH & UG Conductors & Conduit					
Customer Related 83%	7	128,514,594	5,455	1,364	1,364
Demand Related 17%	4	25,579,643	530,815	751,883	407,722
Line Transformers					
Customer Related 64%	11	35,354,826	0	0	0
Demand Related 36%	5	19,766,511	0	0	0
Services	10	27,193,804	0	0	0
Meters	8	12,509,383	26,286	16,233	6,549
Installation on Customer Premise	Direct	1,609,949	0	0	0
Street Light & Signal System	Direct	4,950,417	0	0	0
Total Distribution Plant		331,118,734	2,132,187	2,992,813	1,621,279
General, Common & Intangible Plant	13	95,060,753	585,659	2,263,758	793,628
Common - Intangible - CC&B & PCAD	6	7,872,688	335	83	83
General, Common & Intangible Plant, incl. CC&B & PCAD		102,933,441	585,994	2,263,841	793,711
Acquisition Adjustment	29	7,381,702	44,358	235,201	75,510
Total Electric Plant in Service		1,049,258,731	6,415,074	24,858,868	8,708,120

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	Allocation Factor	Total North Dakota	Total IT Demand Response Rate 38	Total Contract Tesoro	Total Contract Sabin
Less: Accumulated Depreciation					
Production Plant	2	139,506,807	838,323	4,445,080	1,427,056
Wind Production Plant	3	0	0	0	0
Total Production Plant		139,506,807	838,323	4,445,080	1,427,056
Transmission Plant	2	61,384,598	368,872	1,955,886	627,922
Distribution Plant					
Rights of Way	4	143,560	2,979	4,220	2,289
Station Equipment	4	16,362,608	339,548	480,959	260,808
Poles, OH & UG Conductors & Conduit	15	46,085,142	160,382	225,275	122,346
Line Transformers	19	20,292,634	0	0	0
Services	10	15,950,026	0	0	0
Meters	8	4,667,223	9,807	6,056	2,444
Installation on Customer Premise	Direct	(339,370)	0	0	0
Street Light & Signal System	Direct	424,111	0	0	0
Total Distribution Plant		103,585,934	512,716	716,510	387,887
General, Common & Intangible Plant	13	35,694,527	219,910	850,022	298,000
Common - Intangible - CC&B & PCAD	6	5,166,437	219	55	55
General, Common & Intangible Plant, incl. CC&B & PCAD		40,860,964	220,129	850,077	298,055
Acquisition Adjustment	29	7,381,181	44,355	235,185	75,504
Amort. - Power Plant Decommissioning	2	309,542	1,860	9,863	3,166
Less: Total Accumulated Reserve for Depreciation		353,029,026	1,986,255	8,212,601	2,819,590
Net Electric Plant in Service		696,229,705	4,428,819	16,646,267	5,888,530
Additions					
Materials & Supplies	13	13,868,468	85,442	330,262	115,784
Prepayments	26	1,105,632	6,759	26,195	9,177
Fuel Stocks	1	1,960,046	29,530	90,605	24,928
Unamortized Loss on Debt	26	838,282	5,125	19,860	6,957
Gain/(Loss) on Sale of Building	13	875,617	5,395	20,852	7,311
Unamortized Redemption of Preferred Stock	26	207,687	1,269	4,920	1,724
Provision for Pension & Benefits	23	15,608,892	87,278	333,474	117,287
Provision for Post Retirement	23	3,678,752	20,570	78,594	27,642
Total Additions		38,143,376	241,368	904,762	310,810

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Allocation Factor	Total North Dakota	Total IT Demand Response Rate 38	Total Contract Tesoro	Total Contract Sabin
Total Before Deductions	734,373,081	4,670,187	17,551,029	6,199,340
Deductions				
Accumulated Deferred Income Tax	26 120,747,223	738,238	2,860,724	1,002,118
Accumulated Investment Tax Credit	26 0	0	0	0
Customer Advances For Construction	26 1,447,877	8,853	34,302	12,016
Total Deductions	122,195,100	747,091	2,895,026	1,014,134
Total Rate Base	612,177,981	3,923,096	14,656,003	5,185,206
Rate of Return - Per Books	5.347%	18.425%	4.958%	3.116%
Electric Operating Revenues				
Retail Sales				
Residential	Direct 69,769,528	0	0	0
Small General Electric Service	Direct 10,032,962	0	0	0
Irrigation	Direct 100,003	0	0	0
Large General Service - Primary	Direct 14,563,657	0	0	0
Large General Service - Secondary	Direct 60,580,979	0	0	0
TOD Large General Service - Primary	Direct 158,043	0	0	0
TOD Large General Service - Secondary	Direct 1,173,919	0	0	0
Space Heating - Secondary	Direct 3,608,230	0	0	0
Small Municipal Electric Service	Direct 281,253	0	0	0
Municipal Lighting - Primary	Direct 80,434	0	0	0
Municipal Lighting - Secondary	Direct 899,801	0	0	0
Municipal Pumping - Primary	Direct 1,254,219	0	0	0
Municipal Pumping - Secondary	Direct 1,624,130	0	0	0
Outdoor Lighting	Direct 362,968	0	0	0
Interruptible Demand Response	Direct 2,099,767	2,099,767	0	0
Contract - Tesoro	4,874,206	0	4,874,206	0
Contract - Sabin	Direct 1,438,878	0	0	1,438,878

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	Allocation Factor	Total North Dakota	Total IT Demand Response Rate 38	Total Contract Tesoro	Total Contract Sabin
Total Electric Retail Sales Revenues		172,902,977	2,099,767	4,874,206	1,438,878
Other Revenue					
Miscellaneous					
Reconnect Fees	7	45,720	2	0	0
NSF Check Fees	7	34,041	1	0	0
Other Miscellaneous Service Revenue	27	9,294	59	222	79
Rent from Electric Property					
Facilities Rental	27	1,250,571	7,955	29,900	10,577
Pole Attachments	15	77,937	271	381	206
Street Lights	Direct	903,186	0	0	0
Yard Lights	Direct	360,800	0	0	0
Joint Use Facilities	30	17,644	106	562	179
Miscellaneous	27	17,621	113	421	148
Other Electric Revenues					
Late Payment Revenue	92	178,090	0	0	0
2-Year Average KVAR Penalty	14	584,936	3,767	5,286	2,863
Sales of Construction & Sundry Junk Material	14	43,398	279	392	212
Patronage Dividends	23	15,145	85	323	113
Joint Use Agreements	8	82,144	173	106	43
Big Stone Miscellaneous	29	207,328	1,246	6,605	2,121
Miscellaneous	23	70,310	393	1,501	528
Total Other Revenues		3,898,165	14,450	45,699	17,069

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	Allocation Factor	Total North Dakota	Total IT Demand Response Rate 38	Total Contract Tesoro	Total Contract Sabin
Total Operating Revenues		176,801,142	2,114,217	4,919,905	1,455,947
Operation & Maintenance Expenses					
Production Expense					
Fuel	1	18,235,994	274,741	842,979	231,917
Purchased Power - Energy	1	23,830,979	359,034	1,101,613	303,070
Purchased Power - Capacity	2	3,747,271	22,518	119,399	38,332
Other Production	2	13,324,439	80,069	424,554	136,299
Total Production Expense		59,138,683	736,362	2,488,545	709,618
Transmission Expense	2	6,495,412	39,032	206,963	66,445
Distribution Expense	14	11,249,462	72,439	101,678	55,082
Customer Accounts Expense	12	2,895,512	353	108	81
Customer Service & Info. Expense	12	256,354	31	10	7
Sales Expense	7	102,864	4	1	1
Administrative & General Expenses	24	21,440,879	119,890	458,072	161,109
Total Electric O&M Expenses		101,579,166	968,111	3,255,377	992,343
Total Operating Expenses					
Cost of Fuel & Purchased Power		45,814,244	656,293	2,063,991	573,319
Other O&M Expenses		55,764,922	311,818	1,191,386	419,024
Total Operation & Maintenance Expenses		101,579,166	968,111	3,255,377	992,343
Depreciation Expense					
Production Plant	2	9,835,190	59,102	313,377	100,607
Wind Production Plant	3	0	0	0	0
Total Production Plant + Amor + Def. Gen.		9,835,190	59,102	313,377	100,607
Transmission Plant	2	3,929,539	23,613	125,206	40,195
Distribution Plant					
Rights of Way	4	7,440	154	219	120
Station Equipment	4	2,351,115	48,789	69,107	37,474
Poles, OH & UG Conductors & Conduit	15	4,988,147	17,360	24,382	13,242
Line Transformers	19	1,784,594	0	0	0
Services	10	880,074	0	0	0
Meters	8	404,962	851	525	212
Installation on Cust. Premises	Direct	52,082	0	0	0

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Street Light & Signal Systems	Direct	160,497	0	0	0
Total Distribution Plant		10,628,911	67,154	94,233	51,048
General, Common & Intangible Plant & Amort of Gain/L	13	4,496,935	27,704	107,088	37,542
Common - Intangible - CC&B & PCAD	6	650,395	28	7	7
Total Plant		5,147,330	27,732	107,095	37,549
Amort. Of Decomm. Of Power Plants	29	647,584	3,891	20,634	6,624
Amort. Of Preferred Stock Redemption	26	20,943	128	495	173
Total Depreciation Expense		30,209,497	181,620	661,040	236,196
Taxes Other Than Income					
Ad Valorem Taxes					
Production Plant	29	2,347,268	14,105	74,791	24,012
Transmission Plant	30	1,221,216	7,339	38,911	12,492
Distribution Plant	14	1,519,173	9,783	13,731	7,438
General, Common & Intangible Plant	13	529,439	3,262	12,608	4,420
Total Ad Valorem Taxes		5,617,096	34,489	140,041	48,362
Other Taxes					
Other Taxes - Payroll, Franchise, Other	23	1,739,321	9,725	37,159	13,069
Total Taxes Other Than Income Taxes		7,356,417	44,214	177,200	61,431
Total Operating Expense		139,145,080	1,193,945	4,093,617	1,289,970
Income Taxes					
Interest Expense, AFUDC Equity & Other Adjustments	27	13,689,326	87,080	327,301	115,782
Taxable Income		23,966,736	833,192	498,987	50,195
Less: State Income Tax	44	1,032,966	35,911	21,506	2,163
Federal Taxable Income		22,933,770	797,281	477,481	48,032
Federal Income Tax					
@ Current Rate of 21%		4,816,092	167,429	100,272	10,088
State Income Taxes	44	1,032,966	35,911	21,506	2,163
Credits and Adjustments					
Plant Related Excess Deferred - ARAM	27	(926,911)	(5,897)	(22,161)	(7,839)
Federal and State Income Taxes		4,922,147	197,443	99,617	4,412
Total Operating Expenses		144,067,227	1,391,388	4,193,234	1,294,382
Total Operating Income		32,733,915	722,829	726,671	161,565

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