

BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Xcel Energy’s Petition for
Approval of its 2023 Annual Fuel Forecast
and Monthly Fuel Cost Charges

)
)
) Docket No. E-002/AA-22-179
)
)

Surrebuttal Testimony and Schedule of

Brian C. Andrews

On behalf of

Xcel Large Industrials

September 17, 2025



BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Xcel Energy’s Petition for Approval of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges)))))	Docket No. E-002/AA-22-179
--	-----------------------	-----------------------------------

**Table of Contents for the
Surrebuttal Testimony of Brian C. Andrews**

	<u>Page</u>
I. INTRODUCTION.....	1
II. RESPONSE TO XCEL WITNESS DETMER	2
III. AVOIDED 2029 COST OFFSET	8
IV. HISTORICAL PERFORMANCE ADJUSTMENT	10
V. CAPACITY ACCREDITATION.....	11
VI. CONCLUSION	12

Schedule 1

BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Xcel Energy’s Petition for)
Approval of its 2023 Annual Fuel Forecast)
and Monthly Fuel Cost Charges)
_____)

Docket No. E-002/AA-22-179

Surrebuttal Testimony of Brian C. Andrews

I. INTRODUCTION

1

2 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017.

5 Q PLEASE STATE YOUR OCCUPATION.

6 A I am a consultant in the field of public utility regulation and a Principal with the firm of
7 Brubaker & Associates, Inc. (“BAI”), energy, economic and regulatory consultants.

8 Q ARE YOU THE SAME BRIAN C. ANDREWS WHO FILED DIRECT
9 TESTIMONY IN THIS PROCEEDING ON JULY 2, 2025?

10 A Yes, I am.

11 Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

12 A I am testifying on behalf of the Xcel Large Industrials (“XLI”).

1 **Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

2 A The purpose of my Surrebuttal Testimony is to respond to the rebuttal testimony filed
3 on August 13, 2025 on behalf of Xcel. I will reiterate my opinion that the replacement
4 power costs associated with the outage at the Prairie Island Nuclear Generating Plant
5 (“PINGP”) should be based on a Locational Marginal Pricing (“LMP”) method. I will
6 also provide XLI’s position on the offsets that Xcel has proposed to reduce the refund
7 due to customers.

8 **II. RESPONSE TO XCEL WITNESS DETMER**

9 **Q DOES XCEL WITNESS DETMER AGREE WITH YOUR DIRECT**
10 **TESTIMONY THAT THE REPLACEMENT POWER COSTS OF PINGP**
11 **SHOULD BE BASED ON THE LMP METHOD?**

12 A No. Mr. Detmer continues to advocate for the replacement power costs to be based on
13 the results of the Company’s PLEXOS modeling. He pushes back on my criticisms of
14 the PLEXOS modeling, with respect to a base case calibration, and the impact of the
15 PINGP outage on the output of other generators and the LMPs. Mr. Detmer has also
16 provided some clarifications of questions that I raised in my direct testimony.

17 **Q HAS XCEL PROVIDED CLARIFICATION ON HOW THE PLEXOS**
18 **MODELING WAS PERFORMED?**

19 A Yes. Mr. Detmer has provided some clarification in his rebuttal testimony and included
20 responses to XLI’s discovery requests on the matter as exhibits to his rebuttal testimony.
21 Mr. Detmer has further explained how the base case and the change case were modeled.

1 In the base case, the generators were set at their actual output, any surplus or shortfall
2 was then made up by MISO purchases or sales. In the change case, along with the
3 availability of PINGP, the generators were then allowed to be dispatched by the input
4 LMPs, the MISO sales and purchases determined in the base case were held constant,
5 and the model was also allowed to make extra sales. The difference in cost between
6 these two runs is what Xcel argues is representative of the replacement power costs.

7 **Q DOES THIS CLARIFICATION RESOLVE YOUR CONCERNS WITH THE**
8 **CALIBRATION OF THE BASE CASE?**

9 **A** It does not. While this way of modeling may provide an accurate measure of the costs
10 of each generating unit during the outage period, it is not an accurate measure of Xcel's
11 actual power costs during the outage. Because actual generator output and actual fuel
12 and operating costs were used, the model does likely provide an accurate estimate of the
13 cost to run each generator during the outage. This, however, is only a portion of Xcel's
14 power costs. MISO market interaction is also a significant component of Xcel's overall
15 power costs. Indeed, the modeled cost of MISO purchases during the outage totaled
16 **[TRADE SECRET DATA BEGINS ... [REDACTED] ...TRADE SECRET DATA**
17 **ENDS]** and the modeled revenues from MISO sales were **[TRADE SECRET DATA**
18 **BEGINS ... [REDACTED] ...TRADE SECRET DATA ENDS]**. These are significant
19 figures considering that Xcel contends the replacement power costs of PINGP were
20 **[TRADE SECRET DATA BEGINS ... [REDACTED] ...TRADE SECRET DATA**

1 **ENDS]**¹ The actual cost from MISO purchases and revenues from MISO sales are likely
2 drastically different than what has been represented by the PLEXOS modeling. Xcel
3 has provided nothing demonstrating that net costs associated with MISO purchases and
4 sales are representative of actual costs. In fact, the LMPs used within the PLEXOS
5 modeling also concerns me.

6 **Q WHY DO THE LMPS USED IN THE PLEXOS MODELING CONCERN YOU?**

7 A The MISO LMPs that Xcel used in the PLEXOS model are based on the Real-Time
8 LMPs (“RT-LMP”) at the NSP.NSP node in MISO. The use of RT-LMPs is concerning,
9 because most of MISO market interactions occur in the Day-Ahead market, using
10 Day-Ahead LMPs (“DA-LMP”). Nearly all load and generation clears in the
11 Day-Ahead market. The Real-Time market is used to adjust for differences that occur
12 between the two. In fact, Mr. Detmer in his direct testimony provides a several page
13 explanation of how the majority of costs are decided by the Day-Ahead market.²

14 Further, as another datapoint, I updated the LMP analysis that I discussed in my
15 direct testimony, with the LMPs that Xcel used in the PLEXOS modeling, and
16 determined that the replacement power costs of PINGP outage would be [TRADE
17 **SECRET DATA BEGINS ... [REDACTED] ...TRADE SECRET DATA ENDS]**,
18 which is [TRADE SECRET DATA BEGINS ... [REDACTED] ...TRADE SECRET
19 **DATA ENDS]** or 35% greater than the [TRADE SECRET DATA BEGINS ... [REDACTED]

¹Exhibit NJD-1, Schedule 2, page 990.

²Detmer Direct at pages 3-10.

1 [REDACTED] ...TRADE SECRET DATA ENDS]³ that I estimated in my direct testimony
2 to confirm the accuracy of Xcel's replacement costs calculations using the LMP
3 Method. The clarifications provided by Xcel simply do not meet the burden of proof to
4 demonstrate the PLEXOS modeling represents an accurate measure of system costs.

5 **Q DOES XCEL'S CLARIFICATION RESOLVE YOUR CONCERNS WITH THE**
6 **PLEXOS CHANGE CASE?**

7 A No. Xcel has clarified how its MISO market interactions were conducted in the Change
8 Case. As I mentioned earlier, in the Base Case, the excess or shortfall from actual
9 generation to meet load was used to determine what the MISO sales and purchases were.
10 These sales and purchase volumes were held constant in the Change Case. In the
11 Change Case, the generators were dispatched to the same RT-LMPs that were used in
12 the Base Case. Xcel also allowed for excess sales. These excess sales totaled roughly
13 631,000 MWh.⁴ These excess sales represent just 16% of the PINGP generation. What
14 concerns me most is that Xcel did not allow for the change case to have any reduction
15 of MISO purchases. While I would fully expect the availability of PINGP to result in
16 more MISO sales, significantly more than just 16% of its output, I would also expect
17 for MISO purchases to be nearly eliminated. This is a fatal flaw in the PLEXOS
18 modeling. As I mentioned earlier, the Base Case showed MISO purchases during the
19 outage cost [TRADE SECRET DATA BEGINS ... [REDACTED] ...TRADE
20 SECRET DATA ENDS], I would fully expect this figure to be materially reduced in a

³Direct Testimony of Brian Andrews at page 13, lines 2-6.

⁴Detmer Rebuttal at page 6, lines 7-8.

1 correctly modeled Change Case. A reduction in the cost associated with MISO
2 Purchases would decrease the overall cost of the Change Case, thus showing the
3 replacement power costs are higher than what has been incorrectly estimated by Xcel
4 using the PLEXOS model. Therefore, the results of Xcel’s PLEXOS modeling should
5 not be used to determine the replacement power costs for the PINGP outage.

6 **Q DOES MR. DETMER AGREE WITH YOU THAT THE PINGP OUTAGE**
7 **WOULD HAVE MINIMUM IMPACT ON LMPS?**

8 A It would appear that he does. While he disagrees with me that the LMP Method is the
9 correct method to determine the replacement power costs of the PINGP outage, it does
10 appear he agrees that LMPs would be largely unaffected. In his rebuttal to the
11 Department, he reiterates his support for Xcel’s modeling, which kept the LMPs the
12 same in the Base and Change cases, stating, “This assumption is reasonable because it
13 is easily observable and any assumed change in the price for energy in the MISO energy
14 market between the base and change cases would have a negligible impact on the
15 replacement power cost estimation.”⁵

⁵Detmer Rebuttal at page 5, lines 16-19.

1 Q IF HE AGREES THAT LMPs WOULD BE LARGELY UNCHANGED, WHY
2 THEN WHY DOES HE DISAGREE WITH YOU THAT THE LMP METHOD IS
3 THE APPROPRIATE MANNER TO DETERMINE REPLACEMENT POWER
4 COSTS?

5 A His primary criticism of the use of the LMP calculation method seems to be tied to the
6 displacement of other generation within MISO North. He states,

7 [T]he LMP Calculation Method is only appropriate when the size of
8 the facility at issue is small, so that other nearby resources would be
9 unaffected by that facility's availability. XLI witness Andrews
10 argues that PINGP is small as compared to the size of MISO, in
11 total, and that all the generators in aggregate would have been
12 unaffected by its operation.

13 Mr. Detmer mischaracterizes my testimony. The comparison of PINGP to MISO was
14 to demonstrate there would be little to no impact on the LMPs. On this point, he largely
15 agrees, as discussed in my previous answer. Actual market operations are based on the
16 LMPs. If there is little to no change in LMPs, then there would be little to no change in
17 the output of the generation that was actually available during the PINGP outage.
18 Mr. Detmer claims that PINGP is a large portion of MISO North and that there is
19 transmission congestion that would impede energy flow from MISO North to MISO
20 South. On these issues, he provides no data demonstrating how this affects the analysis.
21 The fact is that Mr. Detmer agrees that it is reasonable to assume that LMPs would be
22 unchanged, and it must then follow that the LMP calculation method is a reasonable
23 proxy to determine replacement power costs.

1 Q DO YOU CONTINUE TO RECOMMEND THE REPLACEMENT POWER
2 COSTS FOR THE PINGP OUTAGE BE BASED ON THE LMP METHOD?

3 A Yes. Xcel's PLEXOS modeling has not been shown to be conducted in a reasonable
4 manner. Xcel has provided no demonstration that the net costs from MISO purchases
5 and sales are reflective of their actual costs. Further, the PLEXOS change case only
6 allows for additional sales, but does not allow for any reduction in MISO purchases.
7 These fatal flaws cannot be overcome. Xcel agrees that the PINGP outage would have
8 little to no effect on the MISO LMPs. Because all generators within MISO are
9 dispatched according to LMPs, there should be little to no change market-wide in actual
10 generator output. Therefore, the LMP calculation method continues to be a reasonable
11 approach to calculate the replacement power costs associated with the PINGP outage.
12 Minnesota's allocated share of the replacement power costs for the PINGP outage
13 estimated by the LMP Method are no less than [TRADE SECRET DATA BEGINS
14 ... [REDACTED] ...TRADE SECRET DATA ENDS].

15 III. AVOIDED 2029 COST OFFSET

16 Q ARE YOU FAMILIAR WITH THE ISSUES SURROUNDING XCEL'S
17 PROPOSED 2029 AVOIDED COSTS OFFSET?

18 A Yes. I have reviewed both the OAG's and Department's direct testimonies on the
19 subject, as well as Xcel's direct and rebuttal testimonies on the same.

1 **Q DO YOU HAVE ANYTHING TO ADD TO THE DISCUSSION OF XCEL’S**
2 **PROPOSED 2029 AVOIDED COST OFFSET?**

3 A Yes. To determine the 2029 avoided cost offset, Xcel again used the PLEXOS model
4 to determine these costs. As with the PINGP outage PLEXOS modeling, I would not
5 expect these costs to be accurately calculated for the same reasons I discuss above and
6 in my direct testimony and I would be highly cautious in trusting the results. Xcel had
7 to make dozens of assumptions to forecast costs out to 2029. The hourly LMPs, hourly
8 loads, monthly fuel prices, monthly Operation and Maintenance (“O&M”) of every
9 generator, unit heat rates, outage rates, start-up costs and fuel transportation costs would
10 all need to be estimated for 2029. I’m not aware of any of these assumptions receiving
11 sufficient scrutiny to justify reducing a refund to customers who endured real
12 measurable cost increase due to the PINGP outage. Furthermore, Xcel witness Krug
13 states that the 2029 jurisdictional allocator, which increased from 71.44% in 2024 to
14 77.30% in 2029, which increases the offset, is based on an assumption that over 2,000
15 MW of data center load is added to the system. The assumptions necessary to determine
16 any 2029 avoided costs are speculative at best, and therefore should not be relied upon.
17 The PINGP outage resulted in real, measurable harm suffered by ratepayers and the
18 refund should not be reduced by speculative future costs.

19 **Q IS THERE REGULATORY PRECEDENT TO INCLUDE THIS TYPE OF**
20 **OFFSET?**

21 A No. In fact, it is my understanding that the Minnesota Public Utilities Commission
22 (“Commission”) recently rejected this type of offset. In the matter to determine the

1 replacement power cost incurred as a result of the unplanned outage of Sherco 3, the
2 Commission did not allow Xcel to offset a customer refund based on other benefits that
3 may have accrued from resolving the consequences of imprudent behavior, stating,
4 “Xcel’s prudent management of the restoration process—including efforts to mitigate
5 costs—[is] the expectation and does not offset or mitigate Xcel’s prior imprudence.”⁶
6 The Commission has categorically denied this type of proposed offset and the
7 Administrative Law Judge and the Commission should similarly do so here.

8 **IV. HISTORICAL PERFORMANCE ADJUSTMENT**

9 **Q ARE YOU FAMILIAR WITH THE ISSUES SURROUNDING HISTORICAL**
10 **PERFORMANCE ADJUSTMENT?**

11 **A** Yes. Xcel contends that because PINPG operated so well during the 2018-2022
12 timeframe, that it should be rewarded for this and only refund customers 51% of the net
13 replacement power cost. The OAG is opposed to this offset⁷ and the Department⁸ has
14 some concerns with it. XLI is also opposed. Xcel is a monopoly with captive customers.
15 Those customers pay for electric utility service at regulated rates. Xcel’s base rates are
16 reflective of the costs to operate and maintain its generating units, including PINGP.
17 Xcel should not be rewarded, via a reduced refund, for operating one of its plants. The
18 customers have already paid for PINGP’s operation and maintenance and continue to
19 do so in their base rates. Again, the PINGP outage resulted in real, measurable harm to

⁶*In re Appl. of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.* (“Sherco 3 Forced Outage”), Docket No. E-002/GR-12-961, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED at 36 (Dec. 24, 2024) (eDocket No. 202412- 213317-01).

⁷Lee Direct at 18.

⁸Golden Direct at 18, lines 5-7.

1 Xcel’s customers, totaling [TRADE SECRET DATA BEGINS ... XXXXXXXXXX
2 ...TRADE SECRET DATA ENDS]. Any benefit from past performance does not
3 offset the increased costs that were paid by ratepayers as a result of the PINGP outage.
4 Historical performance cannot be banked to excuse imprudence and the historical
5 performance adjustment should be rejected.

6 **V. CAPACITY ACCREDITATION**

7 **Q XCEL HAS PROPOSED AN OFFSET RELATED TO ITS PAST**
8 **PERFORMANCE OF PINGP. HAS XCEL ESTIMATED THE IMPACT OF**
9 **THE PINGP OUTAGE ON ITS CAPACITY ACCREDITATION VALUE USED**
10 **IN THE MISO CAPACITY AUCTIONS?**

11 **A** Yes. In response to XLI data requests, Xcel has provided the estimated impact of the
12 PINGP outage on its Accredited Capacity (“AC”) value. For Unit 1, Xcel states that its
13 AC has been adversely impacted by 25 MW in the summer and 7 MW in the winter.
14 For Unit 2, the AC has been adversely impacted by 1 MW for the spring. Xcel estimates
15 similar impact for the next two MISO planning years. The discovery responses on this
16 issue have been included as Schedule 1 to this surrebuttal testimony.

17 **Q HAS XCEL QUANTIFIED THE COST ASSOCIATED WITH THIS**
18 **REDUCTION OF AC?**

19 **A** No. However, for the 2025/2026 planning year, the summer capacity cost is
20 \$666.50/MW-day. The largest incremental cost will be associated with additional
21 capacity that must be procured in the summer, and that calculation, 25 MW times the

1 capacity price times 90 days for the summer period, results in additional capacity costs
2 of \$1.5 million. For the winter, the capacity price is much lower, so the incremental
3 cost will be lower. The winter capacity price is just \$33.20/MW-Day, so the impact is
4 low, near \$20 thousand. The PINGP outage will continue to result in additional summer
5 capacity costs for Xcel’s customers for the next two MISO planning years, which
6 potentially could be an increased cost totaling \$4.5 million for the 2025/2026,
7 2026/2027, and 2027/2028 MISO Planning Years. When allocated to Minnesota, using
8 an average allocation factor of 70.77%, the lost AC revenue is \$3.2 million. These AC
9 costs have not been quantified anywhere in Xcel’s calculations. Xcel’s failure to include
10 these costs, but eagerness to request a historical performance adjustment is concerning.
11 As the Commission has noted,⁹ the reduced accreditation of PINGP stemming from
12 Xcel’s imprudence has and will result in reduced MISO revenues, to the detriment of
13 customers, and Xcel should refund \$3.2 million to customers to account for these lost
14 revenues.

15 **VI. CONCLUSION**

16 **Q PLEASE SUMMARIZE THE RECOMMENDATIONS FROM YOUR**
17 **SURREBUTTAL TESTIMONY?**

18 **A** I continue to recommend that the replacement power costs associated with the PINGP
19 outage be calculated using the LMP Method. Xcel’s further explanation of its PLEXOS
20 modeling has only highlighted additional flaws, namely that the Change Case did not

⁹Order Approving 2023 Fuel Clause True-up Report, Requiring Additional Filings, Finding Imprudence, and Notice of and Order for Hearing at 8 (Nov. 11, 2024) (eDocket No. 202411-211999-01).

1 allow for a reduction of MISO market purchases, demonstrating that the PLEXOS
2 modeling does not provide an accurate measure of Xcel’s power costs. Xcel has
3 estimated the replacement power costs for the PINGP outage, using the LMP Method,
4 to be [TRADE SECRET DATA BEGINS ... ██████████ ...TRADE SECRET
5 DATA ENDS].

6 Xcel ignored Commission precedent disallowing an offset of a refund for
7 avoided future work and the estimated values of that avoided future work are speculative
8 at best. As such, the \$20.5 million offset for the avoided 2029 work should be rejected.
9 Xcel also should not be allowed to reduce the refund with its proposed historical
10 performance adjustment, which would reduce the refund by roughly half. Xcel’s
11 customers have been fully paying for all costs of the PINGP plant since it was
12 constructed through its base rates. Historical performance does not make up for the
13 measurable harm that was caused by the PINGP outage.

14 Finally, Xcel has not accounted for any lost capacity market revenue in its
15 calculations. These additional capacity costs are directly attributable to the PINGP
16 outage and will be incurred for the 2025/2026 MISO planning year and the following
17 two planning years, and these costs totaling \$3.2 million should be refunded to
18 customers.

19 The final refund due to customers should be should be [TRADE SECRET
20 DATA BEGINS ... ██████████ ...TRADE SECRET DATA ENDS], which
21 accounts for the replacement power costs and lost capacity market revenue.

1 **Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

2 **A** Yes, it does.

546104

- Highly Confidential Not-Public Document – Not For Public Disclosure
- Not-Public Document – Not For Public Disclosure
- Public Document – Highly Confidential & Not-Public Data Has Been Excised
- Public Document

Xcel Energy Information Request No. 9
 Docket No.: E002/AA-22-179
 Response To: Xcel Large Industrials
 Requestor: Andrew P. Moratzka, Amber S. Lee, and Eden A. Fauré
 Date Received: August 27, 2025

Question:

Please provide the capacity value of Prairie Island Units 1 and 2 used in the MISO capacity auctions from 2018-2025.

Response:

Table 1 below shows the capacity value of Prairie Island Units 1 and 2 used in the MISO capacity auctions from 2018-2025.

There is one value for each unit in Planning Year 2018/2019 through 2022/2023. Starting in the 2023/2024 planning year, MISO implemented the seasonal resource adequacy construct, so every resource receives four capacity accreditation values instead of one.

Table 1

Unit	PI Unit 1				PI Unit 2			
PY 2018/2019	512.0				476.8			
PY 2019/2020	522.0				492.5			
PY 2020/2021	529.4				524.6			
PY 2021/2022	526.4				527.8			
PY 2022/2023	526.5				526.5			
Season	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
PY 2023/2024	541.2	576.3	576.0	574.5	556.8	551.2	584.6	582.5
PY 2024/2025	551.0	570.8	648.2	618.2	541.3	569.1	647.4	579.0
PY 2025/2026	515.6	517.3	582.9	581.4	518.0	530.9	602.6	537.9

Witness: n/a
Preparer: Ben Kaldunski
Title: Resource Planning Analyst II
Department: NSP Resource Planning and Bidding
Telephone: 608-280-7314
Date: September 10, 2025

Witness: n/a
Preparer: Amanda J. Jepson
Title: Manager, Nuclear Regulatory Policy
Department: Nuclear Policy Planning
Telephone: 651-212-1679
Date: September 10, 2025

- Highly Confidential Not-Public Document – Not For Public Disclosure
- Not-Public Document – Not For Public Disclosure
- Public Document – Highly Confidential & Not-Public Data Has Been Excised
- Public Document

Xcel Energy Information Request No. 11
Docket No.: E002/AA-22-179
Response To: Xcel Large Industrials
Requestor: Andrew P. Moratzka, Amber S. Lee, and Eden A. Fauré
Date Received: August 27, 2025

Question:

Please provide the annual equivalent forced outage rate of Prairie Island Unit 1 and 2 from 2018 through 2025.

Response:

The annual equivalent forced outage rates of Prairie Island Unit 1 and Unit 2 from 2018 through 2025 are shown in Table 1 below.

Table 1
Equivalent Forced Outage Rate (EFOR)

	2018	2019	2020	2021	2022	2023	2024	2025
PI U1	0	0	1.2	0.02	0	20.16	22.12	9.58
PI U2	0	0.04	0	0	0	13.42	21.32	0.65

Witness: n/a
Preparer: Amanda J. Jepson
Title: Manager, Nuclear Regulatory Policy
Department: Nuclear Policy Planning
Telephone: 651-212-1679
Date: September 10, 2025

- Highly Confidential Not-Public Document – Not For Public Disclosure**
- Not-Public Document – Not For Public Disclosure**
- Public Document – Highly Confidential & Not-Public Data Has Been Excised**
- Public Document**

Xcel Energy Information Request No. 12
Docket No.: E002/AA-22-179
Response To: Xcel Large Industrials
Requestor: Andrew P. Moratzka, Amber S. Lee, and Eden A. Fauré
Date Received: August 27, 2025

Question:

Please provide the annual availability factor of Prairie Island Unit 1 and 2 from 2018 through 2025.

Response:

The annual availability factors of Prairie Island Unit 1 and Unit 2 from 2018 through 2025 are shown in Table 1 below.

Table 1
Annual Availability Factor

	2018	2019	2020	2021	2022	2023	2024	2025
PI U1	87.37	96.79	88.6	97.67	84.95	77.68	59.8	86.75
PI U2	97.43	89.35	97.1	88.95	97.46	69.51	74.36	96.85

Witness: n/a
Preparer: Amanda J. Jepson
Title: Manager, Nuclear Regulatory Policy
Department: Nuclear Policy Planning
Telephone: 651-212-1679
Date: September 10, 2025