STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports	MPUC Docket No. E-999/AA-20-171 OAH Docket No. 82-2500-37082

MINNESOTA POWER'S REPLY BRIEF

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MINNESOTA POWER

David R. Moeller
Senior Attorney and Director
of Regulatory Compliance
30 West Superior Street
Duluth, MN 55802
Telephone: (218) 723-3963

TAFT STETTINIUS &
HOLLISTER LLP

Kodi J. Verhalen
Matthew R. Brodin
Elizabeth M. Brama
2200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402
Telephone: (612) 977-8400

Attorneys on behalf of
Minnesota Power

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I. INTRODUCTION

Minnesota Power (the "Company") respectfully submits this reply brief ("Reply Brief") in response to the Initial Briefs filed by the Department of Commerce, Division of Energy Resources ("Department") and the Large Power Intervenors ("LPI"). In its Initial Brief, Minnesota Power showed that it has demonstrated by a fair preponderance of the evidence that its maintenance programs and unplanned outages were prudent and reasonable and consistent with good utility practice. Minnesota Power's Initial Brief addressed many of the arguments raised in the Department and LPI's Initial Briefs and it continues to rely on those arguments. The Company will address below the most pertinent issues raised in those Initial Briefs.

As discussed in Minnesota Power's Initial Brief, this contested case was ordered because the Department claimed that the higher than average level of unplanned outages during the 18-month Annual Automatic Adjustment ("AAA") review period in 2018 and 2019 was caused because the Company reduced generation maintenance spending and activity.[1] However, the Department's Initial Brief confirms that it has abandoned that argument after Minnesota Power produced evidence demonstrating that none of the unplanned outages were caused by any changes, much less reductions, to the Company's generation maintenance programs or activities.[2] Instead, the Department refocuses its claims on whether the Company's actions prior to and during the unplanned outages were consistent with good utility practice.[3]

As a policy matter, the shift in the basis for the Department's claims is concerning. Minnesota Power demonstrated rather quickly that the Department's initial premise was unsupported by the evidence.[4] Rather than ending the inquiry there, the Department shifted its

[1] Ex. 9, Schedule 1 at 10 (Rostollan Direct); ORDER FOR HEARING at 8 (EX. 1).
[2] *See generally* Department Initial Brief.
[3] *See id* at 8-25.
[4] Minnesota Power Initial Brief at 13-20.

focus to second guessing Minnesota Power's generation maintenance programs and Boswell Energy Center ("Boswell") personnel's actions during the three most significant unplanned outages during the 18-month review period – the Boswell Unit 4 ("BEC4") hot reheat ("HRH") steam line outage, the Boswell Unit 3 ("BEC3") hydrogen leak outage, and the BEC3 phase bushing failure outage. Thus, the Department was no longer investigating whether unplanned outages were caused by Minnesota Power reducing its generation maintenance spending and activity, but was instead exploring whether it believed that Minnesota Power should have implemented maintenance and inspection practices above and beyond those in place during the test year in the Company's last rate case and whether repair practices undertaken during unplanned outages could have been altered. The Department further second-guessed specific decisions and actions of Boswell's personnel based upon information that only became available with the benefit of hindsight.[5]

If this type of basis-shifting proceeding that requires utilities to defend every policy and action against hindsight analysis by the Department becomes standard, maintenance and inspection costs borne by customers will almost certainly increase considerably. Inevitably, if the Department's standard becomes adopted in Minnesota, utilities will need to make maintenance and inspection decisions to incorporate only the highest or most extensive recommendations that might exist in the industry so that they cannot be questioned by the Department in future

[5] *See, e.g.*, Department Initial Brief at 21-25. The Department appears to suggest that "good utility practice" means what common sense would dictate in hindsight. That is not the standard, however, the Commission has set out for evaluating the Company's handling of unplanned outages, which is good utility practice. Furthermore, the Department's equating of maintenance of an internal combustion engine of a personal vehicle with operating and maintaining the largest baseload generation plant in northern Minnesota is a gross simplification of the issue at hand and should be ignored.

proceedings instead of making reasonable decisions regarding what maintenance and inspection protocols will provide the most economic, reliable, and safe electric service to customers.

Despite the Department's complete shift in the focus of this contested case proceeding, Minnesota Power demonstrated that its generation maintenance programs were consistent with good utility practice. Specifically, Minnesota Power established that its ten-year HRH steam line inspection frequency, with areas of higher risk or stress being subject to more frequent inspections, was consistent with at least 50 other utilities' inspection programs, which constitutes a significant portion of coal-fired power generators across the country.[6]

The Department's expert attempted, but failed, to rebut Minnesota Power's showing that its HRH steam line inspection program was consistent with good utility practice. Mr. Polich argued, based upon his knowledge of the seam-welded HRH steam line inspection programs at two facilities, application of the incorrect (and non-mandatory) portion of an American Society of Mechanical Engineers ("ASME") code, and his reading of literature from the Electric Power Research Institute ("EPRI"), that Minnesota Power should have implemented a five-year inspection frequency for HRH steam lines at Boswell.[7] But according to an EPRI survey cited by Mr. Polich, less than half of respondents complied with the five-year testing interval.[8] A more recent EPRI publication further acknowledged that utilities view the five-year inspection interval as cost prohibitive.[9] This is consistent with the statements of Minnesota Power's HRH steam line expert, Thielsch Engineering, Inc. ("Thielsch") that none of its more than 50 other clients with

[6] Minnesota Power Initial Brief at 55-76.
[7] Exs. 14 and 15, Rebuttal Schedule 1 at 5, response to MP IR 05(b) (Undeland Rebuttal) (Public and Nonpublic); Ev. Hrg. Tr. at 59-60 (Polich); Minnesota Power Initial Brief at 63.
[8] Exs. 14 and 15, Rebuttal Schedule 1 at 33 (Undeland Rebuttal) (Public and Nonpublic); Minnesota Power Initial Brief at 9.
[9] Exs. 14 and 15 at 25, Rebuttal Schedule 1 at 427 (Undeland Rebuttal) (Public and Nonpublic).

seam-welded HRH steam lines utilized a five-year inspection frequency.[10] Additionally, the ASME Code relied on by Mr. Polich does not apply to the superheated dry steam piping at Boswell.[11] Thus, the Department has not demonstrated that a five-year inspection interval is the minimum threshold for good utility practice or that the Company's ten-year inspection frequency is inconsistent with the practices of all significant portions of the industry.

Minnesota Power further demonstrated that its actions to diagnose and fix the hydrogen gas leak at BEC3 were consistent with good utility practice. Although oil leaked from the float valve system into the phase bushings during Minnesota Power's novel testing techniques that helped shave approximately fourteen weeks from the length of the hydrogen leak outage, it was reasonable for Minnesota Power to have believed that it had cleaned up all of the oil prior to restarting the generator given the facts known at the time. Moreover, General Electric, the original equipment manufacturer ("OEM") for the phase bushings, concluded that there was no way to determine whether the presence of oil or one of many other potential issues caused the phase bushing to subsequently fail.[12]

With the benefit of hindsight, the Department's expert concluded that Minnesota Power should have measured the amount of oil added to the system to test the float valve so that it could have determined whether any had migrated to other areas of the generator.[13] This presumption is unsupported for three reasons. First, if the system's alarm had been working properly (which Minnesota Power believed was the case), no oil would have been spilled so there was no preemptive reason to measure the oil. Second, oil was not added to the system, as Mr. Polich

[10] *See* Exs. 14 and 15 at 23, 30-31 (Undeland Rebuttal) (Public and Nonpublic).
[11] *See* Minnesota Power Initial Brief at 64-65.
[12] Minnesota Power Initial Brief at 7.
[13] Department Initial Brief at 6.

presumes. Rather, oil within the integrated systems within BEC3 was piped into the float valve system, where a simplistic mass balance of oil as Mr. Polich suggests would not have been feasible. And third, the integrated oil systems do not contain flow measurement devices, so it would not have been possible to solely track the amount of oil used in the testing process. Ultimately, Mr. Polich's post-hoc conclusions are uninformed and inaccurate.

LPI offered no independent testimony in this case, but instead relied upon the erroneous conclusions of the Department's expert.[14] In addition to mirroring the Department's claims regarding good utility practice, LPI suggests that even if Minnesota Power's maintenance programs and actions are deemed to be consistent with good utility practice, it should still be ordered to refund the amounts collected for replacement energy during the unplanned outages. LPI claims that it would be unfair to allow the Company to "pocket" both the additional revenues due to the lower generation maintenance expenses and the replacement energy costs charged to customers. This conclusion was based upon the Department's initial comments in the AAA filing, which it later abandoned and has not pursued in this case. As discussed in detail in Minnesota Power's Initial Brief, this theory lacks any evidentiary basis and should be disregarded.

II. ARGUMENT

A. Clarification of the Burden and Legal Standard

The Department and LPI both stress that Minnesota Power has the burden of proving that its unplanned outage costs were reasonably and prudently incurred, applying good utility practice.[15] While Minnesota Power agrees that is the standard set forth by the Commission, it disagrees with both parties regarding how that standard must be applied.

[14] *See, e.g.*, LPI Initial Brief at 1. LPI immediately begins its post-hearing brief by relying on the Department's testimony, and not on any evidence LPI introduced on its own. In fact, LPI did not provide any testimony during this proceeding.
[15] Department Initial Brief at 1, 7, 8, 16, 19, 20, 22, 24, 26; LPI Initial Brief at 4-6.

The parties largely agree on the definition of "good utility practice," which, in full, is:

> [A]ny of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition.
>
> … "Good Utility Practice" is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to refer to acceptable practices, methods, or acts generally accepted in the region in which the Project is located. "Good Utility Practice" includes, but is not limited to, North American [Energy] Reliability Corporation (NERC) criteria, rules, guidelines, and standards, Federal Energy Regulatory Commission (FERC) criteria, rules, guidelines, and standards, and Minnesota Public Utilities Commission criteria, rules, guidelines, and standards, where applicable, and as they may be amended from time to time, including the rules, guidelines, and criteria of any predecessor or successor organization to the foregoing entities.[16]

Despite purporting to agree on the above definition, the Department and LPI implicitly argue that Minnesota Power must disprove, through the production of substantive evidence, every other theory of what could constitute good utility practice to meet its burden of demonstrating that its practices were consistent with good utility practice.

For example, the Department claims that the Company failed to meet its burden because it did not conduct a formal cost-benefit analysis demonstrating that a five-year, phased-array ultrasonic testing frequency for the HRH steam line would be cost prohibitive, and, thus, inconsistent with good utility practice.[17] But the Department's proposed standard is inconsistent with Minnesota Power's burden. As the Department concedes, "good utility practice" includes "<u>any</u> of the practices, methods, and acts engaged in or approved by <u>a significant portion</u> of the

[16] Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic).
[17] Department Initial Brief at 19.

electric utility industry during the relevant time period[.]"[18] Thus, the Company must show that its inspection frequency was within the range of frequencies engaged in or approved by a significant portion of the industry – not that all other inspection frequency possibilities are inconsistent with good utility practice.

Minnesota Power can also demonstrate that it acted consistent with good utility practice by showing that it exercised reasonable judgment in light of what it knew at the time of the decision. The Company is not, however, required to demonstrate that its decisions were reasonable based upon information that only came to light after the unplanned outages occurred, as the Department and LPI essentially argue.

Finally, the parties agree that good utility practice is not limited to the optimum practice, but is meant to include the range of acceptable practices across the industry.[19] However, based upon review of the Department and LPI's Initial Briefs, this agreement appears to be merely lip service as they both seek to hold Minnesota Power to a higher, inapplicable standard. The Department and LPI attempt to hold Minnesota Power to specific standards without addressing whether other standards are used or approved by a significant portion of the industry. By limiting their analysis to whether the Company met an optimum practice rather than identifying the range of acceptable practices, the Department and LPI ignore the agreed-upon definition of good utility practice.

LPI notes that Minnesota Power must satisfy its burden by a preponderance of the evidence, but argues that the standard is different than in a civil case.[20] While this is true for the Commission's partially legislative decision whether, even if true, the alleged facts demonstrate

[18] *Id.* at 7.
[19] *Id*. at 8.
[20] LPI Initial Brief at 5-6.

that it is just and reasonable for customers to bear costs incurred by the utility, the standard of proof is generally the same as in a civil case when the Commission is acting in its quasi-judicial function by making findings of pure fact.[21] The amount of expenses incurred is one such fact, but this case also requires a factual determination whether Minnesota Power's maintenance and inspection programs and the actions of its employees were consistent with good utility practice. Thus, the Commission must first determine whether Minnesota Power has met its burden of proof regarding questions of fact—such as the amount of expenses incurred and whether the Company's programs and actions were consistent with good utility practice—by a fair preponderance of the evidence. The Commission then may draw its own inferences and come to its own conclusions as to the reasonableness of recovering the unplanned outage costs from customers.[22]

B. The Department and LPI Have Not Demonstrated that Minnesota Power's HRH Inspection and Maintenance Programs Were Inconsistent with Good Utility Practice

1. Minnesota Power Established that Its Ten-Year HRH Steam Line Inspection Frequency Was Consistent with Good Utility Practice

The Department and LPI argue that Minnesota Power did not satisfy its burden of demonstrating that its HRH steam line inspection frequency was consistent with good utility practice.[23] But, as discussed in more detail in Minnesota Power's Initial Brief and as summarized below, the Company produced more than sufficient evidence to demonstrate that its maintenance and inspection programs, as well as its actions related to the contested outages, were consistent with good utility practice. The evidence produced by Minnesota Power demonstrates that the ten-year inspection frequency and associated inspection methodology deployed for BEC4's HRH

[21] *In re N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
[22] *Id*. at 722-23.
[23] *See generally* Department Initial Brief at 8-19; LPI Initial Brief at 6-9.

steam line was both (1) consistent with the practices of a significant portion of the coal-fired power generation industry, and (2) reasonable in light of the facts known at the time.

a. A Ten-Year Inspection Frequency Was Used or Approved of by a Significant Portion of the Coal-Fired Power Plant Industry

Minnesota Power regularly confirmed through its third-party HEP system expert, Thielsch, that the Company's inspection protocols were consistent with practices of other utilities throughout the country.[24] Thielsch has worked with more than 50 other customers that operated power facilities with seam-welded HRH steam lines, so it was able to advise Minnesota Power regarding the practices of a significant portion of similar facilities across the country and how Minnesota Power's program compared.[25]

In addition to learning about industry-wide practice through Thielsch and developing inspection protocols and identifying high-stress areas for more frequent inspections based on analysis by Thielsch and Sargent & Lundy as recently as 2010,[26] Minnesota Power's maintenance and inspection programs were audited by the Company's insurer, FM Global.[27] Specifically, Minnesota Power only implemented its HRH steam line inspection program after FM Global indicated that it was comfortable in Thielsch's abilities, expertise, and recommendations.[28]

At the very minimum, the fact that Minnesota Power's HRH steam line maintenance and inspection programs were on par with the programs of more than 50 of Thielsch's other customers demonstrates that the standards utilized by the Company were engaged in or approved by a significant portion of the industry. Accordingly, the HRH steam line maintenance and inspection programs were consistent with good utility practice.

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[24] Ex. 6 at 13 (Poulter Direct).
[25] *Id.* at 18-19.
[26] Ex. 7 at 17 (Undeland Direct).
[27] Ex. 6 at 15 (Poulter Direct).
[28] *Id.*

b. Minnesota Power's Decision to Implement a Ten-Year HRH Steam Line Inspection Frequency Was Reasonable

Alternatively, Minnesota Power's decision to implement a ten-year HRH steam line inspection interval was consistent with good utility practice because it was reasonable given the facts known at the time.

Minnesota Power was aware of the history of HRH steam line failures over the past 40 plus years.[29] In response to that known issue, Minnesota Power developed its risk-based HRH steam line inspection and maintenance programs. As discussed above, the Company ensured those programs were accordant with good utility practices as they evolved over the past several decades by incorporating information received from expert consultants and Minnesota Power's insurer.[30] Consistent with other utilities in the industry, Minnesota Power implemented a ten-year inspection frequency for the lowest stress and lowest risk HEP, including the HRH steam line, and utilized higher frequency inspections for the areas of higher stress and greatest risk.[31]

In addition to regularly obtaining information from Thielsch regarding industry-wide HRH steam line inspection practices, approximately every ten years the Company discussed internally and with its expert consultants whether there were any changes in test results, operations, or the industry that would require modification of the maintenance and inspection programs or replacement of any HEP systems.[32] Until the HRH steam line post-failure analysis in 2019, none of the prior testing indicated that there was any material cracking or creep developing in the HRH steam line longitudinal seam welds.[33] As a result, Minnesota Power had no evidence indicating

[29] *Id.* at 12-13.
[30] *Id*. at 7, 12-14, 18-19.
[31] Ex. 7 at 16 (Undeland Direct); Ex. 5 at 24 (Simmons Direct); Ex. 6 at 7, 12-14, 18-19 (Poulter Direct).
[32] Ex. 6 at 7, 12-14, 18-19 (Poulter Direct).
[33] *Id*. at 13-14.

that the HRH steam line required either a significantly stepped-up inspection frequency or replacement prior to the 2019 outage. On the contrary, the inspection results prior to the 2019 unplanned outage indicated that the HRH steam line was in good operational shape.

Minnesota Power utilized the advice of Thielsch, Sargent & Lundy, and FM Global, as well as taking into account past inspection results, known areas of concern, and industry bulletins when developing its HRH inspection program.[34] Given this information, Minnesota Power was justified in determining that a ten-year HRH steam line inspection interval was consistent with good utility practice and would accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition.

2. The Department and LPI's Arguments Fail to Overcome Minnesota Power's Showing of Good Utility Practice

Rather than identifying what the range of good utility practice was at the time of the HRH steam line leak, the Department and LPI attempt to show that Minnesota Power's inspection and maintenance programs were not consistent with good utility practice because, with the benefit of hindsight, more could have been done to prevent the failure. But, as discussed above, that is not the applicable standard. None of the Department or LPI's arguments disprove either that a significant portion of the utility industry utilized or approved of a ten-year HRH inspection frequency, or that Minnesota Power's decision to implement such a frequency was reasonable given the facts known at the time.

a. When the Cracks May Have Been Detectable Does Not Establish Good Utility Practice

The Department claims that Minnesota Power's ten-year inspection schedule for the HRH steam line seam welds was not good utility practice because a five-year inspection schedule would

[34] Exs. 14 and 15 at 22 (Undeland Rebuttal) (Public and Nonpublic).

have identified the creep prior to the pipe failure.[35] This argument is not supported by substantial evidence and is irrelevant to what constituted good utility practice at the time.

Using an estimate from Thielsch regarding how many operating hours had passed between when the creep cracks first started and the HRH steam line rupture in 2019, the Department calculated that the creep cracks would have been detectable between early 2011 and late 2012.[36] But the Thielsch report indicated that was its estimate of when the "cracking initiated[,]" not when the cracks would have developed beyond a critical flaw size so as to become detectable.[37] The Department has not established precisely when the creep damage would have become reasonably detectable using its proposed phased array ultrasonic testing.

In support of their arguments, the Department and LPI also cite to a particular finding from Structural Integrity's ("SI") HRH steam line failure analysis report stating "it is difficult to understand how [the cracks] would not have been identified and reported previously."[38] However, the "cracks" SI was addressing with this comment were not associated with creep damage to the HRH steam line seam weld, but rather were transverse flaws found within the base metal of the pipe that were most likely created during the process of manufacturing the pipe decades before the outage occurred.[39] Thus, the conclusion SI made about transverse flaws, a subject area which SI admitted was entirely outside of its experience base,[40] is unrelated to the creep damage and seam weld failure in the HRH steam line.

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[35] Department Initial Brief at 9-10.
[36] *Id.*
[37] Exs. 10 and 11, RAP-6 at 7 (Polich Direct) (Public and Nonpublic).
[38] LPI Initial Brief at 8; and Department Initial Brief at 4 (both citing Exs. 10 and 11, RAP-11 at 61 (Polich Direct) (Public and Nonpublic)).
[39] Exs. 10 and 11, RAP-11 at 31, 61 (Polich Direct) (Public and Nonpublic); Ex. 7, Schedule 3 at 5 (Undeland Direct).
[40] Exs. 10 and 11, RAP-11 at 60 (Polich Direct) (Public and Nonpublic) ("The transverse flaws are outside of SI's experience base").

Notwithstanding the lack of evidence to support the conclusion that the creep would have been detected prior to the HRH steam line failure if a five-year inspection frequency had been adopted, even if that was the case it would not mean that a ten-year frequency was inconsistent with good utility practice at the time of the outage. Any time power plant equipment fails in a way that could have been detected using a higher inspection frequency or a different inspection method, it would be possible to retrospectively argue that the stepped up inspection protocol should have been used. For example, the Department could have argued that a one year inspection frequency should have been used on the HRH steam line because it would have prevented the outage. But whether a more frequent inspection schedule would have, in hindsight, potentially prevented the HRH steam line seam weld failure has no bearing on whether either a ten-year frequency was common in the industry or Minnesota Power acted reasonably in establishing that frequency given what was known at the time. Accordingly, this argument is immaterial to the good utility practice determination and does nothing to rebut Minnesota Power's evidence demonstrating that its ten-year HRH steam line inspection frequency was consistent with good utility practice.

b. Minnesota Power Did Not Over Rely on Magnetic Particle Testing

The Department asserts that Minnesota Power's overreliance upon magnetic particle testing was not good utility practice.[41] This premise, however, entirely misses the point.

Minnesota Power's HRH steam line maintenance and inspection program includes testing of all areas of the pipe using several different testing technologies, consistent with good utility practice. The different types of testing are not all used at the same intervals, which means that not all testing methods will be used during each inspection.

[41] Department Initial Brief at 5, 10.

Multiple testing technologies are necessary because they each provide information on different areas of the piping. Because phased array ultrasonic testing is designed to detect subsurface flaws in the weld and adjacent metal,[42] it would not identify flaws in other areas of the pipe. Magnetic particle testing and in-situ metallographic examination, on the other hand, are used for detection of external surface flaws.[43]

Phased array ultrasonic testing is but one inspection tool that is used as part of good utility practices. Contrary to the Department's assertions, use of other testing methods is not inconsistent with good utility practice, but rather is necessary for the detection of potential flaws in the pipe that start somewhere other than the inner surface.

c. ASME Recommendations for Erosion/Corrosion Testing Are Inapplicable

The Department avers that the ASME Code recommends a five-year inspection interval for HRH steam lines.[44] More specifically, the Department claims that Minnesota Power failed to comply with Section 8 of Non-mandatory Appendix V of ASME Code B31.1, which covers "Piping Corrosion."[45]

A closer examination of the Code and the Department's claims exposes the fatal flaws in the Department's argument. The Department's expert, Mr. Polich, testified that HEP systems can develop "rust" that will cause erosion/corrosion damage.[46] But as Company witness Mr. Undeland testified, the BEC4 HRH system is not in a corrosive environment in that it does not carry wet steam, only dry, superheated steam.[47] Notably, none of the pre- or post-outage HRH steam line

[42] Exs. 10 and 11, RAP-11 at 14-15 (Polich Direct) (Public and Nonpublic).
[43] *Id.*, RAP-11 at 13.
[44] Department Initial Brief at 11-13.
[45] *Id*.
[46] Ev. Hrg. Tr. at 78 (Polich).
[47] Exs. 14 and 15 at 20-21 (Undeland Rebuttal) (Public and Nonpublic).

inspection reports by Thielsch or SI indicate any signs of rust, erosion, or corrosion in the pipes. This further underscores that the HRH steam line is not an erosive or corrosive environment.

Most importantly, however, the ASME Code explicitly defines "erosion/corrosion" as "a flow-accelerated corrosion process that leads to loss of wall thickness in carbon or low alloy steel pipe exposed to water or wet steam."[48] Similarly, the ASME Code's list of the "Systems and Components Susceptible to Erosion/Corrosion" does not include the HRH steam line, and states that "Piping damage due to [Erosion/Corrosion] is not limited to these systems and may occur in any system of carbon steel or low alloy piping that is exposed to water or wet steam and operates at a temperature greater than 200°F (93°C)."[49]

Pursuant to the express terms of the ASME Code, a corrosive/erosive environment requires the presence of water or wet steam. Because the HRH steam line carries only superheated dry steam, it does not create a corrosive/erosive environment. Accordingly, Mr. Polich's assertion that Appendix V-8 (Piping Corrosion) applies to the HRH steam line is misplaced.

d. EPRI Recommendations Alone Do Not Establish Good Utility Practice

As discussed in more detail in Minnesota Power's Initial Brief, EPRI is a member utility organization that provides recommendations to its fee-paying members, and is not a standard setting entity. While EPRI publications and recommendations are one data point to consider when determining the parameters of good utility practice, there is simply no basis for the Department's assertion that EPRI's recommendations set forth the minimum standards for compliance with good utility practice. Thus, whether Minnesota Power strictly followed EPRI's guidelines is not

[48] Ex. 22a at 319 (emphasis added).
[49] *Id*. (emphasis added).

dispositive of whether its HRH steam line maintenance and inspection protocols were consistent with good utility practice.

The Department argues that EPRI's guidelines are consistent with good utility practice because "almost 50% of [EPRI survey] respondents followed the EPRI Guidelines related to ultrasonic flaw 'detection[.]'"[50] This means that less than 50 percent of those utilities that responded to EPRI's survey followed the ultrasonic flaw detection portion of the guideline. But Minnesota Power does not dispute that EPRI's suggested five-year inspection frequency falls within the range of good utility practice. Rather, the Company argues only that EPRI's recommendations do not set forth the minimum threshold for good utility practice, and that other non-EPRI-recommended practices also fall within the acceptable range. This argument is underscored by the fact that, according to EPRI's 1993 survey,[51] more than half of respondents[52] did not comply with EPRI's creep detection recommendations.[53] Hence, by EPRI's own survey results, its recommended practices are not followed by such a majority of the industry that noncompliance would necessarily be inconsistent with good utility practice.

The Department's argument further requires the nonsensical conclusion that only specific portions of EPRI's recommendations and publications set forth the baseline for good utility practice, while others may be ignored. For example, the Department attempts to disregard the EPRI survey result that "only 2% of utilities surveyed complied completely with EPRI Guidelines"

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[50] Department Initial Brief at 14 (citing Ex. 14, Rebuttal Schedule 1 at 33 (Undeland Rebuttal) (EPRI Guidelines)).

[51] Mr. Polich claims that EPRI told him that more recent surveys indicate the current percentages are approximately the same. Exs. 14 and 15, Rebuttal Schedule 1 at 2-3 (Undeland Rebuttal) (Public and Nonpublic).

[52] EPRI's results are also likely skewed given that the "respondent" utilities were prone to be EPRI members and did not include only utilities that operated power generation facilities that used seam-welded pipe for high energy piping applications.

[53] Exs. 14 and 15, Rebuttal Schedule 1 at 33 (Undeland Rebuttal) (Public and Nonpublic).

by asserting that this negligible percentage specifically applied to compliance with all EPRI guidelines, and not only to compliance with the creep detection recommendations (which were followed by less than half of respondents).[54] But the Department provides no rationale why only certain EPRI recommendations establish good utility practice, while others may be ignored by 98 percent of the responding utilities.

The Department also would have the Administrative Law Judge ignore EPRI publications that are far more recent than the 1993 survey that call into question the practicality of its five-year HRH steam line inspection frequency recommendation. For instance, in a 2017 publication on 30 years of power generation industry seam weld failures (the "30 Year Report"), EPRI stated: "Increasingly, economic pressure on end-users is necessitating a reevaluation of legacy guidelines for inspection of long-seam welded components. In particular, the [EPRI Guideline] regarding a five-year inspection interval is viewed as cost-prohibitive with the estimated cost for a single HRH piping system to be on the order of $5 million."[55] Thus, EPRI has recently acknowledged that its five-year inspection frequency recommendation may have to be reevaluated given its real world implications and the actual practices within the industry.

The Department tries to cast doubt on the validity of EPRI's statement regarding the cost of implementing a five-year inspection frequency by characterizing it as "a single sentence in an EPRI whitepaper[.]"[56] The Department illogically seems to suggest that Minnesota Power must rely upon the EPRI guidelines to be consistent with good utility practice, but should disregard more recent EPRI publications updating the institute's positions on those guidelines. At the same time, the Department relies upon the 30 Year Report multiple times in its Initial Brief, including

[54] Department Initial Brief at 14.
[55] Exs. 14 and 15 at 25, Rebuttal Schedule 1 at 427 (Undeland Rebuttal) (Public and Nonpublic).
[56] Department Initial Brief at 18.

in support of Mr. Polich's argument that EPRI requires a five-year interval for 100 percent HRH steam line inspection using phased array ultrasonic testing.[57] The Department cannot have it both ways. Regardless of the particular format, the 30 Year Report was an official EPRI publication that expressed EPRI's views. Thus, if the Department is going to rely upon EPRI's inspection interval recommendations in the 30 Year Report, it must also acknowledge that EPRI has cast doubt on the real-world practicality and rate of adoption of those recommendations.

Ultimately, even EPRI has acknowledged through its 1993 survey and the 30 Year Report that its five-year inspection interval recommendation for HRH steam lines was, at best, utilized by less than a majority of utilities and is viewed as cost-prohibitive within the industry. Thus, not even EPRI supports the Department's position that EPRI's recommended five-year inspection interval represents the minimum threshold for good utility practice.

e. The Cost of a Five-Year Inspection Interval Is Both Prohibitive and Irrelevant to Whether Ten-Year Inspection Frequency Is Consistent with Good Utility Practice

The Department argues that Minnesota Power has not produced sufficient evidence to demonstrate that a five-year inspection interval of its HRH steam lines would be cost prohibitive. First, Minnesota Power does not have to demonstrate that a five-year inspection interval would be cost prohibitive to prove that its ten-year inspection interval (with high-stress areas inspected multiple times over that period) is consistent with good utility practice. Second, there is more than sufficient evidence in the record to demonstrate that a five-year interval is not only viewed by the majority of the industry to be cost prohibitive, it is also neither an explicit inspection interval

[57] *Id.* at 4, 5, 13, 16-18. Minnesota Power's Initial Brief discusses that the Department has not cited to any EPRI publications that plainly state that EPRI recommends phased array ultrasonic testing of 100 percent of HRH piping at least every five years. Instead, the EPRI Guidelines include a decision tree analysis, which the Department's expert admitted during the hearing he did not conduct. Minnesota Power Initial Brief at 68.

required by the Department's cited and relied upon 2003 EPRI guidance document nor a frequency used by a majority of those surveyed by EPRI.

Under the definition of good utility practice, five-year and ten-year inspection frequencies are not mutually exclusive since both could be used by significant portions of the industry. As a result, Minnesota Power need not prove that a five-year interval is inconsistent with good utility practice in order to demonstrate that its ten-year frequency falls within the range of good utility practice. In fact, portions of Minnesota Power's HRH steam line were subjected to more frequent inspections during the overall ten-year inspection interval.

Minnesota Power provided evidence that its ten-year HRH steam line inspection frequency was consistent with the programs of Thielsch's 50 other clients, and it was reviewed and approved by its insurer. The Department, on the other hand, submitted evidence that two utilities currently utilize a five-year HRH steam line inspection interval for its seam welded piping, and that somewhat less than half of 1993 EPRI survey respondents used that frequency. Even taking the Department's evidence as true, it does not come close to establishing that a five-year frequency was the minimum threshold for good utility practice to the exclusion of all longer intervals. There is more than sufficient evidence in the record to establish that a ten-year HRH steam line inspection frequency was consistent with good utility practice.

With regard to the exact cost of implementing a five-year inspection interval, Minnesota Power never conducted a detailed estimate because it was apparent that the cost of the protocol would almost certainly be higher than the potential benefit.[58] While Mr. Polich disagreed with this assertion, he readily admitted that utilities view EPRI's recommended five-year HRH steam line inspection protocol as cost prohibitive and estimated the cost of implementation to be

[58] Exs. 14 and 15 at 28 (Undeland Rebuttal) (Public and Nonpublic).

approximately $5 million per HRH steam line.[59] That industry-wide conclusion was made in light of all of the well-documented worst-case-scenario HRH steam line failures cited by the Department.[60] Given that the Department's expert agrees, and EPRI has acknowledged, that utilities view a five-year HRH steam line inspection protocol as cost prohibitive, there is more than sufficient evidence in this record to support the reasonableness of that conclusion.

f. Minnesota Power's Reliance Upon Thielsch Was Reasonable

To ensure that its HRH steam line maintenance and inspection program was consistent with good utility practice around the country, Minnesota Power regularly utilized the utility-wide expertise of its expert HEP consultant, Thielsch.[61] As an expert in the subject matter that had experience with approximately 50 other utilities, Thielsch was able to provide the Company with invaluable insight into the actual practices of other coal-fired power plants that Minnesota Power could not have readily obtained or replicated through other sources.[62]

The Department characterizes Thielsch's advice to Minnesota Power as unreliable hearsay.[63] However, pursuant to OAH Rules of Evidence, the "judge may admit all evidence which possesses probative value, including hearsay, if it is the type of evidence on which reasonable, prudent persons are accustomed to rely in the conduct of their serious affairs."[64] Much of what Minnesota Power must rely upon in determining what practices are common throughout the industry consists of statements from OEMs and industry experts that are not always officially

[59] Ev. Hrg. Tr. at 69-70 (Polich).
[60] Exs. 14 and 15 at 25, Rebuttal Schedule 1 at 427 (Undeland Rebuttal) (Public and Nonpublic).
[61] Ex. 6 at 18-19 (Poulter Direct).
[62] *See* Exs. 14 and 15 at 23, 30-31 (Undeland Rebuttal) (Public and Nonpublic).
[63] Notably, the Department's expert, Mr. Polich, relies upon conversations he had with EPRI regarding more recent versions of the documents and studies upon which he relies.
[64] Minn. R. 1400.7300, subp. 1.

documented. The Company then performs its own diligence in discussing operations with other coal-fired power plant operators as well.

In this case, one of the issues is whether Minnesota Power's decision to implement a ten-year HRH steam line inspection frequency was reasonable, given the facts known at the time. Thielsch's statement regarding its experience with the practices of many other utilities within the industry represents a fact upon which Minnesota Power based its decision.[65] The Company submits that it is not only reasonable, it is entirely consistent with good utility practice to take into account industry perspectives provided by outside expert consultants. This facilitates the exchange of information across the power generation industry and allows Minnesota Power to leverage the industry-wide knowledge of a subject matter expert.

The very definition of good utility practice requires the comparison of a utility's program with the rest of the industry. This cannot be accomplished using only internal resources. Third-party expert consultants often represent the best source of information about the programs and practices of other utilities. Thus, it would be a wholly unreasonable precedent if utilities may not rely upon advice from recognized and credentialed subject matter experts within the power generation industry when developing maintenance and inspection programs and protocols.

[65] Thielsch's statements on this issue were discussed in the Direct Testimony of Mr. Poulter (Ex. 6 at 18-19 (Poulter Direct)) and the Direct Testimony of Mr. Undeland (Ex. 7 at 17 (Undeland Direct)), so the Department was on notice of this statement from the beginning of this contested case. The Department's tardy request to discount or disallow the Thielsch customer information should be rejected. The Administrative Law Judge has admitted into evidence all testimony offered by the Company. The Department stipulated to the admission of the Company's testimony and neither objected to its admission nor sought an evidentiary ruling from the Administrative Law Judge seeking to limit the evidentiary value of any testimony to anything less than the truth of the matter asserted.

The Department avers that the practices of Thielsch's customers do not equate to good utility practice.[66] This is somewhat confusing given that the Department's definition of good utility practice includes practices engaged in by a significant portion of the industry. The Department cannot seriously argue that 50 utilities does not constitute a "significant portion" of the industry, especially given that Mr. Polich has knowledge of only two facilities' seam-welded HRH steam line inspection programs.[67]

In sum, Thielsch is recognized as an expert in the area of HEP maintenance and inspection within the power generation industry.[68] Minnesota Power has worked with Thielsch since approximately 1983, so they are very familiar with Boswell's HEP systems.[69] Based upon Thielsch's widespread knowledge and client-base within the industry, Minnesota Power reasonably relied upon Thielsch's statements that none of its more than 50 customers had implemented a five-year HRH steam line inspection interval, and that Minnesota Power's ten-year interval was consistent with its customers' practices.[70]

C. The Department and LPI Have Not Demonstrated Minnesota Power's Actions in Addressing the Hydrogen Leak and Phase Bushing Failure Were Inconsistent with Good Utility Practice

1. Minnesota Power Established that Its Actions in Addressing the Hydrogen Leak and Phase Bushing Failure Were Consistent with Good Utility Practice

The Department and LPI argue that the actions of Minnesota Power's employees during the BEC3 hydrogen leak diagnosis were inconsistent with good utility practice, which ultimately caused the failure of the phase bushings.[71] But this argument is made based upon hindsight and

[66] Department Initial Brief at 10.
[67] Ev. Hrg. Tr. at 59-60 (Polich).
[68] Ex. 6 at 15 (Poulter Direct).
[69] *Id*.
[70] *Id.* at 18-19.
[71] Department Initial Brief at 20-25; LPI Initial Brief at 9-12.

incorrect assumptions about the BEC3 facility. Given the facts known at the time, the Boswell personnel acted reasonably and in accordance with good utility practice.

During diagnostic testing of the BEC3 hydrogen leak, the Company raised the level of oil in the float trap to determine whether there was an oil level that would stop the hydrogen leak.[72] There is no observation window to see inside of the tank that houses the float trap, so it was not possible to see exactly what was happening inside.[73] The oil level in the float trap was increased using oil from the air detraining tank or the bearing oil header, which, as the diagram of the system shows, also supply oil to other interconnected systems within the facility, including the voluminous vacuum tank.[74] Unbeknownst to the Company at the time, the alarm that would have notified plant personnel that seal oil was reaching the top of the sight glass in the float trap was improperly configured, so the alarm did not provide notice that seal oil was overtopping the sight glass during diagnostic testing.[75]

Once Minnesota Power discovered that oil had leaked, it removed the oil from the system using the liquid detector drain valve.[76] Boswell personnel noted no other signs that oil had entered the phase bushings and no further oil was migrating to the liquid detector valve.[77] Further investigation of components that were covered or sealed (such as the phase bushings) to ensure that no oil was present would have required a significant amount of time to take apart, inspect, and reassemble every component.[78] For the phase bushings, this would have required disassembly of

[72] Ex. 7, Schedule 4 at 9 (Undeland Direct).
[73] *Id.*, Schedule 4 at 6.
[74] *Id*. at 3.
[75] Exs. 10 and 11, RAP-15 at 6-7 (Polich Direct) (Public and Nonpublic).
[76] *Id.*, RAP-15 at 5.
[77] *Id.*, RAP-15 at 5.
[78] *See Id.*, RAP-16 at 3-5.

components in which there was asbestos containing material.[79] This would have caused a significant extension of the hydrogen leak unplanned outage.[80] Based upon the information known at the time, Minnesota Power reasonably concluded that it had drained all of the oil that had overtopped the float trap sight glass.

Minnesota Power's willingness to try novel testing methods allowed it to diagnose and fix the hydrogen leak.[81] This reduced the length of the unplanned outage by approximately 14 weeks compared to if the Company had merely waited for General Electric to supply a replacement float valve to use in testing to determine if that was the cause of the leak.[82] Thus, Minnesota Power's handling of the hydrogen leak far exceeded the minimum threshold for good utility practice.

2. The Department and LPI's Arguments Fail to Overcome Minnesota Power's Showing of Good Utility Practice

The Department suggests that Minnesota Power failed to follow good utility practice because it did not precisely measure the amount of oil it added to the float trap system during, and then drained from the generator after, the diagnostic testing of the BEC3 hydrogen leak.[83] It was not reasonable, however, for Minnesota Power to have foreseen the need to make such measurements. And even if the Company wished to precisely measure the amount of oil added to the float trap, there was no available method to make such measurements within the system.

Mr. Polich's standard would require Minnesota Power to predict with perfect foresight the potential issues that were identified only through the benefit of hindsight. Contrary to Mr. Polich's position, however, good utility practice requires only that Minnesota Power's decision be reasonable given all of the facts known at the time. As discussed above, had the alarm been

[79] *Id*.
[80] *See Id.*
[81] *Id.*, RAP-15 at 6-7; Ex. 7 at 28-29, Schedule 4 at 9 (Undeland Direct).
[82] Ex. 7 at 28-30, Schedule 4 at 9 (Undeland Direct).
[83] Department Initial Brief at 6.

operating properly (and it was the understanding at the time that there were no issues with its operation), oil never would have overtopped the sight glass during the diagnostic testing of the float trap. As a result, given the facts know at the time, there was no reason to believe that it would be necessary to precisely measure the amount of oil added to the float trap.

More importantly, there was not a viable way for Minnesota Power to measure the amount of oil added to the float trap – contrary to the Department's assertion, this system is not like changing the oil on a car. When Minnesota Power tested the float trap by adding seal oil, it did not literally pour barrels of oil into the system, as Mr. Polich seems to envision. Rather, the oil levels in the float trap were increased using oil piped in from the integrated system.[84] Given the interconnected nature of all of the systems receiving oil from multiple tanks and direct inputs, and the absence of flow measurement equipment within the system, there was no practical way to precisely measure the amount of oil added to the float trap during diagnostic testing, as Mr. Polich suggested should have occurred.[85] Hence, even if Minnesota Power had wanted to measure the amount of oil added to the float trap, the nature of the integrated system would have prevented such measurements.

The Department also emphasizes that approximately 30 gallons of seal oil was found in the phase bushings.[86] But the BEC3 generator is a massive facility that uses thousands of gallons of oil across multiple interconnected systems, so the loss of 30 gallons is roughly equivalent to a drop in the bucket.[87] In other words, it would not have been readily apparent to Boswell personnel that 30 gallons of oil had been lost from the system.

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[84] Ex. 7, Schedule 4 at 3 and 9 (Undeland Direct).
[85] *See id.*; Exs. 10 and 11, RAP-15 at 5 (Polich Direct) (Public and Nonpublic).
[86] Department Initial Brief at 21.
[87] The magnitude of the BEC3 boiler system is shown in a scale drawing in Ex. 7, Schedule 2 at 5, Fig. 1 (Undeland Direct).

The Department further claims that it is common sense that excess seal oil caused the A phase bushing to overheat and fail.[88] Minnesota Power's Initial Brief discusses in more detail why that is not the case.[89] Most importantly, General Electric, the OEM and the contractor brought in to diagnose the cause of the phase bushing failure, could not determine the cause.[90] The other potential causes identified in Minnesota Power's Initial Brief merely demonstrate that there are several possibilities for why the A phase bushing failed, especially given that it passed General Electric's recent testing by a lower margin than all of the other phase bushings.[91] Mr. Polich's claim that it is "common sense" that the proximate cause of the phase bushing failure was the presence of seal oil is belied by the fact that General Electric, the preeminent expert on BEC3's phase bushings, could not make such a conclusion.

The Department seeks to penalize Minnesota Power for an unforeseen effect (oil in the phase bushings) of its creative solution to the hydrogen leak that demonstrably shortened that outage by about fourteen weeks, especially given the phase bushing outage lasted 18 days.[92] This would be a bad precedent to set. If Minnesota Power is penalized for an unforeseen potential[93] consequence of its implementation of an outside-of-the-box solution to a novel problem, it will be disincentivized to attempt anything like that again in the future in order to minimize unplanned outages.

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[88] Department Initial Brief at 22-23.
[89] Minnesota Power Initial Brief at 50-52.
[90] Exs. 10 and 11, RAP-15 at 7-8 (Polich Direct) (Public and Nonpublic).
[91] Exs. 14 and 15 at 35 (Undeland Rebuttal) (Public and Nonpublic).
[92] Ex. 7 at 32-34 (Undeland Direct).
[93] As discussed in Minnesota Power's Initial Brief, not even General Electric, the OEM, could determine whether the presence of oil in the A phase bushing caused it to fail. Minnesota Power Initial Brief at 7.

D. No Unplanned Outage Replacement Power Costs Should Be Refunded Because Minnesota Power Followed Good Utility Practice

LPI argues that even if Minnesota Power demonstrates that its actions and programs were consistent with good utility practice, allowing cost recovery for the utility's unplanned outage replacement power costs would be unjust and unreasonable.[94] LPI did not offer any testimony or evidence in support of this claim. Instead, LPI's position is based upon the Department's oversimplified (and since abandoned) theory that because Minnesota Power spent $12.4 million less in generation maintenance expenses in 2019 than was included in the 2017 test year, and collected $7.727 million in unplanned outage costs during the 18-month AAA evaluation period in 2018 and 2019, the Company must have "pocketed" the maintenance savings while passing the increased unplanned outage costs on to customers.[95] In addition to lacking any evidentiary basis, LPI's assumptions are wrong for a multitude of reasons. And adopting LPI's rationale would result in overly rigid generation maintenance budgeting and spending that would be entirely contrary to good utility practice.[96]

As discussed in detail in Minnesota Power's Initial Brief, the intent of test year budgets is not to set a rigid spending amount by line item for future years.[97] It is understood and expected that the individual cost components used to develop the rates will vary from year to year.[98] In this case, the lower generation maintenance spending in 2019 compared to the test year can be explained by the retirement of several generation facilities in 2018 and 2019, changes to the maintenance expenses of facilities other than Boswell, higher than projected capitalization of

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[94] LPI Initial Brief at 13.
[95] *Id*.; *see also* Minnesota Power Initial Brief at 20.
[96] *See* Minnesota Power Initial Brief at 20.
[97] *Id*. at 15.
[98] *In re the Complaint of Myer Shark et al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).

maintenance projects, and different points in the long-term outage plan (2017 had a three week planned boiler outage at BEC4, with shorter outages planned for 2018 and 2019).[99] Importantly, Minnesota Power did not reduce maintenance or inspection activity or spending on any of the Boswell systems at issue in this proceeding.[100] In fact, there has been no evidence presented by any party in this proceeding that would suggest that reduced maintenance spending was even a contributing cause of any of the unplanned outages during the 18-month evaluation period.

Additionally, LPI's assertion that Minnesota Power gets to "keep" the cost savings due to reduced generation maintenance expenses is overly simplistic and inaccurate.[101] Generation maintenance costs are highly cyclical based upon what types of outages are scheduled each year. In years where no significant outages are scheduled in the long-term outage plan, like in 2018 and 2019, generation maintenance expenses are typically lower than the test year.[102] When scheduled major outages occur, the Company's generation maintenance expenses typically exceed the test year amount.[103] Moreover, when there are actual savings in one area, they are often offset by cost increases in other areas.[104] Despite these variations, "no adjustment (with the exception of the pass-throughs) is made outside of a rate case for increases or decreases in the individual components of rates."[105]

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[99] Ex. 9 at 17, 20, 22-23 (Rostollan Direct).
[100] Ex. 6 at 11 (Poulter Direct); Ex. 5 at 15-20 (Simmons Direct); Exs. 14 and 15 at 17 (Undeland Rebuttal) (Public and Nonpublic).
[101] LPI Initial Brief at 13-14.
[102] Ex. 9 at 23-26 (Rostollan Direct).
[103] *Id*.
[104] *Id*.
[105] *In re the Complaint of Myer Shark et al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).

The "netting adjustment" sought by LPI in this matter would constitute ratemaking outside of a rate case because it would be based solely upon differences in spending levels, not on whether the Company's actions were consistent with good utility practice. Commission precedent is clear that this would be inappropriate ratemaking. For these reasons, LPI's request for a "netting adjustment" should be rejected.

III. CONCLUSION

Based on the record and the arguments presented in this proceeding, Minnesota Power requests that the Administrative Law Judge find by a fair preponderance of the evidence that Minnesota Power's maintenance practices were consistent with good utility practice and replacement power costs for the unplanned outages that occurred during the AAA evaluation period of July 1, 2018 through December 31, 2019, were reasonably and prudently incurred for the benefit of Minnesota Power's customers.

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MINNESOTA POWER

David R. Moeller
Senior Attorney and
Director of Regulatory Compliance
30 West Superior Street
Duluth, MN 55802
Telephone: (218) 723-3963
dmoeller@allete.com

TAFT STETTINIUS & HOLLISTER LLP

_/s/ *Kodi J. Verhalen*_____
Kodi J. Verhalen
Matthew R. Brodin
Elizabeth M. Brama
2200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402
Telephone: (612) 977-8400
KVerhalen@Taftlaw.com
MBrodin@Taftlaw.com
EBrama@Taftlaw.com

Attorneys on behalf of Minnesota Power