OAH Docket No. 82-2500-37082
MPUC Docket No. E999/AA-20-171

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Review of the July 2018–December 2019 Annual Automatic Adjustment Reports	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS**

The Minnesota Public Utilities Commission (Commission) referred this matter to the Office of Administrative Hearings for a contested case proceeding in September 2020. Administrative Law Judge Barbara J. Case was assigned to the matter. The Commission directed the Administrative Law Judge to consider whether Minnesota Power's forced outage costs between July 2018 and December 2019 were reasonable and prudent, applying good utility practice—and, if not, the overcharges plus interest that should be returned to ratepayers.[1]

A remote evidentiary hearing was held on June 3, 2021, via Microsoft Teams. Initial briefs were filed on June 23, 2021. Reply briefs were filed on July 12, 2021.

David Moeller, Senior Attorney and Director of Regulatory Compliance, Minnesota Power, and Kodi Verhalen and Matthew Brodin, Taft Stettinius & Hollister, LLP, appeared on behalf of Minnesota Power (Company).

Katherine M. Hinderlie and Richard E.B. Dornfeld, Assistant Attorneys General, appeared on behalf of the Department of Commerce, Division of Energy Resources (Department).

Andrew P. Moratzka, Sarah J. Phillips, Jessica L. Bayles, and Riley A. Conlin, Stoel Rives, LLP, appeared on behalf of the Large Power Intervenors (LPI).

Jason Bonnett appeared on behalf of the Commission staff.

STATEMENT OF THE ISSUES

1. Were Minnesota Power's forced outage costs for July 2018 through December 2019 reasonable and prudent, applying good utility practice?

[1] Ex. 1 (Order Accepting 2018-2019 Electric AAA Reports; Notice of and Order for Hearing at 4 (Sept. 16, 2020) (Order for Hearing)). The exhibits can be found in the Stipulated Exhibit List (eDocket No. 20216-174787-01). Unless otherwise noted, the citations provided are to the public versions of exhibits.

2. If not, what is the amount of overcharges plus interest that Minnesota Power should be required to return to ratepayers through its Fuel Adjustment Clause rider mechanism?

SUMMARY OF RECOMMENDATIONS

1. The Administrative Law Judge (ALJ) recommends that the Commission find that the costs of Minnesota Power's maintenance activities and forced outage events relating to hot reheat lines at Boswell Unit No. 4 were not reasonably and prudently incurred applying good utility practice. The Administrative Law Judge further recommends the Commission find outages stemming from stopping a hydrogen leak and the subsequent and related replacement of its generator phase bushings at Boswell Unit No. 3's was not inconsistent with good utility practice.

2. Based on the above recommendations, the ALJ recommends the Commission order the Company's forced outage costs, including interest, associated with Boswell Unit No. 4's hot reheat line outage should be refunded to ratepayers.

Based on the evidence in the hearing record, the Administrative Law Judge makes the following findings:

FINDINGS OF FACT

I. PROCEDURAL HISTORY

1. Minn. R. 7825.2800-.2830 (2021) require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.[2]

2. Minnesota Power filed its Annual Automatic Adjustment (AAA) of Charges Report on March 2, 2020, pursuant to Minn. R. 7825.2800-.2830.

3. On April 15, 2020, the Department filed its Review of the July 2018-December 2019 Annual Automatic Adjustment Reports.[3]

4. On April 30, 2020, Minnesota Power filed Reply Comments in which it provided additional information requested by the Department in its Report.[4]

5. On May 29, 2020, the Department filed its Response Comments.[5]

[2] Minn. R. 7825.2800-.2830 (2021).
[3] Review of the July 2018-December 2019 Annual Automatic Adjustment Reports (Apr. 15, 2020) (eDocket No. 20204-162132-02).
[4] Minnesota Power Reply Comments (Apr. 30, 2020) (eDocket No. 20204-162709-01).
[5] Department Response Comments (May 29, 2020) (eDocket No. 20205-163578-01).

6. On June 10, 2020, Minnesota Power filed a supplement to the 2020 AAA Report.[6]

7. On July 1, 2020, Minnesota Power filed Additional Comments in response to the Department's May 29, 2020 Response Comments.[7]

8. On July 24, 2020, the Department filed Additional Response Comments in response to the Company's July 1, 2020, Additional Comments.[8]

9. On July 31, 2020, Minnesota Power filed a letter in response to the Department's Additional Response Comments of July 24, 2020.[9]

10. After meeting on August 20, 2020 to consider Minnesota Power's 2020 AAA Report, on September 16, 2020, the Commission issued the Order for Hearing referring the case to OAH to "thoroughly develop a full record addressing, at a minimum, whether Minnesota Power's forced outage costs for the period were reasonable and prudent and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers through the [fuel clause adjustment] (FCA)."[10]

11. The Order for Hearing established Minnesota Power and the Department as parties to this proceeding.[11]

12. The Commission also noted that the Department could seek authorization to retain an outside engineering expert to assess whether Minnesota Power's maintenance activities and force outage events were consistent with good utility practice.[12] Consistent with this guidance, the Department issued a request for proposal in October 2020 to secure a contractor with engineering expertise to assist in the matter. The Department's first request for proposal was unsuccessful, and the Department reposted the request for proposal in December 2020.[13] To accommodate the need to retain an expert, the parties agreed to modify the procedural schedule.[14] The Administrative Law Judge issued a Second Prehearing Order with the modified procedural schedule.[15]

13. In February 2021, the Department informed the Office of Administrative Hearings that it had retained engineering consulting firm GDS Associates, Inc.[16] Mr. Richard Polich of GDS Associates assisted the Department in conducting an

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[6] 2020 AAA Report Supplement (June 10, 2020) (eDocket No. 20206-163842-01).
[7] Minnesota Power Additional Comments (July 1, 2020) (eDocket No. 20207-164474-01).
[8] Department Additional Response Comments (July 24, 2020) (eDocket No. 20207-165268-01).
[9] Minnesota Power Letter (July 31, 2020) (eDocket No. 20207-165493-01).
[10] Ex. 1 at 4-5 (Order for Hearing).
[11] *Id.* at 7.
[12] *See id.* at 5.
[13] Department Extension Request (Dec. 7, 2020) (eDocket No. 202012-168840-01).
[14] *Id.*
[15] Ex. 4 (Second Prehearing Order)
[16] Department Protective Agreement Cover Letter (Feb. 2, 2021) (eDocket No. 20212-170635-01).

independent investigation of the forced outages at Minnesota Power's Clay Boswell coal plant and provided testimony on behalf of the Department in this proceeding.[17]

14. Mr. Polich is the managing director of GDS Associates, Inc., a consulting and engineering firm. Mr. Polich earned a Bachelor of Science in Mechanical Engineering in 1979, and a Bachelor of Science Nuclear Engineering in 1979, and a Master of Business Administration in 1990, all from the University of Michigan in Ann Arbor, Michigan. He is a registered Professional Engineer in the State of Michigan and has over 40 years of experience in the utility industry and energy sector, performing duties and services for myriad companies and organizations. [18]

15. On September 30, 2020, LPI petitioned to intervene.[19]

16. On October 14, 2020, LPI moved to admit Jessica L. Bayles pro hac vice.[20]

17. On December 17, 2020, the Administrative Law Judge issued a Second Prehearing Order,[21] which, among other things, amended the procedural schedule for the contested case, and set the following procedural schedule:

Document or Event	**Due Date**
Direct Testimony (Minnesota Power)	January 26, 2021
Deadline for Intervention	March 19, 2021
Direct Testimony (Other Parties)	April 19, 2021
Rebuttal Testimony (All Witnesses)	May 24, 2021
Status Conference	May 28, 2021
Evidentiary Hearings	June 3, 2021
Initial Briefs	June 28, 2021
Reply Briefs & Proposed Findings of Fact	July 12, 2021
Administrative Law Judge Report	August 11, 2021

18. On January 26, 2021, Minnesota Power filed the direct testimony and schedules of Todd Z. Simmons,[22] William Poulter,[23] Paul J. Undeland,[24] Leann Oehlerking-Boes,[25] and Joshua G. Rostollan.[26]

[17] Ex. 10 at 1 (Polich Direct).
[18] *Id.* at 1-2, RAP-1.
[19] LPI Petition to Intervene (Sept. 30, 2020) (eDocket No. 20209-166962-02).
[20] LPI Motion for Admission of Jessica L. Bayles Pro Hac Vice (Oct. 14, 2020) (eDocket No. 202010-167280-01).
[21] Ex. 4 (Second Prehearing Order).
[22] Ex. 5 (Simmons Direct).
[23] Ex. 6 (Poulter Direct).
[24] Ex. 7 (Undeland Direct).
[25] Ex. 8 (Oehrlinking-Boes Direct).
[26] Ex. 9 (Rostollan Direct).

19. On April 19, 2021, the Department filed the direct testimony and attachments of Richard A. Polich[27] and Nancy A. Campbell.[28]

20. On May 12, 2021, the Department filed errata to the direct testimony of Richard A. Polich.[29]

21. On May 24, 2021, Minnesota Power filed the rebuttal testimony and schedules of Paul J. Undeland,[30] Leann Oehlerking-Boes,[31] and Joshua G. Rostollan.[32]

22. On May 27, 2021, Minnesota Power filed errata to the direct testimony of Joshua G. Rostollan.[33]

23. On May 28, 2021, the Administrative Law Judge convened a status conference by telephone.[34]

24. On June 3, 2021, the Administrative Law Judge held a one-day evidentiary hearing via Microsoft Teams.[35]

25. On June 28, 2021, Minnesota Power, the Department, and LPI filed initial post-hearing briefs.

26. The parties filed reply briefs on July 12, 2021.

II. BACKGROUND

27. Under Minn. Stat. § 216B.16, subd. 7 (2020), and Minn. R. 7825.2390-.2920 (2021), rate-regulated gas and electric utilities may adjust their rates between general rate cases to reflect fluctuations in energy-related costs—that is, the prices they pay for gas or electricity purchased for delivery to ratepayers, or for fuel purchased to generate electricity for ratepayers. These adjustments are called automatic adjustments because a utility generally implements these rate changes in advance of Commission approval.[36]

28. The adjustments automatically affect retail rates and some wholesale transactions. The tariffs of each regulated electric utility contain a fuel clause adjustment (FCA) mechanism setting forth the formula for making adjustments to the utility's retail rates to reflect changes in the utility's energy-related costs. And the terms of each wholesale transaction govern whether and how fluctuations in energy-related costs alter the amount charged to a wholesale customer. Commission rules require utilities to make

[27] Exs. 10, 11 (Polich Direct) (Public and Nonpublic).
[28] Exs. 12, 13 (Campbell Direct) (Public and Nonpublic).
[29] Exs. 10, 11 (Polich Direct Errata) (Public and Nonpublic).
[30] Exs. 14, 15 (Undeland Rebuttal) (Public and Nonpublic).
[31] Exs. 16, 17 (Oehlerking-Boes Rebuttal) (Public and Nonpublic).
[32] Ex. 18 (Rostollan Rebuttal).
[33] Ex. 9 (Rostollan Direct Errata).
[34] *See* Ex. 4 (Second Prehearing Order).
[35] *See id.*
[36] Ex. 1 at 2 (Order for Hearing).

detailed filings supporting each automatic adjustment. They also require utilities to make comprehensive annual filings reporting on all automatic adjustments made during a specified twelve-month period.[37]

29. The automatic adjustment rules direct public utilities to make an annual filing (Annual Automatic Adjustment or AAA report) including certain categories of information required in the rules. Over the years, the Commission has ordered utilities to provide reports on other topics, such as costs and revenues related to their interaction with the Midcontinent Independent System Operator (MISO) and certain auxiliary businesses. Most relevant for this matter, the Commission directed Minnesota Power and other Companies to report the amount that each utility spends for maintaining its plant, as well as the maintenance budget that ratepayers provide to each utility, as reflected in the utility's last rate case. The Department then compares this data with data about unplanned (or forced) outages in the utility's plant. When a utility's plant cannot operate, the utility may need to buy replacement energy from the wholesale market—and the FCA causes ratepayers to bear the cost of this replacement energy.[38]

30. Historically, even when there has been evidence of actual mistakes leading to outages, the Commission has not required refunds of forced outage costs.[39] As an example, Minnesota Power cited a case where the Department recommended refunds of forced outage costs resulting from an Allen wrench falling into a duct at a generating station. There the Commission declined to require a refund stating, "[t]he record in this docket does not contain detail sufficient …to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance." The Commission further stated, "[t]he prudence of costs related to the forced outages identified by the Department remain subject to review by the Commission at a future date."[40]

31. Commission staff note the Department has been concerned for several years that, because the utilities can automatically recover the cost of replacement power through automatic fuel clause adjustments, utilities may not be adequately spending money budgeted for operation and maintenance of their generating plants and therefore not optimizing the plants' availability.[41]

32. In a February 6, 2008, Order in Docket No. E-999/AA-06-1208 (the 06-1208 Order), the Commission declared that "utilities have a duty to minimize unplanned facility outages through adequate maintenance, and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work."[42]

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[37] *Id.*
[38] *Id.* at 2-3.
[39] *See In re Review of the 2010-2011 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-11-792, Order Acting on Electric Utilities' Annual Reports at 5 (Aug. 16, 2013).
[40] *Id.*
[41] *See* Staff Briefing Papers at 1 (Aug. 20, 2020) (eDocket No. 20208-165810-01).
[42] *In re Review of the 2006 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities*, MPUC Docket No. E-999/AA-06-1208, Order Acting on Electric Utilities' Annual Reports, Requiring Further Filings,

To guard against the possibility that a utility would seek to increase profits by skimping on maintenance—with the expectation that ratepayers would bear any financial consequences—the Commission monitors utility expenditures related to maintenance and forced outages.[43]

33. This requirement stems from a noticeable increase in Independently Owned Utilities' (IOUs) outage costs during Fiscal Year (FY) 06 and FY07. When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those purchases' flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates.

34. Also, in the 06-1208 Order, the Commission considered additional reporting on outage issues, developing benchmarks to quantify acceptable outage performance, and creating financial incentives to keep scheduled and unscheduled outages within specified parameters. The Commission noted that while the utilities did not object to providing more detailed data, they did oppose benchmarks, contending that unscheduled outages were situation specific and do not readily fall into a handful of pre-established categories. The utilities also contended that there was no evidence that utilities were not managing outages, scheduled and unscheduled, competently, and resourcefully. The Commission decided it would "require additional reporting . . . to ensure that regulators and the public have the data required to ensure that utilities are managing outages for the maximum protection of ratepayers" to inform the ongoing investigation into the appropriateness of automatic adjustments for electric utilities.[44]

35. Minn. R. 7825.2390-.2920 direct applicable utilities to adjust their FCA amount monthly, and to draft their AAA reports to address the period from July 1 to June 30 (the fiscal year). But in 2018, in a matter titled *In re an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*,[45] the Commission varied its rules and directed the Companies, starting January 1, 2020, to begin making these adjustments annually, and to report these changes on the basis of a calendar year rather than a fiscal year.[46] To transition to this new regulatory regime, the Commission directed the Companies to draft their next AAA report to cover the period July 2018 through December 2019—that is, the final 18 months in which they would make monthly adjustments.[47]

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and Amending Order of December 20, 2006 on Passing MISO Day 2 Costs Through Fuel Clause at 5 (Feb. 6, 2008).

[43] Ex. 1 at 3 (Order for Hearing).

[44] *In re Review of the 2010-2011 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-11-792, Order Acting on Electric Utilities' Annual Reports at 5 (Aug. 16, 2013).

[45] *In re an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, MPUC Docket No. E-999/CI-03-802, Order Revising Implementation Date, Establishing Procedural Requirements, and Varying Rule (Dec. 12, 2018).

[46] *Id.* at 7.

[47] *Id.*; *see also* Ex. 1 at 3-4 (Order for Hearing).

36. Minnesota Power's AAA Report, at issue in this matter, included a section addressing forced or unplanned outage events between July 2018 and December 2020 as required by the 06-1208 Order.[48] In the AAA Report, Minnesota Power identified 26 different forced outage events during the reporting period.[49]

37. A forced or unplanned outage event is a situation where an electrical generating unit is removed from service for emergency reasons, for example due to a component failure or other condition requiring removal outside of a planned maintenance or planned outage period. Forced outages may result in a utility incurring forced outage expenses when its own generation facilities are not available for service. These forced outage expenses might include higher replacement power costs.[50] Minnesota Power reported $7.727 million in replacement power costs that were ultimately charged to retail customers through its Fuel and Purchased Energy Adjustment Rider (Fuel Adjustment Clause Rider or FAC Rider) associated with the forced outages.[51]

38. The Department filed a Review of the July 2018-December 2019 Annual Automatic Adjustment Reports with the Commission on April 15, 2020, that assessed the compliance of various filings made by the utilities and the reasonableness of costs charged by utilities to retail customers through automatic adjustment mechanisms including Minnesota Power's FAC rider. In its comments, the Department explained that when a power plant "experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those purchases flows through the FAC directly to ratepayers."[52]

39. After reviewing Minnesota Power's AAA Report, the Department concluded that the Company's purchased power costs had increased significantly in 2019 and 2020. Purchased power is wholesale electricity procured by the utility from a third-party such as an independent power producer or a regional transmission operator such as the Midcontinent Independent System Operator (MISO). Specifically, the Department found that Minnesota Power's total costs per megawatt hour were 10.2 percent higher in 2019 than 2018.[53] The Department requested that the Company describe the main factors driving these cost increases and provide support for the $13.6 million in MISO charges for February 2019 and provide any plant outages information for February 2019, in its

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[48] Minnesota Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206-08 (Mar. 2, 2020) (eDocket No. 20203-160872-01).
[49] *Id.*
[50] Ex. 12 at 6-7 (Campbell Direct).
[51] Minnesota Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206-08 (Mar. 2, 2020) (eDocket No. 20203-160872-01).
[52] Review of the July 2018-December 2019 Annual Automatic Adjustment Reports at 12 (Apr. 15, 2020) (eDocket No. 20204-162132-02).
[53] *Id.* at 22, 51.

reply comments.[54] The Department also requested that Minnesota Power provide information comparing budgeted to actual generation maintenance expense.[55]

40. On April 30, 2020, Minnesota Power filed reply comments to the Department's comments, providing actual 2019 Generation and Maintenance Expenses and explaining the cost increases were caused by "significant outages" at its Boswell Energy Center in 2019. The Company explained that the coal plant had outages in February (26 days), March (29 days), June (22 days), and July (20 days). Specifically, in February 2019 Boswell Unit No. 4 had a major unplanned outage to repair a hot reheat line steam leak. As a result, Minnesota Power was required to procure power necessary to serve customers from MISO's wholesale energy markets due to having less company generation to serve load.[56] The Company also provided information regarding actual and budgeted maintenance expenses.[57]

41. On June 10, 2020, Minnesota Power filed a supplement to the 2020 AAA report. The filing explained that the original Schedule 15 included with its AAA Report incorrectly understated "the Boswell Unit No. 4 Unplanned Outage related to the Hot Reheat Line Steam Leak . . . by 368,136 MWhs [(Megawatt hours)]."[58]

42. After reviewing Minnesota Power's filings, the Department shared response comments on July 24, 2020, that found: (1) the Company's forced outage costs were "approximately 500 percent higher in the current AAA compared to the average of the past two AAA filing periods," (2) Minnesota Power underspent its annual $42 million generation maintenance budget by 21.9 percent in 2018 and 2019, and (3) the Company passed $7.727 million in forced outage costs onto customers through its FAC Rider.[59]

43. The Department recommended that the Commission deny recovery of 50 percent of Minnesota Power's forced plant outage costs for a resulting refund of $3.864 million in forced outage costs from the fuel clause adjustment.[60] The Department considered it inequitable for Minnesota Power to keep the lower spending levels of $21.6 million for generation maintenance expenses in 2018 and 2019, at the same time as ratepayers were being charged significantly higher replacement power for forced outages.[61]

44. In September 2020, the Commission concluded that further factual development was required to determine "whether Minnesota Power's forced outage costs for the period were reasonable and prudent—and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers." As a result, the Commission referred the matter to the Office of Administrative Hearings for a contested case proceeding. The

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[54] *Id.* at 32.
[55] *Id.* at 13.
[56] Minnesota Power Reply Comments at 3-4 (Apr. 30, 2020) (eDocket No. 20204-162709-01).
[57] *Id.* at Attachment A.
[58] 2020 AAA Report Supplement at 1 (June 10, 2020) (eDocket No. 20206-163842-01).
[59] Department Additional Response Comments at 2 (July 24, 2020) (eDocket No. 20207-165268-01).
[60] *Id.*
[61] *Id.*

Commission further directed that Minnesota Power should "bear the burden of proving that any or all of its forced outage costs were reasonably and prudently incurred, applying good utility practices."[62]

45. The parties to this matter agree that good utility practice means any 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.[63] Furthermore, "good utility practice" includes, but is not limited to, North American 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.[64]

46. Utilities are entitled to recover their "revenue requirement" from their customers.[65] The "revenue requirement" is the total amount of money that a utility needs to collect from customers to pay all costs of service including a reasonable return on investment to its investors. The revenue requirement has two main components: return on rate base and operating expenses and revenues. The revenue requirement is set during a general rate case proceeding.[66]

47. During a general rate case, the Commission considers the utility's representative expenses and revenues during a "test year." A test year is typically a recent or forecasted 12-month period selected for purposes of expressing the utility's need for a change in rates.[67] This test year data is then used to determine the utility's revenue requirement and resulting rates charged to ratepayers.

48. In 2018, the Commission authorized a rate change for Minnesota Power, as part of the Company's last completed general rate case. As part of its decision, the Commission determined that $41,998,904 (approximately $42 million) reasonably represented Minnesota Power's annual generation power plant maintenance expense.[68] This amount effectively serves as the Company's annual maintenance budget for

[62] Ex. 1 at 4 (Order for Hearing).
[63] Ex. 10 at 6-7 (Polich Direct); Ex. 14 at 7-8 (Undeland Rebuttal).
[64] Ex. 10 at 7 (Polich Direct).
[65] *See* Minn. Stat. § 216B.16 (2020).
[66] Ex. 12 at 3-4 (Campbell Direct).
[67] Minn. R. 7825.3100, subp. 17 (2021).
[68] Ex. 12 at 8 (Campbell Direct).

generation plants. However, the utility's spending may either drop below or exceed this budgeted amount depending on its actual maintenance needs each year.[69]

49. In addition to general rate cases, the Commission may adjust utility cost recovery using pass-through mechanisms called "riders." Riders are typically used to charge actual expenses (as opposed to representative amounts set during a test year) such as fuel costs to retail customers.[70] Permanent cost recovery, however, is not guaranteed. Instead, rider costs are provisionally charged to customers subject to Commission review and possible refund.[71] The Fuel and Purchased Energy Adjustment Rider, for example, allows a utility to recover actual fuel expenses and purchased power costs from customers.[72]

50. The interplay between costs recovered based on a representative test year amount and those recovered through a rider based on actual spending can create improper financial incentives.[73] Accordingly, the Commission "monitors utility expenditures related to maintenance and forced outages" to "guard against the possibility that a utility would seek to increase profits by skimping on maintenance—with the expectation that ratepayers would bear any financial consequences." [74] The Commission also requires reporting "to ensure that regulators and the public have the data required to ensure that utilities are managing outages for the maximum protection of ratepayers."[75] The Commission has further explained, "generation-facility outage costs merit careful scrutiny, given their potentially substantial impact on ratepayers."[76]

51. In this case, the Commission found a genuine issue of material fact in dispute about whether Minnesota power's forced outage costs for the period were reasonable and prudent – and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers through the FCA. Therefore, the Commission referred this matter to the Minnesota Office of Administrative Hearings for a contested Case proceeding ordering Minnesota Power to bear the burden of proving that any or all of its forced outage costs were reasonably and prudently incurred, applying good utility practices. [77]

III. Minnesota Power's Forced Outages at Boswell

52. Minnesota Power's AAA Report identified 26 different forced outage events during the July 2018 through December 2019 reporting period. All of the forced outages

[69] *See id.* at 24; Ex. 9 at 23 (Rostollan Direct).
[70] Ex. 12 at 4 (Campbell Direct).
[71] Minn. Stat. § 216B.16, subd. 7(1) (2020) (authorizing rider cost recovery); Minn. R. 7825.2920 (2021) (provisionally approving rider costs subject to further review).
[72] Ex. 12 at 4 (Campbell Direct); *see also* Minn. Stat. § 216B.16, subd. 7(1).
[73] Ex. 12 at 5 (Campbell Direct).
[74] Ex. 1 at 3 (Order for Hearing).
[75] *In re 2006 Annual Automatic Adjustment of Charges for All Elec. & Gas Utils.*, MPUC Docket No. E-999/AA-06-1208, Order Acting on Electric Utilities' Annual Reports at 5 (Feb. 6, 2008).
[76] *Id.*
[77] Ex. 1 at 4 (Order for Hearing).

occurred at Minnesota Power's Boswell coal-fired power plant located in Cohasset, Minnesota. Boswell is Minnesota Power's largest thermal facility and at its peak generated coal-fired power from four operating units, which were constructed between 1958 to 1980. Two of the generating units, Boswell Unit Nos. 1 and 2, were retired from operation in 2018. The two remaining units Boswell Unit Nos. 3 and 4, with a combined generating capacity of approximately 823 MW, have historically provided approximately half the energy needs of Minnesota Power's customers. Boswell Unit No. 3 was commissioned in 1973 and Boswell Unit No. 4 in 1980. Both units have undergone major environmental retrofits, completed in 2009 and 2015 respectively.[78]

53. During the period at issue here, there were 16 forced outages due to boiler tube leaks, two forced outages due to condenser tube leaks, one forced outage to clean the Boswell Unit No. 4 condenser, a forced outage caused by seal failure in a circulating water pump at Boswell Unit No. 3, a forced outage due to a leak in the blowdown flash tank on Boswell Unit No. 4, a forced outage due to hot reheat pipe failure on Boswell Unit No. 4, extension of the spring 2019 Boswell Unit No. 3 outage to complete leak repairs on a generator hydrogen cooling system, and a forced outage to replace oil soaked line-side phase bushings on the "A" phase of the Boswell Unit No. 3 generator.[79]

54. On behalf of the Department, GDS Associates reviewed all of Minnesota Power's forced outages at Boswell Unit Nos. 3 and 4 during the relevant period to determine whether Minnesota Power followed good utility practice. Specifically, GDS Associates reviewed sixteen forced outages from boiler tube leaks, two forced outages from condenser tube leaks, one forced outage to clean a condenser, a forced outage due to a failed water pump, a forced outage due to a leak in the blowdown flash tank, a forced outage due to a hot reheat line failure on Boswell Unit No. 4, the extension of the spring 2019 Boswell Unit No. 3 outage to complete leak repairs on a generator hydrogen cooling system, and a forced outage caused by grounding in the phase bushings of the Boswell Unit No. 3 generator.[80] The Department expressed concern about whether outages associated with three different systems were consistent with good utility practice; and accordingly, whether the costs associated with those outages were "reasonably and prudently" incurred.[81]

55. Based on its review GDS did not find any systemic causes, maintenance practices, or commonality trends for the types and frequency of the boiler tube leaks, condenser outages, or the boiler circulating pump outage and found that Minnesota Power's practices concerning these components during the period at issue were consistent with good utility practices.[82] GDS Associates determined, following its review of the blowdown flash tank outage, that Minnesota Power could have done a better job identifying the leak's location both prior to shutting down the plant and during the outage

[78] Ex. 6 at 2-3 (Poulter Direct).
[79] Ex. 10 at 16-17 (Polich Direct).
[80] *Id.*
[81] Ex. 1 at 4-5 (Order for Hearing); Ex. 12 at 11 (Campbell Direct).
[82] Ex. 10 at 17-18 (Polich Direct).

and should have noted the frequency of problems in the years leading up to the outage.[83] The Department, however, did not recommend that Minnesota Power refund these outage costs because GDS did not conclude that Minnesota Power's conduct was inconsistent with good utility practice.[84]

56. There were forced outages in each of the 4 Boswell units between July 1, 2018, through December 31, 2019.[85] The Department's concerns are focused on three outages that occurred at Boswell Unit Nos. 3 and 4.[86] GDS determined that Minnesota Power failed to follow good utility practices related to the hot reheat line outage, the extension of the spring 2019 outage to find and fix the leak in the hydrogen cooling system, and the generator "A" phase bushing failure.[87] Because the failure to follow good utility practice to more expeditiously locate the hydrogen leak did not contribute significantly to the extension of the spring 2019 outage, the Department recommended that Minnesota Power only be required to refund forced outage costs arising from the hot reheat line failure and phase bushing failure.[88]

57. Boswell Unit No. 3 was originally constructed by General Electric Company. There are approximately 30 similar units in the United States. In 2009, the Boswell Unit No. 3 High Pressure-Intermediate Pressure (HP-IP) turbine was retrofitted to an "Alstom design." The Low Pressure (LP) turbine and generator remain original. There are not any identical Alstom units in the United States with this retrofit.[89]

58. Boswell Unit No. 4 was originally constructed by Siemens Westinghouse. This unit has a common HP-IP turbine with dozens constructed in the United States. The two LP turbines were less common. In 2010, the entire rotor train was converted to an Alstom design. The generator was refurbished in 2008 and is the only one like it in the United States.[90]

59. Minnesota Power uses a ten-year long-term outage plan for Boswell centered on performing manufacturer recommended major maintenance on boilers and steam turbines.[91] Minnesota Power does not generally revise its long-term major outage schedule within the 10-year cycle, but it may modify the scope of work within the plan based on emergent work identified during the execution of the scheduled outage.[92] Minnesota Power witness Todd Simmons testified that, "Generally, the long-term outage plan is only updated to add future years as current year rolls off and to maintain reference when the last turbine overhaul or boiler chemical clean was completed."[93] Outage

[83] *Id.* at 18-19.
[84] Ex. 12 at 17-18 (Campbell Direct).
[85] Ex. 6 at 2 (Poulter Direct).
[86] *Id.* at 3.
[87] Ex. 10 at 48-49 (Polich Direct).
[88] Ex. 12 at 17 (Campbell Direct); Ex. 10 at 45-46 (Polich Direct).
[89] Ex. 6 at 3 (Poulter Direct).
[90] *Id.* at 4.
[91] Ex. 5 at 7 (Simmons Direct).
[92] *Id.* at 13.
[93] *Id.*

schedules may change during an outage plan, however, due to inspections that discover required work that was not previously identified.[94]

60. While Mr. Polich generally agreed that Minnesota Power's maintenance and outage planning and timing was consistent with other utilities, he testified that most utilities he has worked with use a five-year long-term outage plan because major maintenance on turbines and the boiler are defined by operating time, number of cycles, and other time-oriented factors, which change from year to year.[95]

61. Minnesota Power hires consultants to aid in developing schedules, inspections, and repair plans, if equipment specifications or limitations on in-house knowledge require it.[96] Some maintenance and equipment inspection requires consultants to execute the work or inspection.[97] Contractors hired for large jobs will develop their own schedule and then present it to Minnesota Power to consider and incorporate into the plant's broader outage schedule.[98]

62. Use of consultants cannot absolve the plant owner of its responsibility to properly perform necessary and required maintenance, adhere to various codes, and comply with permits governing the plant's operation.[99] Power plant owners must therefore maintain knowledge of the American Society of Mechanical Engineers (ASME) Pressure Vessel Code requirements and recommendations, and must have the in-house engineering expertise needed to keep up with the most recent maintenance recommendations set forth by key industry groups such as the Electric Power Research Institute (EPRI), Institute of Electrical and Electronics Engineers (IEEE), equipment user groups, and other like entities.[100]

A. Boswell Unit No. 4's Hot Reheat Line

63. The first outage at issue in this proceeding relates to Boswell Unit No. 4's hot reheat line (HRH line). The HRH line is an approximately 33-inch diameter pipe with about 1.5-inch thick walls.[101] The pipe is more than 640 feet long and spans 20 floors with limited access within the unit.[102] It is designed to carry approximately 1,000 ℉ high-pressure steam from the unit's boiler back to the turbine where it is used to generate electricity.[103] The pipe used on Boswell Unit No. 4's hot reheat line is a longitudinal seam-welded pipe made of material that conforms with American Society for Testing and Materials Specification A-155, Grade 2-1/4 CR-1 Mo electric fusion welded steel pipe—a technical specification for manufacturing pipe for use in high-temperature applications.

[94] *Id.* at 14.
[95] Ex. 10 at 7-8 (Polich Direct).
[96] Ex. 5 at 11 (Simmons Direct).
[97] *Id.*
[98] *Id.*
[99] Ex. 10 at 10 (Polich Direct).
[100] *Id.*
[101] *Id.* at 20.
[102] *Id.*; Ex. 7 at 16 (Undeland Direct).
[103] Ex. 10 at 20 (Polich Direct).

These specifications include requirements for the thickness, shape, and width of the longitudinal weld—for high pressure service.[104] Longitudinal seam-welded pipe is formed by rolling plate steel into a pipe shape and welding the seam down the length of the pipe.[105]

64. On February 6, 2019, the HRH steam line experienced a seam weld failure which left a 2-foot-long crack, resulting in high-pressure steam release, which necessitated immediate action to begin shutting down Boswell Unit No. 4.[106] Minnesota Power determined that the leak was a failure of the welded seam of the HRH pipe. Because this is a dangerous failure, Boswell management and engineers organized a complete inspection of the HRH pipe which identified another six areas to be repaired.[107] During the shutdown, the Company replaced three sections of the pipe, approximately 20 feet in length, and repaired the other sections. The unit returned to service on March 27, 2019.[108]

65. The section of the HRH line that failed had last been inspected in 2010 and no actionable defects were discovered at that time. Minnesota Power asserts that it is rare, cost-prohibitive and time consuming to perform a complete inspection of the entire (High Energy Piping) HEP system during a single planned outage. Minnesota Power bases its inspection plans on past results, known areas of risk, industry bulletins, insurance carrier and third-party expert recommendations.[109] Specific to the seam rupture here, the vertical run of pipe where the seam rupture occurred is not considered to be a high stress section of the HRH piping. In general, vertical pipe runs experience lower weight loads and hence lower stress levels. For low stress level locations, Minnesota Power inspections are planned to occur every five to ten years. The location of the failure was identified as a low stress area in pipe inspections dating back to 1985. It had a stress test analysis done by Sargent and Lundy in 2010 and was due for inspection in 2020. No operational issues were observed by the unit's system engineers in the meantime. Minnesota Power established its preventive maintenance (PM) and development of maintenance (PdM) programs for HRH piping systems with the assistance of Thielsch Engineering and with third party consultants, such as Sargent and Lundy who has a recognized program for analyzing pipe stress. [110]

66. When asked why Minnesota Power chose a 10-year inspection frequency given a possible frequency between five and ten years, the Company explained that its ten-year inspection cycle for low stress parts of the pipe was informed by their independent consulting engineer telling the Company that none of the 50 U.S. power companies the consultant worked with inspected 100 percent of their low stress longitudinal seam welds on a five-year cycle. Thielsch told Minnesota Power that its

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[104] *Id.* at 20-21.
[105] *Id.* at 21.
[106] Ex. 7 at 15 (Undeland Direct); Ex. 10 at 22 (Polich Direct).
[107] Ex. 7 at 15 (Undeland Direct).
[108] Ex. 10 at 22-23 (Polich Direct).
[109] Ex. 7 at 16 (Undeland Direct).
[110] *Id.* at 16-17.

inspection frequency is consistent with good utility practice among the 50 coal-fired generation facility owners for which they work.[111]

1. Industry Experience with Hot Reheat Line Failures

67. Hot reheat line failures can have severe consequences because these pipes carry superheated steam under immense pressure. These extreme operating conditions also place pipes under great stress and create a heightened risk of failure absent appropriate inspection and repair procedures.[112]

68. Power plants have been using seam-welded pipe for high pressure and temperature steam (considered "high energy" application) transport since at least the 1940s. Documented failures of seam-welded pipe used in high energy piping started in 1970.[113] Since 1985, the Electric Power Research Institute (EPRI) has documented no less than 42 seam welded high energy pipe failures.[114] In 1985, for example, Southern California Edison – Mohave Generation Station's 30-inch diameter hot reheat line failed killing six people, injuring ten others, and causing an estimated $155 million in plant damage.[115] Many other hot reheat line failures on seam welds have been recorded, including failures at power plants in Texas in 1979, Michigan in 1986, and West Virginia in 2014.[116] The failure history of seam- welded pipe led EPRI and ASME to recommend that 100 percent of seam-welded pipe used in high energy processes be inspected at least once every five years.[117]

69. Minnesota Power was aware of industry concerns surrounding hot reheat lines and noted that "HRH piping has been an on-going power generation industry topic for over 30 years."[118] Minnesota Power focused "more direct attention on the high-stress areas," which it describes as those areas "where there are attachments such as pipe hangers or laterals."[119] Minnesota Power indicated that "it is rare for a plant to experience a weld seam failure on a vertical line in a low stress level location."[120]

70. One study noted that, although seam-weld failures may be less common than clamshell welds and girth welds, almost all of the very largest outages involved seam welds.[121]

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[111] *Id.* at 18-19.
[112] *See* Ex. 14, PJU-1 at 401 (Undeland Rebuttal) (*30-Plus Years of Long-Seam Weld Failures in the Power Generation Industry* (30 Year Report)).
[113] Ex. 10 at 22 (Polich Direct).
[114] Ex. 14, PJU-1 at 403 (Undeland Rebuttal) (30 Year Report).
[115] *Id.*, PJU-1 at 405, 410-12, 422.
[116] *See id.* at 399-432.
[117] Ex. 10 at 22 (Polich Direct).
[118] Ex. 6 at 12 (Poulter Direct).
[119] *Id.* at 13.
[120] *Id.* at 5.
[121] Ex. 21 at 4 (Cohn et al, *A Quantitative Approach to a Risk-Based Inspection Methodology of Main Steam and Hot Reheat Piping Systems*).

2. Inspections and Reports Following Boswell Unit No. 4's Hot Reheat Line Failure

71. Minnesota Power has had its longest on-going consulting relationship for piping systems and headers with Thielsch Engineering.[122] Following the hot reheat line rupture, Minnesota Power asked Thielsch to assess the failure and determine the extent of the damage.[123] Thielsch began its inspection on February 8, 2019, and released it analysis on February 20, 2019.[124]

72. Thielsch's inspection revealed six additional damaged or degraded pipe sections. Three sections, approximately 20 feet in length, had to be replaced entirely, and an additional three sections with significant traverse cracking were repaired with steel patches that ran along the welded seam of the pipe, 140 feet in length.[125] Thielsch concluded that the hot reheat line's cracking started approximately seven to nine years before the actual rupture.[126]

73. After receiving Thielsch's analysis, Minnesota Power concluded that the hot reheat line failed due to a mechanism called "creep."[127] Boswell Unit No. 4's hot-reheat-pipe creep damage was caused by slow developing voids and microcracks in the longitudinal seam-welds that ultimately resulted in pipe failure.[128] These cracks begin in the pipe interior and eventually spread to the outside.[129] At some point, the pipe will fail as the cracks propagate from the inside of the pipe toward the pipe surface through a significant portion of the pipe wall and become long enough that the pipe's strength is compromised and cannot sustain the operating pressure.[130]

74. Phased array ultrasonic examination can locate the voids and microcracks that occur deep within the longitudinal seam-welds of a hot reheat pipe.[131]

75. Thielsch had inspected multiple hot reheat pipe sections in 2012, 2015, and 2017.[132] But these inspections did not include longitudinal seam-weld inspection using ultrasonic examination techniques that could have identified interior cracking or deterioration in the longitudinal seam-welded pipe.[133] In those inspections, Thielsch, used "in-situ metallographic examination" and "magnetic particle inspection" techniques.[134]

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[122] Ex. 6 at 14 (Poulter Direct).
[123] Ex. 10 at 29 (Polich Direct).
[124] *Id.* at 29-30, RAP-6.
[125] *Id.* at 22-23.
[126] *Id.* at 38.
[127] *Id.* at 30, 32-33.
[128] *Id.* at 33.
[129] *Id.*; *see also* Ex. 19 at 3-22, 3-23 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
[130] Ex. 10 at 33 (Polich Direct).
[131] *Id.*; Ex. 14, PJU-1 at 31-32 (Undeland Rebuttal) (EPRI Guidelines).
[132] Ex. 10 at 26 (Polich Direct).
[133] *Id.*
[134] *Id.*

Neither technique, however, can identify cracks or creep deterioration unless those defects are located near the outside pipe surface.[135]

76. On February 22, 2019, EPRI, having learned of the seam rupture, contacted Minnesota Power to see if they could assist.[136] EPRI recommended, among other things, that Minnesota Power bring in a second entity to perform failure analysis and life assessment of the hot reheat piping.[137] EPRI also requested the failed pipe for their analysis.[138]

77. Later, EPRI provided Minnesota Power with its *High Energy Piping Systems. Still a Clear and* Present *Danger* presentation.[139] EPRI concluded that there was a basis for more frequent inspection of the seam-welded pipe and that 100 percent of the hot reheat line should have been examined at least every five years using phased array ultrasonic examination.[140]

78. Following EPRI's recommendation, Minnesota Power hired Structural Integrity Associates to perform additional evaluation of the hot reheat pipe.[141]

79. In its report, Structural Integrity questioned why the hot reheat pipe flaws had not been previously found.[142] Structural Integrity concluded that almost all welds had exceeded their calculated life fraction consumed values.[143] Life fraction consumed values means the portion of the predicted usable life of the pipe that has been used with the pipe in service.[144] For example, if a pipe has a usable life of 100,000 hours and it has been in service for 90,000 hours then the life fraction consumed values would equate to 90 percent of the pipe's projected usable life that has been consumed.[145]

80. Structural Integrity also found that any repairs to the hot reheat pipe should only be considered temporary and further repair or replacement would be needed within the next year.[146]

81. Minnesota Power planned to replace the HRH pipe during a spring 2021 outage.[147]

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[135] *Id.* at 27-28.
[136] *Id.* at 30, RAP-8.
[137] *Id.* at 30, RAP-9; Ex. 7, PJU-3 at 7 (Undeland).
[138] Ex. 10 at 30, RAP-9 (Polich Direct).
[139] Ex. 11, RAP-13 (Polich Direct) (Trade Secret). The specific content of the EPRI power point presentation is proprietary and designated as trade secret.
[140] Ex. 10 at 22, 28, RAP-13 (Polich Direct).
[141] *Id.* at 30, RAP-7.
[142] *Id.*, RAP-11 at 61.
[143] *Id.* at 34, RAP-11 at 56.
[144] *Id.* at 34.
[145] *Id.*
[146] *Id.*, RAP-11 at 62.
[147] Ex. 7 at 20 (Undeland Direct).

82. Minnesota Power also formed a "Hot Reheat Learning Team" to review the failure, inspections, testing and operation prior to the failure and make recommendations to improve Minnesota Power's high-energy piping program.[148] The Hot Reheat Learning Team compiled a presentation with its findings and recommendations.[149] The team concluded that "a stronger and more formalized inspection program would have decreased the chances of failure."[150]

3. Minnesota Power's High-Energy Piping Program

83. Minnesota Power maintains that its high energy piping program was consistent with industry practice before the hot reheat line failure.[151] Minnesota Power stated that good utility practice only requires inspections of "those areas that are most likely to have indications," which are visual or operational deviations from what is expected of the equipment.[152] Minnesota Power stated that in the early years of the pipe, "the most likely area to inspect is at an attachment or discontinuity . . . as a result of fatigue. As the pipe ages, the failure mechanism transitions from fatigue into creep." According to Minnesota Power, over time inspections include replication and/or boat samples to detect creep in its earliest stages.[153] A "boat sample" or "scoop sample" is a type of destructive testing where a sample is removed from the pipe with a precision cut and that sample is subjected to various laboratory tests to evaluate the microstructure and condition of the pipe.[154]

84. Minnesota Power asserts that "[i]t is unknown when, over the nine-year period since the last detailed inspection, the seam weld began to fail."[155]

85. Mr. Polich testified that the flaws in the hot reheat piping would likely have been found before the pipe ruptured if Minnesota Power had been performing proper inspection techniques.[156] He also stated that the high failure rate of longitudinal seam-welded piping has been known since the 1980s and each year evidence has accumulated on the potential rupture and/or catastrophic failure risks of this type of pipe when used in high-pressure, high-temperature situations. The history of failures in this type of high energy piping, show that most of these failures occurred in low-stress long vertical and horizontal runs.[157]

[148] Ex. 10 at 35 (Polich Direct).
[149] *See id.*, RAP-12.
[150] *Id.*, RAP-12 at 12.
[151] Ex. 5 at 20 (Simmons Direct).
[152] *Id.* at 24.
[153] *Id.* at 24-25.
[154] *Id.* at 25.
[155] Ex. 7 at 18 (Undeland Direct).
[156] Ex. 10 at 38 (Polich Direct).
[157] *Id.* at 38, 41.

86. Previous failure of seam welded high-energy pipe have caused changes in recommended inspection process and frequency in the ASME B31.1 Code and EPRI guidelines.[158]

87. According to Mr. Polich, Minnesota Power should have known that the hot reheat pipe's age and hours of operation were beyond the point that only performing 100 percent inspection of seam-welds once every ten years should have continued.[159] This position is supported by Structural Integrity's finding almost all welds had exceeded their calculated life fraction consumed values.[160]

88. Mr. Polich asserted that all longitudinal seam-welded hot reheat piping should have been inspected at least once every five years using phased array ultrasonic examination.[161] The Department's expert based his recommendation of a five-year full inspection schedule, not ten years as Minnesota Power had been using since 1999,[162] with guidelines from EPRI and recommendations from the ASME Code B31.1, which addresses high pressure piping.[163]

89. "[Ultrasonic testing] is generally described as the introduction of high-frequency sound waves—generally in the range of 0.5 MHz to 50 MHz—into a component, part, or structure for the purpose of determining some characteristic of the material from which the component, part, or structure is made."[164] "[F]or fossil power plant inspection, ultrasonic inspection is used primarily for flaw detection, classification, and sizing, and for dimensional measurement (thickness)."[165] Phased array ultrasonic testing is a type of advanced ultrasonic testing.[166] "A phased array system permits the inspection of a cross-sectional area of interest with a minimal number of probe positions."[167]

90. Good utility practice dictates that any evidence of degradation in seam-welded pipe along the longitudinal welds should automatically trigger a more rigorous inspection of the entire pipe.[168]

91. The ASME Code recommends examining hot reheat lines at intervals not exceeding five years.[169] Section 8 of Appendix V of the ASME code provides the recommendations at issue. Section 8.1 describes the types of power piping subject to ASME's five-year maximum inspection recommendation, which includes critical piping systems subject to internal or external corrosion-erosion:

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[158] *Id.* at 38.
[159] *Id.*
[160] *Id.* at 34, RAP-11 at 56.
[161] *Id.* at 28.
[162] Ex. 7 at 17-18 (Undeland Direct).
[163] *See* Ex. 22a (ASME Code) (Nonpublic).
[164] Ex. 19 at 10-13 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
[165] *Id.*
[166] *Id.* at 10-15, 10-20.
[167] *Id.* at 10-20.
[168] Ex. 10 at 39 (Polich Direct).
[169] *Id.* at 24 (discussing ASME Code Section 8 located at MP Ex. 22a at 325, 329 (ASME Code B31.1, Appendix V)).

> This section pertains to the requirements for inspection of critical piping systems that may be subject to internal or external corrosion-erosion, such as buried pipe, piping in a corrosive atmosphere, or piping having corrosive or erosive contents. Requirements for inspection of piping systems to detect wall thinning of piping and piping components due to erosion/corrosion, or flow-assisted corrosion, are also included. Erosion/corrosion of carbon steel piping may occur at locations where high fluid velocity exists adjacent to the metal surface, either due to high velocity or the presence of some flow discontinuity (elbow, reducer, expander, tee, control valve, etc.) causing high levels of local turbulence. The erosion/corrosion process may be associated with wet steam or high purity, low oxygen content water systems. Damage may occur under both single- and two-phase flow conditions. Piping systems that may be damaged by erosion/corrosion include, but are not limited to, feedwater, condensate, heater drains, and wet steam extraction lines. Maintenance of corrosion control equipment and devices is also part of this section. Measures in addition to those listed herein may be required.[170]

92. The Department's expert explained that hot reheat lines generally are covered by Section 8 because they are subject to erosion/corrosion.[171] As stated in the code, "Erosion/corrosion of carbon steel piping may occur at locations where high-fluid velocity exists adjacent to the metal surface."[172] The Department's engineering expert explained that high-energy steam piping systems will develop "certain innate oxide layers on the surface of the piping"—"rust" in lay terms.[173] High-velocity fluids strip rust away exposing bare pipe causing erosion of the piping, which weakens the pipe over time.[174]

93. Minnesota Power agreed that its hot reheat line is a critical piping system.[175] Minnesota Power disagreed that Section 8 of the ASME Code recommendation applied to its hot reheat line.[176] Minnesota Power also argued that the ASME code recommendations did not apply because erosion or corrosion was not the cause of the failure.[177]

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170 Ex. 14 at 20 (Undeland Rebuttal). A public version of the relevant section of the ASME code is contained in Mr. Undeland's rebuttal testimony. The code itself is proprietary and designated as Trade Secret. The full version of ASME Code B31.1 is included in the record as MP Ex. 22a.
171 Evid. Hrg. Tr. at 78-79 (Polich).
172 Ex. 14 at 20 (Undeland Rebuttal).
173 Evid. Hrg. Tr. at 78-79 (Polich)
174 *Id.* at 79 (Polich).
175 *Id.* at 31 (Undeland).
176 Ex. 14 at 19-21 (Undeland Rebuttal).
177 MP Initial Brief at 65 (June 28, 2021).

94. Minnesota Power argued that Section 12 of the ASME recommendations was the applicable section it specifically discusses creep damage.[178] Section 12 states that "a procedure should be developed to select piping areas more likely to have greater creep damage" and "[t]he frequency of examination, determined by the Operating Company, should be based on previous evaluation results and industry experience."[179]

95. Minnesota Power maintains that there are some equipment components that cannot be fully and frequently inspected economically, so it focuses inspection cycles on areas of known concern.[180] The Company points to its high energy piping system, of which the failed hot reheat line is a component, as an example of this balancing. The high stress areas of the high energy piping system are inspected more frequently than low stress areas.[181]

96. Minnesota Power claimed that performing ultra-sonic phased array examination of the longitudinal seam welds to prevent this type of hot reheat line failure would be prohibitively expensive. The Company stated that "[a] full inspection of all components and welds of the [hot reheat] line takes four to six weeks of time and costs in excess of one million dollars due to the significant amount of insulation that must be removed prior to, and reinstalled after inspection, as well as accessibility constraints where the [hot reheat] line is located."[182]

97. Minnesota Power later revised its cost claims for a full inspection of the hot reheat line to $5 million dollars.[183] For this proposition, Minnesota Power relied on the following language in a white paper put out by EPRI: "Increasingly, economic pressure on end-users is necessitating a re-evaluation of legacy guidelines for inspection of long-seam welded components. In particular, the recommendation in [8] regarding 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."[184] The "[8]" refers to the *Guidelines for the Evaluation of Seam Welded High-Energy Piping*.

98. Minnesota Power, however, did not provide an estimate of the costs that would be associated with performing the recommended inspection procedure and timeline at the Boswell Unit No. 4 facility, stating that it had "not specifically estimated the cost associated with such an inspection protocol because it would be significantly higher than the potential benefit."[185]

[178] *Id.* at 65-67.
[179] *Id.* at 66.
[180] Ex. 5 at 24 (Simmons Direct).
[181] *Id.*
[182] *Id.*
[183] MP Initial Brief at 72.
[184] Ex. 14, PJU-1 at 427 (Undeland Rebuttal).
[185] *Id.* at 29.

99. Mr. Polich pointed to Thielsch's offer to inspect the vertical section of the hot reheat pipe for $35,000 in 2013, as an example of ways that increased maintenance costs may decrease forced-outage costs in the long-run.[186] Mr. Polich noted that:

> [I]f this inspection had been performed using industry standard inspection procedures and frequency for longitudinal-welded pipe, it is very likely that the flaws in the HRH pipe would have been found long before the February 2019 hot-reheat pipe rupture and repaired during a planned outage at a much lower cost and avoiding the forced outage.[187]

100. In response, Minnesota Power stated that this was "a bid from Thielsch for limited testing of the HRH, and did not include the costs of scaffolding, removing insulation, surface preparation, reinsulating, removing the scaffolding, and potentially extending an outage to complete the full inspection."[188] Minnesota Power, however, did not provide any specific estimates for the individual items that it claimed would increase the costs above the $35,000 quote from Thielsch in 2013.[189]

101. Minnesota Power's claim that following the EPRI guidelines would cost more than $5 million dollars is unsupported. Minnesota Power failed to introduce any more specific cost estimates for this type of inspection than Thielsch's $35,000 quote from 2013 and the generalized statements in the EPRI white paper. Minnesota Power has not explained the wide gap between the $35,000 actual quote in the record to the $5 million it claims or even $1 million, if the inspections were spread over five years. Minnesota Power has not provided substantial evidence of its claimed costs in the record.

102. Mr. Undeland claimed that the inspection costs should be weighed solely against the actual forced outage costs in this proceeding.[190] But Mr. Simmons testified on behalf of Minnesota Power that corrective maintenance, such as that arising from the hot reheat line failure, includes other expenses, including material and labor cost, in addition to the replacement power costs noted by Minnesota Power witness Mr. Paul Undeland.[191] Mr. Undeland confirmed Minnesota Power also incurred costs to replace the hot reheat line and conceded that other plants experiencing similar failures have likely incurred costs from injuries that occurred.[192]

103. Mr. Undeland testified that "[w]hile more planned outage time, longer planned outages, and additional equipment disassembly and testing could reduce the number of outages, it would significantly increase the Company's generation maintenance expense, in turn providing a reasonable basis to increase customer rates to a level that outweighs the benefit of such practices in excess of good utility practice."[193]

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[186] Ex. 10 at 15, RAP-3 (Polich Direct).
[187] *Id.* at 15.
[188] Ex. 14 at 28 (Undeland Rebuttal).
[189] Evid. Hrg. Tr. at 33-35 (Undeland).
[190] *See* Ex. 14 at 29-30 (Undeland Rebuttal).
[191] Ex. 5 at 27 (Simmons Direct)
[192] Evid. Hrg. Tr. at 36-39 (Undeland).
[193] Ex. 7 at 8 (Undeland Direct).

104. Mr. Polich agreed that some forced outages are unavoidable but stated that some of the forced outages at issue here could have been avoided. In particular, he disagreed that increased planned outages will increase costs forcing an increase in rates. He noted that during the period at issue and prior, Minnesota Power's maintenance costs were below the maintenance costs the Commission approved in the Company's last rate case. So additional maintenance would not have caused increases.[194] He also notes that many equipment inspections can be planned, scheduled, and accomplished within the period of a planned maintenance outage. Furthermore, unless a probabilistic risk analysis comparing the impact of additional maintenance costs versus forced outage costs on customer rates is performed it is unknown whether the costs would outweigh the benefits. He posits that the HRH pipe failure is an example of a situation where inspection would have been more cost effective than the forced outage that occurred.[195]

4. Conclusions on the Hot Reheat Line Outage

105. The Commission asked whether Minnesota Power's forced outage in its HRH line was consistent with good utility practice. As agreed by the parties, good utility practice means any 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.[196]

106. More simply, the Commission asked whether Minnesota Power's practices related to this forced outage were reasonable and prudent. Prudent is defined as exercising good judgement or common sense and characterized by or resulting from care or wisdom in practical matters or in planning for the future.[197]

107. At even the level of nonexpert understanding, a utility plant is a complicated system with some inherent dangers that, left unaddressed, can result in injury and death. Moreover, for all the reasons explained in this matter, lack of maintenance can lead to forced outages and higher consumer costs. The outside parameter for inspection of the HRH is, at the most, every ten years with expert technical organizations recommending a shorter five-year period. Taking into consideration the critical nature of the HRH, the known history of such failures throughout the industry, the potential consequences of its failure and considering the age and peculiarities of the Boswell plant, a reasonable and

[194] Ex. 10 at 14-15 (Polich Direct).
[195] *Id.* at 15.
[196] *Id.* at 6-7. Minnesota Power does not dispute the Department's proposed definition of "good utility practice." Ex. 14 at 8 (Undeland Rebuttal).
[197] *American Dictionary Onlin*e (July 29, 2021) https://www.ahdictionary.com/word/search.html?q=prudent.

prudent maintenance schedule should have been closer to every five years than to every ten years. It is reasonable and prudent to anticipate more frequent, not regular or lessening, inspection and maintenance of any complexly engineered system for which good working order is critical for reliability and safety.

108. Minnesota Power should have inspected the hot reheat line more frequently based on the line's age and potential for catastrophic failure.[198]

109. Minnesota Power's own engineering consultants, Thielsch, calculated the date when cracks would have first appeared in the failed portion of the hot reheat pipe. Thielsch concluded that the cracks likely began 7.5-8.9 years before the failure.[199] Therefore, even if Minnesota Power had examined the "low stress areas," including the longitudinal seam-welds, once every seven years with appropriate creep detection methods, evidence of pipe degradation would likely have been found and could have been repaired. As shown by the numerous degraded pipe sections that were found during the full inspection following the rupture, if Minnesota Power had been applying good utility practices it would have found at least one of these indications of degradation within the nine years since the last inspection of longitudinal weld seams. This would have triggered the need to inspect all the seams.[200]

110. It is undisputed that Minnesota Power has the burden of proof in this case to show that it properly inspected and maintained Boswell Unit No. 4's hot reheat line. Minnesota Power's claim that its ten-year inspection schedule of longitudinal seam-welds is supported solely by advice from its contractor, Thielsch.[201] Minnesota Power retains the responsibility to ensure that advice it accepts from its contractor comports with good utility practice. Unsworn claims from its contractor that other utilities advised by the contractor have similar inspection schedules offers minimal support, because it is unreliable hearsay and the product of a feedback loop where Thielsch gives similar advice to its other power plant clients.[202]

111. In contrast, the Department introduced expert testimony that a five-year inspection program was consistent with good utility practice.[203] The Department's expert supported his informed opinion with recommendations from ASME, guidelines from a utility trade organization, EPRI, and statements and conclusions from Minnesota Power's own contractors.[204] EPRI has been studying and documenting identical failure of seam-welded pipe as occurred here.[205] In addition, the Department provided evidence that the high-potential cost of a hot reheat line failure obliged Minnesota Power to perform more

[198] Ex. 10 at 38-41 (Polich Direct).
[199] *Id.* at 39.
[200] *See id.* at 15.
[201] Ex. 7 at 18 (Undeland Direct); Ex. 14 at 23, 27 (Undeland Rebuttal); Evid. Hrg. Tr. at 24-29 (Undeland).
[202] Evid. Hrg. Tr. at 29 (Undeland).
[203] Ex. 10 at 24-41 (Polich Direct).
[204] Evid. Hrg. Tr. at 52 (Polich); Ex. 10 at 24-41 (Polich Direct).
[205] *See* Ex. 14, PJU–2 at 399-432 (Undeland Rebuttal) (EPRI 30 Year Report).

frequent inspections.[206] The age of the line, near the end of its life, also supports the Department's position that the line should have been fully inspected more often.[207]

112. Minnesota Power failed to rebut the Department's evidence. Minnesota Power's claims of the high expense of the Department's proposed inspections were unsupported with specific evidence in the record.[208] As the party with the burden of proof, Minnesota Power must show that the costs would be unreasonable.[209] Instead it claimed, without support, that "the cost associated with such an inspection protocol . . . would be significantly higher than the potential benefit."[210] This is especially concerning when the dangers of an HRH failure are not merely an unplanned outage, but possible loss of life or significant injury.

113. Evidence in the record shows that it is likely that the hot reheat line failure could have been avoided had Minnesota Power inspected it more often.[211]

114. Minnesota Power has not met its burden to show that good utility practice allowed it to wait ten years between full hot reheat line inspections for a pipe of this age with a method that can detect creep damage.

115. Minnesota Power failed to show that its high-energy inspection program was reasonable and prudent and constituted good utility practice.

B. 2019 Hydrogen Leak Repair at Boswell Unit No. 3

116. The second forced outage at issue was caused by the hydrogen cooling system at Boswell Unit No. 3. Electric power generators produce significant heat that must be removed to maintain operating efficiency. Hydrogen gas is typically used as a coolant for large generators, including Boswell Unit No. 3. Hydrogen's low density, high specific heat, and thermal conductivity make it a superior coolant relative to other options such as air, water, and oil. Hydrogen's flammability, however, means that plant operators must exercise vigilance to ensure that hydrogen does not escape from the generator where it could cause an explosion or fire.[212]

117. Boswell Unit No. 3 uses an oil system to seal hydrogen gas within the generator shaft and avoid leaks into surrounding areas. The shaft penetration is sealed with a shaft hydrogen seal. This relies on seal oil to provide the seal between the seal and the rotating shaft. For that reason, the seal oil vacuum tank and float trap are inspected once every five years for any accumulated dirt or debris. The float trap valve is removed from the housing to inspect the valve for any debris or binding in the linkage. [213]

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[206] Ex. 10 at 24-41 (Polich Direct).
[207] *Id.* at 38-39.
[208] *See* Evid. Hrg. Tr. at 33-35.
[209] Ex. 1 at 4 (Order for Hearing).
[210] Ex. 14 at 29 (Undeland Rebuttal).
[211] Ex. 10 at 48-49 (Polich Direct).
[212] *Id.* at 41-42.
[213] Ex. 7, PJU-4 at 2 (Undeland Direct).

118. Boswell Unit No. 3 is a fully sealed generator system that is filled with hydrogen gas. The original equipment manufacturer (OEM) of this generator is General Electric (GE). The generator is filled with hydrogen gas for three primary reasons: (1) hydrogen gas (when pressurized) is a better insulator than air, (2) the density of hydrogen gas is one tenth the density of air, resulting in less rotating losses in the generator during operation, and (3) hydrogen has far superior heat transfer characteristics than air. Hydrogen gas is, however, a very flammable gas that can self-ignite when it leaks from a pressure vessel under specific conditions. It is an invisible gas that can accumulate in unseen areas and create an explosive atmosphere if not properly contained or vented. Because of these considerations, significant repairs to the hydrogen gas system require that the unit be taken offline.[214]

119. The system also relies on the integrity of the float trap for purposes of operating the hydrogen-filled system. From past experience at Boswell Unit No. 3, the valve (a double seated 1.25-inch brass valve) has to be removed from the float trap housing and inspected every five years. The Company had an experience in 1989 where debris caused the valve to malfunction. The Company has also had an experience at another plant where a similar valve had wear in the linkage resulting in malfunction. During operation, the valve is always open, so tight shutoff is not necessary. For that reason, the valve seats are not checked for 100 percent contact.[215]

120. Boswell Unit No. 3 noted high hydrogen gas consumption in November 2018. After checking common locations and doing several operational tests, a weekend outage was scheduled for February 2 and 3, 2019. During that short outage, the unit was purged of hydrogen and pressurized with air and helium in an effort to locate the source of the leak. This test identified a substantial leak on the terminal plate to leadbox gasket. An epoxy was used to seal the leak from an external location until a planned spring 2019 outage, when a full investigation could be undertaken, and repairs could be made.[216]

121. After the spring 2019 outage commenced, the repair and associated inspections were initiated. The leadbox dam was installed according to the pre-outage plan developed with GE. As part of the spring outage, the inspection technicians undertook an inspection of the float valve and the hydrogen seal at the generator shaft was sent to Power Plant Services for full refurbishment. These measures were intended to restore the system and minimize the risk of future hydrogen gas leaks. During the inspections of the float valve and float trap, the inspection technicians determined that the valve was clean of any debris and moved freely and showed no sign of wear on the linkage. Additionally, neither the float valve nor "trap" showed any signs of wear, defects, or debris that would be causing a hydrogen leak like the one Boswell Unit No. 3 had experienced in the winter of 2018 and 2019.[217]

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[214] *Id.*
[215] *Id.*
[216] *Id.*, PJU-4 at 4, 7.
[217] *Id.*, PJU-4 at 5.

122. During the March planned outage, Minnesota Power working with GE, performed repairs of much of the equipment in the generator area.[218] New gaskets were used, as was a gasket sealant that has been effective and in use for 20 years on hydrogen and oil gaskets. [219]

123. On June 4, 2019, Minnesota Power tested the system, around the time of the end of the original scheduled outage, but the generator failed the test and still indicated a sizable leak, about ten times the amount considered acceptable for the test.[220] The outage was extended beyond the initial end date to address ongoing repair issues.[221] Therefore, the final days of the hydrogen leak repair were classified as an "unplanned" outage.[222]

124. At that time, further analysis was done which indicated that the leaking was focused on the turbine end, not the generator end of the unit as Minnesota Power originally believed.[223] To reach this conclusion, Minnesota Power, in consultation with GE and others, performed multiple protocols to isolate the cause of the leak. Theses protocols are described in detail in Schedule 4 of Mr. Undeland's direct testimony.[224]

125. Minnesota Power continued to perform further root cause analysis but was still unable to locate the source of the major leak. Minnesota Power again contacted GE to assist in the root cause analysis and hired another contractor that specializes in hydrogen leaks.[225]

126. Also, in early June, as part of the troubleshooting effort, the oil level in the float trap tank was raised using the manual isolation and bypass valves. Once the oil level went well above normal operating level, the leak stopped.[226] Boswell personnel discovered that the float trap had to be completely flooded for the leak to stop. This was about 8-12 inches above the valve. The normal oil level was controlled about 3-4 inches above the valve suction under normal operating conditions for the system. The results of this oil test were communicated back to GE and Power Plant Services. While neither company had an answer, they offered to reach out to their contacts at other generating units. As part of this effort, they identified a customer that had a similar problem.[227]

127. Without Minnesota Power, GE or Power Plant Services being able to identify the root cause of the issue, Minnesota Power solved the problem by replacing the

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[218] *Id.* at 27.
[219] *Id.*, PJU-4 at 7.
[220] *Id.* at 27, PJU-4 at 8.
[221] *Id.* at 29.
[222] *Id.* at 14, 29.
[223] *Id.* at 27.
[224] *Id.*, PJU-4 at 8.
[225] *Id.* at 28.
[226] *Id.*, PJU-4 at 9.
[227] *Id.*

valve itself. Replacing the valve was a convoluted process because GE was unable to provide a replacement valve for 15 weeks.[228]

128. After testing many different designs, Minnesota Power found a valve that solved the problem, and the unit was put back into service. Minnesota Power then inquired of GE and Power Plant Services about what other issues to look for or systems to inspect. The companies had no suggestions other than to replace the valve. The limited experience they had (one plant for each) with similar situations, was that the problem was on an older unit and there was nothing to explain a root cause of the problem or why it was remedied by replacing the valve. [229]

129. While replacement of the float trap ultimately resolved the hydrogen leak, Minnesota Power did not keep track of the amount of additional seal oil it allowed into the system versus the amount of oil it took out before putting the hydrogen cooling system back online. Minnesota Power stated in response to a Department information request: "several barrels of oil were required to perform the testing, although the specific number was not recorded."[230] Regarding the seal oil's removal, Minnesota Power stated, "several barrels of oil were drained from the generator liquid detector. The precise amount of drained oil was not recorded."[231]

130. Minnesota Power also did not inspect whether additional oil remained in the generator after completion of the hydrogen leak repairs.[232] Minnesota Power stated, "Once a solution was found to the float trap problem around June 20, 2019, the only additional check that was made was to verify that no oil was coming from valve H-72 (liquid detector drain)."[233] It also stated that it performed a visual inspection of the leadbox, which was "clean and dry."[234]

131. Mr. Polich concluded that Minnesota Power did not apply good utility practice in how it addressed and repaired the generator hydrogen leak. He emphasized the amount of time that it took Minnesota Power to recognize that the float valve could have been the cause and stated that all potential sources of the leak should have been identified and tested in the first root cause analysis.[235] However, in Mr. Polich's opinion, because Minnesota Power's roundabout method of diagnosing the leak only resulted in a small extension of the planned outage,[236] the Department did not recommend that Minnesota Power be disallowed from recovering those costs.[237]

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[228] *Id.*
[229] *Id.*, PJU-4 at 9-10.
[230] Ex. 10 at 43, RAP-15 at 5 (Polich Direct).
[231] *Id.*, RAP-15 at 5.
[232] *Id.* at 43.
[233] *Id.*, RAP-15 at 5.
[234] *Id.*, RAP-15 at 4.
[235] *Id.* at 44-45.
[236] *Id.* at 45.
[237] Ex. 12 at 17 (Campbell Direct).

132. The Department's expert asserts that the way in which Minnesota Power ultimately determined the cause of the leak was not consistent with good utility practice.[238] Minnesota Power's improper overfilling of the hydrogen seal oil system likely led to seal oil leaking into the generator.[239] According to the Department expert, "Good utility practice would be to keep track of the amount of seal oil used in any testing process, track any leakage, and clean up any leaked seal oil so it does not cause damage to other components of the generator."[240] Thus, while the Department does not seek to disallow Minnesota Power's costs related to the Hydrogen Leak, it asserts that Minnesota Power's actions are material to this matter because the alleged overuse of seal oil spilled over into the third and final forced outage in this matter.

133. Minnesota Power's forced outage costs related to the hydrogen leak were reasonable and prudent.

134. The Department that Minnesota Power has not shown that Minnesota Power did not efficiently conduct a root cause analysis and so delayed bringing the plant online for an excessive amount of time.

135. The problems, analysis and actions related to the hydrogen gas leak provide an object lesson in the difficulty of evaluating maintenance prudence, practice, and expenditures on a case-by-case basis. The parties agree that hydrogen leaks are dangerous and require immediate action. The hydrogen leak presented a unique puzzle such that GE, the original OEM, Power Plant Services with an ex-GE engineer on staff, and an external contractor that specializes in hydrogen leak location were not able to troubleshoot the source of the problem. These facts illustrate the lack of a template for prudent, good utility practice in certain situations. Unlike, for example, the frequency of certain system inspections, seldom seen problems cannot be deemed to have a common industry practice. In hindsight, it would have been better practice to measure the amount of oil that was pumped into the system. But in the moment, knowing that the barrier between dangerous hydrogen gas and the plant was seal oil, that seal oil resolved the leak, and without an industry or OEM protocol for the problem, it is reasonable to find that Minnesota Power made reasonable and prudent decisions in attempting to resolve the problem.

C. Boswell Unit No. 3's 2019 Phase Bushing Failure

136. The third outage relates to Boswell Unit No. 3's phase bushings. Bushings are cylindrical structures that insulate a conductor carrying electric current at high voltage. Bushings are needed to prevent the electric field created by the electric current flowing through the conductor from causing excess current leakage or a flashover event that could, in turn, start a fire or damage the facility.

[238] Ex. 10 at 44 (Polich Direct).
[239] *Id.*
[240] *Id.*

137. Boswell Unit No. 3 has a total of six bushings. They consist of three line-side bushings (A, B, and C phases) and one neutral bushing for each of the three phases on the generator.[241]

138. The generator has a water-cooled stator winding that requires vacuum dehydration prior to testing. Minnesota Power has always used GE, the OEM, to test the generator because GE has the necessary equipment to do the dehydration. Another benefit of using GE is that the water-cooled windings have a fleet history of water leakage and GE is best equipped to deal with those leaks. Minnesota Power historically experienced leaks, which culminated in a generator stator rewind in 2001. There had been no problems since then.[242]

139. On July 8, 2019, a relay on the generator "A" phase detected a ground fault and operators took the plant off-line.[243] Electricity is transmitted in three phases (A, B, and C), and the generator in question has six bushings, two bushings per phase.[244] The Company investigated the ground fault and determined that the ground fault occurred in the "A" phase of the system, but were unable to determine the specific component that had failed.[245] Minnesota Power hired General Electric to provide more specialized personnel to investigate, and General Electric determined on July 14, 2019 that the failure was on the A phase line side bushing which would need to be replaced.[246] Minnesota Power and General Electric ultimately decided to replace all six bushings.[247]

140. These six phase bushings had all been tested at a scheduled outage three months earlier on April 18, 2019. As Mr. Undeland testified "[d]uring that inspection and testing, the General Electric generator specialist reported that all six phase bushings installed on BEC3 were operating within General Electric's acceptable limits. The direct-current (DC) leakage test that was performed was within acceptable criteria with no other indication to support further investigation, allowing the equipment to be returned to service."[248]

141. Minnesota Power does not know the age of the bushings that failed; they could either have been installed in 1970 or 2001.[249] Minnesota Power claimed, "This outage was not only unplanned, but also beyond any foreseeable protocols that could have been put in place to prevent this outage."[250] Minnesota Power focused on the recent inspection, noting that increasing the time between inspections would not have prevented the outage because the inspection occurred only three months earlier.[251]

[241] Ex. 7, PJU-5 at 2 (Undeland Direct).
[242] *Id.*
[243] Ex. 10 at 46 (Polich Direct).
[244] Ex. 7 at 32 (Undeland Direct).
[245] *Id.* at 33.
[246] *Id.*
[247] *Id.* at 33-34.
[248] *Id.* at 32.
[249] *Id.* at 35.
[250] *Id.*
[251] *Id.* at 36.

142. General Electric, however, produced a report replete with references to seal oil that it located in the phase bushings and the potential for oil-soaked bushings to overheat and cause a ground fault. As the General Electric report notes in the second paragraph of the Executive Summary:

> This unit had been inspected in the spring of this year, and the customer described incidents where large amounts of oil had ingressed into the unit after restart involving the hydrogen seals and the float trap. This oil ingress included large amounts of oil in the lower frame extension including the cooling passages through the high voltage bushings (HVB).[252]

143. The General Electric report includes the following passages regarding the presence of oil in the both the bushing insulation and the phase bushings themselves:

> "Because of the possibility that the oil had blocked the cooling passages and overheated a bushing, it was decided to strip the bushing clamshells on the A-phase . . . ."[253]
>
> "As the insulation was removed from these two bushings, it was seen that there was no putty on the T4 bushing. It was also seen that the insulation was soaked with oil completely through the thickness of the layers of insulation. Oil was also found in the insulation of the T1 bushing, but it was not saturated as it was on T4."[254]
>
> "A crew of millwrights working for the customer removed the isophase box and the T4 bus[h]ing from the unit. *The bushing was seen to be full of oil.*"[255]
>
> "All of the bushings on this unit were full of oil. Oil will block the cooling passage through these bushings and can cause the bushings to overheat. A small pump was used to pump as much oil as possible out of the five bushings still in the unit. An estimated five gallons of oil was pumped out of each of the bushings."[256]

144. Minnesota Power stated that it replaced all six bushings, because six had arrived instead of the three that the Company ordered and because "General Electric did

[252] Ex. 10, RAP-16 at 3 (Polich Direct).
[253] *Id.*, RAP-16 at 4.
[254] *Id.* (emphasis added).
[255] *Id.* (emphasis added).
[256] *Id.*, RAP-16 at 5.

not know why the A phase line side bushing failed."[257] According to the GE report, however, "The customer originally planned to replace only the T4 bushing, which had gone to ground. But with six new bushings on hand, as well as higher than expected DC microamp leakage on the T1 HVB, and the knowledge that all six of the in-service bushings had been filled with oil, it was decided to replace all six HVBs."[258]

145. Mr. Polich testified that oil in the bushings can cause them to fail due to the oil blocking the cooling passages, which causes the bushings to overheat.[259] Minnesota Power agrees that the oil in the bushings was seal oil: "[I]t was apparent to plant personnel and our third-party expert consultants that the oil present in the phase bushings was seal oil. This oil was introduced into this area during the float trap valve testing and repairs . . . ."[260]

146. Mr. Polich concluded that Minnesota Power should have followed good utility practice by investigating whether seal oil leaked into the generator when trying to locate the hydrogen leak.[261] And if that investigation had found seal oil leakage, Minnesota Power should have cleaned up the oil.[262] He concluded that these steps would have prevented the phase bushings from being filled with seal oil or would have found the seal oil prior to restarting the plant.[263] This would have avoided the bushing failure and the need to purchase replacement bushings and a roughly two-week unplanned outage.[264]

147. Minnesota Power did not dispute that the oil in the bushings was from its testing of the hydrogen gas leak. Minnesota Power faulted the Department for presenting "no evidence that the phase bushing failure was due to the presence of seal oil in the phase bushing."[265] Minnesota Power stated that "General Electric was unable to conclude whether the presence of oil did or did not contribute to the failure."[266]

148. Among the alternative causes that Minnesota Power pointed to were sudden load changes, excessive vibration, overheating, overheating of the leads, and normal vibration over long periods of time.[267] Minnesota Power confirmed, however, that General Electric did not find any of these alternative potential causes to be the cause of the phase bushings failure.[268] Moreover, there is little mention of these other potential causes, besides overheating caused by the bushings being soaked in oil, in General Electric's report.[269]

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[257] Ex. 7 at 33-34 (Undeland Direct).
[258] Ex. 10, RAP-16 at 12 (Polich Direct).
[259] *Id.* at 47.
[260] *Id.*, RAP-15 at 4.
[261] *Id.* at 47.
[262] *Id.* at 47-48.
[263] *Id.* at 48.
[264] *Id.*
[265] Ex. 14 at 34 (Undeland Rebuttal).
[266] *Id.* at 35.
[267] *Id.*
[268] Evid Hrg. Tr. at 39-43.
[269] Ex. 10, RAP-16 (Polich Direct).

149. One of the alternative causes focused on by Minnesota Power was that vibrations over time caused the outage as evidenced by a tar like substance on the mounting flange.[270] However, Mr. Undeland acknowledged that he was not aware of General Electric noting concerns about tar during the April 2019 inspection.[271]

150. Minnesota Power also emphasized that the bushings "could have been approximately 50 years old," but Minnesota Power admitted they did not know whether these bushings had been replaced as recently as 2001.[272]

151. Minnesota Power ultimately acknowledged that General Electric stated that the bushings could have failed from overheating due to the seal oil blocking proper cooling.[273]

152. Minnesota Power also blamed its failure to detect the oil leakage on an alarm that was not properly configured.[274] But Minnesota Power admitted that it was responsible for the improper configuration.[275]

153. Minnesota Power's alternative theories of what caused the phase bushing failure are unpersuasive. The Administrative Law Judge notes that it is unlikely that three bushings would have suddenly failed simultaneously for any of the reasons theorized by Minnesota Power. Furthermore, statements in the General Electric report, and the timing of the failure soon after the bushings passed inspection makes a conclusion that the phase bushings failed because they overheated after being soaked with oil more likely than any of the potential causes posited by Minnesota Power.[276]

154. The Administrative Law Judge concludes that Minnesota Power made reasonable and prudent decisions in addressing the phase bushing failure. The Administrative Law Judge agrees that the phase bushing failure was a consequence of the oil that was added to the float valve to address the hydrogen gas leak. However, with regard to the phase bushings, just as in responding to the hydrogen leak, the Company made the best decisions it was able to make based on the knowledge it had at the time. There was no evidence that there was an industry standard for testing of the improperly configured alarm or a specific schedule for anything related to the bushings' failure. The problem resulted from a failure to consider every possible undesired consequence of the hydrogen leak repair but not from a failure to perform advised maintenance or failure to adhere to industry standards.

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[270] Evid. Hrg. Tr. at 40 (Undeland).
[271] *Id.* at 41 (Undeland)
[272] Ex. 14 at 35 (Undeland Rebuttal).
[273] Ev. Hrg. Tr. at 43 (Undeland).
[274] MP Initial Br. at 8, 50, 53.
[275] *Id.* at 8, 50.
[276] Ex. 10, RAP-16 (Polich Direct)

IV. Conclusions

155. Based on the above findings, the Administrative Law Judge finds that Minnesota Power's maintenance and inspection programs for Boswell Unit No. 4's hot reheat line were inconsistent with good utility practice.

156. Based on the findings above, the Administrative Law Judge finds that Minnesota Power's maintenance and inspection of the hydrogen gas leak and bushings failures were not the result of a failure to adhere to good utility practice.

157. Having concluded that the hot reheat line outage was not consistent with good utility practice, the Administrative Law Judge concludes that the expenses associated with the outage were not reasonably and prudently incurred as set forth in the Commission's referral order and as a result should be refunded to customers as discussed further below.

158. Minnesota Power's incremental forced outage costs associated with Boswell Unit No. 4's hot reheat line were not reasonably and prudently incurred because they resulted from outages that likely could been avoided with maintenance and inspection programs aligned with good utility practices. Accordingly, the expenses relating to the purchase of replacement power from third parties over and above Boswell's own generation costs should not be charged to customers and should be refunded along with interest.

159. The Department and Minnesota Power agree on the amount of incremental costs associated with Boswell Unit No. 4's hot reheat line.

160. Minnesota Power and the Department agree that the Company should apply the U.S. Federal Reserve prime rates that were applicable during the refund period to calculate the required interest.[277] Minnesota Power states it would use "the prime interest rate in effect from the month the outage costs were charged to the customers until the month that customers would receive the refund."[278]

161. Minnesota Power stated that it would calculate specific refund amounts for the eight Large Power customers and seventeen Municipal customers based on their actual kilowatt hour usage. For its other customers, Minnesota Power stated that it would calculate the refund by taking the remaining refund amount divided by the forecasted sales for the applicable remaining customer classes. This rate would be applied to actual usage in the refund month.[279] The Department agreed that this methodology would produce reasonable results.[280] The Commission has ordered utilities to provide rider refunds or credits to ratepayers for overcharges in the past. The Commission typically has used rider adjustments to ensure that customers are repaid where a utility either

[277] Ex. 12 at 19-20 (Campbell Direct); Ex. 16 at 3 (Oehlerking-Boes Rebuttal).
[278] Ex. 16 at 3 (Oehlerking-Boes Rebuttal).
[279] *Id.* at 3-4.
[280] DER Initial Br. at 26-27 (June 28, 2021).

overcharged them or imprudently incurred the expense.[281] This matter implicates the second situation. As previously discussed, Minnesota Power incurred incremental forced outage costs by failing to observe good utility practice.

162. In a similar situation, the Commission ordered another utility to refund replacement power costs that were charged to ratepayers. The Commission concluded that these costs were caused by the utility's failure to observe industry procedures. The Commission, accordingly, reasoned that allowing the utility to "retain recovery of these costs would penalize ratepayers for imprudent actions that resulted in otherwise preventable outages."[282]

163. In addition, the Administrative Law Judge notes that riders are a common tool for adjusting utility rates outside of a rate case and that these incremental costs were originally charged to ratepayers using a rider. The Administrative Law Judge finds that it is appropriate to use an accounting tool intended to make financial adjustments outside of the rate case to provide a prompt refund to Minnesota Power's customers. This is further true, here, where it maintains the symmetry with how customers were originally charged. In summary, riders are the appropriate accounting tool for providing timely refunds or credits to ratepayers. Riders are simply pass-through mechanisms that can be used to correct for either past overcharges or undercharges.[283]

164. Based on the foregoing Findings of Fact and the record in this proceeding, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judge have jurisdiction over the subject of the proceeding pursuant to Minn. Stat. §§ 216B.03, .16, subd. 7 (2020), Minn. R. 7825.2900, .2920 (2021), and Minn. Stat. §§ 14.57-.62 (2020).

2. Proper notice was timely given and all relevant substantive and procedural requirements of law or rule have been fulfilled and, therefore, the matter is properly before the Administrative Law Judge.

3. Pursuant to the Commission's Order, Minnesota Power bore the burden to demonstrate by a preponderance of the evidence that its maintenance practices were consistent with good utility practice, and that any deviation from this standard did not contribute to the forced outage events at issue in this proceeding.[284]

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[281] Ex. 12 at 26-28 (Campbell Direct).
[282] *In re Review of the 2014-2015 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-15-611, Order Accepting Reports, Requiring Refund, & Setting Additional Requirements at 5 (July 21, 2017).
[283] Ex. 12 at 4, 25-28 (Campbell Direct).
[284] Ex. 1 at 4 (Order for Hearing); Minn. R. 1400.7300, subp. 5 (2021).

4. The utility always retains the burden of proving the reasonableness of costs the utility seeks to charge ratepayers.[285] Submitting evidence on an issue does not create a rebuttable presumption of reasonableness.[286]

5. Based on the findings above and the record in this proceeding, Minnesota Power did not demonstrate by a preponderance of the evidence that its maintenance practices for its Hot Reheat Line were consistent with good utility practice, or that any deviation from good utility practice did not contribute to the outage.

5. The Administrative Law Judge concludes that Minnesota Power did not reasonably and prudently incur forced outage costs resulting from the Hot Reheat Line at issue in this proceeding. The Company and the Department agree on the refund owed to customers.[287] Interest should be calculated using the U.S. Federal Reserve Prime Rate.[288]

6. Utility rate riders are pass-through mechanisms used to adjust utility rates outside of a general rate case.[289] Costs paid by customers through a rider are provisionally authorized subject to subsequent Commission review and adjustment.[290] The Commission has repeatedly used rate riders to refund overcharges and imprudently incurred utility costs.[291]

7. Because rider refunds are authorized by law and consistent with Commission practice, it is appropriate for Minnesota Power to refund imprudently and unreasonably incurred incremental forced outage expenses in this proceeding via its Fuel Adjustment Clause rider. Minnesota Power should calculate specific refund or credit amounts using the procedures agreed upon by the Department and the Company.[292]

8. Any of the forgoing Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

RECOMMENDATIONS

Based on these Findings of Fact and Conclusions of Law, the Administrative Law Judge recommends:

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[285] *In re N. States Power Co.*, 416 N.W.2d 721, 726 (Minn. 1987).
[286] *Id.* at 725-26.
[287] Ex. 12 at 17 (Campbell Direct); Ex. 16 at 2 (Oehlerking-Boes Rebuttal).
[288] Ex. 12 at 19-20 (Campbell Direct); Ex. 16 at 3 (Oehlerking-Boes Rebuttal).
[289] Ex. 12 at 4, 25-28 (Campbell Direct); *see also* Minn. Stat. § 216B.16, subd. 7.
[290] Minn. R. 7825.2920.
[291] *See*, *e.g.*, *In re Xcel Energy's Pet. for Affirmation that MISO Day 2 Costs are Recoverable*, MPUC Docket No. E-002/M-04-1970, Order Establishing Accounting Treatment For Miso Day 2 Costs at 7, 17 (Dec. 20, 2006); *In re Minn. Power's Pet. for Approval of Credits to Customers*, MPUC Docket No. E-015/M-15-875, Order Approving Refund & Requiring Filings at 2-3 (May 26, 2016); *In re Review of the 2014-2015 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E- 999/AA-15-611, Order Accepting Reports, Requiring Refund, & Setting Additional Requirements at 5 (July 21, 2017).
[292] Ex. 16 at 3-4 (Oehlerking-Boes Rebuttal).

1. The Commission find that the Hot Reheat Line forced outage at the Boswell Energy Center was inconsistent with good utility practice, and that Minnesota Power's incremental costs arising from that outage were not reasonably and prudently incurred.

2. Minnesota Power refund the incremental forced outage costs plus interest calculated and distributed to customers using the methodologies agreed upon by the parties and described in the Findings of Fact above.

3. The Administrative Law Judge respectfully recommends that the Commission should adopt the Findings of Fact, Conclusions of Law, and Recommendations set forth above.

Dated: August 11, 2021

Barbara Case

BARBARA J. CASE
Administrative Law Judge

MINNESOTA
OFFICE OF
ADMINISTRATIVE
HEARINGS

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August 11, 2021

See Attached Service List

Re: ***In the Matter of the Review of the July 2018 - December 2019 Annual Automatic Adjustment Reports***

OAH 82-2500-37082
MPUC E 999/AA-20-171

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled matter.

If you have any questions, please contact me at (651) 361-7874, michelle.severson@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,

Michelle Severson

MICHELLE SEVERSON
Legal Assistant

Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
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CERTIFICATE OF SERVICE

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

Nichole Helmueller certifies that on August 11, 2021, she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

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