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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
Saint Paul, Minnesota 55101-2147

In The Matter Of An Application Of Northern States Power Company For Authority To Increase Rates For Electric Service In The State Of Minnesota

In the Matter of the Review of the Annual Automatic Adjustment Reports for All Electric Utilities

OAH Docket No. 65-2500-38746

MPUC Docket Nos. E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-16-523, E999/AA-17-492, E999/AA-18-373

EXCEPTIONS OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

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INTRODUCTION

Northern States Power Company ("Xcel Energy" or the "Company") respectfully files these Exceptions to the May 14, 2024 Administrative Law Judge's ("ALJ") Findings of Fact, Conclusions of Law and Recommendation ("ALJ Report" or "Report")[1] concerning the November 19, 2011 failure (the "Event") of generating unit 3 at the Sherburne County Generating Plant ("Unit 3"). The Report attempts to distill a massive record—stretching back over two decades and including tens of thousands of pages of highly technical discussion—and then draw conclusions and make recommendations for the Commission's consideration. While the Company respects and commends the ALJ's effort to grapple with this immense record and the specialized information it includes, the Report is fundamentally wrong on certain key points and must be revised to comport with Minnesota law and the evidence. Among these fundamental errors:

- The Report misstates the state of industry and Company knowledge regarding stress corrosion cracking ("SCC") prior to the Event;
- The Report fails to demonstrate an understanding of the important differences in generating unit designs, including differences in boilers and turbine blade attachments, and the relevance of such differences with respect to both causation and ability to detect SCC;
- The Report fails to acknowledge that the Event was the first time a turbine with Unit 3's design features failed as a result of SCC in the liberated turbine blade attachments; and
- The ALJ misunderstands the Commission's fuel clause adjustment process, leading the ALJ to reject the level of "replacement power" costs at issue, as

[1] The individual Findings in the Report are cited below as "Report at ¶ xx."

agreed upon by the Company, Department of Commerce ("Department") and Office of the Attorney General ("OAG").[2]

These misunderstandings, and others discussed below, led the ALJ to draw incorrect conclusions – not supported by expert testimony and not supported by any record citation – on several key issues. Moreover, the ALJ applied an overly narrow reading of the Commission's referral of the matter to the Office of Administrative Hearings ("OAH"), declining to consider critical mitigating factors that fully offset the impact of replacement power costs in customers' rates.

A thorough prudence analysis of the Company's actions related to the Event requires looking not only at the specific replacement power costs incurred to supply electricity from November 2011 to October 2013, but also at how the Company operated and maintained Unit 3 prior to the Event, the Company's efforts to restore Unit 3 and still serve its customers after the Event, and the Company's efforts to otherwise recover costs incurred due to the Event and share those proceeds with its customers.

The record of this proceeding establishes that, based on the information the Company had or reasonably should have had prior to the Event, it made reasonable decisions and took reasonable actions at every turn. Therefore, the Company respectfully requests that the Commission find the Company prudently incurred the "replacement power" costs at issue. Should the Commission instead find that the Company acted

[2] As discussed below, only the Company and Department provided testimony on this issue and agreed as to the most reasonable estimate of these costs, further agreeing that the earlier estimate of these costs the ALJ relies on included "certain simplifying assumptions . . . that are not realistic." In briefing, the OAG agreed with the Company and Department. Xcel Large Industrials ("XLI") provided no testimony on this issue.

imprudently in any way, the Company respectfully requests that the Commission carefully consider the appropriate refund amount, if any. That consideration should first recognize the universally agreed-upon level of these costs by witnesses in this case. It should also account for the prior disallowance ordered by the Commission, which removed Unit 3 from rate base and returned $21.6 million to customers in 2013, as well as the settlement proceeds from litigation with GE that were entirely credited to customers. Finally it should account for the additional cost-mitigating actions taken and benefits obtained by the Company for its customers in returning the unit to service. Only after consideration of all these factors should the Commission determine whether customers are owed a further refund for replacement power costs as a result of the Event.

I. XCEL ENERGY PRUDENTLY MAINTAINED AND INSPECTED SHERCO UNIT 3

The Report's prudency analysis ultimately concludes that Xcel Energy's experienced engineers acted unreasonably prior to the Event by not recommending and conducting an atypical, costly, time-consuming, and potentially destructive turbine-blade removal and inspection procedure. Contrary to the ALJ's findings, the record is clear that there was no industry or manufacturer expectation that a utility would undertake this extraordinary procedure unless certain anomalous events transpired, none of which occurred.[3] The record is equally clear that this extraordinary procedure (referred to as the

[3] The Company discusses the issue of "abnormal events or operational anomalies in Section II, below.

"Blades-Off" inspection),[4] which is not a part of either a Major[5] or a Minor[6] inspection, was the *only* way to detect the *internal* stress corrosion cracking in the *specific components* at issue in this matter.[7] Absent a Blades-Off Inspection, there is no way the Company could have discovered the SCC.

The ALJ faced a daunting task in assessing the Company's prudence in maintaining the unit (including its engineers' decision to *not* perform such an inspection), as there are numerous, highly technical distinctions that are critical to judging the reasonableness of the Company's actions. The ALJ's failure to appreciate the nuances of different systems and specific pieces of technical guidance can, and indeed did, lead to misunderstandings and erroneous conclusions about why the Company did what it did. Xcel Energy respectfully suggests that the ALJ's conclusion that the Company failed to prudently operate and maintain Unit 3 is erroneous as it is based on five faulty premises:

1. Industry knowledge about the potential for SCC in steam turbines *generally* is equivalent to actual knowledge about the level of susceptibility of *specific components in specific unit types* to SCC;[8]

2. There was no reasonable basis to re-assign Unit 3's Major inspection interval from 6 years to 9 years—ignoring evidence that 9-year Major inspection

[4] *See* Report at ¶ 42.
[5] "[A] major inspection, which includes 'nondestructive testing,' tries to examine the interior of the turbine rotor and blade attachments without removing the blades." (Report at ¶ 109). In other words, the turbine is disassembled but the turbine blades are not removed absent a specific reason for doing so, given the time, expense and destructive nature of removing blades with finger-pinned attachments.
[6] "Minor inspections primarily consist of visual inspections while the unit is still fully assembled." (Report at ¶ 107; *see also* ¶ 108 (describing visual inspections)).
[7] Exhibit ("Ex.") Xcel-23, Sched. 7 (Sirois Direct – Part 3); Evidentiary Hearing ("Evid. Hrg.") Transcript ("Tr.") Volume ("Vol.") 1 (Nov. 1, 2023) at 227 (Kolb); Evid. Hrg. Tr. Vol. 2 (Nov. 2, 2023) at 50 (Tipton).
[8] Report ¶¶ 118, 122-25.

intervals were well within the range of industry trends, the Company's experience with Sherco Units 1 and 2, and aligned with GE's guidance that acknowledged inspection intervals could be extended beyond 6 years based on numerous factors, including fleet experience;

3. A 1999 GE recommendation that a "complete reinspection" occur after ten years of continued service unequivocally meant that GE recommended that the Company perform a Blades-Off inspection no later than 2009—despite a conflicting Finding that "[i]t is unclear in the record what GE meant by 'completely reinspected,'" and despite GE specifically declining to recommend a Blades-Off inspection prior to the 2011 inspection;

4. A Major inspection in 2011 would have revealed evidence of internal SCC in the finger-pinned attachments, which would have resulted in the Blades-Off inspection, the detection of the SCC, "and could have avoided the Event"—disregarding GE's post-Event guidance that expressly confirms it is "not possible" to inspect finger-pinned attachments for latent SCC in the absence of a Blades-Off inspection as there are no external indications of cracking ;[9] and

5. Although the extensive record in these proceedings fails to reveal evidence of either a conflict or that economic decisions prevailed over engineering judgment, that there was, in fact, a disagreement between the Company's experienced engineers and Xcel Energy's management about the proposed scope of the 2011 inspection, and that management could not be convinced "to invest the time and money" on the Blades-Off inspection "despite the known risk of SCC for finger [pinned] dovetails and the potential for 'catastrophic' results, including units with drum boilers."[10]

Each of these unsupported presuppositions, based on a failure to fully understand the expert and factual testimony in this proceeding, formed a basis for the ALJ's erroneous finding of imprudence. Simply put, the ALJ erred in describing both the Company's and the industry's knowledge about SCC in the specific components present in Unit 3 *at the time of the Event*, and the Report reveals a lack of understanding about the overall maintenance and inspection process. Further, the ALJ's findings erroneously rely upon

[9] Report at ¶ 184.
[10] Report at ¶¶ 181, 207.

speculation about what might (or might not) have been discovered had Xcel Energy performed a Major inspection in 2011. Hypothetical scenarios and outcomes, however, are quintessential hindsight and have no place in the prudency analysis.

The record of this proceeding demonstrates that the Company prudently maintained and inspected Unit 3, including in its decision-making regarding the 2011 inspection. Accordingly, the Commission should not adopt the ALJ's Findings and should find that the Company prudently operated and maintained Unit 3 prior to the Event.

A. The Report Misstates The Record On Several Critical Matters Related To The Event

1. The Findings Overstate the Extent of the "Industry-Wide Knowledge" of Risks Associated with Stress Corrosion Cracking Prior to the Event

The Report criticizes Xcel Energy for not preventing the Event, in part, because SCC and the risks associated with it were "generally known" in the industry.[11] As a result, the Report concludes that, despite having this knowledge, Xcel Energy must have ignored the known risk.[12] In order to arrive at this conclusion, the ALJ disregarded (or misunderstood) the overwhelming record evidence reflecting the state of industry knowledge at the time of the Event related to SCC *in the specific components* present in Unit 3. The Report's conflation of components and systems runs counter to the ***precision*** that witnesses on both sides agreed is required when assessing the Company's prudence prior to the Event.[13]

[11] Report at ¶ 118.
[12] *See, e.g.*, Report at ¶¶ 118-125, 207.
[13] Ex. Xcel-24 at 6 (Sirois Rebuttal); Evid. Hrg. Tr. Vol. 2 (Nov. 2, 2023) at 206 (Polich).

To be clear, there is no dispute that there was industry knowledge—and that Xcel Energy's engineers themselves had such knowledge—about the potential for SCC *generally* in certain low-pressure turbines and with certain types of turbine blade attachments. But there is also no dispute that, at the time of the Event, manufacturers and utilities considered risk based on the specific components of a plant,[14] and that a SCC failure had *never* occurred in a plant with the same components as Unit 3.[15] As result, general knowledge of SCC is not where the analysis ends. For this prudency analysis, it is critical to understand and make distinctions about the following:

- The types of boilers (*i.e.*, once-through boilers as opposed to the drum boiler present in Unit 3);
- The types of "dovetails" (also referred to as "attachments") (*i.e.*, tangential attachments versus the finger-pinned attachments such as those in the L-0 and L-1 rows of Unit 3); and
- The type of "inspections" recommended and available to detect latent and *internal* SCC in finger-pinned attachments (*e.g.*, a Blades-Off inspection).

The ALJ's Findings initially note the important distinctions about the specific components present in Unit 3:[16] it has a drum boiler and the relevant blade rows have finger-pinned attachments. For example, the Report states that, "as compared to a drum boiler, a once-through boiler is more challenging to control steam chemistry and, therefore, the overall turbine cycle is more susceptible to steam contamination. Accordingly, GE has issued steam chemistry and inspection guidance that can sometimes be different for once-

[14] *See, e.g.*, Report at ¶ 56; Ex. Xcel-7 at 17-18 (Kolb Direct); Ex. Xcel-4 at 10-11 (Murray Direct).
[15] Ex. Xcel-8 at 6 (Kolb Rebuttal); Ex. Xcel-24 at 6 (Sirois Rebuttal).
[16] *See, e.g.*, Report at ¶¶ 39-56.

through boilers and drum boilers."[17] Similarly, the Report states that "because tangential dovetail attachment design does not include pins, blades connected to a rotor wheel using tangential dovetail construction are easier to remove from the rotor disk; the blades slide in and out during removal and re-loading. Visual inspection or other examination of the blade attachments is also possible with tangential dovetail attachments while the blades are still attached to the rotor."[18] The difference in blade attachment types, and the implications of those difference was thoroughly discussed in the record and is evident from the following figures:

[17] Report at ¶ 56.
[18] Report at ¶ 47.

Figure 1: Finger-Pinned Attachment Drawings[19]

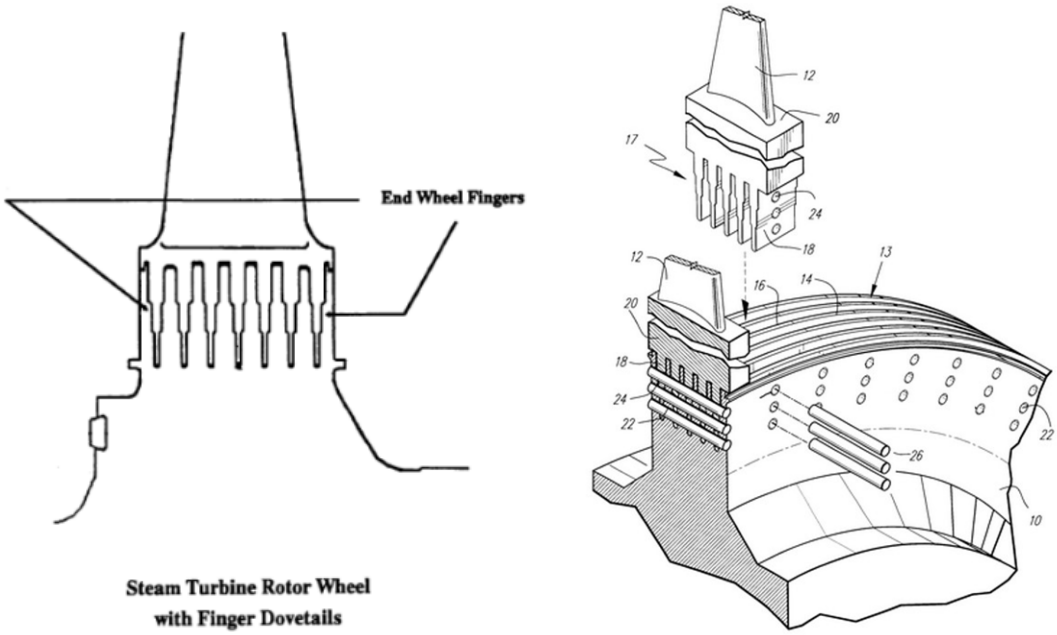
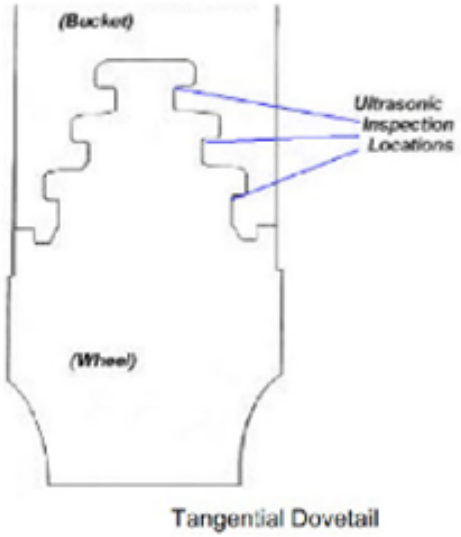


Figure 2: Tangential Entry Attachments Drawing[20]



[19] Ex. Xcel-7 at 18 (Kolb Direct).
[20] Ex. Xcel-7 at 18 (Kolb Direct).

Figure 3: Finger-Pinned Attachments[21]

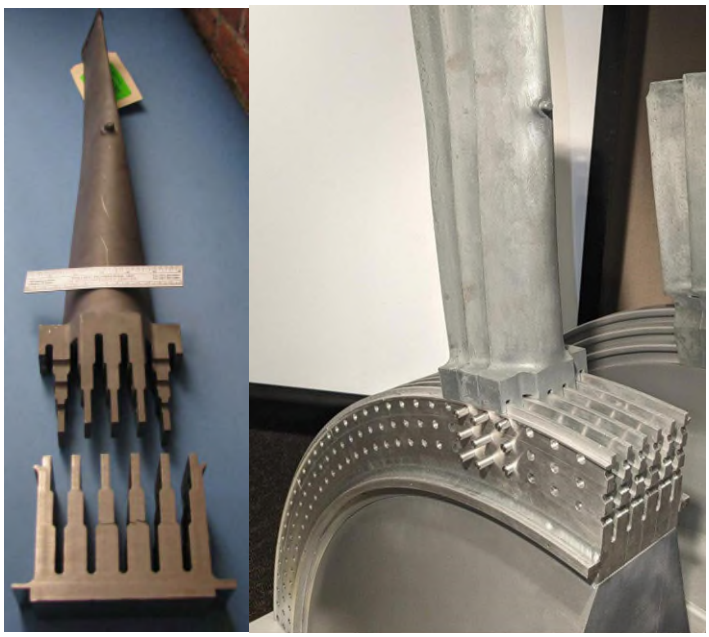


Figure 4: Tangential Entry Attachments[22]

[21] Ex. Xcel-28, Sched. 3 at 267 (Fig. 484) (Tipton Direct – Part 3); Ex. Xcel-B (Demonstrative Ex. B).
[22] Ex. Xcel-B (Demonstrative Ex. B).

But in reaching the conclusion that the Company knew the risks associated with SCC for Unit 3's specific components, the Report then ignores or fails to account for the importance of these critical distinctions, as evidenced in the following Findings, to which the Company takes exception.

Finding(s)	Summary of Finding(s)	Bases for Exception
121-125	In the mid-1990s, the Company was informed about the discovery of SCC in the finger-pinned attachments at Navajo; hence, as far back as that time, the Company had knowledge that SCC was occurring in finger-pinned attachments, specifically in the area of phase transition zones (*i.e.*, L-1 rows).	First, the Navajo units were "super-critical," meaning they used *once-through boilers*, as opposed to "subcritical" units like Unit 3, which had a *drum boiler*. Further, at the time of the Event, Navajo was the *only* example in the industry of stress corrosion racking on *any* GE finger-pinned attachments. In contrast, a 1997 EPRI survey that included over 750 steam turbine units in the United States found that "[n]o cracking was reported in the L-0 or L-1 rows of the GE turbines which have finger and pin attachment design" (such as Unit 3).[23] Therefore, the event on a different unit configuration at Navajo did not and should not have identified to the Company that the finger-pinned attachments at Unit 3 were susceptible to SCC. In fact, it is uncontested that Unit 3 was the ***first*** utility steam turbine generator with a *drum boiler* to fail as a result of SCC in *finger-pinned* blade attachments.[24]

[23] Ex. Xcel-26, Sch. 2 at 85-86 (Tipton Direct).
[24] Ex. Xcel-8 at 6 (Kolb Rebuttal); Ex. Xcel-24 at 6 (Sirois Rebuttal).

Finding(s)	Summary of Finding(s)	Bases for Exception
152-155	GE's Technical Information Letter ("TIL") 1277-2 "mainly advised about the SCC risk for once-through steam turbines with tangential and finger-pinned" attachments. Since Xcel Energy performed the TIL 1277-2 recommended inspections on tangential attachments in Units 1 and 2, this evidenced that "Xcel believed the risk of SCC in dovetails was not limited to just once-through boiler units and could be present in drum boiler units as well."	As an initial matter, it is undisputed that GE never issued TIL 1277-2 to any of the Sherco units because they all had drum boiler units.[25] But at a 2001 conference, GE representatives gave a presentation about SCC observed in units with once-through boilers with *tangential-entry attachments* and began recommending that utilities conduct the TIL 1277-2 phased-array ultrasonic testing on *tangential-attached blade rows* regardless of the boiler type.[26] Accordingly, the Company proactively began following GE's informal recommendations and performed phased-array ultrasonic testing on *tangential-attached* blade rows of the Sherco units.[27] GE, however, had not issued any further warnings, recommendations, or guidance (either formal or informal) regarding SCC concerns with finger-pinned attachments. The ALJ Report's reference simply to "dovetails" apparently conflates the two types of attachments, ignoring the critical differences between them and how they were treated by GE and others in the industry.
162, 167, 169	System Health Reports prepared by the Company's engineers "acknowledge[ed] the 'industry-wide problem' of dovetail pin cracking."	This is a misstatement of those documents. While the System Health Reports memorialize, generically, general risks for the turbines, the "industry-wide problem" identified in those Reports is "rotor wheel cracking"—*not finger-pinned dovetail cracking*.[28]

Contrary to these Findings, prior to 2011 there was no industry knowledge that finger-pinned attachments at units with drum boilers were susceptible to SCC. Rather, as a first-of-its-kind occurrence, the Event substantially contributed to industry knowledge about the potential of latent, internal SCC in finger-pinned dovetails and prompted GE to subsequently issue TIL 1886, its first technical guidance on SCC to include time-based inspection recommendations specific to low pressure turbines with L-1 finger-pinned dovetails and a drum boiler—i.e., the same type of low pressure turbine and blade attachments present in Unit 3.[29]

2. The Findings Inaccurately Assume That Major Inspection Intervals Cannot Be Re-Assigned

Along with mischaracterizing the nature of industry knowledge of SCC prior to the Event, the Report also inaccurately depicted industry and Company inspection practices—and misstates the basis for the Company's decision to move Unit 3 to a nine-year inspection interval. Contrary to a seeming premise of the Report's Findings, there was not a "hard-set" or "industry standard" Major-inspection-interval policy that the Company violated when it decided to re-assign Unit 3 to a nine-year Major inspection cycle. To the contrary, the Company constantly evaluated plant data and industry guidance and made sound maintenance and inspection decisions for Unit 3 and longer inspection intervals were

[25] Ex. Xcel-7 at 40 (Kolb Direct).
[26] Ex. Xcel-4 at 14-15 (Murray Direct); Ex. Xcel-7 at 40 (Kolb Direct).
[27] Ex. Xcel-4 at 15 (Murray Direct); Ex. Xcel-7 at 40-41 (Kolb Direct).
[28] Ex. Xcel-23, Sched. 14 (Sirois Direct – Part 3).
[29] Ex. Xcel-24 at 24 (Sirois Rebuttal).

consistent with industry trends at that time. Therefore, the Company takes exception with the following inspection-interval and scope findings for the reasons set forth below:

Finding(s)	Summary of Finding(s)	Bases for Exception
106	According to a General Electric Knowledge Bulletin ("GEK") 111680, the manufacturer recommended that operators perform Major inspections "every six years."	It is undisputed that, at the time of the Event, GEK 111680 represented GE's most current formal advice applicable to Unit 3.[30] However, GEK 111680 did *not* require or recommend Major inspections every six years in all cases. Rather, GEK 111680 reflected the industry trend towards longer inspection intervals, observing that Major inspection intervals could be six years *or longer*, depending on factors such as "fleet experience, testing results, and operational assessment." GEK 111680 also expressly recognized that multiple factors go into determining inspection frequency, with many of those factors (such as performance and health trend monitoring results) best determined by the operator.[31]
163, 164, and 175	These Findings characterize inspection "plans" or "schedules" as rigid and unchangeable.	Uncontradicted testimony and documentary evidence in the record establishes that prudent maintenance and inspection planning is not written in stone, but rather requires constant evaluation and updating.[32] The record demonstrates that the Company's maintenance and inspection decisions at Unit 3 reflected: (1) existing guidance from GE; (2) general industry practices at that time; (3) the Company's own internal experiences with Unit 3 and units across its entire fleet; (4) careful evaluation of numerous data points that were monitored and evaluated by the team of engineers dedicated to Unit 3; and (5) input from the Company's designated GE representatives.[33] In short, the Company's experienced engineers were constantly re-evaluating the maintenance and inspection timing and scope based on the information available.[34] Importantly, the ALJ's Findings fail to mention that the Company had already successfully transitioned the Unit 1 and 2 low-pressure turbines to approximately nine-year Major inspection intervals by the time of the Event, after considering the operational history of Units 1 and 2, industry resources and guidance, and evaluations of the risks and benefits.[35] Unit 1 was moved to this longer schedule after the 1998 Major inspection and Unit 2 after the 2000 Major inspection.[36]

3. The Findings Illogically Conclude That GE Recommended That A Blades-Off Inspection Should Have Been Performed No Later Than 2009

The ALJ further erred by mischaracterizing GE's inspection recommendations for Unit 3 (separate from the TILs and GEKs). Specifically, and critically, the ALJ inaccurately represented that, in 1999, GE recommended a "complete reinspection" should occur no more than after ten years of additional service and that this meant a Blades-Off inspection should have happened no later than 2009.[37] Based on this misunderstanding, the ALJ made unsupported findings that GE and the Company's engineers believed that a Blades-Off inspection should have occurred by 2009. Therefore, the Company takes exception with the ALJ's "complete reinspection" findings for the reasons set forth below:

[30] Evid. Hrg. Tr. Vol. 2 (Nov. 2, 2023) at 212–16 (Polich).
[31] Ex. Xcel-25, Sched. 4 (Sirois Rebuttal).
[32] Ex. Xcel-7 at 24-28 (Kolb Direct); Ex. Xcel-5 at 17-21 (Murray Direct).
[33] Ex. Xcel-8 at 3 (Kolb Rebuttal).
[34] Evid. Hrg. Tr. Vol. 1 (Nov. 1, 2023) at 215-216 (Kolb).
[35] Ex. Xcel-7 at 27, 45-46 (Kolb Direct); Ex. Xcel-4 at 18 (Murray Direct).
[36] Ex. Xcel-6 at 27 (Murray Rebuttal).
[37] Report at ¶¶ 132, 161.

Finding(s)	Summary of Finding(s)	Bases for Exception
130, 132, 144, 179	In Finding 130, the ALJ notes that GE's 1999 inspection report recommended that the *rotors* should be "completely reinspected" after no more than ten additional years of service. However, the ALJ interpreted this recommendation in subsequent findings to represent that GE's "complete reinspection" recommendation meant performing a Blades-Off inspection.	As an initial matter, the ALJ's findings cannot be reconciled. In Finding 130, the ALJ acknowledged that "[i]t is unclear in the record what GE meant by "completely reinspected." Yet, despite acknowledging that the record is insufficient to determine what GE meant, later findings interpreted the "complete reinspection" recommendation to specifically mean a Blades-Off inspection. For example, in Finding 132, the ALJ concluded that "[b]ased on GE's recommendation for a 'complete reinspection' after ten years, the next major inspection *of the blades for SCC* would be in 1999." This erroneous extrapolation is then used to support other findings. For example, in Finding 144, the ALJ notes that Mr. Kolb consulted with a vendor to determine if there was anything less than a Blades-Off inspection that would satisfy the "complete reinspection" recommendation. And Finding 179 suffers from the same flawed premise: "The inspection Kolb is referring to is a blades-off major inspection in 2011, as recommended by GE in TIL 1121-3AR1 and in GE's recommendation from 1999 that a 'complete reinspection' of the LP rotor blades occur after ten years of continued use." GE made no such recommendation, despite the Company specifically asking GE, prior to the 2011 inspection, if it recommended this "Blades-Off" inspection.[38]

[38] Ex. Xcel-7 at 43–44 (Kolb Direct).

4. The Findings Wrongly Assume that a 2011 Major Inspection Would Have Detected Evidence of the Latent Stress Corrosion Cracking of the Internal Finger-Pinned Attachments

Throughout the ALJ Report's Findings it is suggested that, had a Major inspection been performed in 2011—which, as noted above, would not have included a Blades-Off inspection, there *could have been* indicators present that *might* have led to the discovery of the cracking.[39] But speculation had no place in this prudency analysis. And GE's post-Event guidance in TIL 1886 confirmed that inspecting the finger-pinned attachments for evidence of latent SCC ***is not possible*** in the absence of the Blades-Off inspection as the finger-pinned cracking was confined to the ***internal*** fingers ***with no external evidence of cracking***:

> Inspection of the wheel finger dovetails for SCC is not possible without removal of the buckets. SCC of finger dovetail stages has involved the internal fingers with no external indication of cracking.[40]

The Company takes exception with the ALJ's Findings that a Major inspection would have revealed evidence of SCC or the need for a Blades-Off inspection for the reasons set forth below:

[39] Report at ¶¶ 107-11.
[40] Ex. Xcel-23 at Sched 16 (Sirois Direct – Part 3).

Finding(s)	Summary of Finding(s)	Bases for Exception
188	"The preponderance of the evidence" establishes that Xcel Energy would have discovered the SCC in the L-1 finger-pinned attachments and avoided the loss "had Xcel conducted a major inspection of the LP turbines" in 2011, which would have also included a Blades-Off inspection that allowed for a Magnetic Particle Inspection of the finger-pinned attachments.	First, the ALJ presumes without evidentiary support that the originally planned 2011 Major inspection would have necessarily included a Blades-Off inspection. This is false.[41] A Major inspection does not include removing the blades unless there is a pre-determined technical justification for doing so—*i.e.*, abnormal events or operational anomalies or a plan to replace the blades.[42] Accordingly, even if the originally planned Major inspection had occurred, only a peripheral magnetic particle exam on all the rotor external surfaces would have been performed.[43] And as confirmed by TIL 1886 and Department witness Mr. Polich, unless you also perform a Blades-Off inspection, an operator cannot detect the SCC in the internal finger-pinned attachments.[44] Accordingly, it is pure speculation that, had a Major inspection been performed, there *could have been* indicators present that *might* have led to the discovery of the cracking. In the Event, *all* of the SCC was on the *internal* fingers; thus, even if a Major Inspection had been performed in 2011, the normal examinations would not have detected the cracking that led to the failure[45]

[41] Ex. Xcel-4 at 19-20 (Murray Direct); Ex. Xcel-7 at 45 (Kolb Direct).
[42] Ex. Xcel-4 at 12-13 (Murray Direct); Ex. Xcel-7 at 31-32 (Kolb Direct).
[43] Ex. Xcel-5 at 27 (Murray Rebuttal).
[44] Evid. Hrg. Tr. Vol. 2 (Nov. 2, 2023) at 211 (Polich).
[45] Ex. Xcel-24 at 27 (Sirois Rebuttal).

Finding(s)	Summary of Finding(s)	Bases for Exception
67-71, and 203	The ALJ accepts Mr. Polich's conclusion as to the cause of the Event based on the premise that the Company's expert (Tipton) "was not aware that Xcel had deferred the six-year major inspection recommended by GE, which was to have occurred in 2011." The ALJ further observed that Tipton "had no firsthand knowledge of the operation and maintenance of the unit." As such, the ALJ accepted Mr. Polich's conclusion that the Event was due to "Xcel's decision to postpone the 2011 inspection of Unit 3 and not remove the buckets with finger dovetail joints for magnetic particle inspection. With proper inspection practices…the SCC in the finger dovetail joints would have been discovered and remedied, and the failure could have been avoided."	First, the ALJ's analysis ignores that Company witness Mr. Tipton, who has over 40 years of metallurgical engineering experience and has performed over 300 failure analyses and root cause analyses of turbines over the course of his career, led an 18-month, comprehensive and hands-on investigation and analysis following the Event, which included (among numerous other things), observation and inspection of Unit 3 and its component pieces prior to and during disassembly.[46] Mr. Tipton presented the only full root cause analysis in the record, and he testified that his analysis focused on what the Company had actually done from a maintenance perspective, as opposed to hypothetical scenarios. In contrast, Polich conducted an after-the-fact critique of others' work. Second, although the ALJ found it noteworthy that Mr. Tipton had no firsthand knowledge of the operation and maintenance of the unit, the ALJ failed to note that Mr. Polich also had no such firsthand knowledge. Finally, Polich's conclusions are fundamentally flawed as, even if the Major inspection had not been deferred, the Company had never planned to perform a Blades-Off inspection—*i.e.*, "removing the buckets." As such, Mr. Polich's conclusions, adopted by the ALJ, are erroneous because the latent SCC in the internal finger-pinned dovetail attachments could not have been detected unless the turbine blades had been removed.

[46] Ex. Xcel-26 at 3, 9-10, 12-16, and Schedule 2 (Tipton Direct).

5. The Findings Wrongly Assume that Xcel Energy Management Disregarded the Experienced Engineers Recommendations and Made Inspection Decisions Based on Economic Considerations

The ALJ Report goes to great lengths to suggest that there was a conflict between the Company's experienced engineers who offered testimony in these proceedings and "Xcel management." The ALJ erroneously inferred that the engineers believed that a Blades-Off inspection was prudent in 2011, but that there was disagreement with "Xcel management" and, ultimately, the engineers were unable to convince management to perform the Blades-Off inspection. As such, the ALJ erroneously concluded that Xcel management "made the informed decision to defer the 2011 major inspection despite the known risk of SCC for finger [pinned] dovetails and the potential for 'catastrophic' results, including units with drum boilers," and further found that this decision was "financially driven."[47]

This "engineers versus management" narrative, however, is not borne out by the extensive record in these proceedings. To the contrary, the ALJ's "conflict" conclusions are extrapolated from one witness's statement in a deposition given during the GE Litigation. As shown below, that one statement did not reflect the entirety of the witness's testimony, as the witness (Mr. Kolb) was simply acknowledging that, ultimately, he would be accountable to "upper management" *and* "the PUC" if he used ratepayer money to perform expensive and destructive inspections "on a whim" and without justification:

[47] Report at ¶¶ 181, 207.

Report at Finding ¶ 179	**Deposition Testimony Read into Record[48]**	**Full Deposition Testimony[49]**
The ALJ editorializes that "Kolb lamented, 'We [Kolb and Murray] wanted to do the [2011 Blades-Off] inspection but we weren't given the documents from the OEM [GE] that we required to expend that kind of dollars and time to do that inspection.' The inspection Kolb is referring to is a blades-off major inspection in 2011, as recommended by GE in TIL 1121-3AR1 and in GE's recommendation from 1999 that a 'complete reinspection' of the LP rotor blades occur after ten years of continued use."	Q: So at 196, Line 4, you say: That's the shame of it. We wanted to do the inspection but we weren't given the documents from the [Original Equipment Manufacturer] that we required to expend that kind of dollars and time to do that inspection. That was your testimony, right? **A: That was my testimony.**	**A: "Yes. And that's the shame of it. We wanted to do the inspection but we weren't given the documents from the [Original Equipment Manufacturer] that we required to expend that kind of dollars and time to that inspection. It's – We are ultimately accountable to upper management, the PUC. I – I can't do inspection on a whim or because I think it may apply.**

Notably, the ALJ's Findings ignore Mr. Kolb's later testimony at the Evidentiary Hearing that provided the full context for his earlier deposition statement, which demonstrated the Company's efforts to make prudent inspection decisions (and prudent use of ratepayer money)[50] based on information available to operators at the time of the Event—and the lack of any supposed conflict with "management":

[48] Evid. Hrg. Tr. Vol. 1 (Nov. 1, 2023) at 204 (Kolb).
[49] Ex. Xcel-58 at 196 (Kolb Deposition Transcript).
[50] Consideration of cost is a necessary part of a prudence analysis. As the ALJ Report notes, prudent actions or "good utility practices" are "practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act 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."* Report at ¶ 23 (emphasis added).

> We wanted [GE] to confirm whether this [Blades-Off inspection] is a test that we really needed to do or not. We needed to answer that before we could decide positively if we should be doing such an intrusive, expensive, long duration test.
>
> So we needed to find out from GE first. Some of the input came from GE. We needed to hear from them, their opinion on whether we needed to do this and they would not – we – we had some assumption that this might be an issue coming up. *It wasn't at the time, per all of our data, all of our monitoring, per the GE documents that were in existence at the time, nothing said that we had to do this test.*
>
> The turbine was in excellent shape. All the inspections, all the reports, even GE said that our turbine was in very good condition. They saw a lot more in the industry than we did. Compared to industry, they thought our turbine was in very good condition as far as pitting and deposits and the way we operated it.
>
> But we were trying to be proactive and say, we see these trends coming on the tangential entry, which wasn't Unit 3, and we were trying to proactively look ahead and say, could this be coming for Unit 3 on our finger [pinned] dovetail. *There hadn't – there had been no incidents in the industry other than in a different type of boiler, which is the once-through.*
>
> *So our type of boiler, our type of plant, our type of finger [pinned] dovetail, industry had never seen this. We were the first. It's easy after the fact to say you should have done it.*
>
> So we proactively went to GE and said, are you going to be revising the TIL, the document that gives me the horsepower to spend millions of dollars and take a forced outage. I could spend those dollars better on real problems.
>
> And they – they said they hadn't. No this doesn't apply to your turbine. It does not apply to boiler turbines—or drum turbines, drum boilers, and they had no intention of revising the TIL that would have given us their input confirming that, yes, this is an inspection you should do, we recommend it. That's what this whole thing was about.[51]

[51] Evid. Hrg. Tr. Vol. 1 (Nov. 1, 2023) at 208-210 (Kolb) (emphasis added).

Therefore, the Company takes exception with the ALJ's Findings that Xcel Management overruled the engineers' inspection recommendations for the reasons set forth below:

Finding(s)	Summary of Finding(s)	Bases for Exception
181	Mark Kolb, who the ALJ observed to have provided "earnest and credible" testimony, believed that a Major and Blades-Off inspection was necessary in 2011 but that he was "unable to convince Xcel Energy management to invest the time and money on such intrusive and destructive testing"	The whole of Mr. Kolb's testimony in this matter completely contradicts the ALJ's Findings. Mr. Kolb was consistent throughout his testimony that the Company operated and maintained Unit 3 in a reasonable manner that was consistent with industry practices and knowledge existing at the time. At no time did Mr. Kolb testify that he had tried to convince Xcel Energy's management to invest the time and money on such intrusive testing without success and no testimony or documentary evidence supports such a conclusion.
207	Xcel Energy's management made an "economic decision" to defer the 2011 Major inspection.	The ALJ suggests that Xcel Energy's maintenance and inspection decisions were driven primarily by financial considerations—*i.e.*, that economic decisions won out over engineering judgment. This is false and the ALJ does not cite to any evidence to support this theory. In contrast, Company witnesses specifically and thoroughly addressed their constant effort to balance prudent investment and safety. The Company presented uncontroverted testimony that it would "pay more for an inspection" if it had a benefit that warranted the cost.[52] And the Company demonstrated that it was willing to incur costs for above-and-beyond, additional inspections when there was objective evidence or technical justification to do so—such as when the Company elected to take an unplanned outage in 2008 to inspect Unit 2 after issues were discovered in Unit 1, which was operated identically and contained the same components.[53]

B. Three Critical Omissions Also Undermine the ALJ Report's Maintenance and Inspection Findings and Conclusions

In addition to relying on flawed premises that are not supported by the record, the ALJ Report ignores three critical, undisputed facts that are essential to the prudency analysis:

- Unit 3 was the ***very first*** utility steam turbine generator with a *drum boiler* to fail as a result of SCC in *finger-pinned* blade attachments. Indeed, much of what is *now* known in the industry about SCC in finger-pinned attachments in units with drum boilers is a direct result of the subsequent investigation into the Event itself, and was not known prior to the Event;[54]

- Xcel Energy's decision to transition Unit 3's Major inspection interval to 9 years was well within the range of common industry practices associated with Major inspection intervals as they existed at the time of the Event. The ALJ failed to acknowledge the undisputed record evidence regarding industry trends, which were memorialized in a GE PowerPoint presentation provided to Xcel Energy in 2006 and supported by expert testimony. In that document, GE—the manufacturer of the Unit 3 turbine—expressly confirmed *at least 5 years prior to the November 2011 Event* that the industry trend for Major inspection intervals had increased from "5 to 7 years" to "10-12" years;[55] and

- While the ALJ acknowledged that the finger-pinned design made the Blades-Off inspection a "time-consuming and expensive process"[56] and that removing the pins can be a "destructive process"[57] that "consumes a portion of the useful life of the rotor,"[58] the Findings failed to consider the potentially imprudent action of performing costly inspections that were not technically justified. Both under-inspection and over-inspection introduce separate risks. Accordingly, the goal is to strike the proper balance of optimizing maintenance intervals relative to averting the introduction of risk to the

[52] Evid. Hrg. Tr. Vol. 1 (Nov. 1, 2023) at 237 (Kolb).
[53] Ex. Xcel-4 at 17 (Murray Direct).
[54] Ex. Xcel-8 at 6 (Kolb Rebuttal).
[55] Ex. Xcel-5, Sched. 2 (Murray Rebuttal).
[56] Report at ¶ 43.
[57] Report at ¶ 44.
[58] Report at ¶ 111.

> machines, ensuring efficient and reliable operations, and weighing the cost to the customers and the Company in time, resources, and labor to perform the work based on the available information at the time. Indeed, disregarding the real and potentially substantial risks of performing destructive inspections that were not technically justified would be patently *unreasonable*. Thus, it was reasonable for the Company to consider the risk to the unit when making its maintenance and inspection decisions.

With knowledge that Unit 3 suffered a catastrophic failure, and now looking back after more than a dozen years, it is tempting to second guess the Company's actions or imagine how things *could* have been different. The record, however, is clear that the Company had no reasonable basis to believe that Unit 3 was particularly susceptible to SCC in the L-1 row of its low-pressure turbines, so as to justify deviating from GE's formal inspection guidance. To the contrary, the overwhelming evidence demonstrated that the focus of the industry during the relevant time frame was on ***tangential attachments and once-through boilers***—not on units with finger-pinned attachments in units with drum boilers (like Unit 3).[59] The ALJ's Findings confirm that the Company was paying attention to the evolving industry knowledge surrounding SCC generally, and proactively implementing informal guidance that related to other attachment designs that are not at issue in this proceeding (*i.e.*, tangential).

The Company's maintenance and inspection decisions were prudent: they conformed with industry standards, manufacturer guidance, and information reasonably

[59] As the ALJ correctly observed in Finding 56, "a once-through boiler is more challenging to control steam chemistry and, therefore, the overall turbine cycle is more susceptible to steam contamination." As such, GE issued inspection guidance "that can sometimes be different for once-through boilers and drum boilers." In other words, the ALJ's Finding confirms that there are important differences between once-through and drum boilers and which boilers were more susceptible to stress corrosion cracking.

known at the time about Unit 3's specific components' susceptibility to SCC. Accordingly, the Company requests that the Commission reject the ALJ's maintenance and inspection conclusions as they are premised upon faulty premises and critical omissions.

II. THE INCIDENTS NOTED IN THE REPORT DID NOT RISE TO THE LEVEL OF "ABNORMAL EVENTS OR OPERATIONAL ANOMALIES" BUT WERE NONETHELESS CONSIDERED BY THE COMPANY

As to "abnormal events or operational anomalies," the ALJ concluded that two incidents—alleged condenser tube leaks in 2002 and 2003 and a steam wash event in 2005—"contribute to Xcel's share of fault in the Event,"[60] because "Xcel did not consider these anomalies or abnormal events in its decisions regarding the timing and need for major or Blades-Off inspections . . ."[61] Essentially, while the ALJ found that there was no evidence that either incident affected the steam chemistry of Unit 3,[62] the ALJ simultaneously found that the Company was imprudent because no documentation specifically ties the Company's consideration of these benign incidents with its decision to not conduct a Blades-Off inspection of Unit 3's low pressure turbines in 2011. Xcel Energy takes exception to this finding as not supported by the weight of the evidence: the incidents did not need to be specifically documented, as there is no evidence they had any impact on Unit 3 cycle chemistry, and, in any event, the plant personnel who needed to be aware of these incidents for inspection planning purposes were undisputedly aware of them.

[60] Report at ¶ 306.
[61] Report at ¶ 306.
[62] *See* Report at ¶¶ 292, 295-296, 305.

A. TIL 1121 Does Not Require Consideration of a Blades-Off Inspection Any Time an Incident Occurs

The ALJ found that a GE guidance document required consideration of a Blades-Off inspection because these incidents occurred, regardless of whether the incidents resulted in contamination. Pointing to "leaking condenser heating tubes, caustic or chemical ingestion or contamination, and water ingestion,"[63] the ALJ found as to these two incidents that: "under TIL 1121, these are the types of abnormal events or operational anomalies that should have at least been considered by Xcel when it was deciding whether to conduct a Blades-Off inspection."[64] That is not an accurate summary of TIL 1121. TIL 1121 states: "Abnormal events or operational anomalies that ***cause concern for long term reliability*** of the unit ***may be reason to consider*** removal of buckets. . . ."[65] The cover letter of TIL 1121 similarly states: "[T]his TIL DOES NOT recommend the removal of buckets for inspection of the rotor wheel finger dovetails, unless abnormal events or operational anomalies are encountered ***which may increase the risk of stress corrosion and/or fatigue.***"[66] TIL 1121 thus does not require or even recommend a Blades-Off inspection any time such an event occurs. As stated plainly in the record, TIL 1121 gives the operator discretion to ascertain whether an incident creates long-term reliability issues or increases the risk of SCC such that a Blades-Off inspection may be needed. There is therefore no

[63] Report at ¶ 288.
[64] Report at ¶ 304.
[65] Ex. Xcel-23, Sched. 7 (Sirois Direct – Part 3) (emphasis added).
[66] Ex. Xcel-23, Sched. 7 (Sirois Direct – Part 3) (emphasis added).

support for the requirement imputed by the ALJ that the Company was imprudent for failing to do a Blades-Off inspection simply because either of these two incidents occurred.

B. Consideration Of the Incidents Cited By the ALJ Was Not Necessary Because Neither Incident Caused Concern for Long Term Reliability of the Unit or Risk of SCC

Critically, there is nothing in the record to support that either of these incidents affected the cycle chemistry of Unit 3 such that the Company should have been concerned about the long-term reliability of the Unit or an increased risk of SCC and thus considered a Blades-Off inspection. Indeed, the ALJ expressly found that as to the two incidents: "Importantly, there is ***no evidence*** that these events actually resulted in water or steam contamination, caused chemical makeups to exceed EPRI limits for any length of time, or even caused the SCC that resulted in the blade liberation. ***Thus, it is more likely than not that these events where (sic), as Xcel witnesses explained, immediately discovered and swiftly corrected without damage to Unit 3***."[67] Therefore, even if the Company did not consider these incidents in its inspection planning for Unit 3, there is no evidence in the record, let alone a preponderance of evidence, to support that such a failure was imprudent or unreasonable.

When discussing these condenser tube leaks, the ALJ found that "Daniels summarily concluded that, in all these situations, 'laboratory personnel immediately addressed the contamination and worked together with operations using boiler operating

[67] Report at ¶ 305 (emphasis added) (citations omitted); *see also* ¶ 249 (finding more broadly that "a preponderance of the evidence establishes that the Company was reasonably prudent in its chemistry monitoring or real-time data collection practices.").

pressure, blowdown, and other measures to ensure that the steam purity was not compromised.'"[68] This Finding ignores the robust record of Mr. Daniels' analysis of these incidents, provided in rebuttal to the original Schultz Report on which the Department entirely relied for this argument.[69] Indeed, incorporated into Mr. Daniels' testimony on this issue was his rebuttal report.[70] In that report, he provided a detailed analysis of Schultz's assertions supporting his conclusion that the plant "ensured that the steam purity was not compromised."[71] This conclusion is further supported by the ALJ's own finding, discussed above, that "there is ***no evidence*** that these events actually resulted in water or steam contamination, caused chemical makeups to exceed EPRI limits for any length of time, or even caused the SCC that resulted in the blade liberation."[72] Importantly, the ALJ found the testimony of the Mr. Daniels more credible than that provided by the Department.[73]

C. The Company Was Fully Aware of These Minor Incidents as It Considered the Maintenance and Inspection of Unit 3

Regarding the finding that the Company should have, but did not, consider these incidents "in [its] decision to defer the 2011 major inspection," the ALJ concluded that "[t]hese anomalies were not referenced in System Health Reports and there is no evidence

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[68] Report at ¶ 292.

[69] *See* Report at ¶ 291 [**PROTECTED DATA BEGINS:** *XXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX* **PROTECTED DATA ENDS].**

[70] *See* Ex. Xcel-11 at 20 n.34 (Daniels Rebuttal).

[71] Ex. Xcel-15 at 2-5 (Daniels Rebuttal – Part 5).

[72] Report at ¶ 305.

[73] Report at ¶ 249 ("The Administrative Law Judge finds that Daniel's evaluation of data was more extensive and more knowledgeable of the Company practices than Klotz's review. Accordingly, the Judge relies on Daniels' analysis of historical chemistry data.").

that these incidents were considered in Xcel's decision to defer the 2011 major inspection. At a minimum, these incidents should have been documented in the System Health Reports, which formed the bases for Xcel Energy's determinations of whether to continue on the GE-recommended six-year inspection and whether the planned 2011 major inspection should be deferred."[74] The Company takes exception to this finding for the reasons set forth below.

1. The Company Was Aware of and Considered These Incidents

The ALJ's conclusion that these incidents were not considered in the Company's inspection decision making process ignores the evidence—evidence expressly cited in the ALJ's other findings—that the plant personnel making the inspection decision, Mark Kolb and Tim Murray, were aware of and involved in the follow-up to these incidents. As the ALJ found, Mr. Kolb "was responsible for the operation, maintenance, and inspection of Unit 3."[75] The ALJ also found that Mr. Murray was "involved in making decisions and recommendations about Xcel's maintenance, service, and operation of the turbines, including inspection/maintenance schedules."[76]

Mr. Kolb specifically testified as to whether there was "leaking condenser heating tubes, caustic or chemical ingestion or contamination, and water ingestion,"[77] per TIL 1121. He testified: "I watched for and considered each of the events listed in TIL 1121-

[74] Report at ¶ 304.
[75] Report at ¶ 137; *see also* ¶ 227 ("Kolb worked closely with management and 'key personnel' leading the operations and maintenance functions of Unit 3.").
[76] Report at ¶ 120.
[77] Report at ¶ 288.

3AR1. My understanding from conversations with GE representatives is that GE felt these anomalies 'existed' for purposes of TIL 1121-3AR1's application only in severe instances of such anomalies. Nothing in Unit 3's operations rose to that level,"[78] as he specifically addressed each sub-category of potential events.[79] Further, substantial evidence supports that he was aware of these incidents when they occurred and that he concluded that they did not result in a need to consider a Blades-Off inspection discussed in TIL 1121.[80]

Further supporting that Mr. Kolb was aware of these incidents, the ALJ found that Mr. Kolb was involved in the daily review and assessment of the Unit. The ALJ found: "Each morning, representatives from the different functional groups would meet at the plant. . . . Kolb engaged in these meeting[s] to gather updates on system performance and centralize the information in his management of the turbines. In Kolb's daily status meeting with representatives of the various functional groups, including the chemistry group, included reviewing reports and data for Unit 3 from overnight, checking in with staff, assessed the nature and significance of any events that may have occurred since the previous day's status meeting, and consulted with relevant managers to address any noted issues or problems."[81]

[78] Ex. Xcel-7 at 35 (Kolb Direct).
[79] Ex. Xcel-7 at 36-37 (Kolb Direct).
[80] Ex. Xcel-7 at 35-37 (Kolb Direct); Ex. Xcel-52 at 1-2 (Kolb Surrebuttal).
[81] Report at ¶ 230.

2. The Incidents Did Not Need to Be Referenced in the System Health Reports to be "Considered"

At the crux of the ALJ's finding that the Company was imprudent is the ALJ's statement, unsupported by any witness testimony, that "[a]t a minimum, these incidents should have been documented in the System Health Reports, which formed the bases for Xcel's determinations of whether to continue on the GE-recommended six-year inspection and whether the planned 2011 major inspection should be deferred."[82] Essentially, because the ALJ found no written documentation tying these incidents to the decision to defer the 2011 major inspection, the ALJ then found imprudence on this issue. Such a finding puts form over substance and ignores the preponderance of the evidence in the record. As set forth above, the ALJ found that there is *no* evidence that these incidents had *any* negative impact on Unit 3's cycle chemistry. There is therefore no reason that these incidents should have been documented in the system health reports. Moreover, the ALJ expressly found that "Kolb worked with Murray . . . to draft all of the System Health Reports…"[83] Taken together, the Company personnel responsible for drafting the system health reports and determining the inspection cadence for Unit 3, undisputedly knew about and considered the two incidents in hand. The ALJ's conclusion that these events were "not considered" simply because such consideration was not written down is not supported by the weight of the evidence.

[82] Report at ¶ 304.
[83] Report at ¶ 137.

III. THE REPORT FUNDAMENTALLY MISSTATES THE FUEL CLAUSE ADJUSTMENT PROCESS AND MAKES UNSUPPORTED FINDINGS ON THE COST OF "REPLACEMENT POWER"

Two witnesses analyzed the cost of any replacement power that may have been incurred during the time Unit 3 was out of service – Company witness Mr. Detmer and Department witness Mr. King. These two witnesses, who provided the exclusive testimony on this topic, agreed on the reasonable estimate of any such costs.[84] Moreover, in its Initial Brief, OAG agreed with the Company and the Department on this issue.[85] Nonetheless, the ALJ Report rejects this agreed-upon estimate in favor of an earlier, less rigorous estimate prepared years earlier but not supported by any witness in the current proceeding. In doing so, the Report reveals a lack of understanding of the regulatory process by which utilities recover their costs of energy, and the ALJ Findings on this issue must be rejected.

To unwind the ALJ Report's confusion on this issue, it is helpful to step back and remember how the regulatory process related to energy cost recovery works. As the Commission is well aware, the Fuel Clause Adjustment ("FCA") process involves an annual review of the electric utilities' automatic adjustment of charges for the previous twelve-month period (i.e. the fiscal-year from July 1 through June 30). This review occurs after the utilities file annual automatic adjustment ("AAA") of charges reports on September 1 of each year, and, after the Department submits its analysis of the AAA reports. Through this process, the Department, Commission and any other interested parties

[84] *See* Evid. Hrg. Tr. Vol. 2 (Nov. 2, 2023) at 142 (Detmer); Ex. DOC-10 at 15 (King Rebuttal).
[85] OAG Initial Brief ("Br.") at 5-6.

examine the utilities' total costs of fuel and purchased power, the total funds recovered for fuel and purchased power during the year, and then "true up" any difference going forward, such that utilities recover their prudently incurred costs of fuel and purchased power – no more and no less.

Unit 3 was out of service from November 2011 until October 2013 and was therefore not available to provide power for all or a portion of three AAA fiscal years – the years ending June 30, 2012, 2013 and 2014. Given Unit 3's unavailability, the Company incurred costs for purchased power during these AAA years that it may not have incurred had Unit 3 been operational and any such costs would have been included in the total energy costs incurred during that time period.[86]

The Commission reviewed the Company's AAA reports for all three years, 2012-2014, in April, 2016.[87] During the three years, the Company incurred a total of approximately $2.644 billion in fuel and purchased power costs.[88] At the same time, the Company recovered approximately $2.655 billion for these fuel and purchased power costs.[89] After review, the Commission accepted the Company's AAA reports (resulting in a true-up in customers' favor of approximately $11 million), meaning Xcel Energy has now recovered the full fuel and purchased power costs reported during those years (and no

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[86] *See* Ex. Xcel-33 at 2 (Detmer Direct).
[87] *See* Docket Nos. E-999/AA-12-757, AA-13-599 & AA-14-579, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS (June 2, 2016) ("2016 AAA Order") (eDocket No. 20166-121943-04).
[88] *See* Docket Nos. E-999/AA-12-757, AA-13-599 & AA-14-579, Staff Briefing Papers at 3-4 (eDocket No. 20164-119760-03).
[89] *See* Docket Nos. E-999/AA-12-757, AA-13-599 & AA-14-579, Staff Briefing Papers at 3-4 (eDocket No. 20164-119760-03).

more), but the Commission reserved any final decision as to whether some portion of those costs related to "replacement power" needs during the time Unit 3 was not available may not be appropriate for recovery, such that some remedy may be required.[90]

Given this backdrop, in the current proceeding, if the Commission determines that the Company was imprudent in operating and maintaining Unit 3 and that this imprudence caused the Company to incur additional power costs that have already been recovered from customers, the question becomes what portion of this $2.65 billion in fuel and purchased power cost was incurred due to the unavailability of Unit 3.

Due to the complexity of the energy market as a whole, and a specific utility's interaction with that market, the parties agree that it is not possible to *precisely* determine replacement power costs incurred as a result of any particular outage.[91] A precise determination would require comparison of two sets of historical data that cannot simultaneously exist: the total energy costs the utility would have incurred had the outage not happened, compared to the total energy costs actually incurred during the outage that did happen – a "counterfactual scenario" that is both complex and involved. [92] However, that analysis can be conducted, and a reasonable estimate of replacement power costs can be developed.[93] As the Department put it: "the amount at issue should, *as closely as*

[90] 2016 AAA Order at 11 (eDocket No. 20166-121943-04).
[91] Ex. Xcel-33 at 11 (Detmer Direct).
[92] Ex. Xcel-33 at 11 (Detmer Direct); Ex. DOC-4 at 9 (King Direct).
[93] *See* Ex. Xcel-33 at 11 (Detmer Direct).

possible, match the incremental amount customers were charged in the FCA due to the Sherco 3 outage."[94]

Back in September 2013, as part of it 2013 AAA Report, the Company provided an "Informational Sherco 3 Outage Summary" that included an *estimate* of the replacement power costs that may have been incurred due to the Unit 3 outage (the "AAA Estimate").[95] Using a simplified methodology, the Company estimated total replacement power costs of approximately $55.5 million, or $41.2 million on a Minnesota jurisdictional basis.[96]

For purposes of the GE Litigation, the Company conducted a more robust analysis in support of a more sound and defensible estimate for the replacement power costs associated with the Event (the "Litigation Estimate").[97] As Company witness Mr. Detmer explained, the Litigation Estimate incorporated significant data not considered in the earlier AAA Estimate, including:

> 1) An estimate for some forced and maintenance outages at Sherco Unit 3 that would have occurred, while the [AAA Estimate] assumes zero outages or 100% availability;
>
> 2) The impact to the whole Xcel Energy portfolio and the Locational Marginal Prices actually experienced at both load and generation, while the [AAA Estimate] only takes into account the Locational Marginal Prices at load;
>
> 3) The impact on Day-Ahead and Real-Time Locational Marginal Prices had Sherco Unit 3 generation been offered into the MISO market, while the [AAA Estimate] only compares the cost the Sherco Unit 3

[94] Ex. DOC-4 at 15 (King Direct) (emphasis added).
[95] Docket No. E999/AA-13-599, Xcel Energy Annual Report at Part S (Sept. 3, 2013) (eDocket No. 20139-90908-02).
[96] Ex. Xcel-33 at 11-12 (Detmer Direct).
[97] Ex. Xcel-33 at 15-17 and Sched. 3 (Detmer Direct).

generation with the cost of the Real-Time market without accounting for the impact of that generation on the market;

4) Heat rate and capacity improvements at the Sherco Unit 3 plant; and

5) Avoided O&M costs while the unit was being repaired.[98]

This more accurate and reliable analysis resulted in an estimate of the total replacement power cost during Unit 3 restoration to be approximately $45.4 million total, and approximately $33.7 million on a Minnesota jurisdictional basis.[99]

After reviewing the Company's testimony and supporting documentation in this proceeding, the Department agreed with the reasonableness of the Litigation Estimate of replacement power costs.[100] Department witness Mr. King agreed that the Litigation Estimate was "more comprehensive than the analysis underpinning the AAA [Estimate] because it considers broader market impacts to Xcel Energy's load and other resources. Additionally, the AAA [Estimate] contains certain simplifying assumptions related to forced outage rates and start-up costs that *are not realistic* for the long outage that Sherco 3 experienced."[101]

As noted above, no party provided testimony disputing the Company's Litigation Estimate or the Department's concurrence with that estimate and the OAG affirmatively agreed with the reasonableness of this estimate.

[98] Ex. Xcel-33 at 18-19 (Detmer Direct).
[99] Ex. Xcel-33 at 18 and Sched. 3 (Detmer Direct).
[100] Ex. DOC-10 at 15 (King Rebuttal).
[101] Ex. DOC-10 at 15 (King Rebuttal).

Despite the clear and uncontradicted testimony on this issue, the Report purports to identify and require refund of the amount of replacement power costs "ratepayers *actually paid* as a result of the Event," as though replacement power costs associated with the Event were somehow separately accounted for and charged to customers.[102] In doing so, the ALJ Report appears to assume that, in its AAA Report, the Company separately identified and requested recovery of replacement power costs associated with the Event. For example, the Report states:

> Even though [the Company] anticipated that the GE Litigation energy replacement cost calculation would likely be less than its AAA calculation, the Company nonetheless asked the Commission to approve recovery from ratepayers *in the larger amount* stated in the AAA filing.[103]

To be clear, the Company did not ask the Commission to approve recovery in some "larger amount" in the AAA dockets. Rather, the Company followed the process as prescribed by Commission rules, which provides for recovery of the Company's total energy costs, subject to prudence review. That is the amount the Company requested and that has been recovered from customers–its total fuel and purchased power costs during those AAA years. While the Company provided the AAA Estimate earlier in these dockets to inform the Commission and parties of the amount of its power costs that may have been related to replacement power needs associated with the Event, the Commission made clear that it was deferring any final decision on replacement power issues pending further record development.[104]

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[102] *See, e.g.,* Report at ¶¶ 315-317, 319, 331.
[103] Report at ¶ 319.
[104] 2016 AAA Order at 11.

The Company firmly believes the record of this proceeding demonstrates the Company prudently operated and maintained Unit 3, such that any replacement power costs were prudently incurred. However, should the Commission disagree, the record *unequivocally establishes that the best estimate of any replacement power costs incurred due to the Event were $33.7 million on a Minnesota jurisdictional basis*. Use of an earlier, less accurate estimate, that used assumptions the Department agrees are not realistic, cannot be justified, and the ALJ Findings on this issue must be rejected.

IV. THE REPORT FAILS TO APPROPRIATELY RECOGNIZE THE GE SETTLEMENT AND FAILS TO CONSIDER OTHER COST MITIGATING FACTORS

After recommending overstated replacement power costs, the ALJ Report compounds its errors by failing to accurately reflect the impact of the GE Settlement and failing to even consider other cost mitigating factors that have reduced any incremental costs borne by customers due to the Event. Full and proper consideration of these issues demonstrates that, due to Commission decisions and the Company's prudent actions *after* the Event, *customers have not paid more for power than they would have had the Event not occurred*. Therefore, regardless of the Commission's determination on prudence, no "refund" of replacement power costs is warranted or appropriate.

A. The Commission Must Fully Recognize The Impact to Customers of the GE Settlement

The ALJ Report reflects a woefully inadequate analysis of the GE Settlement and its impact on customers. There can be no dispute that the Company settled all claims against GE in September 2018, prior to trial. By that time, the Company had already received

substantial insurance recoveries and those recoveries were credited to customers in the Company's 2013 rate case.[105] There can also be no dispute that the Company credited the entirety of the Minnesota jurisdictional portion of that settlement amount to customers through the fuel clause adjustment in February 2019.[106] This settlement provided material rate relief to customers. The ALJ's recommendation that only a minimal percentage of that rate relief be recognized and accounted for as an offset to any replacement power costs in the event of a finding of imprudence, is manifestly unreasonable.

The ALJ Report recommends that less than 25 percent of the GE Settlement be considered an offset to any replacement power costs incurred. It does so on the basis that the Company's *original* claims in the litigation categorized 24.4% of the Company's damages attributable to loss of use (i.e., replacement power) and 76.5% of its damages as property loss.[107] This recommendation completely ignores the procedural posture of the Aegis Litigation.

First, consistent with the settlement's global resolution of all claims, the GE settlement did not allocate the proceeds in the manner now recommended by the ALJ. However, customers unquestionably received the direct benefit of these proceeds in the form of a full credit to purchased power costs, by flowing the credit through the fuel clause

[105] *See* Ex. Xcel-1 at 14 (Krug Direct); Xcel Energy Sherco Litigation Update (Nov. 2, 2018) (eDocket No. 201811-147564-11). The Company's insurers did not settle with GE, but litigated the matter in an effort to recuperate the cost of the insurance claims they had paid to the Company (the "Aegis Litigation").
[106] *See, e.g.*, Ex. Xcel-1 at 14 (Krug Direct).
[107] Report at ¶¶ 340-41.

adjustment in February 2019. Any analysis of replacement costs should, therefore, consider the credit of the full amount of the GE settlement proceeds as an offset to any such costs.

If *any* post hoc allocation is considered, however, it needs to reflect the reality of the total Event-related costs at issue and what claims Xcel Energy did and did not have *at the time of the settlement*. The total Event-related costs were $138.4 million, inclusive of restoration costs, replacement power costs, and excess fuel oil costs.[108] However, upon obtaining $99.2 million in insurance recovery for restoration work and excess fuel oil costs from its insurers (on a Minnesota jurisdictional basis), Xcel Energy no longer had claims against GE for recovery of those costs.[109] Rather, Aegis and the Company's other insurers held those claims, which formed the basis of the Aegis Litigation.

To the extent the Commission agrees with the ALJ that the GE Settlement proceeds must be apportioned, therefore, the Commission must recognize that the Company's recovery of **[PROTECTED DATA BEGINS** *XXXXXXXX* **PROTECTED DATA ENDS][110]** in the GE Settlement resolved the *remaining claims held by the Company*, virtually all of which were represented by replacement power costs. After insurance recovery, capital costs only accounted for approximately $5.1 million of Xcel Energy's remaining claims,[111] whereas replacement power costs accounted for $33.7 million (on a

[108] Ex. Xcel-1 at 12 (Krug Direct).
[109] *See* Ex. Xcel-1 at 13-15 (Krug Direct).
[110] The Company contacted counsel for GE to request its agreement that the settlement amount can be publicly disclosed. GE did not agree and specifically stated its intent to hold the Company to the terms of the settlement, which requires the Company to maintain this amount as a confidential number.
[111] Of the $104.3 million in restoration costs, insurance recovery covered $99.2 million. Ex. Xcel-1 at 12-13 (Krug Direct).

Minnesota jurisdictional basis).[112] Using the ALJ's logic that the Settlement should be apportioned by the percentage of damage attributable to replacement power costs, this calculation should be performed *at the time of settlement*—after accounting for the insurance proceeds received by the Company and credited to customers, and the subrogation of those claims to the Company's insurers. Thus, if any apportionment is applied, 86.8 percent of the settlement proceeds should be apportioned to replacement power costs (i.e., $33.7 million in replacement power costs ÷ $38.8 million in remaining claims against GE). Under this methodology, the amount of the settlement that should be directed to replacement power costs is **[PROTECTED DATE BEGINS** *XXXXXXXXXX* **PROTECTED DATA ENDS],** not the **[PROTECTED DATA BEGINS** *XXXXXXXXXX* **PROTECTED DATA ENDS]** recommended by the ALJ**.**[113]

In addition, the ALJ Report fails to recognize the *timing* of the GE Settlement. Again, it is undisputed that the Company returned the settlement proceeds to customers in their entirety through its monthly fuel clause adjustment in *February 2019*.[114] Customers, not the Company, have had the benefit of the settlement proceeds since that time. However, the Report ignores this point. Instead, the Report calculates a total amount of estimated replacement power costs, adding interest since those estimated costs were recovered from

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[112] Ex. Xcel-33 at 18 (Detmer Direct).

[113] Report at ¶ 342. **[PROTECTED DATA BEGINS** *XXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXX* **PROTECTED DATA ENDS]**.

[114] Ex. Xcel-1 at 14 (Krug Direct).

customers, and then proposes simply deducting any settlement offset from that total amount as though customers received the settlement funds today. In other words, the Report recommends the Company be required to provide ongoing interest on funds *returned to customers over five years ago*. To the extent that Commission orders any refund, the Company recommends a compliance filing to detail the final refund amount and recognizing the timing of the GE Settlement credit (and other offsets) to customers.

B. The Commission Must Recognize That Customers Received Rate Relief of Over $21 Million As A Result of the 2012 Rate Case Order

As the ALJ Report recognized, the Commission's decision in the 2012 rate case resulted in a total disallowance of $21.6 million to the Company, including $13.2 million in disallowed recovery due to the removal of Unit 3 from the Company's rate base and $8.4 million in disallowed operations and maintenance expenses.[115] Thus, the Commission's decision provided $21.6 million in rate relief to customers *in 2013* by excluding Unit 3 from the Company's portfolio of generation assets that were paid for by customers during the 2013 test year.[116] As Company witness Mr. Krug explained, the Commission effectively determined that, during that time, the Company's portfolio of generation assets used to serve (and therefore paid for by) customers should not include Unit 3.[117] As such, since customers did not pay for the unit during that time, there should be no expectation that any energy would have been generated by the unit during that time to serve customers

[115] Report at ¶¶ 346, 349; *see also* Ex. Xcel-1 at 17-18 (Krug Direct).
[116] Ex. Xcel-3 at 10 (Krug Rebuttal).
[117] Ex. Xcel-1 at 18 (Krug Direct); Ex. Xcel-3 at 10 (Krug Rebuttal).

and offset market energy purchases. That prior decision must be taken into account as the Commission now addresses any issues around replacement power. [118]

The ALJ determined, however, that, due to an overly-narrow interpretation of the language of the Commission's referral of this matter to the Office of Administrative Hearings, the ALJ did not have jurisdiction to determine anything other than the amount of replacement power costs incurred during the Unit 3 outage.[119] Of course, the *Commission* is not so limited any should fully consider any impact to customers due to the Event. Any such consideration must take into account the rate case disallowance and the resulting rate relief received by customers back in 2013. Earlier in this proceeding, the Department agreed that this disallowance must be factored into any possible rate relief to customers related to the cost of replacement power. In discussing whether customers should receive a refund of any size, the Department discussed what it referred to as "remaining ratepayer harm," stating:

> To determine the ratepayer harm, the Department examined the Sherco 3 outage costs and the counteracting payments; specifically, the reimbursements by insurers and the settlement with the turbine manufacturer. Further in its Compliance Filing, Xcel states that the Commission previously disallowed $21.6 million in costs associated with the Sherco outage in 2012, and that it would be unreasonable to count these costs again to determine the remaining replacement power costs. *The Department agrees and, therefore, subtracts the previously denied costs from the total calculated damages* to determine the remaining damage to ratepayers due to the outage.[120]

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[118] Ex. Xcel-1 at 18 (Krug Direct); Ex. Xcel-3 at 10 (Krug Rebuttal).
[119] Report at ¶ 349.
[120] Comments of the Minnesota Department of Commerce, Division of Energy Resources (Jan. 15, 2021) at 19 (eDocket No. 20211-169851-14) (emphasis added). In other prior comments, the Department had also recommended that the Commission consider a jury

That prior Department recommendation makes sense. If the Commission ultimately requires a refund in this matter, it will have necessarily decided that, had the Event not occurred, Xcel Energy would not have incurred, and passed on to customers, some amount of replacement power costs. At the same time, had the Event not occurred, customers would have paid the costs disallowed in the prior rate case. In other words, just as it is true that but for the outage, Xcel Energy's Minnesota customers would not have incurred approximately $33.7 million in replacement power costs, but for the outage, Minnesota customers *would* have paid the $21.6 million that was disallowed in the Company's 2012 rate case. Any decision now by the Commission must recognize this fact.

Finally, as with the GE Settlement proceeds, any required refund must reflect the timing of the rate relief—in 2013—provided by the rate case disallowance.

C. The Commission Should Also Recognize That The Company Conducted The Restoration Of Unit 3 In A Manner That Brought Cost Savings To Customers

The record also establishes that the restoration and refurbishment work the Company conducted significantly benefitted customers beyond simply returning Unit 3 to service. Again, the ALJ Report determined that the ALJ did not have jurisdiction to consider such benefits, meaning the ALJ did not consider whether customers actually paid more for power than they would have had the Event not occurred. The Commission need

finding in the Aegis Litigation that Xcel Energy bore 48 percent responsibility for the Event, while GE bore 52 percent responsibility, and require the Company to refund 48 percent of the Replacement Power costs. Comments of the Minnesota Department of Commerce, Division of Energy Resources (Jan. 14, 2019) at 6-9 (eDocket No. 20191-149180-03). The Department now appears to have abandoned both of these prior positions.

not, and should not, take such a limited view. Customers received new or upgraded equipment for many of the impacted components or systems damaged during the Event, received the benefit of thorough inspections and repairs during the restoration, received significant performance improvements from additional work conducted by the Company with no additional downtime and without the need for a future planned or forced outage, received the benefit of the reduction in risk that this work achieved, and benefitted by avoiding the costs that these repairs and inspections would have accrued when performed as planned in future years.[121]

Unit 3 had been in service for over 22 years at the time of the Event.[122] Due to the magnitude of damage that occurred in the Event, the restoration work required purchasing and installing numerous new components, auxiliaries, systems, and subsystems.[123] Because the costs to acquire and install the new and upgraded equipment was almost entirely covered by insurance proceeds, customers significantly benefited and continue to benefit by having a more efficient, safe, and reliable unit without the inclusion of those costs in the rate base or otherwise recovered from customers.[124] Additionally, some restoration work avoided the need for future planned restoration projects. As one example, the twelve blade rows on each of the low-pressure turbines required replacement due to damage that occurred during the Event, and the Company secured insurance proceeds to replace all

[121] Ex. Xcel-31 at 13-14 (Schottler Direct).
[122] Ex. Xcel-31 at 11 (Schottler Direct).
[123] Ex. Xcel-31 at 11 (Schottler Direct).
[124] Ex. Xcel-31 at 13 (Schottler Direct).

blades during the restoration.[125] This work not only restored Unit 3 to service, but also provided measurable benefits to the Company and customers, including the avoidance of future outage time associated with future blade replacement, improved efficiency and reduced fuel consumption, and reduction in the risk of a future failure event.[126] In this way, much of the restoration work also provided measurable customer benefits that can be assessed against Replacement Power costs.

Further, significant additional work was performed during the restoration period that was not required to bring Unit 3 back to service, but was performed at that time to avoid future planned outages and improve the unit's performance and efficiency.[127] The Company was able to conduct these "Opportunity Projects" without extending the restoration period or delaying the return of Unit 3 to service as expeditiously as possible.[128] By performing the "Opportunity Projects" without the need for future outages, the Company avoided the future Replacement Power costs it would have accrued during those outages. Additionally, the performance and efficiency improvements gained by the "Opportunity Projects" reduced the amount of coal burned and emissions released, reducing fuel charges that would have been passed on to them through the Company's fuel adjustment clause.[129] For many of these "Opportunity Projects," the direct capital replacement costs were lower in 2012 and 2013 than they would have been in future years

[125] Ex. Xcel-31 at 11 (Schottler Direct).
[126] Ex. Xcel-31 at 11 (Schottler Direct).
[127] Ex. Xcel-31 at 12 (Schottler Direct).
[128] Ex. Xcel-31 at 13 (Schottler Direct).
[129] Ex. Xcel-31 at 12 (Schottler Direct).

when the projects were initially planned to occur. Thus, the Company's prudent decision to accelerate these "Opportunity Projects" from future years and conduct them during the restoration period netted customers numerous quantifiable benefits that must be considered.

In summary, the Company demonstrated that its management of the restoration process provided customer benefits in four categories: (1) the avoidance of direct cost of future work that was performed as part of the restoration work and avoidance of labor and material costs during the outage, (2) the reduction of future outage time, (3) improved performance and efficiency of Unit 3, and (4) the reduction of future risk of significant failure events.[130] In total, the Company estimated that, for those categories capable of reasonable estimation, Xcel Energy customers received benefits of approximately $16,260,000 to $16,760,000 on a Minnesota jurisdictional basis due to its management of the restoration process.[131] These customer benefits must be recognized in determining whether any refund is appropriate.

D. The Combined Impact of the Regulatory Relief, Company Recoveries Returned To Customers and Cost Savings Resulting From The Company's Restoration Efforts Have Resulted In No (or Minimal) Net Costs Being Borne By Customers

The record shows that the Company acted prudently and responsibly after the Event to return Unit 3 to service as expeditiously as possible to avoid unnecessary Replacement Power costs, while simultaneously using the restoration period to inspect, repair, and

[130] Ex. Xcel-31 at 14 (Schottler Direct).
[131] Ex. Xcel-31 at 20 (Schottler Direct). The Company did not attempt to estimate the value to customers of the reduction of future risk of significant failure events.

replace necessary components with insurance proceeds that avoided future direct costs and reduced future planned outages. Similarly, the Company acted prudently to undertake "Opportunity Projects" to reduce future outage time and provide improved unit efficiency earlier than planned, thus avoiding future Replacement Power costs and extending the duration of time that customers realized the improvement-based savings. Moreover, the Company acted prudently in its efforts to recover costs associated with the Event from insurers and the manufacturer, GE. These efforts, in addition to the Commission's disallowance of the inclusion of Unit 3 in the Company's rate base in its 2012 rate case, have already provided significant rate relief to Xcel Energy customers. As a result, *customers have not paid more for power than they would have had the Event not occurred* as demonstrated in the table below, summarizing the cost of replacement power and the rate relief already provided to customers, together with the timing of those costs or offsets.[132]

Total Replacement Power Costs and Offsets
(presented on a Minnesota jurisdictional basis)

Category	**Timing**	**Costs/(Offsets)**
Replacement Power Costs	November 2011-October 2013	$33.7 million[133]

[132] The timing of these costs and offsets is critical to recognize in determining the appropriate amount of accrued interest, if any, related to the replacement power costs.
[133] *See* Ex. Xcel-1 at 12 (Krug Direct).

Category	**Timing**	**Costs/(Offsets)**
GE Settlement Proceeds	February 2019	**[PROTECTED DATA BEGINS** *XXXXXXXXXXXX* XXXX[134] **PROTECTED DATA ENDS]**
2012 Rate Case Disallowance	2013	($21.6 million)[135]
Avoided Direct Costs and O&M Expenses	2014-2020	($8.66 million)[136]
Avoided Future Outage Time	2014 - 2030	($4.3 million - $4.8 million)[137]
Improved Performance and Efficiency Savings	October 2013 - present	($2.4 million)[138]

In sum, even if the Commission determines that the Company did not act prudently *before* the Event, which the Company vigorously disputes, the Company's prudent actions *after* the Event must still be considered. Given the prior rate case disallowance, the refunds and offsets to rate base provided to customers, and the avoided costs achieved by the Company's efforts during the restoration, no further refund is appropriate or warranted.

CONCLUSION

The record of this proceeding establishes that, based on the information the Company had or reasonably should have had prior to the Event, it made reasonable

[134] *Supra* Section IV.A.
[135] Ex. Xcel-1 at 17 (Krug Direct).
[136] Ex. Xcel-31 at 15, 20 and Sched. 4 (Schottler Direct).
[137] Ex. Xcel-33 at 20 and Sched. 4 (Detmer Direct).
[138] Ex. Xcel-31 at 16 (Schottler Direct).

decisions and took reasonable actions with respect to the operation and maintenance of Unit 3. Therefore, the Company respectfully requests that the Commission find the Company prudently incurred the "replacement power" costs at issue.

Should the Commission instead find that the Company acted imprudently in any way, the Company respectfully requests that the Commission first recognize the appropriate estimate of replacement power costs and then fully recognize the cost-mitigating actions taken by the Company after the Event, the rate relief provided by the GE Settlement, and the prior disallowance ordered by the Commission in the Company's 2012 rate case. Such a full analysis of the impact of the Event on customers demonstrates that customers have not paid more for power than they would have had the Event not occurred. Therefore, no customer refund is necessary or appropriate.

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