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BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street, St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350, St Paul MN 55101-2147

In re of Sherco Unit 3 Energy Replacement Costs.	OAH Docket No. 65-2500-38476
In re the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, et al.	MPUC Docket No. E-002/GR-12-961
In re the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, et al.	MPUC Docket No. E-002/GR-13-868
In re the Review of the 2012-13 Annual Automatic Adjustment Reports for All Electric Utilities	MPUC Docket No. E-999/AA-13-599
In re the Review of the 2013-14 Annual Automatic Adjustment Reports for All Electric Utilities	MPUC Docket No. E-999/AA-14-579
In re the Review of the 2015-16 Annual Automatic Adjustment Reports for All Electric Utilities	MPUC Docket No. E-999/AA-16-523
In re the Review of the 2016-17 Annual Automatic Adjustment Reports for All Electric Utilities	MPUC Docket No. E-999/AA-17-492
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OPENING BRIEF
OF THE MINNESOTA DEPARTMENT OF COMMERCE

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INTRODUCTION

In November 2011, Xcel's Sherco 3 generating facility failed when several blades separated from a rotor, substantially destroying the facility. The facility was out of service for approximately 22 months. The cost to restore the facility exceeded $104 million and Xcel incurred replacement power costs of approximately $33.7 million.

The issue in this case is whether ratepayers should get stuck with paying to replace the power that would have been produced by Sherco 3 during the period that it was out of service or whether Xcel should be required to refund those costs. Because Xcel, not ratepayers, failed to prudently operate and maintain Sherco 3, Xcel, not ratepayers, should bear the costs of the outage.

Xcel has the burden to prove that it acted prudently and has failed to carry that burden. Xcel failed to take action that a reasonable operator would have taken to prevent the disaster. First, Xcel did not have an adequate program in place for monitoring the presence of harmful chemical contaminants in Sherco 3's steam cycle. Second, Xcel failed to follow reasonable inspection practices, including failing to follow its own established inspection interval for conducting a major inspection of the Sherco 3 low pressure turbines. Because Xcel failed to take prudent actions that would have avoided the disaster at Sherco 3, costs of replacement power that were incurred because of the disaster were not prudently incurred and must be refunded to ratepayers.

BACKGROUND

This case represents the final chapter in the long-running saga of Sherco 3 that began more than a dozen years ago. Sherco 3 consists of four turbines, each of which has a series of blades (or "buckets")[1] that are attached to a rotor. On November 19, 2011, Xcel was bringing Sherco 3 back into service following an outage for planned maintenance. During testing, the rotor of one of

[1] Because the documents and testimony in this case usually refer to these structures as "buckets," this brief will generally use the term "bucket" rather than "blade."

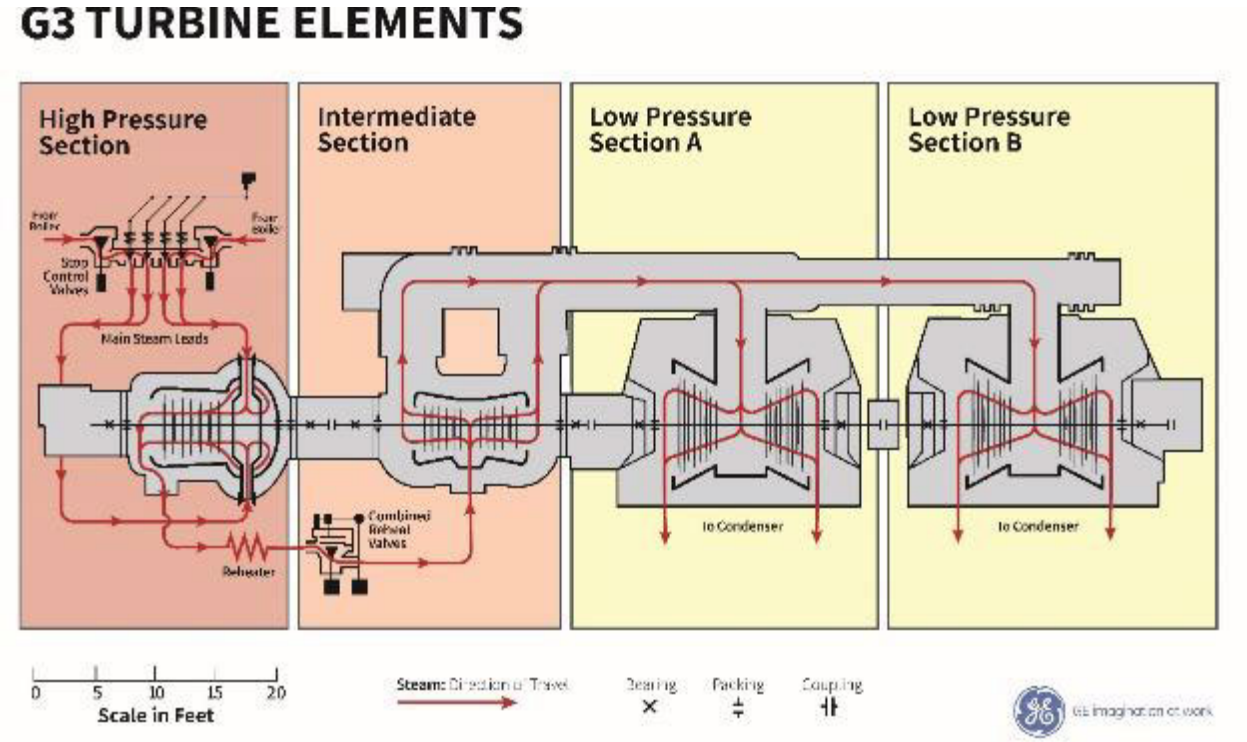
Sherco 3's low pressure turbines failed. This failure caused several buckets to come loose from the rotor, triggering an explosion and a fire that destroyed not only the turbine that had experienced the failure, but also Sherco 3's other low pressure turbine, its high pressure turbine, its intermediate low pressure turbine, and its generator.

I. SHERCO 3'S DESIGN AND OPERATION

Sherco 3 is one of three coal-fired generating units owned and operated by Xcel in Sherburne County. Xcel put Sherco 3 into service in 1987; it is the largest of the Sherco units, with a generating capacity of 900 megawatts. Xcel owns a 59% interest in Sherco 3, with the Southern Minnesota Municipal Power Agency (SMMPA) owning the remaining 41% interest. At the time of the turbine failure, Xcel was 100% responsible for all plant operations, maintenance, and other decisions associated with the plant, pursuant to an ownership and operating agreement between Xcel and SMMPA.[2]

As illustrated below, Sherco 3 has four turbines: a high pressure (HP) turbine, an intermediate pressure (IP) turbine, and two low pressure (LP) turbines (referred to as LP turbines A and B).[3] These four turbines combine to make up Sherco 3's the turbine generator train.[4]

[2] Ex. DOC-1 at 7-8 (Polich Direct). The Department will reference the exhibit number for the public version of testimony unless the not public information is directly relevant.
[3] *Id.* at 8, Figure 2.
[4] Evid. Hrg. Tr. Vol. 1 at 151-52, 157-58 (Kolb).

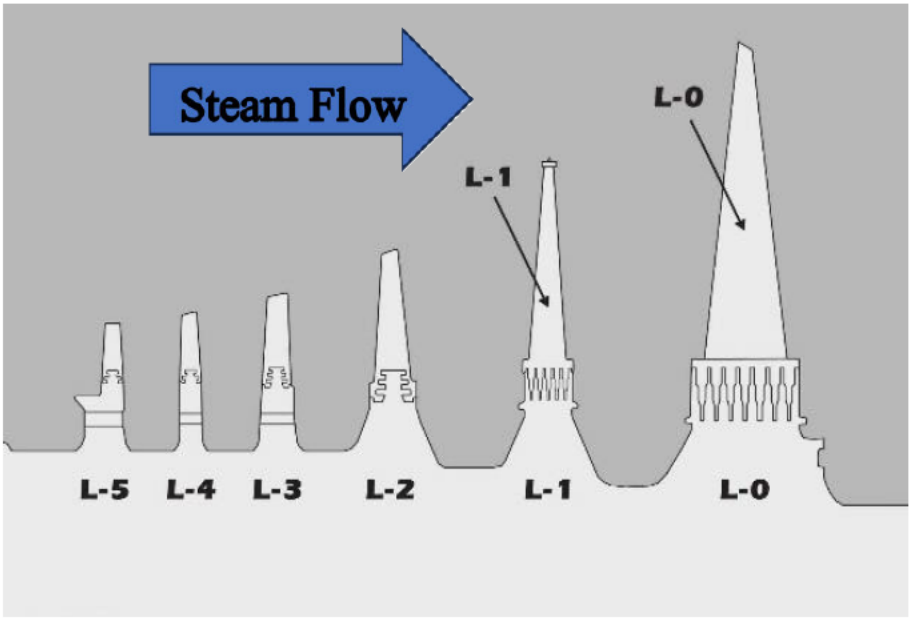


Sherco 3 burns coal to turn water into the steam that powers the turbines. Each turbine has multiple rows (or stages) of buckets. Sherco 3's LP turbines are double-flow turbines in which the steam enters the center of the turbine and flows in opposite directions. There are six stages of buckets on each side of each of the LP turbines, identified as stages L-0 through L-5. Pressurized steam entering the turbine first encounters nozzles that help to distribute the steam around the entire 360 degrees of the turbine.[5] As the steam exerts force on the buckets, the buckets convert the energy of the steam to horsepower in the turbine shaft that is used to power the generator.[6]

As the steam passes through each stage of buckets, the steam pressure drops and the steam expands, requiring longer buckets to maximize the conversion of steam energy to horsepower.[7]

[5] Ex. DOC-1 at 11, Figure 6 (Polich Direct)
[6] *Id.* at 11.
[7] *Id.* at 11-12.

As shown in the diagram below, each row of buckets becomes progressively longer as steam passes through the turbine. The longest row is the L-0 row and the next longest is the L-1 row.[8]

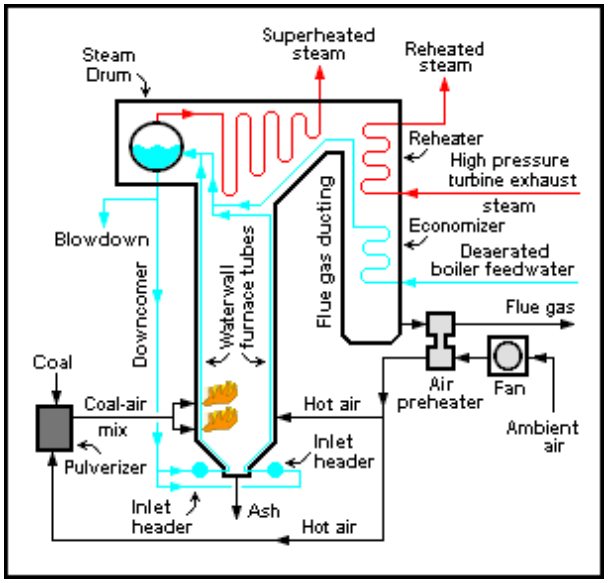


The buckets of the Sherco 3 LP turbines are attached to the rotor in one of two ways. The L-2, -3, -4, and -5 stages connect to the rotor with "tangential dovetails," which use an interlocking configuration, like the pieces of a jigsaw puzzle fitting together, to connect the buckets to the rotor. The L-0 and L-1 rows connect to the rotor using finger-pinned dovetails, which are finger-like structures that mate with grooves in the rotor and are held in place by pins inserted into the rotor disk.[9]

Sherco 3 makes steam using a type of boiler called a "drum boiler," which is illustrated below. A drum boiler has a large steel drum at the top of the boiler, which serves multiple purposes, one of which is to separate steam from water in the steam-production process. The boiler feedwater in a power generation plant like Sherco 3 enters the boiler through an economizer section which performs the initial water heating. From the economizer, the feedwater typically enters the steam

[8] Ex. Xcel-4 at 9 (Murray Direct); Ex. DOC-1 at 10-11, Figure 5 (Polich Direct).
[9] Ex. DOC-1 at 12, Figure 7 (Polich Direct); Ex. Xcel-4 at 10-11 (Murray Direct).

drum. The drum is designed with tubes on the bottom which circulate water down vertical sections of tubing (called the "water walls") of the boiler and tubes on the top which extract steam from the drum. The water from the bottom of the drum circulates down through the walls of the boiler and then back to the drum, gaining sufficient heat to turn the water into saturated steam (steam containing water droplets). The drum separates the water from the steam and sends the steam to the high temperature sections of the boiler where it is superheated and sent to the steam turbine.[10]



After the steam leaves the turbine, it is condensed into water and returns to the boiler to be re-circulated.[11] The area of the turbine where the steam begins to condense into water is known as the "phase transition zone" or the "Wilson line."[12] In the case of Sherco 3, the phase transition zone is generally in the area of the L-1 row of buckets.[13]

[10] Ex. DOC-1 at 9-10. Figure 3 (Polich Direct).
[11] *Id.*
[12] Ex. Xcel-26 at 11 (Tipton Direct); Ex. Xcel-62, part 1, GE Litigation Tr. Vol. 2, at 307-308 (Oct. 17, 2018) (Murray); Ex. Xcel-62, GE Litigation Tr. Vol. 3 at 595-596 (Oct. 18, 2018) (Kolb).
[13] Evid. Hrg. Tr. Vol. 1 at 63-64 (Nov. 1, 2023) (Murray); Ex. Xcel-62, GE Litigation Tr., Vol. 2 at 307-308 (Oct. 17, 2018) (Murray).

The term "cycle chemistry" refers to the chemistry associated with the boiler water and turbine steam cycle in fossil fuel electric generating plants. It is synonymous with the water chemistry (liquid water and steam) of the boiler water and turbine steam cycle.[14] Maintaining the cycle chemistry in a manner that minimizes the presence of contaminants that may cause damage to the turbines is critical to maintaining the generating unit's safe operation and reliability. There are several sources of guidelines for maintaining cycle chemistry of fossil fuel generating plants such as Sherco 3. One leading source of such guidelines is the Electric Power Research Institute (EPRI), whose guidelines the staff responsible for maintaining Sherco 3's cycle chemistry relied on. General Electric (GE), the manufacturer of the turbine, also published its own steam purity guidelines, which closely match the EPRI guidelines.[15]

II. THE CATASTROPHIC FAILURE

In November 2011, Sherco 3 had been in operation for approximately 24 years. Xcel took Sherco 3 offline for a planned outage to provide an opportunity for maintenance on the unit. During the planned outage, Xcel performed work on the HP and IP turbines to increase the amount of electricity those turbines were able to produce. This work was discretionary; it was not necessary to perform a repair or address a safety issue.[16] To accommodate work on the HP and IP turbines, Xcel decided to defer to 2014 a major overhaul (also known as a major inspection or major outage) of the LP turbines that, under Xcel's established inspection schedule, would've taken place in November 2011. Xcel instead elected to perform a more limited minor inspection on the LP turbines. [17]

[14] Ex. DOC-7 at 6 (Klotz Rebuttal).
[15] Ex. DOC-7 at 6-7 (Klotz Rebuttal); *see also* Ex. DOC-1 at 29-30 (Polich Direct).
[16] Evid. Hrg. Tr. Vol. 1 at 85 (Nov. 1, 2023) (Murray).
[17] Ex. DOC 1 at 38-39 (Polich Direct); *see also* Ex. Xcel-4 at 18-19 (Murray Direct); Ex. Xcel-7 at 45 (Kolb Direct); Evid. Hrg. Tr. Vol. 1 at 81-83 (Nov. 1, 2023) (Murray).

On November 19, Xcel had completed the maintenance outage and was performing testing before bringing the unit back online. One test was an "overspeed test," which is designed to test the function that shuts the turbine down if it exceeds a certain RPM threshold. During this testing, some of the L-1 bucket attachment points on the LP turbine rotor failed. As a result, some of the L-1 buckets came loose from the rotor, which caused a mass imbalance in the rotor and significant vibration that essentially caused the turbine to self-destruct. The generator shaft and the exciter shaft fractured, hurling a 200-pound part of the generator across the turbine floor and into the operator's room. A fire broke out when oil systems and the hydrogen cooling system ruptured and were ignited by overheating bearings. The resulting catastrophic failure of the LP turbine substantially destroyed the HP turbine, the IP turbine, both LP turbines, and the generator. Flying debris and fire caused significant damage to the control room and other plant facilities. The damage was catastrophic and fortunately no one was injured.[18]

Restoring Sherco 3 cost approximately $104.3 million and the unit was out of service for nearly two years.[19] While the unit was offline, Xcel had to purchase replacement power from the Midcontinent Independent System Operator. These replacement power costs totaled over $30 million for the outage period.[20]

An engineering firm that Xcel retained concluded that the L-1 rotor failed because of a condition called "stress corrosion cracking" or "SCC."[21] SCC causes a material to crack well below its design strength when placed under stress. Xcel's expert found that finger pinned attachments at the L-1 turbine end disk had failed due to SCC, most likely resulting from sodium

[18] Ex. DOC-1 at 13-14 (Polich Rebuttal); *see also* Ex. Xcel-1 at 10-11 (Krug Direct).
[19] Ex. Xcel-1 at 11-12 (Krug Direct).
[20] Ex. DOC-3 at 4, 18 (King Direct).
[21] Evid. Hrg. Tr. Vol. 2 at 33-35 (Nov. 2, 2023) (Tipton); Ex. Xcel-26, AAT-D-2 at 3 (Tipton Direct, Schedule 2).

hydroxide contamination of the steam.[22] Xcel's expert concluded that the SCC that caused the LP rotor to crack had formed some number of years – perhaps more than ten – prior to the accident.[23]

III. PROCEDURAL BACKGROUND

The turbine failure and resulting destruction of the Sherco 3 generating plant was the subject of civil litigation that produced an extensive evidentiary record and Commission proceedings concerning Xcel's recovery of costs resulting from the catastrophe.

A. The GE Litigation

In 2013, Xcel, SMMPA, and their insurers sued GE, seeking to recover damages resulting from Sherco 3's destruction.[24] The parties engaged in extensive discovery. In 2018, Xcel settled with GE and the case proceeded to two-week jury trial with Xcel's insurers pursuing a subrogation claim.[25] Many of the witnesses who testified for Xcel at trial also provided testimony in the current contested-case proceeding, including staff involved in operating and maintaining Sherco 3 (Messrs. Murray, Kolb, Schottler and Wold) and Xcel's expert witnesses (Messrs. Daniels and Tipton). Two other Xcel witnesses in this case, Messrs. Sirois and Detmer, submitted expert reports and were deposed in the GE Litigation but did not testify at trial.

At the close of evidence, the trial court dismissed Xcel's claim that GE had a post-sale duty to warn, finding that there was no way a jury could find that Xcel was unaware of the risk of harm to the turbine from SCC.[26] The jury found that Xcel was negligent in its operations and maintenance of Sherco 3 and that this negligence was a direct cause of damage to the facility. The

[22] Ex. Xcel-26, AAT-D-2 at 3 (Tipton Direct, Schedule 2).
[23] Evid. Hrg. Tr. Vol. 2 at 44 (Nov. 2, 2023) (Tipton).
[24] Evid. Hrg. Tr. Vol. 1 at 33-34 (Nov. 1, 2023) (Krug); Ex. DOC-15 (Case No. 71-CV-13-1472, Amended Complaint).
[25] Ex. DOC-16; Evid. Hrg. Tr. Vol. 1 at 41-44 (Nov. 1, 2023) (Krug); Ex. DOC-1, RAP-D-9 (Polich Direct, Schedule 9).
[26] Ex. DOC-1, RAP-D-8 at 31-36 (Polich Direct, Schedule 8).

jury further found Xcel to be 48% at fault and GE to be 52% at fault.[27] The court held, however, that because the jury had not found GE to be willfully and wantonly negligent or grossly negligent, Xcel's insurers failed to prove a necessary element of their remaining claims. Accordingly, the court ruled in GE's favor as a matter of law.[28]

The Court of Appeals affirmed. Specifically with respect to the failure to warn claim, the Court of Appeals found that the district court had properly determined "there is no basis to establish [post-sale duty to warn] because there's no way a jury could find that NSP was unaware of the risk of harm." The Court of Appeals agreed with the district court that there was ample evidence that NSP had a general awareness of the risks of SCC. This evidence included Xcel-prepared "System Health Report" that essentially predicted the catastrophe. That report stated that "[low pressure turbines] also experience dovetail pin cracking problems, erosion damage and may suffer from an industrywide problem with rotor wheel cracking. . . . Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles)." [29]

B. Proceedings before the Commission

In its rate case filed in November 2012, Xcel sought recovery of $35.4 million in Sherco 3 plant costs incurred in the test year and also asked to defer 2012 and 2013 property taxes and depreciation expenses relating to Sherco 3 in order to recover those expenses beginning in January 2014 over the 21-year remaining useful life of the plant. Noting that the Sherco 3 had been out of service for nearly 22 months, the Commission removed all direct costs, except for property taxes, from Xcel's rates. Further, the Commission granted Xcel's request to defer property taxes and

[27] Ex. DOC-1, RAP-D-9 (Polich Direct, Schedule 9).
[28] Ex. DOC-1, RAP-D-10 (Polich Direct, Schedule 10).
[29] *Aegis Ins. Servs v. Gen. Elec. Co.*, No. A19-0640, 2020 WL 614775, at *4 (Minn. Ct. App. Feb. 10, 2020).

depreciation, reasoning "Deferral recognizes that, although the unit was not used and useful during the 2013 test year, it remains a valuable asset and an integral part of the Company's generating fleet." Finally, the Commission stated that it would address replacement power cost when Xcel requested for approval of its fuel clause adjustment.[30]

When that issue came before the Commission in 2016 in the context of Xcel's petition for approval of its fuel clause adjustment, the Commission agreed with the Department and Office of the Attorney General – Residential Utilities Division (OAG-RUD) that it would be premature to decide the issue while the GE Litigation was still pending. In deferring power replacement costs to a later proceeding, the Commission observed:

> Sherco 3's outage caused Xcel Electric to incur greater energy-related costs than it otherwise would have. The ongoing litigation between Xcel Electric and General Electric may well reveal facts about the steps each of those parties took, or failed to take, that contributed to the outage and related costs. Consequently the Commission agrees with the Department and OAG that it would be premature to render a decision about these matters at this time. But the Commission also concurs with Xcel Electric that it would be premature to initiate another proceeding to address this issue while Xcel Electric and General Electric are already engaged in a separate proceeding. Rather, the Commission will simply defer its decision on this issue until the Commission has a sufficient record regarding the recovery of the cost of replacement energy.[31]

In November 2018, Xcel informed the Commission that Xcel and GE had reached a settlement under which GE would pay Xcel nearly **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** and that Xcel would file its plan to credit the applicable portion of the settlement to ratepayers.[32]

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[30] *In re Appl. of No. States Power Co. for Authority to Increase Rates for Elec. Serv. in the State*, E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 23 (Sept. 3, 2013) (eDockets20139-90902-01) (Xcel 2012 Rate Case Order)

[31] *In re Review of the 2012-2013 Annual Automatic Adjustment Reports for All Elec. Utils.*, E-999/AA-13-599, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS at 5-6 (June 2, 2016) (eDocket No. 20166-121943-04).

[32] Ex. DOC-17 (Sherco 3 Litigation Update (Nov. 2, 2018) (NOT PUBLIC).

In December 2018, Xcel informed the Commission of its plans to refund the settlement amount to customers through its monthly fuel clause adjustment, beginning on February 1, 2019. The Commission approved Xcel's proposed refund and affirmed that it would withhold any decision on the prudency of replacement power costs until the completion of related civil litigation, including any appeals.[33]

The GE Litigation, including appeals, finally concluded in 2020. The only issues remaining were whether Xcel prudently incurred replacement costs necessitated by the catastrophic failure at Sherco 3 and, if not, the amount of any refund to ratepayers. Concluding that additional record development would assist in deciding this issue, the Commission referred this matter to a contested case proceeding.

LEGAL STANDARD

Xcel bears the burden to prove that it acted prudently with respect to the operation and maintenance of Sherco 3. The Commission laid out the appropriate legal standard in its notice and order for hearing:

> Every rate made, demanded, or received by a public utility must be just and reasonable. In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks. The burden to prove a rate is just and reasonable is on the utility, and any doubt as to reasonableness will be resolved in favor of the consumer.[34]

As noted above, when evaluating whether costs are just and reasonable, the Commission determines whether the utility acted prudently. "Prudence" is "reasonable action taken in good

[33] *In re Application of N. States Power Co. for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, E-002/GR-12-961, ORDER AUTHORIZING SHERCO UNIT 3 RATEPAYER REFUND AMOUNT AND METHOD AND REQUIRING COMPLIANCE FILING (Apr. 11, 2019) (eDocket No. 20194-151886-02).

[34] Notice and Order for Hearing at 4 (citing Minn. Stat. §§ 216B.03, 216B.16, subd. 4).

faith based on knowledge available at the time of the action or decision."[35] And "[a]ctions taken in good faith are those taken without malicious intent, exercising the care that a reasonable person would exercise under the same circumstances at the time the decision was made."[36] Moreover, "[p]rudence is not evaluated using the benefit of hindsight."[37]

For forced outage costs recovered through automatic adjustment of charges and fuel clause adjustment mechanisms, the Commission has emphasized that "utilities have a duty to minimize unplanned facility outages through adequate maintenance."[38] When examining replacement power costs related to power plant failures, the Commission has also recently looked to "good utility practice" as a guiding principle akin to prudence for operating and maintaining utility facilities.[39] "Good utility practice" refers to "[A]ny of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and

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[35] *See, e.g.*, *In re Pet. of N. States Power Co. d/b/a Xcel Energy to Recover February 2021 Nat. Gas Costs*, G-002/CI-21-610, ORDER DISALLOWING RECOVERY OF CERTAIN NATURAL GAS COSTS AND REQUIRING FURTHER ACTION at 5 (Oct. 19, 2022) (eDocket No. 202210-189969-01). The same day, the Commission issued orders for Minnesota's three other natural gas utilities using the same standard.

[36] *Id.*

[37] *Id.*

[38] *In re Review of the 2006 Annual Automatic Adjustment of Charges for All Elec. and Gas Utils.*, E-999/AA-06-1208, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING FURTHER FILINGS, AND AMENDING ORDER OF DECEMBER 20, 2006 ON PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE at 5 (Feb. 6, 2008) (eDocket No. 4928266).

[39] *See In re Review of the July 2018–December 2019 Annual Automatic Adjustment Reports*, E-999/AA-20-171, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED AND REQUIRING REFUND at 5 (Feb. 25, 2022) (eDocket No. 20222-183172-01) ("The Commission agrees with the ALJ that Minnesota Power failed to satisfy its burden to prove that its maintenance of the Boswell Unit 4 hot reheat line was consistent with good utility practice. . . .") (20-171 PUC Order).

expedition."[40] Good utility practice refers to "acceptable practices, methods, or acts generally accepted in the region in which the Project is located" and is not intended to be limited to optimum practices.[41]

The Commission's prudence determination should be guided by Xcel's obligation to maintain and inspect its plants consistent with "good utility practice" as the Commission has done in past proceedings.[42] Specifically, because Xcel cannot show that it maintained and operated Sherco 3 consistent with "good utility practice," the replacement power costs arising from the outage are not reasonably and prudently incurred and must be refunded to ratepayers, with interest.[43] Finally, placing the burden of proof on the utility is consistent with utilities' clear obligation to prove their rates are "just and reasonable" and to resolve "[a]ny doubt as to reasonableness . . . in favor of the consumer."[44]

ARGUMENT

I. THE CAUSE OF THE TURBINE FAILURE AT SHERCO 3 – STRESS CORROSION CRACKING – WAS A WELL-KNOWN PHENOMENON IN THE INDUSTRY

Xcel's responsibility to refund replacement fuel costs to ratepayers is not based on hindsight. It is based on what Xcel knew at the time, both about the risks presented by SCC and how those risks could be avoided.

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[40] *See In re Review of the July 2018–December 2019 Annual Automatic Adjustment Reports*, E-999/AA-20-171, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION at ¶ 45 (eDocket No. 20218-177011-01). The Commission did not modify this definition in its Order. *See* 20-171 PUC ORDER.

[41] *Id*.

[42] *See id.* at ¶ 158 (determining that because Minnesota Power failed to show its maintenance of the power plant in question was in consistent with "good utility practice," "the costs associated with the Boswell Unit 4 hot reheat line outages were not reasonably and prudently incurred.").

[43] *See id.*

[44] Minn. Stat. § 216B.03 (2022).

The condition that caused the failure – SCC -- typically requires three things: a susceptible material, a corrosive environment, and high stress.[45] Corrosion that produces SCC typically occurs when a corrosive chemical, such as sodium hydroxide and/or chloride, penetrates a steel part and works its way into the steel's grain boundaries. Over time, the steel's grain boundary is compromised, forming a crack in the steel. Cracks typically propagate in a part at a high stress location, such as a corner or a notch.[46] In the case of the Sherco 3 failure, the LP turbine "B" rotor disk holding the L-1 buckets failed due to SCC in the pinholes, ledges, and base of the finger dovetail joints that attached the buckets to the rotor.[47] Inspection performed after the failure showed that cracking was prevalent throughout the LP rotor disk that attached the L-1 buckets to the LP rotor.[48] Xcel's experts concluded that cracks had been present in L-1 disks of both LP turbines for several years before the accident.[49]

SCC and risks associated with SCC were well-known in the industry generally and to Xcel in particular long before the Sherco 3 failure.[50] Xcel knew that undetected and unabated SCC could lead to a catastrophic rotor failure.[51] Further, Xcel knew that the area of the turbine where the steam condenses into water, known as the phase transition zone or Wilson line, was particularly susceptible to SCC, because of the greater potential for the concentration of contaminants in that

[45] Ex. DOC-1 at 21-22 (Polich Direct).
[46] Ex. DOC-1 at 22 (Polich Direct).
[47] Ex. DOC-1 at 25 (Polich Direct); Ex. Xcel-26, AAT-D-2 at 3 (Tipton Direct, Schedule 2).
[48] *Id*.
[49] Ex. DOC-1 at 26 (Polich Direct); Evid. Hrg. Tr. Vol. 2 at 44 (Nov. 2, 2023) (Tipton).
[50] Ex. Xcel-62, part 1, GE Litigation Tr., Vol. 2 at 307 (Oct. 17, 2018) (Murray); Ex. Xcel-62, GE Litigation Tr. Vol. 3 at 592-594 (Oct. 18, 2018) (Kolb).
[51] Evid. Hrg. Tr. Vol. 1 at 63-64 (Nov. 1, 2023) (Murray); Ex. Xcel-62, GE Litigation Tr., Vol. 2 at 316 (Oct. 17, 2018) (Murray).

area.[52] Xcel also knew that, in the Sherco 3 LP turbines, the Wilson line is generally found at the L-1 row of buckets, where the November 2011 failure occurred.[53]

Xcel has argued that, although it was aware of SCC as a risk for tangential-entry type dovetail attachments, SCC was not an issue for the finger-pinned type attachments that held the buckets to the L-1 rotor.[54] The evidence does not support this claim. In connection with his employment at Xcel, Mr. Murray was a member of a utility industry group called the L-1 Users' Group, which was a group of utilities who were experiencing problems with GE's L-1 blade design. [55] **[NOT PUBLIC INFORMATON BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** Further, Xcel knew that GE had issued Technical Information Letter (TIL) 1121 recommending that the buckets of low pressure

[52] Ex. Xcel-26 at 11 (Tipton Direct); Ex. Xcel-62, part 1, GE Litigation Tr. Vol. 2, at 307-308 (Oct. 17, 2018) (Murray); Ex. Xcel-62, GE Litigation Tr. Vol. 3 at 595-596 (Oct. 18, 2018) (Kolb).
[53] Evid. Hrg. Tr. Vol. 1 at 63-64 (Nov. 1, 2023) (Murray); Ex. Xcel-62, GE Litigation Tr., Vol. 2 at 307-308 (Oct. 17, 2018) (Murray).
[54] Ex. Xcel-4 at 22 (Murray Direct).
[55] Evid. Hrg. Tr. Vol. 1 at 64 (Nov. 1, 2023) (Murray).
[56] *Id.* ; Ex. DOC-19 (NOT PUBLIC).
[57] Evid. Hrg. Tr., Vol. 1, at 77-79 (Nov. 2, 2023) (Murray); Ex. DOC-24 (Navajo Generating Station Presentation) (NOT PUBLIC).
[58] Ex. DOC-24 (Navajo Generating Station Presentation) (NOT PUBLIC); Ex. DOC-21 (Nowak Report, Navajo Generating Station) (NOT PUBLIC).

turbines be removed in order to conduct a magnetic particle inspection (MPI) of finger dovetails to detect SCC and prevent a failure of precisely the sort that destroyed Sherco 3.[59] Plainly, finger dovetails did not have any special immunity from SCC and Xcel knew this. Xcel's argument to the contrary reflects nothing more than an after-the-fact rationalization of Xcel's risky inspection and maintenance decisions.

The evidence shows overwhelmingly that Xcel should have known and did know of the risk presented by SCC and that SCC could cause exactly the kind of catastrophic failure that occurred in November 2011. Nevertheless, as is discussed in greater detail, Xcel failed to take prudent measures to avoid this risk.

II. XCEL'S MONITORING OF SHERCO 3'S CYCLE CHEMISTRY WAS NOT PRUDENT.

A. Xcel Failed to Follow Key Guidelines for the Safe Operation of Sherco 3.

As Xcel's expert, Mr. Daniels acknowledged, continuous monitoring of the entire steam cycle is critical to equipment reliability.[60] SCC can result from contaminants in the steam cycle and Xcel understood the need for steam purity to minimize the risk of SCC.[61] The root cause analysis performed by Xcel's retained expert concluded that the SCC that caused the turbine failure at Sherco 3 was most likely the result of sodium hydroxide in the steam cycle.[62]

The utility industry has standards for assuring adequate steam purity. The EPRI is a research organization that supports the utilities industry by, among other things, publishing cycle chemistry guidelines that apply to fossil fuel electric generating plants that are intended to reduce the risk of SCC. The EPRI guidelines include recommending: 1) monitoring parameters and

[59] Ex. Xcel-21, HFS-D-7 (Sirois Direct, Schedule 7).
[60] Ex. Xcel-10 at 10 (Daniels Direct).
[61] Ex. Xcel-62, GE Litigation Tr., Vol 3, at 594 (Oct. 18, 2018) (Murray).
[62] Evid. Hrg. Tr. Vol. 2, at 34-35 (Nov. 2, 2023) (Tipton); Ex. Xcel-26, AAT-D-2, at 3 (Tipton Direct, Schedule 2); Ex. Xcel 61, Tipton Dep. Tr. at 27, 32 (Apr. 29, 2016) (NOT PUBLIC).

maximum exposure for each parameter; 2) specific locations in the steam cycle to be monitored; and 3) frequency of monitoring.[63] Certain monitoring parameters are referred to as "core parameters," which are those parameters that are "considered to be the minimum level of surveillance for all units."[64]

EPRI's recommendations represent prudent practices in the industry that Xcel professed to follow.[65] Xcel's steam chemistry expert, Mr. Daniels, previously testified that **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** Further, Mr. Daniels, has acknowledged that the EPRI chemistry guidelines are an authoritative source for steam chemistry and fossil steam plants.[70] As Sherco 3's chemistry supervisor, Duane Wold, testified, Xcel was an EPRI member and relied on the ERPI

[63] Ex. DOC-7, SK-R-10 (Klotz Rebuttal, Schedule 10).
[64] Ex. DOC-7, SK-R-1, at 93 (Klotz Rebuttal, Schedule 1); Ex. DOC-11, Wold Dep. Tr. at 142.
[65] Ex. DOC-7 at 24 (Klotz Rebuttal).
[66] Ex. Xcel-67, Daniels Dep. Tr. at 139 (Apr. 27, 2016) (NOT PUBLIC).
[67] *Id.* at 140 (NOT PUBLIC).
[68] Ex. Xcel-60, Sirois Dep. Tr. at 67-69 (May 6, 2016) (NOT PUBLIC).
[69] Ex. Xcel-61. Tipton Dep. Tr. at 76, 180 (Apr. 29, 2016) (NOT PUBLIC).
[70] Ex. Xcel-62, GE Litigation Tr. at 1202 (Oct. 4, 2018) (Daniels).

guidelines for its water chemistry program.[71] Guidance provided by GE, the manufacturer of the Sherco 3 low pressure turbines, closely mirrored EPRI guidance.[72]

Although Xcel was aware of EPRI's recommendations regarding the monitoring for contaminants at key locations in the steam cycle, they failed to follow those recommendations in numerous respects. The point is not that Sherco 3 did not follow all of EPRI's steam chemistry guidelines in every minute detail. Rather, the point is that the guidelines that Xcel chose to not follow relate directly to the disaster. The Department's analysis focused, in particular, on EPRI recommendations that are the most important for protecting steam turbines from the specific types of contaminants that are most likely responsible for causing SCC.[73] Areas of concern relating to risk of turbine damage from SCC that Mr. Klotz, the Department's steam chemistry expert, identified included the lack of management of risk from carryover,[74] inadequate sodium monitoring,[75] and the potential for contamination from poor makeup water quality.[76] Further, Mr. Klotz noted Sherco 3's lack of a formal cycle chemistry improvement program, which impeded the ability of the Sherco 3 staff to fully appreciate and mitigate risks arising from the lack of adequate monitoring for contaminants in the Sherco 3 steam cycle.[77]

B. Xcel Did Not Follow Prudent Practices for Measuring Mechanical Carryover at Sherco 3.

Limiting carryover from the drum boiler to the steam path is a critical aspect of maintaining steam purity at safe levels. "Carryover" describes a phenomenon whereby contaminants are

[71] Ex. DOC-11, Wold Dep. Tr. at 86-88 (Sept. 5, 2018); Ex. Xcel-62, GE Litigation Tr. Vol. 2 at 311-12 (Oct. 17, 2018) (Murray).
[72] Ex. Xcel-10 at 10 (Daniels Direct).
[73] Evid. Hrg. Tr. Vol. 2 at 268-29 (Nov. 2, 2023) (Klotz); Ex. Xcel-54 (DOC Response to Xcel IR 35).
[74] Ex. DOC-7 at 13-23 (Klotz Rebuttal).
[75] *Id*. at 23-32.
[76] *Id.* at 32-38.
[77] *Id*. at 7-13.

"carried over" from the boiler steam drum into the turbine's steam cycle.[78] Carryover that happens when contaminants are dissolved in the steam is called "vaporous carryover" and carryover that happens when chemical contaminants are entrained in liquid water droplets within the steam leaving the boiler is called "mechanical carryover."[79] EPRI limits for sodium, chloride, and sulfate in the drum water are based on the steam solubility of the contaminants at the operating drum pressure plus a safety factor to take into account mechanical carryover. Acceptable steam purity requires both that the concentration of contaminants in the drum boiler and the amount of mechanical carryover are maintained within acceptable levels.[80] Excessive mechanical carryover would increase the amount of sodium, chloride, and sulfate contamination in the steam path to the turbines, which increases the risk of turbine damage.[81]

Xcel did not follow EPRI guidelines intended to limit corrosion that might result from excessive carryover. EPRI considered limiting carryover to be so important that its guidelines identify measurement of carryover every six months to be a core parameter. However, Xcel did not conduct a six-month carryover measurement as recommended by the EPRI guidelines.[82] When asked about EPRI's recommendation at his deposition, Sherco 3's chief chemist stated that he was unaware of the measurement method referred to in the guidelines.[83]

Alternative methods used by Xcel to attempt to measure mechanical carryover were not sufficient to eliminate mechanical carryover as a potentially significant cause of the Sherco 3 turbine failure. Xcel's reliance on visual inspection of the drum as a way of checking for

[78] *Id*. at 13-14.
[79] *Id.* at 14.
[80] *Id.* at 14-15.
[81] *Id*. at 15.
[82] Ex. Xcel 62, GE Litigation Tr. Vol. 7 at 1212 (Oct. 24, 2018) (Daniels).
[83] Ex. DOC-11, Wold Dep. Tr. at 129 (Sept. 5, 2018).

mechanical carryover was inadequate The frequency of such inspections – every three years – was insufficient and was not assured to identify small gaps or cracks that would allow mechanical carryover to bypass steam separation equipment in the drum.[84] The risk from excessive mechanical carryover was exacerbated by the lack of prudent practices for monitoring sodium, as is discussed in the next section.

C. Xcel Did Not Follow Prudent Practices for Monitoring Sodium at Sherco 3.

Chloride, sulfate, and sodium hydroxide are key contaminants of concern for SCC-related turbine damage. The measurement of total sodium in the steam path includes sodium in sodium hydroxide and sodium associated with chloride and sulfate as well as other contaminants that are not a significant concern for damage from SCC.[85] In this way, monitoring for sodium provides an indirect measurement of chloride, sulfate, and sodium hydroxide.[86]

Monitoring of the steam cycle may be continuous or it may be performed through grab samples. At Sherco 3, continuous monitoring for sodium, as distinguished from a grab sample, was an automated process that measured the concentration of sodium in a steam sample six times a second, with the monitoring data recorded in Sherco 3's plant information (PI) system.[87] A grab sample involved, as the name suggests, "grabbing" a sample from the steam path on one or two week intervals, analyzing the sample, and manually recording the results of the analysis.[88]

EPRI recommended continuous sodium monitoring of either the main steam or the reheat steam as a core parameter.[89] The main steam sample is taken from the steam line between the superheater and the high pressure turbine and the reheat steam sample is taken from the steam line

[84] Ex. DOC-7 at 22 (Klotz Rebuttal).
[85] Ex. DOC-7 at 24 (Klotz Rebuttal).
[86] *Id.; see also* Ex. Xcel-57, Daniels Dep. Tr. at 121 (Apr. 27, 2016) (NOT PUBLIC).
[87] Evid. Hrg. Tr. Vol. 2 at 87-90 (Nov. 2, 2023) (Daniels).
[88] *Id*. at 89-90.
[89] Ex. DOC-11, Wold Dep. Tr. at 134-35 (Sept. 5, 2018).

between the reheater and the intermediate pressure turbine.[90] The lack of Xcel's measurement of carryover elevates the concern about the need to adequately monitor sodium in the main or reheat steam. This is because the level of sodium in either the main or reheat steam represents the amount of sodium carryover from the steel drum in addition to any sodium that is introduced through attemperators, which spray feedwater into the steam path to cool the steam.[91] Continuous monitoring of either the main steam or the reheat steam for sodium is critical because of the potential for sodium to lead to corrosion, with continuous monitoring of reheat steam being the best practice.[92]

EPRI recommended continuous monitoring of the reheat steam for sodium as a core parameter.[93] Xcel did not, however, monitor the reheat steam of the Sherco 3 LP turbines for sodium or any other parameter.[94]

Mr. Daniels, in his testimony in this case, dismissed the lack of monitoring of Sherco 3's reheat steam as "irrelevant."[95] This claim is inconsistent with Mr. Daniels's notes from his meetings with Mr. Wold, Xcel's steam chemist, in connection with his retention by Xcel in the GE Litigation. According to Mr. Daniels's notes, he met with Mr. Wold on July 20, 2012.[96] In that meeting, Mr. Wold described "a number of potential events that could have contributed caustic to the steam and created caustic SCC" including "[m]ultiple RH [reheat] tube leaks." Mr. Daniels's notes reflect that:

> The leaks were found after the unit came down, by maintaining vacuum on the condenser and listening for the vacuum noise cause by the leak. Fly ash could have

[90] Ex. DOC-7 at 27 (Klotz Rebuttal); *see also* Ex. Xcel-9 at 4, Figure 1 (Daniels Direct).
[91] Ex. DOC-7 at 27 (Klotz Rebuttal)
[92] *Id*. at 31.
[93] Ex. DOC-7, SK-R-10; Ex. DOC-11, Wold Dep. Tr. at 134-35, 153-55 (Sept. 5, 2018).
[94] Ex. DOC-11, Wold Dep. Tr. at 134-35.
[95] Ex. Xcel-16 at 11 (Daniels Rebuttal).
[96] Ex. DOC-34 (Xcel Response to DOC IR S61).

> also been sucked in at the time The ash when solubilized would contain some level of caustic Duane [Wold] has no RH sample or way to determine the chemical composition of the RH steam.[97]

Mr. Daniels characterized the reheat tube leaks as one of the two most important potential contributing factors to the accident.

Mr. Daniels returned to the reheat tube leak issue three years later in another meeting with Mr. Wold.[98] In that meeting, Mr. Daniels learned that "[t]he reheater tubes have suffered from a few failures" and that the "tube leaks were allowed to go on for some time before the unit came off for repairs," a delay which could have caused other tubes to leak.[99] Xcel had one of the reheat tubes analyzed in May 2004 and was surprised by the amount of ash-like material found on the inside of the tube. However, since the laboratory sample – i.e., the grab sample – was on the main steam and not on the reheat stem, "the level of contamination during such an incident would never have been detectable."[100] Given this known contamination of the reheat steam, the lack of monitoring of the reheat steam was plainly not irrelevant.

Further, Xcel understood the importance of monitoring reheat steam. In connection with inspection recommendations for SCC, Mr. Murray advised Mr. Wold and others to "note OEM [i.e., GE] recommendations regarding reheat steam purity." In fact, GE's General Electric Knowledge (GEK) 72281c, Steam Purity Recommendations for Utility Steam Turbines, published in 2004, recommended continuous monitoring of reheat steam.[101] Mr. Wold admitted, however, that he never reviewed GEK 72281c and that he did not implement any monitoring of the reheat steam at Sherco 3.[102]

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[97] *Id*. at Attachment A, page 1 of 2.
[98] *Id*. at Attachment B.
[99] *Id.* at Attachment B, page 2 of 3.
[100] *Id*.
[101] Ex. DOC-1, RAP-D-30 (Polich Direct, Schedule 30).
[102] Ex. DOC-11, Wold Dep. Tr. at 151-52 (Sept. 5, 2018).

Xcel did not implement continuous monitoring of Sherco 3's main steam until 2008.[103] Mr. Daniels acknowledged the importance of continuous monitoring of main steam sodium. **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]**

Prior to 2008, Xcel monitored Sherco 3's sodium in the main steam intermittently, through weekly grab sampling.[106] Grab sampling was not an adequate substitute for continuous monitoring of sodium. Without continuous steam monitoring, Sherco 3 was blind to intermittent excessive carryover of sodium hydroxide from the steam drum into the steam path.[107] Further, the specific detection limit of the testing method used at Sherco 3 for weekly sodium analysis only allowed measurement down to five parts per billion sodium, which is 2.5 times the EPRI's recommended normal target value of less than two parts per billion.[108] Thus, Xcel could not determine, using this measurement method, whether main steam sodium was at or below the limit established by the EPRI guidelines. The detection limit of the testing method used at Sherco 3 was far from sufficient for the intended purpose of the test.[109]

[103] Ex. Xcel-62, GE Litigation Tr. Vol. 7 at 1214 (Oct 24, 2018) (Daniels); Ex. DOC-11, Wold Dep. Tr. at 36-37 (Sept. 5, 2018).
[104] Ex. Xcel-57, Daniels Dep. Tr. at 16, 95 (Apr. 27, 2016) (NOT PUBLIC).
[105] *Id.* at 179-80 (NOT PUBLIC).
[106] Ex. DOC-7 at 31 (Klotz Rebuttal).
[107] *Id*.
[108] *Id*. at 31-32, SK-R-10 (Klotz Rebuttal, Schedule 10).
[109] *Id.* at 42.

D. Make-up Water Quality Cannot Be Ruled Out as a Factor that Contributed to the Formation of SCC.

Make-up water, as the name suggests, is water that is added to the steam cycle to make up for losses of water and steam through leaks, sampling, and other causes.[110] At Sherco 3, the make-up water came from well water that was processed through the demineralizer system, which is designed to purify the water for use in the generating plant.[111] The purified water then is forwarded to storage tanks where it is held until it is forwarded to the hot wells of the three Sherco operating units as needed.[112] If make-up water quality is poor, this means it contains higher levels of contaminants, including chloride, sulfate, and sodium, which can contribute to LP turbine SCC damage.[113]

Xcel failed to set prudent limits for make-up water quality. EPRI's recommended limit for concentrations of chloride, sulfate, and sodium was three parts per billion.[114] **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** Although Xcel's expert claimed the Sherco chemistry manual that Mr. Klotz relied on was outdated, Xcel has not identified any alternative makeup water limits that replaced the chemistry

[110] *Id*. at 38; Evid. Hrg. Tr. Vol. 2 at 115 (Nov. 2, 2023) (Daniels).
[111] Ex. DOC-7 at 33 (Klotz Rebuttal).
[112] *Id.*
[113] *Id*.; Evid. Hrg. Tr. Vol. 2 at 115 (Daniels).
[114] Ex. DOC-7 at 38 (Klotz Rebuttal).
[115] Ex. DOC-8 at 34-35 (Klotz Rebuttal) (NOT PUBLIC).

manual. Rather, other chemistry standards applicable to Sherco 3 that Xcel produced in this case did not include any limitations for make-up water.[116]

Xcel has the burden to show the prudency of its steam chemistry practices, including those practices relating to make-up water purity. Make-up water quality data was not sufficient to rule out contamination from make-up water as a contributing cause of the turbine failure. Xcel provided no make-up water quality data from 1999 to March 2004. Subsequent to March 2004, there was no continuous monitoring data, but only data from grab samples taken, on average, once every two to three weeks. This sampling was too infrequent to draw any definitive conclusions regarding make-up water quality at Sherco 3.[117] The Commission cannot conclude, based on a lack of data, that Sherco 3's make-up water did not contribute to the turbine failure.

E. Available Data is Insufficient to Support a Conclusion that Water and Steam Quality Did Not Play Role in the Formation of SCC that Caused Sherco 3's Destruction.

A lack of reliable data prevents Xcel from carrying its burden of proof with respect to the effectiveness of monitoring practices at Sherco 3. Mr. Klotz attempted to perform an analysis of hourly cycle chemistry data that Xcel produced but issues with the quality of data provided prevented him from completing such an analysis. Mr. Klotz noted that there were gaps in the data where no data was reported for several different cycle chemistry parameters. He also noted pervasive instances where identical numbers, down to ten digits, were reported for different parameters for several hours in a row. There were also pervasive instances where the change in different cycle chemistry parameters from hour to hour was exactly the same to 10 digits. Because it is not possible to have exactly the same readings for multiple hours in a row, the only conclusion

[116] Evid. Hrg. Tr. Vol. 2 at 120-23 (Nov. 2, 2023) (Daniels); Exs. DOC-36, 37, and 38 (Xcel Responses to DOC IRs S101, S101 Supplement, and S102).
[117] Ex. DOC-7 at 10-11 (Klotz Rebuttal).

that can be drawn is that the data was not reliable. Without valid hourly chemistry data, it is not possible to accurately evaluate Sherco 3's steam and water chemistry history or even determine whether Sherco 3 had exceeded EPRI's recommended shutdown limits.[118] Although Mr. Klotz did identify instances where it appeared that EPRI shutdown timing limits had been exceeded, issues with the integrity of the available data prevented him from drawing a definitive conclusion.[119] Xcel bears the burden of proof; a determination that Sherco 3's cycle chemistry practices were prudent cannot be based on the absence of reliable data.

Mr. Daniels confirmed the existence of gaps in the available data. For example, after Sherco 3 began continuous sodium monitoring in the main steam in 2008, data from that monitoring was either not recorded or not accurately recorded from January 1, 2009, to February 2010 and from March 2011 until the planned outage.[120] In other words, from 1999 until the planned shutdown in October 2011, data from continuous sodium monitoring of either the main steam or the reheat steam, which EPRI identifies as core monitoring requirements, is available for approximately 24 months out of 154 months. **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** Such data provides no information regarding Sherco 3's cycle chemistry in periods of time between sampling and is not an adequate substitute for the missing continuous monitoring data.

[118] *Id.* at 12.
[119] *Id*.
[120] Evid. Hrg. Tr. Vol. 2 at 87-88 (Daniels); Ex. DOC-32 (Xcel Response to DOC IR S56).
[121] Ex. Xcel-57, Daniels Dep. Tr. at 195-96 (Apr. 27, 2016) (NOT PUBLIC).

Mr. Daniels states that, in connection with his analysis, he became aware that "there were times when data points had not been recorded properly, or the data accuracy was questionable."[122] He specifically identified January 1, 2009, to February 2010, as a period when the Yokogawa recording system then in use at Sherco 3 did not record reliable data regarding sodium monitoring in the main steam.[123] Other than this example, however, Mr. Daniels did not do anything to attempt to determine other periods for which the data produced by Sherco 3's systems were not reliable.[124]

F. Xcel Acted Imprudently in Failing to Implement a Formal Cycle Chemistry Improvement Program.

Cycle chemistry performance and review programs comprise a set of formal activities that take place at regular intervals. Such programs involve evaluating all cycle chemistry data for a specified interval to determine compliance with established limits, identifying compliance gaps, determining causes for compliance gaps, and developing an action plan to address the causes. Compliance chemistry program requirements, such as periodic mechanical carryover testing, are checked. Following a thorough review, a formal summary report of the evaluation is prepared and distributed within the organization to keep management and stakeholders informed of performance, performance gaps, risks, action plans, and progress in completing action plans.[125] The use of such a formal cycle chemistry review program is a well-established practice in the utility industry – as of 1997, 65 utilities around the world had received training regarding EPRI's integrated boiler tube failure/cycle chemistry program and had implemented such a program.[126]

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[122] Ex. Xcel-10 at 26 (Daniels Direct).
[123] Evid Hrg. Tr. Vol. 2 at 88 (Nov. 2, 2023) (Daniels).
[124] *Id.* at 91-92 (Daniels).
[125] Ex. DOC-7 at 9 (Klotz); *see also* Ex. Xcel-55.
[126] Evid. Hrg. Tr. Vol. 2 at 269-71 (Nov. 2, 2023) (Klotz); Ex. Xcel-55 (DOC Response to Xcel IR 33).

Instead of a formal cycle chemistry review program, Xcel relied on informal communications, including emails, phone calls, hallway discussions, and the like that focused on specific day-to-day operating issues.[127] There is no evidence of a holistic review of Sherco 3's performance that would have been conducted had Sherco 3 had a cycle chemistry review program in place.[128] Indeed, the testimony of key Sherco 3 employees confirms cycle chemistry review practices at Sherco 3 that can best be described as ad hoc. Mr. Murray stated, based only on discussions with staff, that he was not aware of any steam chemistry excursions prior to the turbine failure that would call for inspection for SCC, while, at the same time, stating he did not recall any specific discussions regarding that issue.[129] Mr. Kolb testified that he was unaware of any documentation reflecting any analysis of whether any of the conditions calling for inspection of the finger dovetails for SCC had occurred.[130] Mr. Wold testified that he could not recall anyone ever asking him to examine Sherco 3's water chemistry history.[131] Rather than a program to proactively identify potential issues with Sherco 3's cycle chemistry, Sherco 3 took a "no news is good news" approach to Sherco 3's cycle chemistry.[132]

Had Sherco 3 had in place a robust, rigorous chemistry performance review and improvement program, those employees responsible for the safe and reliable operation of the plant would have had a much better understanding the risk of SCC-related turbine damage and would have been better equipped to take action to mitigate that risk.[133]

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[127] Ex. Xcel-53 at 1 (Daniels Surrebuttal).
[128] Ex. DOC-7 at 9-10, SK-R-7 at 6 (Klotz Rebuttal, Schedule 7).
[129] *Id*. at 7-8 (Klotz Rebuttal).
[130] Evid. Hrg. Tr. Vol. 1 at 193-94 (Nov. 1, 2023) (Kolb); Ex. Xcel-58, Kolb Dep. Tr. at 99 (Dec. 18, 2015) (NOT PUBLIC).
[131] Ex. DOC-11, Wold Dep. Tr. at 145 (Sept. 5, 2018).
[132] Ex. DOC-7, SK-R-7 at 10 (Klotz Rebuttal, Schedule 7).
[133] *Id.* at 10.

III. XCEL'S DECISION TO DEFER THE PLANNED 2011 MAJOR INSPECTION OF THE SHERCO 3 LP TURBINES WAS NOT PRUDENT

A. Deferring the Major Inspection of the Sherco 3 LP Turbines from 2011 to 2014 Contradicted Xcel's Inspection Policies

Although Xcel attempts to shift its responsibility for inspection practices at Sherco 3 to GE, there is no question that it was Xcel and not GE that had the ultimate authority and responsibility for determining the frequency and scope of inspections in a manner that took into account Sherco 3's operating conditions.

While GE could, and did, make recommendations, it was up to Xcel to decide whether and how to act on those recommendations.[134] A 1978 GE publication titled "Maintenance and Inspection of Turbine Rotors and Buckets," GEK 463354B, notes that, since inspection frequency depends on a number of factors, such as service duty, system demands, age of the unit, and many other plant requirements that are within the knowledge and control of the owner, "the time interval between inspections must be determined by the owner."[135] Not surprisingly, steam chemistry is a factor that can influence inspection frequency.[136] Xcel did not share steam chemistry data with GE, therfore GE would not have been in a position to take that information into account in making any recommendations regarding inspection frequency and scope.[137]

Although Xcel had established a schedule for frequency of major inspections of the Sherco 3 LP turbines, it failed to follow its own schedule in connection with the 2011 planned outage. Xcel understood that increasing the inspection interval increased risk to the turbine. As part of his job duties, Mr. Kolb prepared an annual System Health Report for the Sherco 3 low pressure

[134] Evid. Hrg. Tr. Vol. 1 at 159-61 (Nov. 1, 2023) (Kolb).
[135] Ex. DOC-1 at RAP-D-18 (Polich Direct, Schedule 18); Evid. Hrg. Tr. Vol. 1 at 159-61 (Nov. 1, 2023) (Kolb); Ex. Xcel-62, GE Litigation Tr. Vol. 3 at 605 (Oct. 18, 2018) (Kolb).
[136] Evid Hrg. Tr. Vol. 1 at 160-61 (Nov. 1, 2023) (Kolb).
[137] *Id*. at 162-62.

turbines for the purpose of keeping Xcel's management informed.[138] A System Health Report dated December 7, 2010 – a little less than a year before the turbine failure caused by SCC – observes that "These LP's may suffer from an industry-wide problem with rotor wheel cracking."[139] Mr. Kolb goes on to note that "Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles)."[140] In his report to management, Mr. Kolb also states that "GE recommends a TBO [time between major overhauls] of 5 years. Increasing inspection interval adds risk. Currently scheduled for a 8 1/3 year TBO this cycle."[141] With respect to inspection plans for the low pressure turbine, the System Health Report states, "Maintain 6 year inspection frequency, consider extending to 9 years" and that "[w]ith the proper engineering study the LP inspection interval could possibly be extended to 9 years . . . . Otherwise maintain 6-year overhaul frequency. Next major scheduled for 2014."[142]

The last major inspection of the Sherco 3 low pressure turbines took place in 2005. If Xcel had stuck to a six-year inspection interval, it would've performed another major inspection in 2011.[143] But that's not what happened. Nor did Xcel do the engineering study that Mr. Kolb's report described as necessary prior to extending the interval from six to nine years.[144] Nevertheless Xcel decided to defer the major inspection of the low pressure turbines for three years, until

[138] *Id*. at 171-72.
[139] Ex. Xcel-24, HJS-D-14 at 18 (Sirois Direct, Schedule 14).
[140] *Id.* at 19.
[141] *Id.* at 18; *see also* Evid. Hrg. Tr. Vol. 1 at 109 (Nov. 1, 2023) (Murray); Evid. Hrg. Tr. Vol. 1 at 179 (Nov. 1, 2023) (Kolb).
[142] Ex. Xcel-23, HJS-D-14 at 21 (Sirois Direct, Schedule 14).
[143] Evid. Hrg. Tr. Vol. 1 at 80-81 (Murray); Ex. DOC-25(Sherco 3 Low Pressure Turbine Operation and Inspection History).
[144] Evid. Hrg. Tr. Vol. 1 at 112-13 (Nov. 1, 2023) (Murray); Ex. Xcel-58 Murray Dep. Tr. at 209 (Apr. 22, 2015) (NOT PUBLIC).

2014.[145] Instead of doing the major inspection of the low pressure turbines in 2011, Xcel did work on the high pressure and intermediate turbines, not out any concerns for safety or reliability, but in order to increase the Sherco 3 plant's output.[146]

B. Performing Only a Minor Inspection of the Sherco 3 Low Pressure Turbines in 2011 Instead of a Major Inspection Unnecessarily Exposed Sherco 3 to the Risk of Catastrophic Failure

A major inspection of the Sherco 3 low pressure turbines would have involved, at least, removing the turbine rotor from the shell, cleaning it, and conducting a thorough visual inspection of the L-1 row.[147] Visual inspection could have revealed chemical deposits on external surfaces indicative of contaminants in the steam cycle.[148] Additionally, with the rotor out of the shell, Xcel could have performed a bucket lift check (also referred to as a "wheel gap check") – a test to detect SCC that, pursuant to Xcel's inspection policy was to be completed "at the next scheduled overhaul where a GE LP turbine is scheduled to be opened for inspection"[149] (i.e., in 2011). A bucket lift check would have involved using a gauge to measure the gap between the bucket attachment and the rotor wheel.[150] An excessive bucket gap would have indicated a need for further investigation, including an ultrasound to determine whether the gap was attributable to cracking of the pins or some other cause, such as SCC in the bucket attachment.[151] If the ultrasound found that the gap was not due to cracked pins, Xcel could then have removed one or more sections of the L-1 row

[145] Ex. Xcel-4 at 18-19 (Murray Direct); Ex. Xcel-7 at 45 (Kolb Direct).
[146] Ex. Xcel-7 at 45-46 (Kolb Direct); Evid. Hrg. Tr. Vol 1 at 85 (Nov. 1, 2023) (Murray).
[147] Evid. Hrg. Tr. Vol. 2 at 220-224 (Polich); Ex. Xcel-4 at 10 (Murray Direct); Ex. DOC-5 at 11-12 (Polich Rebuttal); *see also* Ex. DOC-1 at 11, Figure 6 (Polich Direct) (picture of LP turbine rotor removed from housing).
[148] Ex. DOC-5 at 14 (Polich Rebuttal).
[149] Evid. Hrg. Tr. Vol. 1 at 100-103 (Nov. 1, 2023) (Murray); Ex. Xcel-23, HJS-D-10 at 4 (Sirois Direct, Schedule 10).
[150] Ex. DOC-5 at 13 (Polich Rebuttal).
[151] Ex. DOC-5 at 14 (Polich Rebuttal); Evid. Hrg. Tr. Vol. 2 at 220-24 (Nov. 2, 2023) (Polich).

to perform a magnetic particle inspection to look for SCC.[152] Xcel's own expert acknowledges that, had Xcel done a magnetic particle inspection with the L-1 buckets removed, it would have found the SCC and the disaster would have been averted.[153]

Xcel argues that, even had it done a major inspection of the low pressure turbines during the 2011 planned outage, it would not have removed the buckets and, thus, would not have discovered the SCC that lead to the turbine failure.[154] This claim ignores the purpose of the inspection as well as the additional information that Xcel would have had available to it had it conducted a major inspection.

An inspection is not a purely mechanical exercise. In discussing the significance of a major inspection GE, in GEK 46354B, states:

> Naturally, during a major inspection, with all the rotors exposed, a more thorough inspection should be made. Two methods of inspection are available, visual and non-destructive testing. A good visual examination will quite often reveal the majority of problems that might be encountered *and will generally reveal areas that should be more thoroughly by non-destructive testing*.[155]

As Mr. Kolb acknowledged, if an inspection identifies an issue, Xcel's practice is to follow up and "run it to ground."[156] Xcel cannot confidently say what it would done (or not done) had it performed a major inspection of the Sherco 3 LP turbines in 2011 because, having decided not to do that inspection, it does not know what it would have found.[157] In fact, the cracking was so

[152] Evid. Hrg. Tr. Vol. 2 at 220-24 (Nov. 2, 2023) (Polich).
[153] Evid. Hrg. Tr. Vol. 2 at 44-45 (Nov. 2, 2023) (Tipton); *see also* Evid. Hrg. Tr. Vol. 2 at 49 ("The only thing that would have prevented this, *other than had it been inspected, which is obvious*, is for stresses to have been reduced") (emphasis added) (Tipton)
[154] Ex. Xcel-7 at 45 (Kolb Direct).
[155] Ex. DOC-1, RAP-D-18 at 3 (emphasis added) (Polich Direct, Schedule 18).
[156] Evid Hrg. Tr. Vol. 1 at 224 (Nov. 1, 2023) (Kolb).
[157] Ex. DOC-5 at 12 (Polich Rebuttal).

severe in 2011 that, had the buckets been removed, the cracks likely would have been found through visual inspection.[158]

However, because Xcel did a minor inspection rather than a major inspection of the LP turbines in 2011, the scope of inspection was much narrower. Xcel did not open the turbine or remove the rotor. Xcel opened the turbine manway to visually inspect the L-0 row, with no inspection at all of the L-1 row, even though Xcel knew that was the part of the turbine most susceptible to SCC.[159] Because Xcel deferred the major inspection that was scheduled for 2011, it lost the opportunity to detect the SCC that resulted in Sherco 3's destruction.

In surrebuttal testimony, Mr. Murray asserted that performing a wheel gap check on a finger pinned attachment would not have produced meaningful information. This claim is contrary to a wealth of evidence, including Mr. Murray's own testimony. In the GE Litigation, Xcel produced two documents relating to another generating facility, Navajo Generating Station, that refer to performing a lift check to find SCC in the finger-pinned dovetail connections of the L-1 row of the facility's low pressure turbines.[160] Both documents were in Xcel's possession by the mid-1990s.[161] Mr. Murray knew of the SCC at Navajo and he knew of at least one of these two documents. When asked specifically at his deposition about the experience at Navajo Generating Station, Mr. Murray acknowledged **[NOT PUBLIC INFORMATION BEGINS** [redacted]

[158] Ex. Xcel-58, Kolb Dep. Tr. at 197 (Dec. 18, 2015) (NOT PUBLIC); Evid. Hrg. Tr. Vol. 1 at 201-04 (Nov. 1, 2023) (Kolb).
[159] Evid. Hrg. Tr. Vol. 1 at 88-89 (Nov. 1, 2023) (Murray); Ex. Xcel-58, Kolb Dep. Tr. at 329 (Dec. 18, 2015) (NOT PUBLIC).
[160] Ex. DOC-20, at XCEL_Sherco_06_0011535 and 0011542 (Novak Report Navajo Generating Station (NOT PUBLIC); Ex. DOC-24 at p. 5 (Navajo Generating Station Presentation).
[161] Ex. DOC-22 (Xcel Response to DOC IR S77); Evid. Hrg. Tr. at Vol. 1 at 75-75 (Nov. 1, 2023) (Murray).
[162] Ex. Xcel-59, Murray Dep. Tr. at 244-45 (Apr. 22, 2015) (NOT PUBLIC).

NOT PUBLIC INFORMATION ENDS] In the case of Navajo, SCC was discovered during an inspection rather than as a result of a rotor failure while the unit was in operation.

In 2008, several years after he heard about the discovery of SCC in the finger dovetails at Navajo, Mr. Murray drafted a policy titled "Steam Turbine Rotor Wheel Inspection Recommendations for Stress Corrosion Cracking."[163] The purpose of this policy was "to provide some background on stress corrosion cracking of steam turbine rotors, summarize current OEM recommendations, and provide inspection recommendations where OEM guidance is lacking."[164] One directive in this policy – which applied to all GE reheat steam turbines, including the Sherco 3 turbines – was that "At the next scheduled overhaul where a GE LP turbine is scheduled to be opened for inspection, perform wheel gap checks on the L-1, L-2, L-3."[165]

Mr. Murray argues in his surrebuttal that, if performing a bucket lift check were an industry practice, then GE would have recommended it.[166] In fact, the evidence shows that GE did precisely that. In responding to an Xcel request for proposal (RFP) for "L-1 Bucket Upgrade, Non-Destructive Rotor Examination, Field Engineering Services," dated December 1, 1998, GE proposed performing "bucket dovetail lifting" on the L-1 row.[167] Mr. Murray attempted to dismiss the GE recommendation, claiming it was a generic document that is not specific to Sherco 3 and that it did not mean what it says.[168] Mr. Murray's explanation is not credible. GE's RFP response references the serial number of Sherco 3's low pressure turbines and contains specific information

[163] Evid Hrg. Tr. Vol. 1 at 101 (Nov. 1, 2023) (Murray); Xcel-23, HJS-D-10 (Sirois Direct, Schedule 10).
[164] Evid. Hrg. Tr. Vol. 1 at 101-02 (Nov. 1, 2023) (Murray); Xcel-23, HJS-D-10 at 1 (Sirois Direct, Schedule 10).
[165] Evid. Hrg. Tr. Vol. 1 at 102-03 (Nov. 1, 2023) (Murray); Xcel-23, HJS-D-10 at 4 (Sirois Direct, Schedule 10).
[166] Ex. Xcel-45 at 3 (Murray Surrebuttal).
[167] Ex. DOC-26 (GE Proposal); Evid. Hrg. Tr. Vol. 1 at 93-97 (Nov. 1, 2023) (Murray).
[168] Evid. Hrg. Tr. Vol. 1 at 94-95 (Nov. 1, 2023) (Murray).

regarding the physical characteristics of Sherco 3's L-1 row.[169] Further, in referring to replacement of buckets of the L-1 row, the RFP response refers to the row as "Finger Type Dovetail."[170] There is no basis, beyond Mr. Murray's conclusory assertion, that GE's RFP response was "generic" or cannot be taken at face value.

The evidence shows that bucket lift testing is one tool available to investigate L-1 finger-pinned dovetails for the presence of SCC without removing the buckets. It is not, by itself, conclusive, but, when deployed as part of a prudent inspection program, provides the operator with information that it can use to determine whether further inspection, including removal of the buckets to perform magnetic particle inspection, should be conducted. Although Xcel was well-aware of the value of such testing, it did not, contrary to its own internal policies, perform it.

C. Xcel Imprudently Decided to Forego a "Buckets Off" Inspection of the L-1 Row to Save Money.

GE produced two Technical Information Letters (TILs) to provide guidance regarding inspection of dovetail bucket attachments for SCC – TIL 1277 (1277-2, as amended) and TIL 1121 (1121-3AR1, as amended).[171] That Xcel approached the application of TIL 1277 very differently from the way it approached the application of TIL 1121 shows that Xcel's decision not to do a "buckets off" inspection of the L-1 row of Sherco 3's LP turbines was driven primarily by financial considerations.

TIL 1277 applied only to generating facilities with "once through" type boilers – as distinguished from drum boilers. TIL 1277's stated purpose was to "inform users of the need to inspect dovetails on steam turbines to detect possible Stress Corrosion Cracking."[172] TIL 1277

[169] Ex. DOC-26 at 5 (GE Proposal).
[170] *Id*. at 8.
[171] Ex. Xcel-23, HJS-D-6 and HJS-D-7 (Sirois Direct, Schedules 6 and 7).
[172] Ex. Xcel-23, HJS-D-6 at 1 (Sirois Direct, Schedule 6).

recommended that tangential dovetail connections of the L-1 through L-4 rows on units with once through boilers with more than ten years of service be ultrasonically inspected.[173] TIL 1277 recommended that all rows of finger dovetail attachments on units with once through boilers with more than ten years of service be inspected by removing the buckets and tested with magnetic particle testing.[174]

Although TIL 1277, on its face, applied only to units with once through boilers, Xcel decided to apply it at all three Sherco units, all of which had drum type boilers rather than once through boilers. However, Xcel applied the inspection policy only to the tangential dovetails, not the finger dovetails.[175] Thus, Xcel performed testing of Unit 1's tangential dovetails in 2007 and, when that testing revealed cracking of the L-1 row attachments, performed phased array testing of Unit 2's L-1 row tangential dovetails.[176]

Xcel decided to apply TIL 1277 to the tangential dovetail connections on its drum boilers units on its own initiative, without receiving any formal guidance from GE.[177] **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]**

Unfortunately, Xcel did not take the same "err on the side of safety" approach with respect to TIL 1121. TIL 1121 provides detailed instruction on how to perform magnetic particle

[173] *Id.* at 2.
[174] *Id*.
[175] Ex. Xcel-7 at 40-41 (Kolb Direct); Ex. Xcel-5 at 14-17 (Murray Direct).
[176] Ex. Xcel-5 at 16-17 (Murray Direct).
[177] Evid. Hrg. Tr. Vol. 1 at 113-15 (Nov. 1, 2023) (Murray).
[178] Ex. Xcel-58, Kolb Dep. Tr. at 217-18 (Dec. 18, 2015) (NOT PUBLIC).

inspection of finger dovetail connections for SCC, which requires that the buckets first be removed. TIL 1121 recommends that magnetic particle inspection be performed: 1) whenever the buckets are removed; 2) when abnormal events or operational abnormalities cause concern for the longer-term reliability of the unit. TIL 1121 further defines "abnormal events or operational abnormalities" to mean "out-of-the-ordinary occurrences, during operation or maintenance, which may increase the risk of stress corrosion cracking and/or fatigue cracking."[179] TIL 1121 also provides a non-exhaustive list of such events, including caustic or chemical ingestion or contamination, carryover from boiler, leaking condenser heater tube, overspeeds, and water ingestion. Finally, TIL 1121 states "If in doubt, GE will help evaluate the need for additional MPI of the rotor wheel finger dovetail area."[180]

Although Xcel's witnesses insist that there were no abnormal events or operational abnormalities of the kind described in TIL 1121, Xcel's consideration of these issues was, at best, incomplete. As discussed above, Sherco 3 did not do testing that EPRI recommended and there is reason to be concerned about contamination of the steam cycle from excessive carryover, which was one of TIL 1121's specifically listed examples. Additionally, Mr. Wold described to Mr. Daniels "a number of potential events that could have contributed caustic to the steam and created caustic SCC."[181] Based on his meeting with Mr. Wold, Mr. Daniels noted "the two that are the most important to me now are the number of [reheat] tube leaks that would have allowed ingestion of ash into the tubes and therefore into the turbine; and the fast ramp rates after wind power was incorporated."[182] With respect to fast ramp rates, Mr. Daniels recorded that "Xcel needs to find

[179] Ex. Xcel-23, HJS-D-7 at 4 (Sirois Direct, Schedule 7).
[180] *Id*.
[181] Ex. DOC-34, Attachment A at page 1 (Xcel Response to DOC IR S61).
[182] *Id*. at Attachment A, page 2.

documentation where GE and the boiler manufacturer gave their blessing to ramp this fast."[183] Mr. Daniels never saw the documentation that he believed was necessary.[184] Nor is there evidence that Xcel did anything to follow up on the issue of leaking reheat tubes, even though this issue was known to Xcel years before the accident.[185] **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS]** There is no evidence that Xcel ever considered whether any of these events warranted removal of the L-1 bucket in order to inspect for SCC.[187] There is no documentation, indeed, no evidence at all, that TIL 1121 was considered when Xcel decided to extend the inspection interval.[188] There is no documentation reflecting any analysis of whether any of the TIL 1121 conditions had occurred.[189] Xcel never took GE up on its offer to help evaluate the need for MPI.[190]

[183] *Id*.
[184] Evid. Hrg. Tr. Vol. 2 at 113 (Nov. 2, 2023) (Daniels).
[185] Ex. DOC-34, Attachment B at 2 (reheat tube was analyzed in 2004, Xcel was "surprised by the mount of ash-like material on the inside of this tube. After repairs were made and during the subsequent startup there would have been potential for this material to moved into the IP and LP turbines.")
[186] Ex. DOC-31B (Nov. 1, 2005 email re turbine rotor steam cleaning) (NOT PUBLIC); Ex. Xcel-58, Kolb Dep. Tr. at 228 (Dec. 18, 2015) (NOT PUBLIC).
[187] *Compare* Ex. Xcel-7 at 35-37 (Kolb Direct) (describing what was done to determine whether Sherco 3 had experienced "abnormal or anomalous events" warranting removal of the buckets under TIL 1121).
[188] *See* Evid. Hrg. Tr. Vol. 1 at 119-121 (Nov. 1, 2023) (Murray).
[189] Evid. Hrg. Tr. Vol. 1 at 193-194 (Nov. 1, 2023) (Kolb); Ex. DOC-58 Kolb Dep. Tr. at 99 (Dec. 18, 2015) (NOT PUBLIC).
[190] *Compare* Evid. Hrg. Tr. Vol. 1 at 195-197 (Nov. 1, 2023) (Kolb) (asserting that Murray contacted GE about advice on whether to perform MPI on the Sherco 3 L-1 rows) *with* Evid. Hrg. Tr. Vol. 1 at 121 (Murray) (never contacted GE to evaluate need for MPI for need for MPUC on Sherco 3 rotor dovetails and is not aware of anyone at Xcel who did).

Nevertheless, Mr. Kolb admitted that he and Mr. Murray had wanted to do the buckets off inspection described in TIL 1121 but felt that they needed a specific direction from GE to justify the expense to Xcel's management:

[NOT PUBLIC INFORMATION BEGINS [redacted] **NOT PUBLIC INFORMATION ENDS]**

So why did Xcel decide to err on the side of safety by inspecting the tangential dovetails without any specific direction from GE but was unwilling to inspect the finger dovetails without more direction from GE? The answer is simple. The process for inspecting tangential dovetails is low cost and quick. In contrast, Mr. Sirois estimated that removing buckets and performing MPI, in contrast, would cost $1-$2 million and would require three to four weeks to complete.[192] In this circumstance, financial considerations won out over engineering judgment, resulting in catastrophe.

The Commission has recognized a utility's incentive to skimp on maintenance.[193] Maintenance costs are set in the utilities' test years and apply for future years. So if a utility can spend less than its test year amount on maintenance, that money will be available for other purposes, including shareholder dividends. But replacement power costs caused by improper

[191] Ex. Xcel-58 Kolb Dep. Tr. at 196-97 (Dec. 18, 2015) (NOT PUBLIC).
[192] Ex. Xcel-21 at 20 (Sirois Direct). To provide some context, the estimated $2 million price tag to perform MPI was less than .07% of revenue requirement of $2,795,919,000 approved by the Commission in Xcel's 2012 rate case. *See* 2012 Rate Case Order at 46 (eDockets No. 20139-90902-01).
[193] 20-171 PUC ORDER at 3 (eDockets No. 20222-183172-01).

maintenance are automatically recovered from ratepayers in the absence of a challenge by the Department, Commission, or other party. The Commission has recognized the perverse incentive this creates and carefully monitors maintenance expenditures and practices "[t]o 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."[194] The decision to not remove the LP turbine L-1 buckets in order to complete an inspection for SCC appears to have resulted from the perverse incentive that the Commission has sought to avoid.

IV. XCEL SHOULD REFUND REPLACEMENT POWER COSTS INCURRED DURING THE PERIOD SHERCO 3 WAS OUT OF SERVICE FOLLOWING THE TURBINE FAILURE.

Xcel, not ratepayers, failed to prudently inspect and maintain Sherco 3. Xcel, not ratepayers, should pay for the consequences of its imprudence. Xcel passed on significant replacement power costs to ratepayers during the almost two-year outage. To date, only a small fraction of those costs has been returned. The Commission should require Xcel to refund ratepayers approximately $55.68 million in replacement power costs. This amount appropriately uses the replacement power cost estimate developed by Xcel in the GE Litigation, is reduced by a portion of replacement power costs already refunded to ratepayers through Xcel's settlement with GE, and includes interest.

A. The Replacement Power Cost Estimate Developed by Xcel in the GE Litigation Should Be Used to Calculate the Refund.

The Department, Office of the Attorney General – Residential Utilities Division (OAG-RUD), and Xcel all agree that the most reasonable estimate of replacement power costs is Xcel's estimate from the GE Litigation.[195] This estimate is based on a comprehensive model that

[194] *Id.*
[195] *See* Ex. DOC-9 at 17 (King Rebuttal); Ex. Xcel-34 at 18 (Detmer Direct); Ex. OAG-1 at 13–14 (Lee Rebuttal).

reasonably estimates the MISO market and costs incurred by ratepayers due to Sherco 3's unavailability for nearly two years.

Xcel provided two separate estimates of replacement power costs from the turbine failure. Xcel provided its first estimate in November 2014 in the 2012-13 docket for Xcel's Annual Automatic Adjustment ("AAA") reports—the AAA estimate.[196] The AAA estimate calculation resulted in replacement power costs of $41.2 million for Xcel's Minnesota jurisdiction.[197] Xcel provided the second estimate in its lawsuit against GE to estimate the loss of use damages—the GE Litigation estimate.[198] Under the GE Litigation estimate, the total energy replacement cost is $33.7 million for Xcel's Minnesota jurisdiction.[199]

The GE Litigation estimate is based on complex modeling to estimate the MISO market results under a scenario where Sherco 3 remained available.[200] The AAA estimate, while appropriate to estimate replacement power costs for shorter outages, contains simplifying assumptions on forced outage rates and start-up costs that are not realistic for an outage lasting almost two-years.[201] The GE Litigation estimate is also based on a more comprehensive methodology and considers broader market impacts to Xcel's load and other resources.[202] Last, the GE Litigation estimate was supported by Xcel and its insurers in the extensive litigation, where they had an incentive to seek the highest defensible replacement power costs amount to support

[196] Ex. Xcel-34 at 2, NJD-D-2 (Detmer Direct, Schedule 2).
[197] Ex. Xcel-34 at 11–12, NJD-D-2 at 7 (Detmer Direct, Schedule 2).
[198] Ex. Xcel-34 at 3, NJD-D-3 & 4 (Detmer Direct, Schedules 3 and 4).
[199] Ex. Xcel-34 at 18, NJD-D-3 (Detmer Direct, Schedule 3); Ex. DOC-3 at (King Direct).
[200] Ex. Xcel-34 at 15–17 (Detmer Direct); Ex. DOC-3 at 11 (King Direct).
[201] Ex. Xcel-34 at 13–15 (Detmer Direct); Ex. DOC-9 at 15 (King Rebuttal).
[202] Ex. Xcel-34 at 13–15 (Detmer Direct); Ex. DOC-9 at 15 (King Rebuttal).

higher damages. The GE Litigation estimate is the most reasonable estimate of replacement power costs and should be used to calculate a refund to Xcel's customers.[203]

B. Xcel's Refund Should Reflect the Portion of the GE Settlement Representing Replacement Power Costs that Has Already Been Returned to Ratepayers.

The replacement power cost refund should be reduced by the portion of Xcel's settlement with GE that represents replacement power costs. The GE settlement proceeds have already been refunded to ratepayers and some portion of that amount is related to replacement power costs. This is fundamentally different from Xcel's other claimed avoided costs, which are discussed below.[204] The replacement power cost refund should therefore be reduced by the Department's estimate of the portion of the percentage of the GE settlement attributable to replacement power costs.

Prior to trial in the GE Litigation, Xcel negotiated a settlement with GE of **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS].** The Minnesota jurisdictional portion of the settlement was refunded to electric ratepayers through the February 2019 fuel clause adjustment. The GE settlement was a **[NOT PUBLIC INFORMATION BEGINS** [redacted] **NOT PUBLIC INFORMATION ENDS].**

The Department twice requested that Xcel estimate what portion of the GE settlement should be considered for replacement power costs.[206] Xcel did not provide an estimate, despite

[203] *See* Ex. DOC-9 at 17 (King Rebuttal); Ex. Xcel-34 at 18 (Detmer Direct): Ex. OAG-1 at 13–14 (Lee Rebuttal).
[204] Ex. DOC-9 at 9 (King Rebuttal).
[205] Ex. DOC-4 at 19 (King Direct) (NOT PUBLIC).
[206] *See* Ex. DOC-3, MJK-D-8 (King Direct, Schedule 8) (Xcel Response to DOC IR No. S42) (requesting that Xcel "explain in detail what amount of the GE settlement amount Xcel believes is appropriate to offset energy replacement costs incurred as a result of the Sherco 3 outage" and not receiving a responsive answer); Ex. DOC-9, MJK-R-3 (King Rebuttal, Schedule 3) (Xcel

the opportunity to do so in response to information requests, rebuttal testimony, and the Judge's grant of substantial surrebuttal testimony.[207] Xcel instead argued that because the "settlement did not in any way attempt to break this overall settlement amount into specific categories or components," it should receive credit for the full amount as an offset.[208]

Offsetting the forced outage cost refund by the full amount refunded in the fuel clause adjustment is inappropriate. Doing so would allow Xcel to double-recover approximately $5.5 million for its property losses—first through the recovery of restoration costs not recovered through insurance[209] and second by offsetting imprudently incurred replacement power costs. In addition, some amount of the settlement must be attributable to the more substantial property loss, as the settlement ended Xcel's litigation against GE. Xcel instead argues that ratepayers should be denied a refund of imprudent replacement power costs, simply because it and GE chose not to break up the provisions of their settlement and Xcel chose to remit the GE settlement through the fuel clause adjustment.[210] Xcel's choices in its settlement negotiations or in its refund mechanism should not harm ratepayers by allowing it to offset the full GE settlement amount.

Moreover, Xcel has the burden of proof in this proceeding. It is therefore Xcel that must show *all* the replacement power costs it collected from ratepayers were both prudently incurred and "just and reasonable."[211] Because Xcel has refused to provide an estimate of replacement

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Response to DOC IR No. S46) (asking Xcel "What portion of the GE Settlement amount is applicable to restoration versus replacement power costs?").

[207] *See* Ex. DOC-3, MJK-D-8 (King Direct, Schedule 8) (Xcel Response to DOC IR No. S42); Ex. DOC-9, MJK-R-3 (King Rebuttal, Schedule 3) (Xcel Response to DOC IR No. S46).

[208] Ex. Xcel-3 at 9 (Krug Rebuttal).

[209] *See* Ex. DOC-3, MJK-R-2 (King Direct, Schedule 2) (Xcel Response to Oct. 21, 2020 Information Request) (stating that approximately $5.5 million of restoration costs were included in rate base in Xcel's 2015 rate case).

[210] *See* Ex. Xcel-3 at 9 (Krug Rebuttal).

[211] See Section II for a discussion of the legal standard and burden of proof.

power costs embedded in the GE settlement, the Commission could determine that no amount of the settlement should offset replacement power costs. Such a determination would be consistent with the utility's burden of proof and the statutory directive that "any doubt be resolved in favor of the consumer."[212] But the Department did not advocate such a stringent approach.

The Department reasonably estimated the replacement power costs embedded in the settlement by using the portion of damages from the GE Litigation that Xcel attributed to loss of use (replacement power costs). In the GE Litigation, Xcel categorized 24.4% of its damages attributable to loss of use and 76.5% of its damages as property loss.[213] The Department's cost expert therefore proposed applying the same loss of use percentage to the total GE settlement to estimate the amount applicable to replacement power costs.[214] Using that same proportion of replacement power costs and restoration costs that Xcel advocated in the litigation to determine the component of the settlement for refund purposes is reasonable, particularly in the absence of any alternative explanation provided by Xcel.

Therefore, the Department recommends that the principal amount of replacement power cost calculation be reduced by 24.4% of the GE settlement amount in the month where it was returned to ratepayers.[215]

C. Xcel Should Be Required to Refund Interest.

When referring the matter to the Office of Administrative Hearings, the Commission found a material factual issue regarding whether the replacement power costs from the Sherco 3 outage were reasonable and prudent and "if not, the amount of overcharges, plus interest, that should be

[212] Minn. Stat. § 216B.03 (2022).
[213] Ex. DOC-3, MJK-D-3 at 28, Table 2 (King Direct, Schedule 3)) (Metcalf Report) (noting that in addition to the two described categories, the "Other" category in Table 2 provides a negative $1,696,218, causing the combined percentage to equal more than 100%).
[214] Ex. DOC-9 at 9 (King Rebuttal).
[215] *See* Ex. DOC-10, MJK-R-5 at 4, line 88 (King Rebuttal, Schedule 5) (NOT PUBLIC).

returned to ratepayers."[216] The Commission therefore indicated that if Xcel did not act prudently, refund of any overcharges should include interest. But Xcel has not yet committed to paying interest.[217] Xcel should be required to pay interest on the amount of overcharges determined by the Commission consistent with past Commission orders and the basic principle of the time-value of money.

Ordering Xcel to pay interest is consistent with Commission practice. The Commission has required utilities to pay interest at the prime rate for refunds ranging from replacement power costs to incentive compensation.[218] Interest is also required under statute for any excess amount collected under utilities' interim rate schedules in general rate cases.[219] The Commission has even required a utility to calculate and refund *interest on additional interest* from overcharged interim rates that were not properly remitted to ratepayers.[220]

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[216] Notice and Order for Hearing at 10.
[217] Evid. Hrg. Tr. Vo. 1 at 33 (Nov. 1, 2023) (Krug).
[218] *See, e.g.* 20-171 PUC ORDER at 5 (eDockets No. 20222-183172-01) (requiring electric utility to refund $4.48 million in imprudently incurred replacement power costs plus interest calculated at the prime rate); *In re Application of N. States Power Co. for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, E002/GR-15-826 et al, Order at 2, 5 (Oct. 21, 2020) (eDocket No. 202010-167555-03) (requiring Xcel to apply a refund for over collected property taxes and incentive compensation with interest rates based on Xcel's cost of debt and the prime rate respectively); *In re Application by CenterPoint Energy Res. Corp., d/b/a CenterPoint Energy Minn. Gas for Authority to Increase Nat. Gas Rates in Minn.*, G008/GR-17-285, ORDER ACCEPTING REPORT, REQUIRING STI REFUND, AND ALLOWING STI REFUND TO BE INCLUDED AS PART OF INTERIM RATE REFUND IN DOCKET NO. G-008/GR-19-524 at 4 (Apr. 6, 2021) (eDocket No. 20214-172614-02) (ordering gas utility to refund $147,212 of over collected short-term incentive compensation (STI) to ratepayers plus interest).
[219] Minn. Stat. § 216B.16, subd. 3(c) (2022).
[220] *In re Application by CenterPoint Energy for Authority to Increase Nat. Gas Rates in Minn.*, G008/GR-17-285, ORDER DIRECTING REFUNDS REQUIRING REPORTING AND REQUIRING COMPLIANCE FILINGS at 2 (June 17, 2019) (eDocket No. 20196-153634-01) (requiring a gas utility "within 65 days of May 2, refund the additional interest due via one-time credits to affected customers, plus interest, accruing from December 7, 2018, through the refund date").

The Commission has required utilities to pay interest on overcharges for good reason. The passage of time reduces the value of each dollar.[221] Not requiring Xcel to pay interest on the overcharged replacement power costs would essentially force ratepayers to give Xcel an interest-free loan for the past 10 to 12 years. Ratepayers would be far from whole. Instead, Xcel should be required to pay interest at the prime rate as calculated by Mr. King—approximately $20 million.[222] Should a refund occur after January 2025, the month in which Mr. King calculated a refund occurring,[223] the Commission could require an update using the undisputed and publicly available prime rate.[224]

V. XCEL'S ARGUMENTS THAT IT SHOULD BE RELIEVED FROM PAYING REPLACEMENT POWER COSTS EVEN IF FOUND IMPRUDENT CONFLICT WITH RATEMAKING AND REGULATORY PRINCIPLES.

Xcel reaches for numerous justifications and concocts methods to reduce the amount of replacement power costs it will be required to refund if the Commission finds Xcel acted imprudently. Xcel astoundingly questions whether its ratepayers "ultimately bore any net costs due to the Event" and claims that "customers have not been harmed" by Xcel's imprudence.[225] Xcel unearths various types of "avoided costs"[226] and "customer benefits"[227] it claims resulted from its decisions and argues that these should be netted against the undisputed replacement power

[221] *See* Ex. DOC-3 at 17 (King Direct) ("[I]nterest must be considered to represent the costs in terms of dollars that are relevant today.").
[222] *See* Ex. DOC-10 at 17 (King Rebuttal) (NOT PUBLIC). Notably Mr. King removed the appropriate portion of the GE settlement amount from the interest calculation in the month it was refunded. Therefore, Xcel will appropriately pay interest on that amount for the time it had the use of those ratepayer dollars, but no longer. *See* Ex. DOC-10, MJK-R-5 at 4, row 88 (King Rebuttal, Schedule 4) (NOT PUBLIC) (removing GE settlement amount from the replacement power interest calculation in February of 2019).
[223] Ex. DOC-3 at 17 (King Direct).
[224] Ex. DOC-9 at 16 (King Rebuttal).
[225] Ex. Xcel-38 at 1 (Krug Witness Summary).
[226] *E.g.*, Ex. Xcel-2 at 16 (Krug Direct).
[227] *E.g.*, Ex. Xcel-31 at 20 (Schottler Direct).

costs.[228] But Xcel provides no support in law or Commission practice for netting costs in this way.[229] On the contrary, the Commission has determined that imprudently incurred replacement power costs must be refunded to customers, with interest.[230]

More specifically, Xcel's arguments on these avoided costs and customer benefits lack support and are divorced from ratemaking principles, pricing realities, and common sense. Xcel first incorrectly claims that the Commission's determination in 2012 that the plant was not "used and useful" precludes the Commission from ordering a refund for replacement power costs. Then, if a full prohibition on refunds is unavailable, Xcel shifts to discrete costs that it claims were avoided from various aspects of the power plant rebuild, including offsetting amounts insurers paid to Xcel to repair the facility after the catastrophic failure and future outages Xcel claims were avoided due to Xcel having to rebuild much of its facility.[231] Last, Xcel incorrectly argues that the Department's prudence arguments would have increased the November 2011 planned outage by several months, and this too should act as an offset to the imprudently incurred replacement power costs. The Commission should reject Xcel's efforts to sidestep its responsibility to refund imprudently incurred replacement power costs.

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[228] The Department acknowledges that in comments submitted prior to retaining its experts, it agreed with combining costs to determine damage to ratepayers. *See* Dep't Comments at 19–20 (Jan. 15, 2021) (eDocket No. 20211-169851-08). The Department now has the benefit of analysis from Mr. Polich and Mr. King, and direction from the Commission in its notice and order for hearing to examine replacement power costs, and no longer advocates this approach.

[229] *See generally* Ex. Xcel-2 (Krug Direct); Ex. Xcel-4 (Krug Rebuttal).

[230] *See* 20-171 PUC ORDER at 5 (finding that the costs associated with a hot reheat line rupture were not prudently incurred and requiring refund of *all* replacement power costs with interest).

[231] Xcel also argued that the avoided cost of purchasing replacement power insurance should offset its replacement power costs. *See* Ex. Xcel-2 at 20 (Krug Direct); Ex. Xcel-37 at 7-8 (Miller Direct) (PUBLIC); Ex. Xcel-36 at 7–8 (Miller Direct) (NOT PUBLIC). Since no party in the contested case proceeding has argued that Xcel should have purchased replacement power insurance, the Department anticipates Xcel will no longer pursue the argument that it should receive the benefit of avoided costs for replacement power insurance. If this is incorrect, the Department will provide a more complete response in its reply brief.

A. The Commission's Determination that Sherco 3 Was Not Used and Useful Is Irrelevant to the Determination of Whether Xcel Should Retain Imprudently Incurred Replacement Power Costs.

Xcel continues to claim that it should not be held responsible for any imprudently incurred replacement power costs because the Commission determined that Sherco 3 was not used and useful in the test year in Xcel's 2012 rate case.[232] Xcel has tried this argument before. In comments submitted immediately before the Commission referred this matter to OAH, Xcel argued that, because of the 2012 rate case disallowance, "no further reimbursement of replacement power costs is required in this docket because customers were not incurring any direct costs associated with the plant while it was out of service (and rate base) during the outage period."[233] But Xcel continued, "[t]o the extent the Commission disagrees, however, it should undertake its own investigation and fact-finding, and then apply its specialized knowledge to determine whether the Company acted prudently in connection with the Sherco 3 outage."[234] The Commission elected the second path and ordered a contested case to develop the record, rather than granting Xcel's dismissal request based on an extreme legal theory. The ALJ should not be persuaded by Xcel's attempts to unravel the hard work of this contested case by resurrecting a stale legal argument. Moreover, the issue in the 2012 rate case is separate and distinct from whether ratepayers have unjustly born imprudently incurred replacement power costs.[235] Xcel also omits the fact that it proposed much of the rate treatment of Sherco 3 in the 2012 rate case. In testimony, Xcel stated "we agree that all avoidable O&M costs related to Sherco 3 should be removed from the test year."[236] This concession is appropriate because Xcel should not receive costs to operate and

[232] Ex. Xcel-2 at 18 (Krug Direct).
[233] Xcel Reply Comments at 3 (Jan. 27, 2021) (eDockets No. 20211-170360-05).
[234] *Id.*
[235] Ex. DOC-9 at 6 (King Rebuttal).
[236] Ex. DOC-9, MJK-R-1 at 3–4 (King Rebuttal, Schedule 1) (Excerpt of Rebuttal Testimony of Jeffrey Robinson in 2012 Rate Case).

maintain a plant that it is not incurring. Second, Xcel stated "we propose to lower test year costs further by deferring depreciation expense" for both 2012 and 2013, which preserves fixed costs for recovery.[237] The Commission accepted Xcel's argument on O&M, deferred the 2013 depreciation expense, allowed Xcel to recover property taxes on the unit, and denied other direct expenses of the plant including the return.[238] The Commission also denied a rate of return on the plant. The Commission explicitly did not decide "who should bear the significant costs the company has incurred for replacement power."[239]

Simply because the Commission determined that ratepayers should not be charged some costs or a generation plant that was offline for almost two years, does not in turn make customers whole for incremental energy costs incurred as a result of the same unavailability. The ALJ and Commission should dismiss Xcel's ongoing attempts to shield itself from its obligation to make ratepayers whole by pointing to the Commission's decision in Xcel's 2012 rate case that simply prevented Xcel from profiting from an offline plant.

B. Xcel's Reimbursement for Insurance Benefits Should Not Reduce the Required Refund.

In Xcel's 2013 rate case, the Commission reduced Xcel's rate base by $99.2 million for reimbursement from insurers for the Sherco 3 restoration.[240] This rate base reduction was necessary to prevent Xcel from profiting from the turbine failure by adding to its rate base, thus increasing the amount eligible for a rate of return.[241] Xcel now appears to argue that the reduction

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[237] *Id.*
[238] 2012 Rate Case Order at 22–23 (Sept. 3, 2013) (eDocket No. 20139-90902-01).
[239] 2012 Rate Case Order at 22–23 (Sept. 3, 2013) (eDocket No. 20139-90902-01).
[240] Ex. Xcel-2 at 13 (Krug Direct).
[241] *See In re Application of N. States Power Co. for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, E002/GR-13-868, ORDER REOPENING, CLARIFYING, AND SUPPLEMENTING MAY 8, 2015 ORDER (Aug. 31, 2015) (eDocket No. 20158-113661-01) ("If the amount of the insurance reimbursement were kept in the rate base and accounted for in the Capital True-Up as the Company

to rate base should be credited against any replacement power costs it imprudently incurred.[242] This argument ignores the fundamental differences between property losses and replacement power costs, bypasses the fact that insurance proceeds did not fully cover the property damage caused by Xcel's imprudence, and avoids mentioning that ratepayers fund insurance premium expense through rates.

The insurance reimbursement is only directly relevant to the restoration costs and excess fuel costs. Insurance did not cover any portion of the replacement power costs, and therefore the insurance reimbursement should not reduce the amount of replacement power costs owed to ratepayers.[243]

Moreover, the insurance reimbursement did not fully offset the restoration costs resulting from the turbine failure.[244] Xcel recovered $5.5 million from ratepayers in unpaid restoration costs by adding it to rate base in its 2015 rate case, meaning that ratepayers are not only paying $5.5 million in uncovered restoration costs but also paying a rate of return to Xcel on that amount.[245] If Xcel is permitted to offset the replacement power costs by the amount of insurance reimbursements it received, ratepayers will be further harmed.

Xcel's argument also fails to account for how insurance costs are recovered for regulated utilities in Minnesota. Xcel's recovers a representative amount of insurance premiums from ratepayers through base rates. Therefore, ratepayers, not Xcel, paid the premiums for the insurance

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proposed, ratepayers would pay for the capital costs of the Sherco 3 repair without receiving the benefit of the insurance proceeds.").

[242] Ex. Xcel-30 at 13, Table 2 (Krug Direct).

[243] Ex. DOC-9 at 7 (King Rebuttal).

[244] Ex. DOC-9 at 7, MJK-R-2 (King Rebuttal, Schedule 2) (Xcel Response to Oct. 21, 2020 Information Request).

[245] Ex. DOC-9, MJK-R-2 (King Rebuttal, Schedule 2) (Xcel Response to Oct. 21, 2020 Information Request).

that ultimately covered most of the restoration costs.[246] Moreover, Xcel's insurance premiums may have increased as a result of its claim—an increase that would be passed on to ratepayers through base rates.[247] Xcel should not be permitted to cut ratepayers out of the benefits of that insurance by reducing the replacement power costs refund.

C. Xcel's Purported Avoided Costs Cannot Offset Imprudently Incurred Replacement Power Costs and Are Otherwise Unsupported.

Xcel argues that its replacement power costs should be reduced by Xcel's calculated "benefits" from restoration activities. Xcel claims these benefits include avoided future outages, reduced fuel costs, and costs of the future work itself.[248] At its core, Xcel's argument is that because insurance paid for "most of" the restoration costs, ratepayers got the benefits of new plant that may have fewer forced outages or other efficiencies for no cost. As discussed above, these arguments ignores that ratepayers paid for Xcel's insurance for years before the catastrophic failure and may have higher insurance costs as a result. Any benefits from insurance, therefore, are rightfully ratepayers'.

Xcel's arguments are outside the scope of this proceeding and are untethered from ratemaking principles. Xcel's claimed avoided costs related to planned outages, forced outages, fuel costs, and future plant work are speculative. Finally, even using Xcel's estimations of avoided outages, the cost calculations that Xcel provides are unsupported and do not reflect basic pricing realities in the MISO market. Like Xcel's other arguments, Xcel is reaching for a way to avoid refunding imprudently incurred replacement power costs that ratepayers paid a decade ago. The Commission should not give it credence.

[246] Ex. DOC-5 at 21-22 (Polich Rebuttal).
[247] Ex. OAG-2 at 18 (Lee Rebuttal).
[248] Ex. Xcel-34 at 14-17 (Schottler Direct).

1. Xcel's claimed avoided costs and customer benefits are outside of the scope of this proceeding.

Xcel's claimed avoided costs would have occurred outside of the scope of this proceeding and Minnesota's regulatory system does not support such an offset. The Commission found a genuine issue of fact regarding whether Xcel's replacement power costs incurred during "the period November 2011 to October 2013 were reasonable and prudent."[249] Replacement power costs are passed through to customers and then examined in fuel cost adjustment proceedings. These proceedings are intended to ensure that utilities recover prudently incurred fuel costs, replacement power costs, and other included fuel-related variable costs and customers are not charged an excess amount for the year in which those costs occur.[250] Xcel's claimed benefits should be addressed, if at all, in a future proceeding.

But more importantly, utilities are not meant to profit from the fuel clause adjustment. Xcel's argument regarding "opportunity projects" that were accelerated to occur during the two year outage, ignores that Xcel benefited from including some of these capital improvement in its rate base sooner than it otherwise would have.[251] Correspondingly, ratepayers paid for some capital additions, including paying Xcel a rate of return, sooner than they otherwise would have.[252] Xcel should not now avoid refunding ratepayers costs due to them because it accelerated capital additions at Sherco 3 during the two-year outage.[253]

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[249] Notice and Order for Hearing at 10.
[250] Ex. DOC-5 at 21 (Polich Rebuttal).
[251] *See* Ex. OAG-2 at 16 (Lee Rebuttal).
[252] *Id.*
[253] Moreover, because Xcel does not provide a sufficiently granular level of data about its claimed benefits and the costs of the capital additions included in rate base it is impossible to determine whether these yielded a ratepayer benefit particularly in light of Sherco 3's retirement in 2030. Ex. DOC-5 at 24 (Polich Rebuttal). Sherco 3 has a significant amount unrecovered depreciation and even return on rate base that may still be passed on to ratepayers after the plant is retired. The Commission is exploring how to account for unrecovered depreciation and return on rate base for all early retiring fossil fuel plants in a separate proceeding. *See In re Commission Inquiry into the*

2. Xcel's claimed ratepayer benefits and avoided costs are unsupported.

Besides being out of step with Minnesota's regulatory system, Xcel's claimed ratepayer benefits of avoided restoration costs and "opportunity projects" are unsupported. Xcel witness Mr. Schottler claims to have quantified avoided costs for improved performance of the unit, avoided fuel costs, avoided future work performed as part of the restoration, reduction in the risk of failure events (forced outages), and reduction of future planned outage time.[254]

As Department witness Mr. Polich explained, "to determine the operational benefits Xcel witnesses would need to perform an evaluation of historical Sherco 3 operations to the same *actual* operating parameters after restoration" for a minimum of five years—with a ten year period being necessary for accuracy.[255] Xcel did not perform such an analysis.

Similarly, Xcel's claimed avoided fuel costs are unexplained. Mr. Schottler simply provides a very large range as an estimate and then does not explain his process to reach that estimate or its components.[256] More significantly, Xcel does not provide any evidence of actual efficiency improvements or compare pre- and post-restoration data.[257]

Mr. Schottler's calculations of customer benefits from future avoided restoration work also contain many unproven assumptions and are speculative.[258] For example, Mr. Schottler's claim of avoided replacement of the L-0 blades in 2020 ignores that there is no certainty that this would

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Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Elec. Utils., E002, E015, E017/CI-23-375.

[254] Ex. Xcel 31 at 11 (Schottler Direct).
[255] Ex. DOC-5 at 21 (Polich Rebuttal).
[256] Ex. Xcel-31 at 17, DWS-D-4 (Schottler Direct, Schedule 4).
[257] Ex. DOC-5 at 26 (Polich Rebuttal).
[258] *Id.* at 23-29.

have occurred as it is a life extension project.[259] Xcel plans on retiring the plant in 2030, and it may have chosen to operate the plant without blade replacements.[260]

Moreover, Mr. Schottler's claims that restoration work reduced future forced outages is speculative. As Mr. Polich explained, such a quantification should be reached by performing an analysis of past outage causes and a probabilistic risk assessment for future outages.[261] Again, Xcel did not provide this analysis.

Last, Mr. Schottler's estimates of avoided planned outage times are insufficient to carry its burden. Various activities are performed simultaneously during planned outages, making a determination of an actual reduction in outage time a difficult task.[262] As Mr. Polich explained, to adequately estimate future avoided planned outages "each future planned outage would need to have all the outage tasks defined, schedule the tasks within the outage period, see how it overlaps with other outage activities, and then do the same without the outage tasks" that Xcel claims were avoided.[263] Again, Xcel did none of this to arrive at its claimed avoided planned outage days. Instead, Xcel simply eyeballed it.

3. Xcel's "ballpark" cost calculations for its claimed avoided planned outages are deeply flawed and insufficient to meet Xcel's burden.

Even if Xcel's planned outage days were not speculative, Xcel's cost calculations for these avoided costs are seriously flawed. While Xcel acknowledges that quantifying "avoided costs" with precision is difficult, Xcel's "ballpark" figure is an inaccurate estimate in numerous ways.[264] Xcel's avoided cost estimate does not include MISO costs for the full set of years on which the

[259] Ex. DOC-5 at 24 (Polich Rebuttal).
[260] *Id.*
[261] Ex. DOC-5 at 27 (Polich Rebuttal).
[262] Ex. DOC-5 at 25 (Polich Rebuttal).
[263] Ex. DOC-5 at 25 (Polich Rebuttal).
[264] Ex. Xcel-34 at 19-20 (Detmer Direct).

claimed avoided outages occurred, fails to account for seasonal variations, and inserts high-cost years into the average unnecessarily.

As Xcel's witness on these avoided costs, Mr. Detmer, acknowledged at the hearing, he relied on Mr. Schottler's estimates of 76–84 days of avoided outages occurring from 2014 to 2030—a sixteen-year span.[265] But, as Mr. Detmer also acknowledged, the average MISO cost data supporting his recommended offset used only 2015 through 2022—an eight-year span.[266]

Moreover, within the eight-year span, Mr. Detmer's calculations simply used the annual average MISO costs, even though MISO costs vary on a day-to-day basis.[267] This generalization is a significant flaw because utilities have a duty to "minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work."[268] Because of this, utilities plan routine maintenance and inspections during times when replacement power costs are lower—typically the shoulder seasons of Fall and Spring.[269] But Xcel included the higher priced summer and winter months in its annual average daily prices, and even an extraordinary pricing event occurring in February 2021.[270] These inclusions are not realistic and bias the estimate upwards. Inclusion of the February 2021 pricing event in the average alone amounts to 6.6% of the total eight-year period, despite accounting for only 0.2% of the days.[271]

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[265] Evid. Hrg. Tr. Vol. 2 at 153 (Nov. 2, 2023) (Detmer). At the time of briefing, Xcel does not appear to have submitted errata pages to Mr. Detmer's direct testimony.
[266] *Id.* at 153-155.
[267] *Id.* at 149, 155.
[268] *In re Review of the 2006 Annual Automatic Adjustment of Charges for All Elec. and Gas Utils.*, MPUC DOCKET NO. E,G-999/AA-06-1208, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING FURTHER FILINGS, AND AMENDING ORDER OF DECEMBER 20, 2006 ON PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE at 5 (Feb. 6, 2008) (eDocket No. 4928266).
[269] Evid. Hrg. Tr. Vol 2 at 149-50 (Nov. 2, 2023).
[270] Evid. Hrg. Tr. Vol. 2 at 149-50 (Nov. 2, 2023).
[271] Ex. DOC-9 at 13 (King Rebuttal).

Finally, Mr. Detmer's calculation simply uses the average of that eight-year span—weighting each year equally.[272] This is despite Mr. Schottler's testimony placing several of the claimed "avoided outages" in specific years.[273] The annual averages vary greatly, ranging from a 2022 average of $250,192 megawatt hour (MWh) daily value to a 2020 average of negative $7,943 MWh.[274] Due to the significant variation in annual averages, this lack of specificity illustrates the lack of support for Mr. Detmer's "ballpark" figure. For example, Mr. Schottler states that a 2020 outage would have been extended by 7 to 14 days to replace the L-0 blades on the low pressure turbines.[275] Rather than calculate the outage days by the 2020 daily value, which was negative $7,943, meaning having the plant offline was more profitable than running it on average,[276] Mr. Detmer multiplies the 7 to 14 days in 2020 times $76,758.[277]

Xcel has not shown that its avoided outage figure is in the "ballpark." It is not even in the stadium. Xcel has not carried its burden, and Xcel should refund the full amount of replacement power costs.

D. Reliable Evidence Does Not Support Xcel's Request to Credit Hypothetical Costs It May Have Incurred by Conducting a Timely Inspection to Avoid the Catastrophe.

Xcel seeks to credit itself for the costs that it claims it would have incurred had it followed the prudent inspection practices that Mr. Polich describes.[278] Xcel calculates this amount based on: 1) an estimate provided by Mr. Murray that the outage would have had to be extended by an additional two to three months had Xcel performed the inspection that Mr. Polich suggested,

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[272] *See* Evid. Hrg. Tr. at 161 (Nov. 2, 2023).
[273] *See* Ex. Xcel-31, DWS-D-4 (Schottler Direct, Schedule 4).
[274] *Id.* at 1.
[275] *Id*.
[276] Evid. Hrg. Tr. Vol. 2 at 157–58 (Nov. 2, 2023) (Detmer).
[277] Ex. Xcel-34, NJD-D-7 (Detmer Direct, Schedule 7).
[278] Ex. Xcel-35 at 6-7 (Detmer Rebuttal).

multiplied by 2) Mr. Detmer's attempt to quantify a monthly estimate of Xcel's fuel replacement cost.[279] Xcel claim must be rejected for lack of evidentiary support.

Mr. Murray's claim that an inspection of the kind that Mr. Polich recommended would have added two to three months to the length of the outage[280] is not an estimate, it is a conclusion. Although he attempts to draw comparisons with Xcel's experience of repairing tangential dovetail cracking discovered in Unit 1 in 2005, he provides no documentation relating to the repair that was necessary in 2005, nor does he provide evidence that that experience is similar to what would have been experienced in 2011 for Sherco 3. Xcel could have provided a quote from a vendor regarding the time that would have been associated with such repair but chose not to do so. Absent some corroboration of Mr. Murray's conclusions, there is not sufficient evidence to support giving this claim any weight.

CONCLUSION

When a utility incurs costs because it failed to act prudently, ratepayers should not get stuck with the bill. This case is not about hindsight; it is about what Xcel knew at the time and what it did and didn't do to address known risks. Xcel was well aware of the importance of maintaining adequate purity of Sherco 3's steam cycle chemistry but failed to take industry-accepted measures designed to detect the presence of contaminants that could lead to SCC, which caused the failure of Sherco 3's LP turbine. Xcel decided to not follow its own established interval for completing a major inspection LP turbines at Sherco 3, even though it knew that, by doing so, it was increasing the risk of the very type of failure that Sherco 3 ultimately experienced. Even though Xcel's own subject matter experts had concluded that magnetic particle testing of the L-1 row of Sherco 3's LP turbines for SCC should be completed, no such testing was completed because of the cost.

[279] *Id*. at 7-8.
[280] Ex. Xcel-4 at 13 (Murray Rebuttal).

As a result of Xcel's failure to act prudently in operating and maintaining Sherco 3, power replacement costs that Xcel incurred because of Sherco 3's failure and extended outage – and that ratepayers have already paid – must be refunded in full, together with interest calculated through the date the Xcel makes the refund.

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Respectfully submitted,

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