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Rebuttal Testimony and Schedule
Nicholas J. Detmer

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

IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF ITS 2023 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES	MPUC Docket No. E002/AA-22-179 CAH Docket No. 21-2500-40336

REBUTTAL TESTIMONY OF

NICHOLAS J. DETMER

On Behalf of

NORTHERN STATES POWER COMPANY

August 13, 2025

Exhibit___(NJD-2)

Replacement Power Costs

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Schedule

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Nicholas J. Detmer. I am the Director of Market Operations and Analytics for Xcel Energy Services.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided Direct Testimony and Supplemental Direct Testimony in this proceeding on behalf of Northern States Power Company–Minnesota, d/b/a Xcel Energy (Xcel Energy, NSP, or the Company).

Q. DID ANY INTERVENORS PROVIDE DIRECT TESTIMONY REGARDING THE SCOPE OF YOUR TESTIMONY?

A. Yes. Intervenors commented on my Direct Testimony as it relates to the Company's use of the PLEXOS model and assumptions and level of detail relied upon, performance benchmarks identified, data sets utilized, case constructs used, and other assumptions supporting the Company's Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My testimony here responds to the Direct Testimony offered by the Minnesota Department of Commerce (Department) and Xcel Large Industrials (XLI).

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I have organized my testimony to address each point raised by subject, canvassing the scope of criticisms made.

I specifically address comments on the Company's use of the PLEXOS model and the degree of detail that modeling included, working assumptions I relied upon to reach the conclusions in my testimony, the structures of the base and change cases, and the structures of the 2023 and 2024 data sets.

II. RESPONSE BY POINT

Q. DID ANY PARTY OFFER TESTIMONY REGARDING THE ESTIMATE OF REPLACEMENT ENERGY COSTS FOR THE OUTAGE PERIOD IN YOUR DIRECT TESTIMONY?

A. Yes. The Department and XLI both offered testimony regarding my estimates of replacement energy costs. I will address each party's testimony individually, as they are distinct.

Q. WHAT WAS THE DEPARTMENT'S TESTIMONY REGARDING THE ESTIMATE OF REPLACEMENT ENERGY COSTS THAT YOU PROVIDED IN YOUR DIRECT TESTIMONY?

A. Department witness Andrew Golden acknowledged that exact replacement power costs are not identifiable but argued that, the Company, in its process of determining energy replacement costs resulting from the PINGP outage (Outage), should compare costs the Company paid for energy to what costs would have been had PINGP been available.[1] The Department also argued that the Company's use of PLEXOS to compare a base case (mirroring the available energy supply, etc., of the time period used) to a change case, where the Prairie

[1] Ex. DOC-___ at 6-7 (Golden Direct).

Island Nuclear Generating Plant (PINGP) was available, should have assumed that the price of energy in the Midcontinent Independent System Operation (MISO) market would have been impacted by the availability of PINGP in the change case.[2]

Q. HOW DO YOU RESPOND TO THE DEPARTMENT'S POSITION THAT THE COMPANY SHOULD COMPARE WHAT COSTS WERE TO WHAT THEY WOULD HAVE BEEN TO DETERMINE ENERGY REPLACEMENT COSTS RESULTING FROM THE OUTAGE?

A. I generally agree that the initial step in determining replacement power costs resulting from the Outage requires comparing, to the best of our ability, what the costs were to what the costs would have been if PINGP had been available. I also agree that exact replacement power costs are not possible to determine with absolute certainty. As a result, I explain here why the modeling used by Xcel Energy results in the most reasonable and accurate estimate of replacement power costs.

As I discussed in my Direct Testimony, the Company utilized PLEXOS to model the cost of replacement power by comparing a base case representing actual operations without PINGP to a change case that included generation from PINGP.[3] I note that this change case assumed zero outage time at PINGP – in other words, it assumed perfect performance and maximum energy production from the plant.

[2] Ex. DOC-___ at 7 (Golden Direct).
[3] Ex. Xcel-___ at 16 (Detmer Direct).

The PLEXOS base case was constructed utilizing a fixed generation schedule, meaning the generation was fixed to actual generation and loads during the duration of the Outage. The model then populated purchase and sales detail, deriving purchases and sales from the MISO market to balance the difference. The base case is thus a mirror of actual operations during the Outage.

In the change case, the fixed schedules are removed, allowing plants to redispatch to accommodate the addition of PINGP. Plants that were online were allowed to re-dispatch, while combined units are allowed to change commitment. Incremental sales are priced at NSP Locational Marginal Price (LMP), i.e., a pricing method that provides a way to consider the marginal cost of energy delivery at certain system locations under certain conditions. This convention is used to provide a meaningful pricing reference within modeling constraints. On this basis, the cost difference between the two models results in the best estimate of what costs were as compared to what they would have been, absent the Outage.

Q. WHAT IS YOUR RESPONSE TO THE DEPARTMENT'S CRITICISMS THAT THE CHANGE CASE SHOULD HAVE ASSUMED THAT THE PRICE OF ENERGY IN THE MISO ENERGY MARKET WOULD HAVE BEEN IMPACTED BY THE AVAILABILITY OF PINGP?

A. This criticism is unjustified. The Department's critique ignores that any impact of PINGP on the MISO energy market—and therefore replacement power costs—is essentially impossible to calculate and likely to be very small. When the Department claims that the MISO market is "unchanged" between the Company's base case and change case, I presume what is meant is that the LMPs

are the same between the base and change cases. On this basis, I conclude that the Department recognizes that the price elasticity of supply is most likely non-zero. Meaning, the inclusion of PINGP would likely change the LMPs to be slightly lower than the real-life LMPs (since including PINGP would likely have offset the highest cost, or marginal generator in the base case). The extent to which LMPs would have changed, however, is difficult, if not impossible, to estimate and the result of any analysis would be a rough estimate. So, rather than speculate as to the magnitude of the change, the Company assumed the change in LMPs to be zero. This is not a perfect assumption but, as I explain below, it is the most reasonable approach. As the Department recognizes, replacement power costs cannot be fully known. In other words, there is no perfect assumption. But while these costs cannot be perfectly calculated, they can be reasonably estimated.[4]

As a reasonable estimation, the Company assumed the LMPs to remain the same in both the base and change cases. This assumption is reasonable because it is easily observable and any assumed change in the price for energy in the MISO energy market between the base and change cases would have a negligible impact on the replacement power cost estimation. There are at least two reasons for this. First, as I explained in my Direct Testimony, the Company is both a buyer and seller in the MISO market. That is important because it means that the change in the price for energy referred to by the Department would have both a positive and negative impact on the costs paid by our customers. Put differently, a $1/MWh reduction in LMP would result in lower revenues for

[4] Ex. DOC-___ at 7 (Golden Direct).

every generator (including the Company's), and the same $1/MWh change would reduce costs to *all* loads. Thus, the revenue lost to the Company due to a price change, which flows to our customers, and the cost savings gained, offset one another, *resulting in a net zero change*. Consequently, the only place where the price elasticity of supply would affect total costs would be the pricing of net purchases and sales. Here, that is shown by noting that, for 2023, the sales in the change case increased by 258,615 megawatt hours (MWh), while in 2024 these sales increased to 373,389 MWh.[5]

In other words, the inclusion of PINGP changes both the supply and demand for energy, which would each have an impact on the LMP price in different directions; a $1/MWh reduction would reduce sales revenues by approximately $631k. With replacement power costs estimated to exceed $48 million, the inclusion of the price elasticity of supply, therefore, has only very minor significance.

Q. WHAT ARE THE REPLACEMENT POWER COST CALCULATION CRITICISMS OF XLI?

A. XLI witness Brian Andrews makes two primary criticisms related to the Company's PLEXOS modeling. First, it is my understanding that XLI witness Andrews disagrees that the base case is sufficiently calibrated (or proven to be calibrated) to demonstrate the actual costs incurred during the study period and also argues that a demonstration or analysis comparing the costs that are

[5] *See* the Company's response to XLI Information Request (IR) No. 2, attached to Detmer Rebuttal Testimony as Exhibit___(NJD-2), Schedule 1, showing a correction to a pasted insertion originally provided in Exhibit___(NJD-1), the Direct Testimony and Schedule 2 of Company witness Nicholas J. Detmer, revised in the Company's Errata to the Direct Testimony and Schedule 2 of Nicholas J. Detmer.

produced by the base case in PLEXOS ought to be compared to actual costs incurred during the study period.[6] Second, XLI witness Andrews argues that the PINGP outage would have minimal impact on LMP pricing and proposes an alternative method to calculate replacement energy costs he claims to be based on LMPs.[7]

Q. WHAT IS YOUR PRIMARY CONCERN WITH XLI'S EVALUATION OF THE MODELING THAT THE COMPANY PERFORMED?

A. XLI witness Andrews provides an overly simplistic and distorted description of the Company's analysis that understates the significant level of detail included in the Company's modeling. First, I disagree that there is any indication that the base case is not sufficiently calibrated. Further, I disagree that the alternative method of analysis proposed by XLI witness Andrews could estimate the replacement power costs with the same degree of reliability that the Company's effort provides. To the contrary, the PLEXOS model used in this case is what NSP has used—and what the Commission has relied on—for multiple years in forecasted fuel clause cases in Minnesota, and is the same model used by our power plant management who depend on sound forecasts to plan production-based budgets and schedule maintenance. I discuss these issues in greater detail below.

Q. WHY DO YOU DISAGREE WITH XLI'S POSITION THAT THE BASE CASE IS NOT SUFFICIENTLY CALIBRATED?

[6] Ex. XLI-___ at 4-5 (Andrews Direct).
[7] Ex. XLI-___ at 8-15 (Andrews Direct).

A. I disagree with XLI witness Andrews argument because the modeling process used to develop the base case relies on robust inputs that calibrate the model to represent actual conditions as closely as is possible. As a result, comparing the costs that are produced by the base case in PLEXOS to actual costs incurred during the study period represents an excessive requirement. The base case inputs include actual fuel prices for each day of the outage, fuel transportation costs, heat rates (i.e., the efficiency of each generation unit, which impacts fuel consumption), start-up costs, and variable operations and maintenance (VOM) costs for every generator in the NSP system.[8] The base case is then run such that every generator operates at its actual generation level for every hour of the study period. Each generator's production costs are then calculated and are accumulated to derive the total system production costs. As a result, comparing the costs derived by the model to "actual costs" is an unnecessary burden.

Furthermore, XLI witness Andrews appears to recognize that the Company calibrated the model in this way,[9] yet continues to assert that it "does not tell us that the base case run is an accurate representation of Xcel's actual power costs during the study period."[10] I disagree. The base case costs are sufficiently calibrated, as described above, and the model's use of actual generation on an hour-by-hour basis produces a highly accurate representation of actual production costs over the study period.

[8] The model requires simplified average versions of historical accounting (VOM - $/MWh, or start-up costs - $/Start-up) and engineering data (MMBtu/MWh, or max capacity). Requiring the recasting of these averages is significant and time consuming, and unproductive given that they are the same detail already being utilized in the Company's fuel forecasts before the Commission.
[9] Ex. XLI-___ at 3-4 (Andrews Direct).
[10] Ex. XLI-___ at 4-5 (Andrews Direct).

Q. WHY DO YOU DISAGREE WITH XLI'S ARGUMENT THAT THE LMP METHOD IS A REASONABLE MEANS OF ESTIMATING REPLACEMENT POWER COSTS?

I disagree with XLI witness Andrews' calls for the use of an LMP Calculation Method to estimate replacement power costs[11] because this method is not reliable for the purpose at issue. The LMP Method estimates outage costs by subtracting operating costs from the LMP and then multiplying that value by the unavailable capacity of the PINGP. This method would, per XLI witness Andrews' testimony, presume that no other generation would be altered in relation to the availability of PINGP. XLI witness Andrews' basis for this assumption is his claim that MISO is so large in aggregate that even 1,000 MWs of generation from PINGP would not alter the output of other generation facilities.

Contrary to XLI witness Andrews' assertions, the LMP Calculation Method is not an appropriate method for determining the replacement power costs associated with PINGP in this case, where the size of the facility is large and the generation offset is significant. The LMP Calculation Method is a common, though simplistic, method for calculating replacement power costs and it is often utilized by the Company as a quick and simple estimation tool; in fact, it was used in the Company's initial estimate of PINGP's replacement power costs as shown in Schedule 2 of Xcel Energy witness Allen D. Krug's Direct Testimony (as identified by XLI witness Andrews).[12] That Schedule 2 is a product of the Company's monthly assessment of outage costs to comply with fuel clause reconciliation reporting (consistent with Federal Energy Regulatory

[11] Ex. XLI-___ at 14-15 (Andrews Direct).
[12] Exhibit___(ADK-1), Schedule 2 (Krug Direct).

Commission Annual Automatic Adjustment reporting requirements) and utilizes the LMP Calculation Method as a simple reporting tool to provide intervenors a more general reference to the impact outages may be contributing to the fuel clause. But the method has inherent limitations that are problematic in the replacement power cost analysis completed here. To clarify, the LMP Calculation Method is only appropriate when the size of the facility at issue is small, so that other nearby resources would be unaffected by that facility's availability. XLI witness Andrews argues that PINGP is small as compared to the size of MISO, in total, and that all the generators in aggregate would have been unaffected by its operation. The problem with this argument is that PINGP is not actually a small facility, and the entire MISO footprint is not the appropriate comparison when considering the significance of a unit located in Minnesota. Instead, the MISO segment identified as MISO North is a better reference in this case because constraints in the MISO transmission system frequently impede the flow of energy into and out of MISO North. Due to these constraints, it is more meaningful, and accordingly necessary, to compare the size of PINGP relative to the capacity within MISO North. Considering that the NSP fleet makes up a significant portion of the remaining capacity in MISO North, the availability of PINGP would impact the output of other NSP generators. As a result, the LMP Calculation Method proposed by XLI witness Andrews is not the best tool to evaluate the impact of a large generator like PINGP on a region dominated by other NSP generators; instead, a production cost model is necessary.

There are additional flaws in XLI witness Andrews' argument. He relies on the MISO winter dispatch curve and the modeling done in the Sherco 3 analysis to

support his calculations.[13] There are at least three problems underlying these assertions. First, the NSP and the MISO generation portfolios have significantly changed since 2011 when the Sherco 3 analysis was completed. The region has seen the addition of thousands of MWs of natural gas, wind, and solar generation, along with congested transmission paths. Second, PINGP is a "must-run" unit, meaning that—when not in an outage—it must operate at full output 24 hours a day, seven days a week, regardless of price. As a result, some additional sales will occur from PINGP's operation at certain times, while at other times, other resources within the NSP footprint will be displaced. Third, the MISO winter dispatch curve is for all of MISO, which spans fifteen states from Minnesota to Louisiana and part of Manitoba, Canada and accordingly exceeds NSP as the relevant MISO sub-portion.

XLI is correct that the base case fixed the generation in PLEXOS to actual generation, while in the change case the model was allowed to redispatch and make additional sales.[14] The model is reconciled when true up occurs, with discrepancies in the reconciliation process due to differences in loads, fuel prices, renewable generation, and plant availability. Lastly, the model was set with one price across NSP, not with individual LMPs at each generator. As a result, the Commission can conclude that the Company employed a well-vetted model to perform the replacement power analysis in this case.

Q. DID XLI PRESENT ANY OTHER CRITIQUES THAT YOU WOULD LIKE TO ADDRESS?

[13] Ex. XLI-___ at 9-10, 13 (Andrews Direct).
[14] Ex. XLI-___ at 4-5 (Andrews Direct).

A. Yes. First, XLI asserts that the Company's 2023 and 2024 input and output files do not show that the modeling analyses were conducted in the same manner. The differences that XLI notes in the Company's modeling input and output files were a result of a typographical error that occurred when copying the information from the model and transferring the information to a workpaper. As such, this error did not impact the modeling or its results. The Company has updated its workpapers to correct for this paste error and the clarified workpaper addresses this question.[15]

Second, XLI asserts that the Company erroneously presents in its change case that PLEXOS dispatched all generation to a simple LMP with no change in MISO sales and purchases in the 2023 output file.[16] This conclusion is also a result of the above-noted typographical errors, which the Company addressed in its corrected workpapers.[17] To reiterate, these errors did not impact the modeling but resulted from inaccurately copying model results into the workpapers. As seen in Exhibit___(NJD-2), Schedule 1 to my Rebuttal Testimony, the modeling allowed for a change in sales and purchases and represented the difference in sales between the base and change cases.

Third, XLI witness Andrews argues that the Sherco Unit 3 contested case involved more complex modeling that included the LMP Calculation Method and that that work supports the use of that modeling approach in this case.[18] But XLI mischaracterizes the Sherco Unit 3 contested case. It did not include

[15] *See* Exhibit___(NJD-2), Schedule 1 (Detmer Rebuttal).
[16] Ex. XLI-___ at 7 (Andrews Direct).
[17] *See* Exhibit___(NJD-2), Schedule 1 (Detmer Rebuttal).
[18] Ex. XLI-___ at 13 (Andrews Direct).

the LMP Calculation Method; it instead included a price elasticity of supply calculation to estimate the impact of Sherco 3 on LMPs. The analysis then re-cast all generation based on the Sherco 3 availability in a production cost model. As a result, XLI inappropriately likens their approach to the Sherco 3 approach, falsely claiming similarities in support of XLI witness Andrews' modeling.

The Company did not utilize the Sherco 3 modeling approach here because such tools are no longer in use by the Company. These tools are, at best, speculative when considering the complexity due to congestion that exists now on the NSP system.[19] Instead, other methods, such as the approach described here, are utilized as they are more straightforward, while still producing reliable results.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The Company's use of the PLEXOS model to estimate the replacement costs of PINGP is reasonable. The costs in the base case were determined by fixing the generation in the base case to generation actuals. The change case adds over 1,000 MWs 24 hours a day, seven days a week from PINGP and the PLEXOS model redispatches that to the NSP system and derives changes to market volumes. Using just the historical LMPs or adjusting the historical LMPs based on a MISO-wide dispatch curve is overly simplistic, as NSP sits in the northern region of MISO, which experiences significant transmission congestion and has

[19] The Sherco 3 outage occurred in 2011, during a time period when congestion and market interactions were less complex.

experienced significant increases in renewable energy generation. Additionally, NSP comprises a significant percentage of load and generation within the MISO North region, making PINGP generation notable in that system segment. Lastly, as used here, the PLEXOS model provides a sound estimate of PINGP replacement costs.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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☐ **Public Document**

Xcel Energy		Information Request No.	2
Docket No.:	E002/AA-22-179		
Response To:	Xcel Large Industrials		
Requestor:	Andrew P. Moratzka, Amber S. Lee, Eden A. Faure		
Date Received:	June 27, 2025		

Question:

Please refer to the following files: "22-179 Xcel Workpaper 1 TRADE SECRET July 30, 2024.xlsx" ("2023 Inputs"), "22-179 Xcel Workpaper 2 TRADE SECRET July 30, 2024.xlsx" ("2023 Outputs"), "22-0179 DOC-052_Attachment B-2024 PLEXOS Inputs TRADE SECRET IN ENTIRETY.xlsx" ("2024 Inputs") and "22 0179 DOC-052_Attachment A-2024 PI PLEXOS Results TRADE SECRET IN ENTIRETY.xlsx" ("2024 Outputs").

a. Please provide a detailed explanation as to why the 2023 Inputs workpaper includes an LMP input, but the 2024 Inputs workpaper does not.
b. Please confirm or deny whether Northern States Power ("Company") assumed no change to the LMPs utilized in the change case.
    i. If the Company did not assume any change to the LMPs in the change case, please provide a detailed explanation as to why not.
    ii. If the Company did assume changes to the LMPs in the change case, please provide a detailed description of what changes were assumed. Please also provide information regarding any specific workpapers and relevant tabs that demonstrate the assumed changes.
c. Please provide a detailed explanation as to why the 2023 Outputs file shows MISO Purchases, MISO Sales, and Wind Curtailment, but the 2024 Outputs file does not.
d. Regarding the 2023 Outputs workpaper, it appears that there are no changes to the purchases and sales between the base and change cases. Please provide an explanation detailing why this is the case.
e. Please identify the MW import and export limits that exist for Xcel's purchases and sales to the MISO market.
f. Please explain why the 2023 Inputs contain actual generation, but the 2024 inputs do not include this data.
g. Please provide a detailed narrative explaining if any differences exist in the way that the 2023 and 2024 PLEXOS modeling was performed.

h. Please explain why the Sherburne 2, Fibro Minnesota, and NGPP Biomass generators are not included in the 2024 analysis.

Response:

a. See a revised version of live Attachment A to the Company's response DOC IR No. 52, included with this response as 22-0179 DOC-052_Attachment A-2024 PI PLEXOS Results REVISED TRADE SECRET IN ENTIRETY.xlsx which is updated to include 2024 LMPs.

b. Confirmed. The Company assumed no changes to the LMPs as is it is *de minimis* in this analysis because:
   - Changes in costs result from the absence of Prairie Island unit generation and overwhelm any possible price changes from other drivers.
   - Only MISO can really determine what the LMPs might have been had Prairie Island units been available.
   - To forecast changes to LMPs requires a detailed model that includes loads, available generation, and available transmission topology. Such a modeling effort requires significant oversight to capture daily changes to transmission topology.

c. See the revised spreadsheets provided with this response that properly reflect the data. A paste error originally occurred in assembly of the spreadsheets, but this has now been corrected. The following changes to the output spreadsheets were made:
   a. "22-179 Xcel Workpaper 2 TRADE SECRET July 30, 2024.xlsx" ("2023 Outputs")
      i. "Generation Base" Tab, Purchase MISO was added to column BI, and Sale MISO was added to column BJ
      ii. "Generation Change" Tab MISO purchase was added to column BI, MISO sale was added to column BJ, and Extra Sales was added to column BK
   b. "22-0179 DOC-052_Attachment A-2024 PI PLEXOS Results REVISED TRADE SECRET IN ENTIRETY.xlsx" ("2024 Outputs").
      i. "Base" Tab, Purchases MISO was added to column BE, Sale MISO was added to column BF
      ii. "Change" tab, Purchase MISO was added to column BE, Sale MISO was added to column BF, and Extra Sales added to column BG

d. See subpart c above.

e. Data columns referring to 2023 and 2024 outputs now contain "Extra Sales" which show the incremental volume of sales in the change case. See column BK on the tab "change" in "22-179 Xcel Workpaper 2 TRADE SECRET July 30, 2024.xlsx" ("2023 Outputs") and column BG on the tab "Generation

Change" in "22-0179 DOC-052_Attachment A-2024 PI PLEXOS Results REVISED TRADE SECRET IN ENTIRETY.xlsx" ("2024 Outputs").

f. The updated spreadsheets for both 2023 and 2024 contain actual generation which was used to set up the base case.
g. There are no differences in the modeling steps for 2023 and 2024.
h. Sherco 2 retired at the end of 2023, while NGPP Biomass (Laurentian) and Fibro Minn were Purchase Power Units whose contracts terminated at the end of 2023.

Please note that the live files included with this response are marked as "Not-Public" in their entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The workpapers contain Confidential and Proprietary forecast modeling inputs and outputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Nick Detmer.
3. **Importance:** The workpapers contain competitively sensitive data.
4. **Date the Information was Prepared**: The information was prepared in July 2025.

Witness:	Nicholas J. Detmer
Preparer:	Nicholas J. Detmer
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Department:	Market Operations
Telephone:	303-571-7030
Date:	July 10, 2025

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