# Minnesota Public Utilities Commission

## PUC Agenda Meeting

**Thursday, February 12, 2026** **10:00 AM**

## INTRODUCTION

## DECISION ITEMS

**1.** **Details 2026-015**

** **G022/GR-24-350** **Greater Minnesota Gas, Inc.**

In the Matter of the Application of Greater Minnesota Gas, Inc. for Authority to Increase Rates for Natural Gas Utility Service in Minnesota.

Should the Commission reopen, reconsider, and/or clarify its November 26, 2025 Findings of Fact, Conclusions, and Order? (PUC: **Bonnett**)

The Commission has the authority to accept or decline a petition for reconsideration **with or without** a hearing or oral argument (Minnesota Rules 7829.3000, Subpart 6). In other words, a decision on a petition for reconsideration can be made without taking oral comments at the Commission meeting.

**2.** **Details 2026-013**

** **E002/M-25-245** **Northern States Power Co. d/b/a Xcel Energy**

In the Matter of Xcel Energy's Petition for Approval of its 2025 Annual Administrative Service Agreement.

Should the Commission approve Xcel Energy's 2025 Annual Administrative Service Agreement Petition? (PUC: **Pham**)

**3.** **Details 2024-197**

* **IP7013/WS-19-619** **Apex Clean Energy Holdings, LLC d/b/a Big Bend Wind, LLC**

In the Matter of the Application of Big Bend Wind, LLC for a Large Wind Energy Conversion System Site Permit for the up to 300 MW Big Bend Wind Project in Cottonwood and Watonwan Counties, Minnesota.

Should the Commission approve Big Bend Wind LLC's petition to amend the site permit for the Big Bend Wind Project? (PUC: **Davis, Panait**)

## ADJOURNMENT

*** One star indicates that an agenda item is not disputed.**
**** Two stars indicate that an agenda item is disputed and there may be legal, procedural, or policy issues to be resolved.**
***** Three stars indicate a complex or lengthy disputed agenda item that may have significant legal, procedural, or policy issues to be resolved.**
**Please note: For the complete record, please see eDockets.**

MINNESOTA
PUBLIC UTILITIES COMMISSION

# Staff Briefing Papers

| | | |
|---|---|---|
| **Meeting Date** | **February 12, 2026** | **Agenda Item 1**** |
| Company | Greater Minnesota Gas, Inc. | |
| Docket No. | G-022/GR-24-350 | |
| | **In the Matter of the Application of Greater Minnesota Gas, Inc. for Authority to Increase Rates for Natural Gas Utility Service in Minnesota** | |
| Issues | Should the Commission reopen, reconsider, and/or clarify its November 26, 2025 Findings of Fact, Conclusions, and Order? | |
| Staff | Jason Bonnett jason.bonnett@state.mn.us | 651-201-2235 |

| ✓ **Relevant Documents** | **Date** |
|---|---|
| Minnesota Public Utilities Commission – Findings of Fact, Conclusions, and Order | November 26, 2025 |
| Greater Minnesota Gas, Inc. – Petition for Reconsideration and Clarification | December 16, 2025 |
| Minnesota Department of Commerce, Division of Energy Resources - Answer | December 29, 2025 |
| Office of the Attorney General – Residential Utility Division - Answer | December 29, 2025 |

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## I. BACKGROUND

On November 1, 2024, Greater Minnesota Gas, Inc. (GMG) filed a general rate case with the Minnesota Public Utilities Commission (Commission) requesting a $1.4 million annual increase, or 7.7 percent, to its Minnesota retail natural gas rates, effective January 1, 2025, based on a rate of return on common equity capital of 10 percent.

On November 26, 2025, the Commission issued its *Findings of Fact, Conclusions, and Order* (Order). This Order required GMG to increase its small commercial count to 990 customers because that number more accurately reflected the actual number of small commercial customers than GMG's request of 946 customers.

On December 16, 2025, GMG filed its Petition for Reconsideration and Clarification (Petition). GMG requested that the Commission reconsider its decision requiring GMG to increase its small commercial count to 990 customers.

On December 29, 2025, both the Minnesota Department of Commerce, Division of Energy Resources (Department) and the Office of the Attorney General - Residential Utilities Division (OAG) filed answers to GMG's Petition.

## II. MINNESOTA STATUTES AND COMMISSION RULES

Petitions for reconsideration are subject to Minnesota (Minn.) Statute (Stat.) Section (§) 216B.27, and Minn. Rules, part 7829.3000. Petitions for reconsideration are denied by operation of law unless the Commission acts within sixty days of the request. If the Commission takes no action on GMG's petition, the request would be considered denied as of February 14, 2026. However, since February 14, 2026, is a Saturday, and the following Monday is a federal holiday, this denial would arguably not be in effect until Tuesday, February 17, 2026. The Commission may also take specific action to deny the petition by issuing an order denying reconsideration.

When petitions for reconsideration are filed, the petitioner must "set forth specifically the grounds relied upon, or errors claimed."[1] The Commission traditionally reviews petitions for reconsideration "to determine whether the petition (i) raises new issues, (ii) points to new and relevant evidence, (iii) exposes errors or ambiguities in the underlying order, or (iv) otherwise persuades the Commission that it should rethink its decision."[2]

The motion to require usage of 990 small commercial customers was made by Commissioner

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[1] Minn. R. 7829.3000, subp. 2.

[2] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Order Denying Petition for Reconsideration, Denying Petition for Clarification, and Granting Clarification at 2 (October 6, 2023).

Tuma and was approved on a vote of 4-0, with Commissioner Ham absent. Because it was a 4-0 decision, all Commissioners that participated in the vote are eligible to make a motion to grant GMG's request for reconsideration.

If the Commission takes up a party's request for reconsideration, the Commission can: (1) grant reconsideration, and (a) affirm, (b) modify or (c) reverse its initial decision, or (2) deny the petition for reconsideration and thereby affirm the decision.

## III. DISCUSSION

### A. Introduction

In its initial sales forecast, GMG included 946 small commercial customers in its Test Year, which reflected GMG's expectation that there would be no increase in that customer class. In support of its projection, GMG explained that its growth from 2009 through 2023 resulted from its extension of natural gas service to rural markets that were previously unserved by a natural gas utility. Since GMG did not plan any major extensions into unserved communities during the Test Year, and all the development identified for future growth is residential, GMG projected no additional small commercial customers.

The OAG disagreed with GMG's projection and recommended increasing the small commercial customer count to 990 based on growth in the class in recent years. The OAG observed that GMG already had 970 small commercial customers in October 2024 and 996 by the end of 2024.

GMG did not oppose updating all customer counts, including the small commercial customer count, and asserted that updating the counts to 2024 year-end actuals would provide for the greatest accuracy. GMG submitted an updated sales forecast accordingly.

The OAG recommended against approving the updated sales forecast because GMG did not update all its costs along with the customer counts, which, according to the OAG, resulted in an unreasonable increase in the revenue requirement. The OAG asserted that without updated costs there is no reliable basis in the record to recalculate the sales forecast using 2024 actuals. Even though the OAG was opposed to the updated sales forecast, the OAG continued to recommend increasing GMG's small commercial customer count to 990 based on historical trends.

### B. Commission Decision

In its Order, the Commission determined that there was not a reasonable basis in the record to approve GMG's updated sales forecast.[3] Specifically, the Commission stated:

[3] Findings of Fact, Conclusions, and Order at 26.

> The Commission agrees with the OAG that GMG should increase its small commercial count to 990 because that number more accurately reflects the actual number of GMG's small commercial customers than the Company's request of 946. The record reflects that GMG had 970 small commercial customers in October 2024 and 996 by the end of 2024. Given these numbers, a small commercial customer count of 990 is more reasonable than using a count of 946 even with GMG's projection that it will not add any new small commercial customers during the Test Year.
>
> The Commission also agrees with the OAG that there is not a reasonable basis in the record to approve GMG's updated sales forecast. Updating revenues without updating costs brings into question the accuracy of the updated revenue requirement. The Commission is therefore not persuaded that GMG has met its burden of establishing that the updated sales forecast is reasonable.
>
> To align the ALJ report with these conclusions, the Commission will adopt the OAG's proposed modifications to the ALJ Report, specifically paragraphs 184–196, as they appear in the OAG's July 31, 2025 exceptions.[4]

### C. GMG's Petition for Reconsideration

GMG argued the Commission erred in adjusting GMG's sales forecast only for the small commercial customer class. By updating the Small Commercial Customer count but retaining the customer counts from GMG's original Test Year forecast for all other customer classes, the Commission's Order established an unreasonably high level of sales that is unreliable.

To correct this error, GMG requested that the Commission modify its Order and adopt GMG's updated sales forecast, which includes updated customer counts that better reflect GMG's customer base.

Also, in response to concerns that GMG's updated sales forecast did not also update costs other than the cost of gas, GMG stated "given the relatively modest number of incremental customers at issue here, the vast majority of the costs incurred is the cost of gas, and those costs have been removed in the GMG's updated forecast." [5] Finally, GMG noted that the Commission did not require an adjustment updating costs associated with adopting the OAG's recommended Small Commercial customer count.[6]

[4] *Id*.

[5] GMG Petition at 5.

[6] *Id*.

### D. Department Answer to GMG's Request

The Department recommended that the Commission deny GMG's reconsideration. The Department argued that the Commission correctly determined that GMG's updated sales forecast was inaccurate because it did not update its costs.

Specifically, the Department argued GMG chose to file a forecast for a 2025 test year that not only included fewer small commercial customers than it had on its system at the time of filing but included fewer small commercial customers than it had on its system at the start of February 2024. GMG further compounded the inaccuracy of its forecast by deeming all additions to its system as residential, even though it has consistently added around 30 small commercial customers per year since 2019. The Commission correctly found that even if GMG did not add any new small commercial customers during the test year, it was reasonable to use a count of 990—a number that was still lower than the GMG's actual 2024 end of year count. Allowing GMG to use an updated sales forecast without correspondingly updating its forecasted expenses would not produce just and unreasonable rates.

### E. OAG's Answer to GMG's Request

Similar to the Department, the OAG also recommended that the Commission deny GMG's reconsideration.

#### 1. Error or Ambiguity of Commission Order

The OAG argued the Commission's Order is fully supported by the record. The OAG noted that GMG presented a new forecast of its customer counts for all customer classes in rebuttal testimony that purported to increase its revenue requirement by $92,834. However, GMG did not update any cost other than the cost of gas, meaning this large increase to its revenue requirement was calculated incorrectly using data sets that did not match. The OAG noted that while GMG's actual year-end customer count was lower than in its original forecast, resulting in reduced forecasted revenues in its rebuttal sales forecast, GMG's actual year-end costs were also lower than originally forecasted, which would have offset the reduced revenues if GMG had updated its costs. The Commission found that "using the updated sales forecast but the original costs of service and operating expenses as advocated by GMG would mean an artificially increased overall revenue requirement and incorrect Class Cost of Service analysis."[7]

The OAG noted that the Commission made multiple findings supporting the conclusion that GMG had failed to carry its burden to demonstrate that its small commercial customer count forecast should remain at 946 customers. The Commission found that, whereas GMG had claimed that 946 small commercial customers was reasonable because it had not identified any new commercial loads to be added to its system, GMG already had 970 small commercial customers. GMG then added another 26 customers, ending 2024 with 996 small commercial

[7] Finding of Fact, Conclusions, and Order at 25, 48.

customers.[8] Additionally, the Commission found that GMG had historically added about 30 small commercial customers each year from 2018 to 2023, and that GMG had not carried its burden to demonstrate that it would not add any new small commercial customers in 2025.

The OAG argued that because of these findings, the Commission adopted the OAG's recommendation to use the original test year sales forecast, which appropriately matched forecasted revenues and forecasted costs to calculate an accurate revenue requirement, and to increase the forecasted test-year small commercial customer count to 990 customers to reflect the finding that GMG's projection of zero growth in that class was unreasonable.

### 2. GMG's Failure to Address Commission Finding Regarding the Inaccuracy of GMG's Updated Forecast

In addition to the discussion above, the OAG argued that GMG failed to address the Commission's concern regarding the inaccuracy of GMG's updated Sales Forecast. The OAG argued that GMG failed to address for the Commission's determination that GMG's rebuttal sales forecast is flawed. Specifically, GMG failed to update its costs when it updated its customer counts. Thus, contrary to GMG's contention that the Commission reduced GMG's revenue requirement "by more than $90,000," the OAG argued that the Commission rejected GMG's attempt to artificially increase its revenue requirement by that amount. The Commission concluded that "there is not a reasonable basis in the record to approve GMG's updated sales forecast. Updating revenues without updating costs brings into question the accuracy of the updated revenue requirement."[9]

Also, the OAG argued that GMG failed to address any of the Commission's findings supporting the adoption of a forecasted test-year small commercial customer count of 990 customers. GMG focused on the single statement that 990 customers is closer to GMG's actual small commercial customer count than GMG had forecasted, and ignored all of the Commission's relevant findings, namely that GMG (1) had claimed that it would not add any small commercial customers in 2025 even after it had already added many of them in 2024; (2) failed to provide any explanation for this discrepancy or any evidence that it would not continue to grow; and (3) had added an average of 30 small commercial customers each year from 2018 to 2023. These findings, ignored by GMG, demonstrated that there is no error or ambiguity in the Commission's order.

The OAG argued that GMG inaccurately represented the evidentiary record. For example, GMG stated that "the Commission did not require an adjustment updating costs associated with adopting the OAG's recommended Small Commercial customer count."[10] In response, the OAG noted that the Commission did not "require" an update to costs because the OAG's sales

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[8] Id. at 25, 48.

[9] *Id*. at 26.

[10] GMG Petition at 5.

forecast that the Commission adopted already incorporated updated costs.

The OAG noted that in its rebuttal testimony, GMG did not rebut the OAG's cost calculations or attempt to provide alternative cost estimates for changing the small commercial customer count. Nor did GMG follow the OAG's example and offer its own updated costs, instead updating only its customer counts in order to increase its revenue requirement by $92,834. By contrast, the OAG's recommendation that appropriately incorporated updated costs resulted in only a modest $13,840 reduction to GMG's revenue requirement.

Finally, the OAG argued that instead of performing a supported and methodologically sound sales forecast adjustment in rebuttal, as the OAG did in direct testimony, GMG chose to only update its forecasted customer counts for all classes without updating associated costs. The OAG concluded that GMG's argument relies on ignoring the majority of the relevant Commission findings and should be rejected.

### F. Staff Comments

The Commission traditionally reviews petitions for reconsideration "to determine whether the petition (i) raises new issues, (ii) points to new and relevant evidence, (iii) exposes errors or ambiguities in the underlying order, or (iv) otherwise persuades the Commission that it should rethink its decision."[11] In its Petition, GMG argued that the Commission erred by ordering GMG to increase its sales forecast for the small commercial class from 946 customers to 990 customers. Both the Department and OAG argued that the Commission had ample record evidence to support its decision and recommended denial of GMG's request.

[11] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, Order Denying Petition for Reconsideration, Denying Petition for Clarification, and Granting Clarification at 2 (October 6, 2023).

## IV. DECISION OPTIONS

1. Grant GMG's request for reconsideration. [GMG]

2. Deny GMG's request for reconsideration. [Department, OAG]

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# Staff Briefing Papers

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| **Meeting Date** | **February 12, 2026** | | **Agenda Item 2 **** |
| Company | Northern States Power Co. d/b/a Xcel Energy | | |
| Docket No. | E-002/M-25-245 | | |
| | **In the Matter of Xcel Energy's Petition for Approval of its 2025 Annual Administrative Service Agreement** | | |
| Issues | Should the Commission approve Xcel Energy's 2025 Annual Administrative Service Agreement Petition? | | |
| Staff | Christine Pham | christine.pham@state.mn.us | 651-201-2249 |
| | enter name. | Click or tap here to enter text. | Click here to enter text. |

| ✓**Relevant Documents** | **Date** |
|---|---|
| Xcel Energy – Initial Filing | May 30, 2025 |
| Department of Commerce – Comments | September 29, 2025 |
| Office of the Attorney General – Comments | October 09, 2025 |
| Xcel Energy – Reply Comments | October 10, 2025 |



The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

## I. Background

Northern States Power Company, doing business as Xcel Energy (Xcel or the Company), is required to submit its Annual Service Agreement (ASA) to the Minnesota Public Utilities Commission (Commission).

The Service Agreement, originally approved on April 26, 2001, in Docket No. G, E-002/AI-00-1251, established the terms and cost allocation methods used by Xcel Energy Services Inc. (XES) to provide administrative and management services to Xcel Energy's operating companies.

On August 20, 2004, the Commission approved changes to the three-factor formula used to distribute costs related to corporate governance activities in Docket No. E,G-002/AI-04-181.

On October 22, 2004 the Commission approved new allocation ratios to allocate information technology costs in Docket No. E,G-002/AI-04-666.

On January 29, 2009, the Commission approved changes that accommodate the repeal of the Federal Public Utility Holding Company Act of 1935 in Docket No. E,G-002/AI-08-760.

On November 20, 2014, the Commission approved allocation changes that Xcel had implemented in prior years without Commission notice in Docket No. E,G-002/AI-14-234, finding that the changes maintained cost-causative allocation methods and requiring the Company to submit annual Service Agreement filings for ongoing review of cost allocations and proposed changes.

On November 19, 2015, the Commission accepted this first required annual Service Agreement filing and, through two separate orders under the same docket, approved various changes in allocation methods in Docket No. E,G-002/AI-15-536.

From the year 2016 through 2024 (except for 2021), the Commission accepted Xcel's annual filings with no revisions,[1] in compliance with the requirements of the November 20, 2014 Order in Docket No. E,G002/AI-14-234.

On March 17, 2021, the Commission approved Xcel's revised Administrative Service Agreement with XES (Fifth Amendment) in Docket No. E,G-002/AI-20-514, which included three major changes: Risk Area Realignment; Addition of Total Assets Ratio including Xcel Energy Inc.'s Per Book Assets Definition; and Addition of New Allocation Method for Advanced Metering Infrastructure (AMI).

[1] For years 2016-2019: Docket Nos. E,G-002/AI-16-489; E,G-002/AI-17-456; E,G-002/AI-18-362; E,G-002/AI-19-371.

For years 2021-2024: Docket Nos. E,G-002/AI-21-356, E,G-002/AI-22-259, E,G-002/AI-23-216, and E,G-002/AI-24-203.

On May 30, 2025, Xcel filed its 2025 Annual ASA with XES in compliance with the November 20, 2014 Order in Docket No. E,G-002/AI-14-234.[2] This filing requested Commission approval of the Sixth Amendment to its Service Agreement in which the Company proposed adding a Wildfire Mitigation service function and updating related cost allocation methodology in a manner consistent with Commission guidance and in public interest.

On September 29, 2025, the Minnesota Department of Commerce, Division of Energy Resources (the Department), filed comments and found that Xcel's 2025 ASA Petition met statutory and rule requirements; however, it disagreed with Xcel's proposed method for allocating wildfire mitigation costs.

On October 9, 2025, the Office of the Attorney General – Residential Utilities Division (OAG) filed its comments supporting the Department's recommendation and referred to its direct testimony filed in Xcel's pending rate case, Docket No. E-002/GR-24-320.

On October 10, 2025, Xcel filed its reply comments, disagreeing with the Department's recommendation and requesting that the Commission approve the Sixth Amendment to the Service Agreement between the Company and XES, as discussed in its initial filing on May 30, 2025.

## II. Minnesota Rules

Minn. Stat. § 216B.48 and Minn. R. 7825.2200, Subpart B govern aspects of the relationships between regulated utilities and their affiliated interests and guidelines for utility-affiliated interest filings.

## III. Discussion

### A. Xcel Energy – Initial filing

In this Petition, Xcel explained the background of its cost allocation methodologies, which follow the Commission's guiding principles (Docket No. E,G-999/CI-90-1008) and allocate costs consistently and equitably, ensuring recovery from the responsible entity and avoiding cross-subsidization. Xcel further explained that costs are assigned directly, when possible, grouped into categories for common costs, and allocated based on direct or indirect causation, or general allocators as needed.[3] The Cost Allocation and Assignment Manual (CAAM) details these procedures broadly, while the Service Agreement with XES applies these principles specifically to products and services provided to the Company, subject to Commission review and approval.

[2] In the Matter of the Request by Northern States Power Company for Approval of a Second Amendment to the Service Agreement Between the Company and Xcel Energy Services Inc., Order point 2.

[3] Xcel Initial, pg. 4

Pursuant to Minn. Stat. § 216B.48 and Minn. R. 7825.2200, subp. B, Xcel submitted its Annual Report to the Minnesota Public Utilities Commission (Commission) in Docket No. E-002/M-25-245 regarding proposed changes to its Administrative Service Agreement with Xcel Energy Services Inc. (XES). Through a Sixth Amendment, Xcel proposed adding a new Wildfire Mitigation service function and making various text updates for clarity and consistency.[4] The Company indicated that its review of the current Service Agreement did not identify any changes needed to the cost allocation methodologies for 2025.

The Company explained that it is proposing an amendment to apply an existing allocation methodology to the new Wildfire Mitigation service function because, due to the increased risk of wildfires over the last several years, wildfire mitigation has become a critical focus across Xcel Energy's operating states, including Minnesota. To support planning and risk reduction, the Company proposed adding a Wildfire Mitigation service function to the Service Agreement and allocating its indirect costs using the Total Plant Ratio (TPR), a method already applied to other service functions. The Company asserted that this request is reasonable and in the public interest because it allocates wildfire mitigation costs, an emergent service function for the Company, in the most cost-causative manner.

### B. Department of Commerce – Comments

On September 29, 2025, the Department filed comments regarding Xcel's Petition. Overall, the Department's analysis found that the filing met requirements outlined in Minnesota Rule 7825.2200, Subpart B, (1) – (5) and that Xcel's proposed miscellaneous changes to the Service Agreement are reasonable. However, the Department disagreed with Xcel's proposal to allocate wildfire mitigation costs using the Total Plant Ratio (TPR).

Based on its review of Xcel's proposed Wildfire Mitigation Service Function and allocator, the Department supported incorporating Wildfire Mitigation for transparency and oversight but is concerned that use of the TPR method does not reflect the actual drivers of these costs. The Department stated that TPR assumes wildfire risk is uniform per dollar of plant across all jurisdictions, even though wildfire mitigation costs vary by local factors such as drought, terrain, vegetation, and often concentrating in high-risk areas.

The Department also referenced the direct testimony of Mark Johnson including Information Request (IR)# 2107 filed August 22, 2025[5] in Xcel's pending electric rate case Docket No. E-002/GR-24-320 which had the same conclusions. In that rate case docket, the Department requested that Xcel justify its use of the TPR to allocate Wildfire Mitigation indirect costs or provide an alternative calculation based on NSPM's share of direct wildfire costs. The Company declined to provide impacts of alternative allocators in the rate case's rebuttal testimony. As a

[4] Xcel Initial Filing – see Attachment B, C, D, E.

[5] Docket No. E-002/GR-24-320, Department - Johnson Direct, MAJ-D-10, IR#2107.

result, the Department recommended removing $3.3 million (2025) and $4.3 million (2026)[6] in wildfire allocations to MSPM-Minnesota jurisdiction due to cross-subsidization concerns and concluded that TPR is not the most cost-causative method. The Department further recommended that Xcel allocate Wildfire Mitigation indirect costs based on each jurisdiction's direct Wildfire Mitigation expenditures, as this method reflects cost causation, aligns with the its recommendation in the current rate case, and avoids charging customers for costs from which they do not benefit.

Finally, The Department recommended that the Commission approve Xcel's revised Administrative Service Agreement with XES, with a modification requiring Wildfire Mitigation indirect costs to be allocated based on direct costs rather than the Total Plant Ratio for electric transmission and distribution. Because the proposed allocations are consistent with those used in Xcel's current rate case (Docket No. E-002/GR-24-320), the Department further recommended that the Commission require Xcel to quantify the financial impacts of any approved allocation changes for the 2025 and 2026 test years.

### C. Office of the Attorney General – Comments

In its October 9, 2025 comments, the OAG supported allocating Wildfire Mitigation indirect costs in proportion to each jurisdiction's direct expenditures.

In the OAG's Direct Testimony in Xcel's pending rate case, Docket No. E-002/GR-24-320,[7] the following concerns were addressed about Company's proposal to allocate wildfire mitigation costs using the Total Plant Ratio in the Sixth Amendment Service Agreement:

- Using the Total Plant Ratio to allocate wildfire risk management costs would incorrectly assume wildfire risk is uniform across all operating companies and jurisdictions, treating all plant investment as equally responsible for these costs.

- The Total Plant Ratio reflects only geographic footprint, not actual wildfire risk, which varies by factors such as wildfire frequency, size, restoration costs, weather, and ignition sources. In Minnesota, most wildfires are human caused rather than natural.

Because of the above concerns and the Company did not calculate indirect costs using directly assigned wildfire costs, similar to the Department, the OAG made the following recommendations:[8]

- Allocate XES indirect wildfire risk management costs to NSPM based on directly assigned wildfire costs, not the Total Plant Ratio.

[6] Docket No. E-002/GR-24-320, Department - Johnson Direct, MAJ-D-7 through MAJ-D-9, IR#185-187.

[7] Docket No. E-002/GR-24-320, OAG's Lee Direct (Aug. 22, 2025), pp. 25–28.

[8] Docket No. E-002/GR-24-320, OAG's Lee Direct (Aug. 22, 2025), pp. 29.

- Remove the Minnesota jurisdiction's currently calculated costs from the 2025 Test Year ($3.3 million) and 2026 Plan Year ($4.3 million). The 2025 Test Year and 2026 Plan Year adjustments cannot be determined because the Company did not provide the requested calculations.

### D. Xcel Energy – Reply Comments

In its reply comments on October 10, 2025, the Company disagreed with the Department's recommendations. The Company stated following:[9]

> ".. a core principal of allocating costs from XES to the Company through the ASA is that costs that cannot be direct assigned should be allocated based on a cost-causative methodology. Direct costs incurred are not a cost-causative method of allocating indirect costs (which for wildfire costs include things like situation awareness information technology (IT costs and meteorology/fire science modeling IT costs), and the Company is not clear on how indirect costs can be allocated on a direct cost basis."

Xcel also disagreed with the Department's and OAG's recommendation to allocate indirect costs based on NSPM's share of direct wildfire costs. The Company argued that this approach is inconsistent with the cost-causative framework[10] and could distort year-to-year allocations, as a single year of high wildfire activity might disproportionately affect the following year. Although discrete wildfire events drive direct costs, the Company stated that they do not drive indirect costs, such as IT systems used for situational awareness.[11] Allocating indirect costs based on one year wildfire events could unfairly burden jurisdiction in later years. Xcel further stated that it follows long-approved allocation methodologies in the Administrative Service Agreement, and the proposed changes by the Department and OAG would depart from this established framework.[12]

In its current pending rate case Docket No. E-002/GR-24-320 Rebuttal Testimony of Nicole L. Doyle, filed on October 10, 2025, the Company discussed its disagreement with the Department and the OAG recommendation to remove $3.3 million in 2025 and $4.3 million in 2026 of indirect wildfire mitigation costs allocated to the Minnesota jurisdiction. The Company said by removing the wildfire mitigation costs for the Minnesota jurisdiction, $3.3 million in 2025 and $4.3 million in 2026, would effectively eliminate all wildfire mitigation costs allocated to Minnesota. The Company further explained in response to the Department's IR#2107 that the

[9] Xcel Reply Comments at 2

[10] The framework of how costs are assigned is outlined in Xcel's Cost Allocation and Assignment Manual, initially established in Docket No. E002/GR-92-1185 and reaffirmed in Docket No. E,G999/CI-90-1008

[11] Xcel Reply Comments at 2.

[12] *Id.*

indirect XES costs must be allocated using a cost-causative methodology, as direct costs do not provide an appropriate basis allocating indirect costs, such as information technology for situational awareness or fire modeling.  As shown in Table 1, the breakout for both direct and allocated indirect wildfire mitigation costs for NSPM- Minnesota.

**Table 1 - NSPM Wildfire Mitigation Charges Test Years 2025 and 2026 ($ in Millions)**[13]

| **Direct Charges** | **2025** | **2026** |
|---|---|---|
| Labor | $0.3 | $1.7 |
| Consulting | $1.2 | $0.5 |
| Non-Labor | $0.3 | $0.6 |
| **Total NSPM Direct Charges** | **$1.8** | **$2.8** |
| MN Jurisdictional Allocation Percentage | 87% | 87% |
| **Total MN Direct Charges** | **$1.6** | **$2.4** |
| **Indirect Charges** | **2025** | **2026** |
| Labor | $0.6 | $0.7 |
| Non-Labor | $1.4 | $1.4 |
| **Total NSPM Indirect Charges** | **$2.0** | **$2.1** |
| MN Jurisdictional Allocation Percentage | 87% | 87% |
| **Total MN Indirect Charges** | **$1.7** | **$1.8** |
| **Total Charges** | **2025** | **2026** |
| **Total NSPM Charges** | **$3.8** | **$4.9** |
| **Total MN Charges** | **$3.3** | **$4.3** |

Additionally, Ms. Doyle emphasized that NSPM follows a Commission-approved fully distributed costing methodology, established in prior electric and gas rate cases and reaffirmed in the 1994 Cost Allocation Order. The Company's hierarchical cost allocation framework prioritizes direct assignment where possible and allocates common costs based on cost causation, variability, traceability, benefit, or, if necessary, a general allocator. For Wildfire Mitigation costs, NSPM directly assigns costs to the Minnesota jurisdiction when specific and allocates indirect costs using Total Plant (electric transmission and distribution) as the most cost-causative method available.[14]

Xcel concluded that indirect wildfire mitigation costs should be allocated using the Total Plant Ratio and included in the 2025 and 2026 test years. This approach aligns with Commission-approved cost-causation principles and provides an equitable allocation across jurisdictions. Excluding these costs would under-recover expenses necessary to maintain safe and reliable service and prevent full recovery of wildfire mitigation efforts.  The Total Plant Ratio reflects

13 Docket No. E-002/GR-24-320, Xcel – Doyle Rebuttal (Oct.10, 2025), pp. 15.

14 *Id.,* pp.18.

the underlying drivers of indirect costs and ensures that cost recovery matches the scope and scale of operations.[15]

## IV. Staff Analysis

Staff notes that allocating Wildfire Mitigation indirect costs using the Total Plant Ratio (TPR) may reasonably reflect cost causation; however, wildfire mitigation activities are often driven by localized conditions (e.g., vegetation, terrain, and climate), raising concerns about whether the use of TPR could result in cross-subsidization among operating companies or jurisdictions. If the Commission allows indirect wildfire mitigation costs to be allocated using TPR and included in the Company's current rate case, the Commission may wish to consider the associated financial impacts and require Xcel to identify the Minnesota jurisdictional impacts of alternative allocation methodologies for the 2025 and 2026 test years. Providing this analysis would enable the Commission to better evaluate the reasonableness of the proposed allocator and its rate impacts.

## V. Decision Options

1. Approve Xcel's proposed Sixth Amendment to the Service Agreement between the Company and XES Xcel, including Xcel's proposal to allocate indirect wildfire mitigation costs using the Total Plant Ratio and include them in the Company's current rate case (Docket No. E002/GR-24-320) for the 2025 and 2026 Test Years. [Xcel Energy]

2. Approve Xcel's proposed Sixth Amendment to the Service Agreement between the Company and XES, with the modification requiring Xcel to allocate Wildfire Mitigation indirect costs based on Wildfire Mitigation direct costs instead of using the Total Plant Ratio of electric transmission and distribution plants. [Department, OAG]

3. Require Xcel to provide the financial impact of the Wildfire Mitigation service function in the Company's current rate case (Docket No. E-002/GR-24-320) for the 2025 and 2026 Test Years, reflecting any allocation changes proposed in this docket that are approved by the Commission. [Department, OAG]

[15] Docket No. E-002/GR-24-320, Xcel – Doyle Rebuttal (Oct.10, 2025), pp. 21.

MINNESOTA
PUBLIC UTILITIES COMMISSION

# Staff Briefing Papers

| | | |
|---|---|---|
| **Meeting Date:** | February 12, 2026 | Agenda Item: *3 |
| **Company:** | Apex Clean Energy Holdings, LLC d/b/a Big Bend Wind, LLC | |
| **Docket:** | IP-7013/WS-19-619<br><br>In the Matter of the Application of Big Bend Wind, LLC for a Large Wind Energy Conversion System Site Permit for the up to 300 MW Big Bend Wind Project in Cottonwood and Watonwan Counties, Minnesota | |
| **Issues:** | ▪ Should the Commission approve Big Bend Wind LLC's petition to amend the site permit for the Big Bend Wind Project? | |

| | | | |
|---|---|---|---|
| **Staff:** | Richard Davis | richard.davis@state.mn.us | 651-539-1077 |
| | Cezar Panait | cezar.panait@state.mn.us | 651-201-2207 |

| ✓ **Relevant Documents** | **Date** |
|---|---|
| Application to the Minnesota Public Utilities Commission for a Certificate of Need and Site Permit for the Big Bend Wind Project (27 parts, seven parts are Trade Secret) | 11/09/2020 |
| Supplemental and Amended Site Permit Application (45 parts, 6 parts are Trade Secret) | 09/20/2021 |
| Environmental Assessment (11 parts) | 01/18/2022 |
| Corrections to the Environmental Assessment | 01/25/2022 |

The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

To request this document in another format such as large print or audio, call 651-296-0406 (voice). Persons with a hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

| ✓ **Relevant Documents** | **Date** |
|---|---|
| Corrections to the Environmental Assessment | 02/08/2022 |
| Order Adopting Administrative Law Judge Report, Finding the EA and the record address the issues identified in the scoping decision, Granting Certificate of Need, and Issuing the Site Permit for the Big Bend Wind Project (Four parts) | 09/28/2022 |
| Site Permit Amendment Request (10 parts) | 10/31/2025 |
| Notice of Comment Period on Site Permit Amendment | 11/26/2025 |
| Minnesota Public Utilities Commission Energy Infrastructure Permitting (EIP) Staff Comments and Recommendations | 12/10/2025 |
| Brad Hutchison Comments 1 | 12/11/2025 |
| Brad Hutchison Comments 2 | 12/11/2025 |
| Big Bend Wind, LLC Reply Comments | 12/16/2025 |
| PUC EIP Reply Comments | 12/17/2025 |
| Brad Hutchison Reply Comments | 12/18/2025 |

## ISSUES

- Should the Commission approve Big Bend Wind LLC’s petition to amend the site permit for the Big Bend Wind Project?

## PROJECT BACKGROUND

On September 28, 2022, the Commission issued an order granting a certificate of need and issuing a site permit for the up to 300 megawatt (MW) Big Bend Wind Project (project) to Big Bend Wind, LLC (Big Bend Wind, permittee).[1] The project site permit is Attachment 1 of the order.[2] On December 23, 2024, the Commission issued a revised site permit extending the timelines for the permittee to secure a power purchase agreement (PPA) and to begin project construction.[3]

On October 31, 2025, Big Bend Wind filed a request to amend their site permit under Minn. Stat. § 216I.09.[4] Big Bend Wind is requesting an amendment to update turbine technology changes, proposed changes to the site layout, and to update the site permit to reference Minnesota Statute Chapter 216I.

Turbine technology updates include the removal of turbine model Nordex N-163 from the site permit, and an uprated turbine model GE-158 from 5.8 to 6.1 MW nameplate capacity. The uprating of GE-158 will result in a requested increase in total project nameplate capacity from 300 MW to 311.1 MW.

Big Bend Wind is considering the uprated GE-158 turbine model because of its increased efficiency, which allows for an increased project nameplate capacity of 311.1 MW and a reduction in the total number of turbines to be constructed and operated from 52 to 51. The uprated GE-158 turbine model has the same external dimensions as the GE-158 turbine model that was in the applicant's supplemental and amended site permit application.[5] The GE-158 turbine model was in the original site permit[6] and the revised site permit.[7]

[1] Minnesota Public Utilities Commission, Order – Order Issuing Permits, September 28, 2022, eDocket No. 20229-189351-05

[2] Minnesota Public Utilities Commission, Order – Attachment 1, September 28, 2022, eDocket No. 20229-189351-10

[3] Minnesota Public Utilities Commission, Other – Revised Site Permit, December 23, 2024, eDocket No. 202412-213281-01

[4] Big Bend Wind, LLC, Other-Site Permit Amendment Request Letter, October 31, 2026, eDocket No. 202510-224488-01

[5] Big Bend, LLC, Other-Supplemental and Amended Site Permit Application, September 20, 2021, eDocket No. 20219-178112-02

[6] Minnesota Public Utilities Commission, Order – Attachment 1, September 28, 2022, eDocket No. 20229-189351-10

[7] Minnesota Public Utilities Commission, Other – Revised Site Permit, December 23, 2024, eDocket No. 202412-213281-01

Changes to the site layout include the removal of two potential turbine locations (one primary and one alternate), an additional collection line easement that moves a project collection line to avoid crossing a Minnesota Department of Natural Resources (MDNR) driveway, and shifting the operation and maintenance (O&M) building from the permitted location to an area directly adjacent to the Big Bend Wind Project Substation (Figure 1). The permittee requests various changes to the site permit to bring the permit in line with the current MN Stat. 216I, which was not in effect at the time of issuance of the project's site permit.[8]

## STATUTES AND RULES

Minn. Stat. § 216I.09 Permit Amendments, establishes the process for amending an existing Commission-issued site or route permit for a large energy infrastructure facility. The permittee must submit a written application describing the alteration to be made or the amendment being sought and explaining why the request qualifies under the statute, including identifying any changes to environmental impacts evaluated in the original permit approval; if the proposal would cause significant changes in those impacts, additional environmental review is required.

The Commission must mail notice that the application was received and provide at least a 10-day public comment period, with up to seven days for the applicant to respond. Within 30 days after the permittee's response, the Commission must either authorize the amendment, bring the matter to the Commission for consideration, or determine that a different permitting decision is required under this chapter. The Commission may approve the amendment with reasonable conditions and must provide written notice to the permittee and to anyone who commented or requested notification.

## SUMMARY OF COMMENTS

The Commission issued a Notice of Comment Period on the Site Permit Amendment Request on November 26, 2025.[9] Initial written comments were accepted through December 10, 2025, and reply comments through December 17, 2025. The Commission received initial comments from

[8] Big Bend Wind, LLC, Other-Site Permit Amendment Request Letter, October 31, 2026, eDocket No. 202510-224488-01

[9] PUC, Notice of Comment Period – Notice of Comment Period on Site Permit Amendment, November 26, 2025, eDocket No. 202511-225344-01

one landowner, Brad Hutchison[10,11] and Commission Energy Infrastructure Permitting (EIP) staff.[12] The comment letters are summarized below.

**Initial Comments**

**A. Brad Hutchison**

On December 10, 2025, Mr. Brad Hutchison submitted a public comment in opposition to Big Bend Wind's site permit amendment request.[13] Mr. Hutchison's comments outlined why he believes a new environmental assessment (EA) is needed before the amendment is approved. Mr. Hutchison argued that the data in the EA is outdated. He asserted that background sound level monitoring in 2019 and sound propagation modeling from 2020-2021 are out of date and cannot be relied upon. Mr. Hutchison suggested that the loss of a significant number of old growth trees in the project area, due to the infestation of Emerald Ash Borer (EAB), has significantly changed the topography of the project area, and makes the use of a ground factor of G=0.5 unrealistic for project noise modeling.

Mr. Hutchison also asserted that the final settlement agreement between Big Bend Wind, LLC, the Minnesota Historical Society, and signatory Tribes – an agreement that identifies visual impacts to the Jeffers Petroglyphs and restricts turbine placement within seven miles of the site – establishes a seven-mile buffer should be the minimum distance between homes and project turbines. Mr. Hutchison suggested that the same visual impact analysis performed for the Jeffers Petroglyph site should be performed for area homeowners before the permit amendment is approved or the project is allowed to begin construction.

Mr. Hutchison submitted the same set of comments a second time, via email, on December 11, 2025.[14]

**B. EIP Staff**

[10] Minnesota Public Utilities Commission, Public Comment-Brad Hutchison 1, December 11, 2025, eDocket No. 202512-225744-01

[11] Minnesota Public Utilities Commission, Public Comment-Brad Hutchison 2, December 11, 2025, eDocket No. 202512-225744-02

[12] PUC-EIP, Comments – Comments on Permit Amendment Request, December 10, 2025, eDocket No. 202512-225702-01

[13] Minnesota Public Utilities Commission, Public Comment-Brad Hutchison 1, December 11, 2025, eDocket No. 202512-225744-01

[14] Minnesota Public Utilities Commission, Public Comment-Brad Hutchison 2, December 11, 2025, eDocket No. 202512-225744-02

On December 10, 2025, EIP staff provided comments on Big Bend Wind's proposed permit amendment.[15] Staff noted that the text of Minn. Stat. § 216I.09 does not provide guidance as to how permit amendment requests might be analyzed to determine if the Commission should authorize approval.

Staff reviewed the permit amendment request, including appendices, and evaluated the potential impacts of the requested permit amendments against the September 2021 supplemental and amended site permit application, the 2022 EA and appropriate addendums, the Commission's original permit decision from September 2022, and the Commission's revised permit decision from December 2024.

EIP staff concluded that the turbine technology changes proposed by Big Bend Wind in its proposed permit amendment are anticipated to have the same, or similar, noise and shadow flicker impacts as the originally proposed wind turbines identified in the original and revised 2024 site permits. Staff asked Big Bend Wind to clarify whether the participating landowners anticipated to experience over 30 hours of shadow flicker per year are currently living in their residences, as opposed to the residence being rented to a tenant.

Staff's analysis found that the resulting nameplate capacity increase from 300 MW to 311.1 MW would not result in additional project impacts as the uprated GE-158 turbine model would have the same external dimensions as the GE-158 turbine model included in the 2022 EA, and no turbine locations were added or moved from locations identified in the original and revised 2024 site permits.

Staff analyzed Big Bend's proposed shift of the collection line easement to the north side of County Road 9, and the request to move the permitted O&M building location to be adjacent to the permitted project substation location. The new collection line easement area was included in the EA completed for the project. Staff agreed that moving the collection line to the north side of County Road 9 will minimize impacts to recreational resources. The amended O&M building location will be the same location as the previously reviewed and permitted Red Rock Solar substation.[16] Amending the O&M building location will shift impacts to agricultural land from the originally permitted location to the amended location. Staff believes collocation of the project substation and O&M building would minimize impacts to agricultural operations by

[15] PUC-EIP, Comments – Comments on Permit Amendment Request, December 10, 2025, eDocket No. 202512-225702-01

[16] PUC-EIP, Comments – Comments on Permit Amendment Request, December 10, 2025, eDocket No. 202512-225702-01

creating one developed area to work around versus having two separate developed areas for farmers to work around.

Staff noted that Big Bend Wind's proposed project changes are generally consistent with project's current site permit, and staff agrees with Big Bend Wind's proposed amendments to the current site permit. Staff also provided additional permit amendments to provide clarity and consistency with other recently issued permits.

**Reply Comments**

Reply comments were received from Big Bend Wind, LLC,[17] EIP staff,[18] and Brad Hutchison.[19] The reply comments are summarized below.

**A. Big Bend Wind, LLC**

Big Bend Wind provided reply comments to EIP staff's comments. Big Bend Wind confirmed that the 16 participating landowners whose properties are modeled to experience 30 or more hours of shadow flicker per year, currently live in their residences.[20] All of these landowners have signed shadow flicker waivers with Big Bend Wind. Big Bend Wind also replied to staff's comments about the northern long-eared bat, and stated they don't believe additional review is needed for the species.

Big Bend Wind also provided reply comments to Mr. Hutchison's comments. Big Bend Wind clarified that the sound modeling for the project was updated in the revised sound report included with the permit amendment request. Big Bend Wind also clarified that terrain used in the model is bare earth, and the sound modeling is completed with conservative parameters. Tree canopies and potential noise attenuating effects of trees in the project area are not accounted for in the sound modeling, which means the modeled sound levels are likely higher than they might actually be in areas with stands of trees. Big Bend Wind stated that setbacks from the Jeffers Petroglyphs and from non-participating landowners, such as Mr. Hutchison, were both studied in the EA.

[17] Big Bend Wind, LLC, Reply Comments – Site Permit Amendment Request, December 16, 2025, eDocket No. 202512-225900-01

[18] PUC EIP, Reply Comments – Site Permit Amendment, December 17, 2025, eDocket No. 202512-225975-01

[19] PUC, Public Comment – Brad Hutchison, December 18, 2025, eDocket No. 202512-225998-01

[20] Big Bend Wind, LLC, Reply Comments – Site Permit Amendment Request, December 16, 2025, eDocket No. 202512-225900-01

Big Bend Wind requested the Commission approve the proposed amendment, and they committed to abide by the terms and conditions of the current approved site permit, as modified by the requested amendments.

**B. EIP Staff**

Staff provided reply comments on December 17, 2025, to address Mr. Hutchison's comments. Mr. Hutchison argued that the EA completed for the project is out of date and needs to be updated. Staff acknowledged that the EA was completed in January 2022, but argued that the EA is still adequate with respect to the analysis of the project's potential human and environmental impacts. Staff noted that, for wind facilities, the site permit application is considered the primary environmental review document, and Big Bend Wind provided an updated environmental analysis with the permit amendment request. Staff has reviewed the environmental analysis and found it to be adequate in addressing any potential impacts associated with the amended project.

Staff acknowledged Mr. Hutchison's comment and concerns about potential turbine noise impacts increasing due to the loss of several large ash trees. Staff, however, explained that noise modeling is done with a "worst – case scenario" approach and attenuation by vegetation on the landscape isn't factored into the noise modeling at individual receptors. Staff also stated the loss of individual trees across a project area as large as the Big Bend Wind Project, would not have a significant impact on the ambient sound levels.

Staff addressed Mr. Hutchison's comment that a ground factor of G=0.5 is not realistic. Staff indicated that the Big Bend noise assessment report was conducted in accordance with the ANSI/ACP wind turbine sound modeling standards, which allow for a ground factor of G=0.5 to be used as long as two additional decibels are added to the wind turbine models' sound power levels. This approach was used for the Big Bend project. In response to Mr. Hutchison's comment regarding significant changes to topography within the project area, staff stated that they are not aware of significant grading or excavation that has occurred within the project area, and the topography of the area has not changed since the EA was completed in 2022.

Staff replied to Mr. Hutchison's comments that the Jeffers Petroglyphs settlement agreement implied that visual impacts of the proposed wind turbines experienced by someone at the Jeffer's Petroglyphs would be the same for a homeowner in the project area. Staff indicated that potential visual impacts to a participant of a cultural activity at the Jeffers Petroglyphs are not considered the same as visual impacts to a homeowner in the project area, an individual driving in the project area, or an individual working outdoors in the project area. Staff asserted that simply being able to see a wind turbine during typical everyday activities is not considered to cause human or environmental harm.

Staff stated that the updated sound and shadow flicker modeling completed by Big Bend Wind is an appropriate analysis of potential human and environmental impacts associated with the proposed site permit amendment. Staff recommended the Commission approve the amendments to the Big Bend Wind site permit as described in Staff's December 10, 2025, comment letter.

### C. Brad Hutchison

On December 18, 2025 Mr. Hutchison provided a reply to the PUC-EIP comments. Mr. Hutchison stated that Big Bend Wind's 2025 site permit amendment request is making a false claim when it stated that the the amendment request was incorporating the Department of Commerce's 2019 LWECS Application Guidance, which stated that turbines should be sited so that turbine-only noise is <45 dB(A) at non-participating residences and <47 dB(A) at participating residences. Mr. Hutchison points to the 2025 amendment request, which stated that many homes will have maximum projected sound levels of 47 dB(A) (rather than <47 dB(A)), thus exceeding the 2019 guidance referenced by Big Bend Wind in their amendment request. Mr. Hutchison also noted that most of the data regarding turbine sound and the inputs used for noise modeling are hidden for those who will be impacted.

Mr. Hutchison indicated that EIP staff is supporting changes to how post-construction noise evaluation is completed. Mr. Hutchison stated that Big Bend Wind should not be allowed to develop the post-construction nosie study methology, and having 18 months to complete the required post-construction noise monitoring is too long. Mr. Hutchison asserted that the post-construction noise monitoring protocol should already be written, without the permittee's input, and that the noise monitoring should be completed by a third party at the cost of the permittee. Mr. Hutchison stated that noise levels have been exceeded at other wind farms, and the landowners at those locations are given little opportunity for recourse. Mr. Hutchison requested specific actions be mandated if predicted sound levels are exceeded.

Mr. Hutchison also stated that the noise prediction in this case, ISO 9613-2 standard method, was originally designed to predict sound levels from smalller surface-level sources, not wind turbines. Mr. Hutchison stated that predicting wind turbine noise is challenging because of sound levels depending on atmospheric conditions. Temperature inversions and wind shear conditions at night can result in turbine sound traveling further and remaining louder than predictive modeling suggests. Mr. Hutchison identifed the Freeborn Wind Project as having measured turbine-only sound levels that were two to five decibels higher than the sound modeling predictions indicated. Mr. Hutchison identified the Nord2000 modeling method as being more accurate under most circumstances than the ISO 9613-2 modeling standards.

Mr. Hutchison requested that the Commission deny Big Bend Wind's request for a permit amendment. If the Commission does approve the requested permit amendment, Mr. Hutchison requested that if noise predictions are determined to be underestimated, the permit should include real and costly consequences for the permittee. Additionally, Mr. Hutchison requested that post-construction noise monitoring be completed by an independent third party.

## STAFF DISCUSSION

In reviewing the comments received on the proposed permit amendment, staff believes that Big Bend Wind has provided the necessary updated modeling information for turbine noise and shadow flicker associated with the project. Staff believes the proposed project amendments would have been approved by the Commission, had the information been available at the time of issuing the original site permit.

Staff acknowledges that shadow flicker produced by operating wind turbines can create an annoyance for local residents. The amended site permit will retain a shadow flicker condition, generally limiting residences shadow flicker exposure to less than 30 hours per year. There are currently 16 landowners anticipated to experience more than 30 hours of shadow flicker per year; all of these landowners have signed shadow flicker waivers with Big Bend Wind.

Staff notes that the 2020 original site permit application, the 2021 supplemental and amended site permit application, as well as the 2025 site permit amendment request filed by Big Bend Wind all reference the Department of Commerce's 2019 LWECS Application Guidance. Big Bend Wind's proposed 2025 site permit amendment indicates the turbine locations were determined in accordance with the 2019 guidance, so that turbine-only noise would be <45 dB(A) at non-participating residences and <47 dB(A) at participating residences. However, the noise modeling for turbine model GE-158 shows a turbine-only max L50 of 47 dB(A) (as opposed to < 47 dB(A)). It is unclear to EIP staff why Big Bend Wind stated they used the 2019 guidance, when the turbine-only modeled noise levels are slightly inconsistent with the guidance.

Even with this discrepancy, staff believes the noise modeling and analysis is accurate and has been completed correctly. Staff notes that the 2019 guidance was updated in 2022, and the turbine-only noise modeling guidance was changed by Department of Commerce staff, from <47 dB(A) at participating residences to not contributing more than 47 dB(A) to total sound levels at nearby receptors.

With respect to noise modeling and permit compliance, EIP staff is responsible for reviewing post-construction noise monitoring protocol for all wind projects. Though there are standard approaches to monitoring wind energy projects, each noise protocol is unique and staff is knowledgeable and capable of providing the necessary review. Staff supports the current timeline allowed to complete post-construction noise monitoring within 18 months of the commercial operation date, because effective noise monitoring is dependent on a number of variables, including coordination with landowners for the placement of monitoring equipment, weather conditions, potential equipment failures, possible need to shift monitoring equipment to improve data collection, and turbine operation during the monitoring period.

Once field data collection is complete, data analysis must be completed, and a report must be developed and submitted. Shortening the post-construction monitoring process and timeline has the potential for inadequate data collection, which would increase the possibility of missing exceedances of the state noise standards, should they occur. Staff does not recommend any changes to the site permit conditions on project noise and post-construction noise monitoring.

Big Bend Wind's consultant used the Computer Aided Design for Noise Abatement (Cadna-A) software to complete predictive noise modeling for the project, and was completed in accordance with ISO 9613-2. ISO 9613-2 which is the current accepted standard for methods for predictive modeling of sound pressure levels outdoors, including wind turbine noise. Mr. Hutchison stated that the Nord2000 modeling approach may be more accurate than the ISO 9613-2 methods. Staff acknowledges that there are multiple methods to complete predictive noise modeling, and all models inherently have limitations and advantages. The Nord2000 noise assessment methodology shows promising results, but additional verification and modification are necessary to apply the methodology to wind turbine noise modeling.[21]

Staff recommends that the Commission determine that the amended project has comparable human and environmental impacts to the originally permitted project, and find that the Commission would have made the same decision on the original site permit if the proposed design changes were known at that time. The Commission should authorize the permit amendment. If the Commission determines that the impacts of the amended project are not comparable, or if the Commission would have made a different decision on the original site permit, the Commission should deny the permit amendment.

[21] Stens, A. 2025. Implementation of Nord2000 in Swedish noise assessments for industrial noise: A consequence analysis of a hypothetical transition from ISO 9613-2 to Nord2000 (Dissertation). Retrieved from https://urn.kb.se/resolve?urn=urn:nbn:se:kth:diva-370803

Staff recommends that the Commission authorize the permit amendment, and adopt the amended site permit as requested by Big Bend Wind and incorporating EIP staff's December 10, 2025, recommendations.

## COMMISSION DECISION OPTIONS

1. Grant the site permit amendment as requested by the permittee and incorporating EIP staff's December 10, 2025, recommendations, and issue an amended site permit.

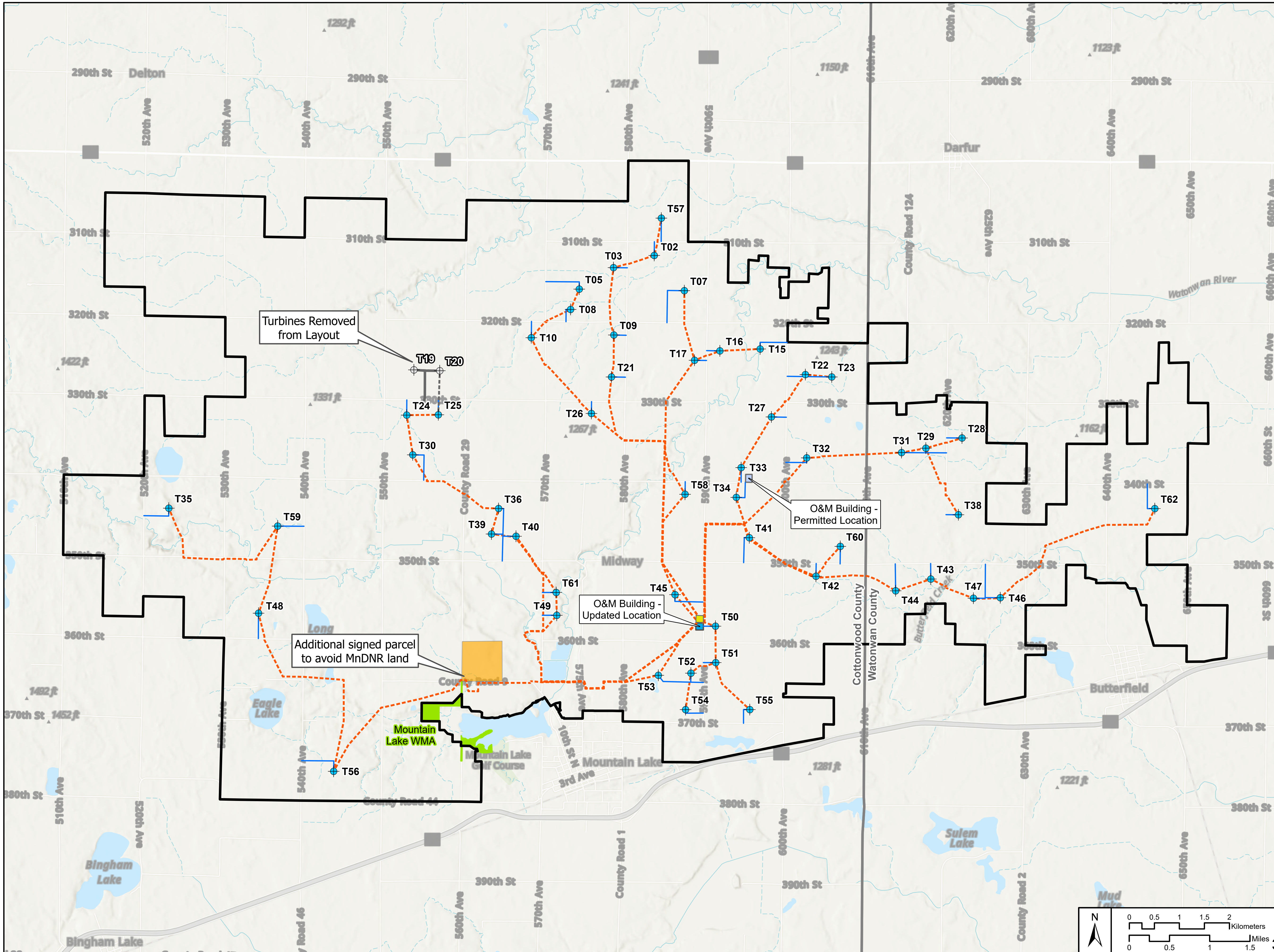
2. Grant the site permit amendment as requested by the permittee and incorporating EIP staff's December 10, 2025, recommendations, with modifications determined by the Commission, and issue an amended site permit.

3. Deny the site permit amendment requested by the permittee.

**Staff Recommendation: 1**


# Big Bend Wind
## Figure 1
## Site Permit Layout Revisions

- Turbine
- Access Road
- Underground Collection
- Turbines - Removed
- Access Road - Removed
- Underground Collection - Removed
- Project Boundary
- Project Substation
- O&M Building - Updated Location
- O&M Building - Permitted Location
- Additional Underground Collection Easement

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**Date: 10/29/2025**

Coordinate System: NAD 1983 StatePlane Minnesota South FIPS 2203 Feet
Projection: Lambert Conformal Conic
Datum: North American 1983
Units: Foot US

BIG BEND WIND