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April 3, 2024

OTTER TAIL POWER COMPANY

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East
Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Otter Tail Power Company's 2022-2036 Integrated Resource Plan
Docket No. E017/RP-21-339
Comments

Dear Mr. Seuffert:

Otter Tail Power Company (Otter Tail) hereby submits to the Minnesota Public Utilities Commission (Commission) its Comments in the above-referenced matter.

We have electronically filed this document with the Commission and copies have been served on all parties on the attached service list. A Certificate of Service is also enclosed. Please contact me at 218-739-8989 or njensen@otpco.com if you have any questions regarding this filing.

Sincerely,

/s/ NATHAN JENSEN
Nathan Jensen
Manager, Resource Planning

kaw
Enclosures
By electronic filing
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2022-2036 Integrated Resource Plan

Docket No. E017/RP-21-339

COMMENTS

I. INTRODUCTION & BACKGROUND

Otter Tail Power Company (Otter Tail or Company) submitted its Application for Resource Plan Approval (Initial IRP) with the Minnesota Public Utilities Commission (Commission) on September 1, 2021. Significant developments affecting the resource planning landscape occurred after the Company filed its Initial IRP. [1] To account for these developments the Company filed its Application for Supplemental Resource Plan Approval (Supplemental IRP) on March 31, 2023. Recognizing significant near to mid-term uncertainty, the Company's Supplemental IRP planned for the Company's continued co-ownership in Coyote Station until such time as the Company would be required to make a material non-routine capital investment in the plant. The Supplemental IRP also sought authority for more renewable resources than what was included in the Initial IRP. The Supplemental IRP also reiterated the Company's support for adding liquified natural gas (LNG) storage capability at Astoria Station. Importantly, both the Initial IRP and Supplemental IRP were premised on traditional integrated system resource planning.

Parties to this docket filed their Comments on September 13, 2023. Otter Tail filed Reply Comments on October 30, 2023. Otter Tail's Reply Comments provided for the Commission's consideration a short-term action plan for renewable resource additions on a Minnesota-only basis, noting the modeling results could support such additions on a Minnesota-only basis similar to our Hoot Lake solar project. Otter Tail provided this information in recognition that continued resource planning on an integrated, multi-jurisdictional basis faced significant headwinds that were not likely to abate, and that these circumstances may require solutions on a non-integrated basis.[2]

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[1] The developments included (1) MISO's adoption of a seasonal resource adequacy construct and capacity requirements that increased planning reserve margins (PRMs), (2) the enactment of the federal Inflation Reduction Act, (3) the enactment of Minnesota's Clean Energy Law, (4) changes in Otter Tail's load forecasts, and (4) MISO's projections for capacity deficits and recent energy market volatility.

[2] We noted that "[m]odifications to Otter Tail's Supplemental Preferred Plan may make it impossible for Otter Tail to comply with all of the laws in the states it serves. Should that occur, Otter Tail would have to tailor solutions to meet the priorities of all three Otter Tail jurisdictions, potentially on a non-integrated basis." Otter Tail Reply Comments p. 7, (October 30, 2023).

On December 15, 2023, the Company filed its Minnesota Preferred Plan with AME which introduced the Commission to specific tools and actions Otter Tail had been discussing with the parties to this docket as a possible basis for settlement. As a baseline the Minnesota Preferred Plan with AME proposed bifurcating Otter Tail's resource planning (i.e. jurisdictional planning) to account for a lack of jurisdictional consensus on Coyote Station and renewable resource additions. Specifically, the Minnesota Preferred Plan proposed designating the Minnesota portion of Otter Tail's interest in Coyote Station as an Available Maximum Emergency (AME) resource that would be called upon by MISO only in the event of a Maximum Generation (Max Gen) Event, such as in the cases of extreme heat, cold, or other extreme events. The AME designation would have the effect of significantly reducing or even eliminating in some years the carbon emissions from the Minnesota share of the plant. The Minnesota Preferred Plan with AME also proposed adding 200 MW of Solar and 150 MW of wind by 2032 the cost and benefits of which would be wholly to the Minnesota jurisdiction.[3]

The Commission's hearing on Otter Tail's IRP filings was held on January 4, 2024. Rather than act on the Company's filings, the Commission directed the parties to further develop the record, and to continue their efforts toward a negotiated settlement. Consistent with this directive, the Commission issued a Notice of Comment Period on January 18, 2024, seeking comments on the following issues:

1. Should the Commission find that jurisdictional system planning is necessary?
2. Should the Commission approve, modify, or reject Otter Tail's Minnesota Preferred Plan with Available Maximum Emergency (AME) as presented in the Company's December 15, 2023, Supplemental Filing?
3. Should the costs and benefits of renewable projects identified in Otter Tail's Minnesota Preferred Plan with AME be wholly allocated to Minnesota customers?
4. Should the Commission authorize OTP to begin the process of withdrawing from Coyote Station in the event the Company is required to make major, non-routine capital investments in the plant?
5. Should the Commission approve Otter Tail's proposal to add onsite liquified natural gas (LNG) fuel storage at Astoria Station in 2027?
6. Should the Commission find that Otter Tail's current resource acquisition process is sufficient and need not be modified?

[3] *See* Otter Tail Supplemental Filing, MPUC Docket No. E017/RP-21-339, December 15, 2023.

The Notice also included the following topics open for comment:

- Has OTP provided enough information for the Commission to determine that designating Coyote Station as an AME Resource and allocating all costs to Minnesota is in the best interests of Otter Tail's Minnesota customers?
- What financial issues that should be addressed as part of this proceeding?
- Does AME address other risks discussed in the record, such as market energy price risk environmental regulations risk to Minnesota ratepayers?
- What are the local job impacts associated with AME compared to other alternatives?
- Should the Commission consider opening a new, separate docket to address jurisdictional cost allocation issues for OTP?
- Are there other issues or concerns related to this matter?

As encouraged by the Commission, Otter Tail has worked toward a settlement in this docket. Otter Tail has consulted and met with all parties. On April 2, 2024, Otter Tail filed a comprehensive settlement agreement (Settlement Agreement) by and among the following parties: (1) Minnesota Department of Commerce, Division of Energy Resources; (2) International Union of Operating Engineers Local 49; (3) North Central States Regional Council of Carpenters; (4) Laborers' International Union of North America Minnesota and North Dakota; and (5) Otter Tail.

The Company provides these Comments, which were prepared before the Settlement Agreement was completed, to provide the full record sought by the Commission. To the extent the Settlement Agreement modifies positions noted in these Comments those modifications reflect compromises fully supported by Otter Tail.

II. OTTER TAIL COMMENTS

1. Should the Commission find that jurisdictional system planning is necessary?

Yes, the Commission should find that jurisdictional planning is necessary. Significant statutory and policy differences make it necessary to approach planning differently than we have in the past. That said, it is important to understand that jurisdictional planning is a modification of and not a full departure from traditional integrated system planning. The Company seeks to retain for our customers the benefits of integrated system planning where appropriate, while allowing for limited jurisdictional resource planning to address the differing legal frameworks and policy prerogatives of our respective jurisdictions.[4]

The differences between our jurisdictions are significant, particularly between Minnesota and North Dakota. There have long been differences in modeling requirements, with North Dakota prohibiting by statute the consideration of externalities[5] and Minnesota statutorily mandating the use externalities. Minnesota's recently enacted statutory changes to its externality requirements[6] have amplified resource planning modeling differences, which in turn can produce significant differences in the timing and nature of resource selections.

Minnesota's recent adoption of the Carbon Free Standard (CFS) is also a key difference between our jurisdictions.[7] The CFS mandates that Otter Tail generate or procure 100 percent of electricity provided to our Minnesota customers from carbon free resources by 2040, with intermediate steps of 80 percent by 2030 and 90 percent by 2035. North Dakota has not adopted any similar mandate.

These fundamental differences become clear when assessing the prudency of resource additions. North Dakota's legal framework for determining the prudency of resource additions is "need plus least cost" and the North Dakota Public Service Commission (North Dakota PSC) is required by law to find prudent the least cost resource regardless of externalities costs.[8] In contrast, Minnesota employs a "in the public interest" standard[9] and the Commission is legally obligated to consider the environmental impacts of energy generation resources and the Commission may consider carbon reduction and CFS compliance in addition to the traditional issues of cost and reliability.[10] The divergence in legal and policy standards can now result in situations where resources deemed in the public interest in Minnesota under the Commission's statutory requirements are deemed to be not needed and fail the least cost standard under North

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[4] In these Comments we focus on the need for jurisdictional planning based on differences between Minnesota and North Dakota. Both states have IRP filing requirements mandated by statute and we are engaged in IRP dockets in both states. South Dakota does not have an IRP process.
[5] *See* N.D.C.C. § 49-02-03.
[6] *See* Minn. Stat. § 216B.2422, subd. 3 and the Commission's December 19, 2023 "Order Addressing Environmental And Regulatory Costs" in Dockets E999/CI-07-1199 and E999/DI-22-236. The recent statutory amendments require the Commission to provisionally adopt and apply the EPA's draft Social Cost of Greenhouse Gas estimates released in 2022, "including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate." The Commission must adopt the EPA's final estimates when available, or the estimates by the federal Interagency Working Group if higher.
[7] Minn. Stat. § 216B.1691, subd. 2g
[8] *See* N.D.C.C. § 49-05-17 (requiring that North Dakota resource planning focus on the "least cost plan"); ND Admin. Code 69-09-12-03(6) ("[T]he North Dakota preferred plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities.")
[9] Minn. Stat. § 216B.2422 subd. 2 (a)
[10] Minn. Stat. § 216B.1691, subd. 2 (g); Minn. R. 7843.0500, subp. 3.

Dakota's statutory requirements. Similarly, we anticipate situations where resources approved in North Dakota will fail to satisfy the public interest standard in Minnesota.

In the past we have been able to identify resource options satisfying the differences between our jurisdictions. We do not believe we can do so in the present docket. The (1) fundamentally different approaches to externalities and (2) the Company's need to plan its resources for compliance with Minnesota's CFS produce significantly different modeling results and planning outcomes. This becomes clear when these differences are filtered through the different legal standards concerning the prudence of resource additions. This has altered and will continue to alter our planning framework.

This point has become clear as we have progressed through parallel resource planning dockets in Minnesota and North Dakota.[11] The Company's December 15, 2023, supplemental filing described the status of resource plans pending before this Commission and the North Dakota PSC. In that filing we identified differences in policies and statutory frameworks guiding our modeling. We also noted views expressed during an informal hearing before the North Dakota PSC. We reiterated these developments and the need for jurisdictional resource planning during the Commission's January 4, 2024, hearing.

Since the January 4th hearing the North Dakota PSC has issued a report assessing our Initial IRP and Supplement IRP filings (North Dakota IRP Report). The North Dakota IRP Report is enclosed as **Attachment 1.**[12] The report confirms that legal and policy differences between our jurisdictions can produce widely divergent resource planning results. For example, the North Dakota IRP Report does not support any renewable resource additions in the five-year action plan.[13] The report suggests that Otter Tail's proposed solar and wind additions were added to satisfy requirements outside of North Dakota requirements.[14] The North Dakota IRP Report also expresses support for Otter Tail's continued participation in Coyote Station.[15]

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[11] *In the Matter of Otter Tail Power Company's Submittal of its 2022–2036 Integrated Resource Plan*, North Dakota PSC Case No. PU-21-380.

[12] Otter Tail Integrated Resource Plan (2021) and Supplemental Integrated Resource Plan (2023) Review and Analysis, March 1, 2024, North Dakota PSC Case No. PU-21-380 (North Dakota IRP Report). The report was prepared by a consultant hired by the North Dakota PSC. Per North Dakota IRP statutes and rules the report is deemed the North Dakota PSC's investigation report.

[13] Id. Executive Summary pp. 1-2; pp. 22-23; pp. 26-27.

[14] "Because the Otter Tail Preferred Plan does not represent the least cost plan and builds more generation than is required to meet the PRMR, this strongly indicates that the additional solar and wind resources were added to satisfy requirements outside of the objectives of the ND PSC IRP rules. The NDAC Section 69-09-12-03(6) requires that 'the North Dakota Preferred Plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities.' " North Dakota IRP Report p. 22.

[15] *See* North Dakota IRP Report p. 1; p.17.

The lack of jurisdictional alignment is significant because our system load is approximately evenly split between North Dakota and Minnesota.[16] Therefore in the current environment we would be unable to allocate to our North Dakota customers any of the cost of renewable resource additions required to comply with Minnesota legal or policy requirements, including the CFS. This reality makes it impossible to proceed with the development and installation of these renewable projects unless the costs and benefits of these renewable additions are allocated solely to our Minnesota customers.

As referenced above, Otter Tail is not seeking to depart entirely from traditional jurisdictional allocation of system resources. The existing joint resources will continue to function and be allocated according to the same historic practices, other than the AME proposal for Coyote Station and any renewable resource additions approved by the Commission for full allocation to Minnesota. Importantly, Otter Tail's proposal does not preclude future shared resources when need and timing align among our jurisdictions. Otter Tail will continue to seek opportunities to add needed resources in the most cost-effective manner to manage cost impacts for customers in Minnesota, North Dakota, and South Dakota.

Otter Tail's proposal is to allow the addition of resources to be accounted for distinctly. This approach will accommodate each jurisdiction's unique balance of reliability, low cost, and carbon reduction goals. The MISO market allows different choices to be effectuated without the separation of Otter Tail's distribution or transmission system; without reallocation of existing generation assets; and while maintaining clear accounting for unique resource selections. Otter Tail will establish distinct accounting nodes within MISO for Minnesota-only resources, just as has been the case for the distinct owners of our shared resources historically. For instance, at Coyote Station, each owner within MISO[17] offers its share of the jointly owned plant as a distinct generation resource into the MISO market. Otter Tail will establish an additional commercial pricing node to allow the OTP-MN share to be offered and dispatched, and accounted for, distinctly from the OTP-Dakota's share. For Minnesota-only generation such as Hoot Lake Solar, these resources will be offered and accounted for through the MISO accounting node, so the generation revenues and benefits flow directly to Minnesota.

The graphic below depicts the current and anticipated shared and jurisdictionally allocated resources.

[16] South Dakota comprises approximately 10% of our system load. South Dakota does not have an IRP process. In this filing we have focused on resource planning differences between our Minnesota and North Dakota jurisdictions.

[17] Otter Tail, Northern Minnesota Municipal Power Agency represented by Minnkota Power Cooperative, and Montana-Dakota Utilities Co.

Figure 1: Current

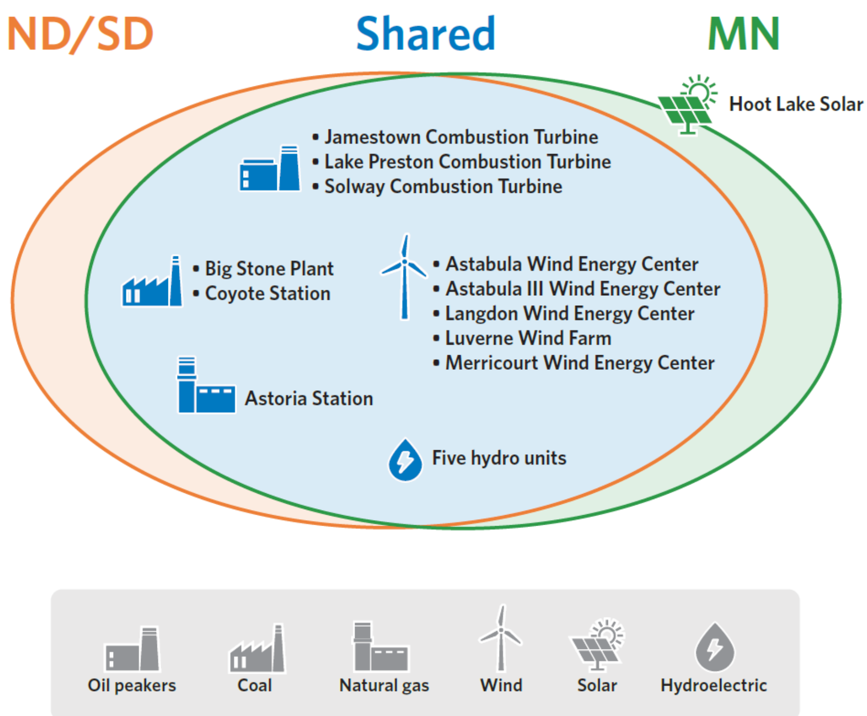
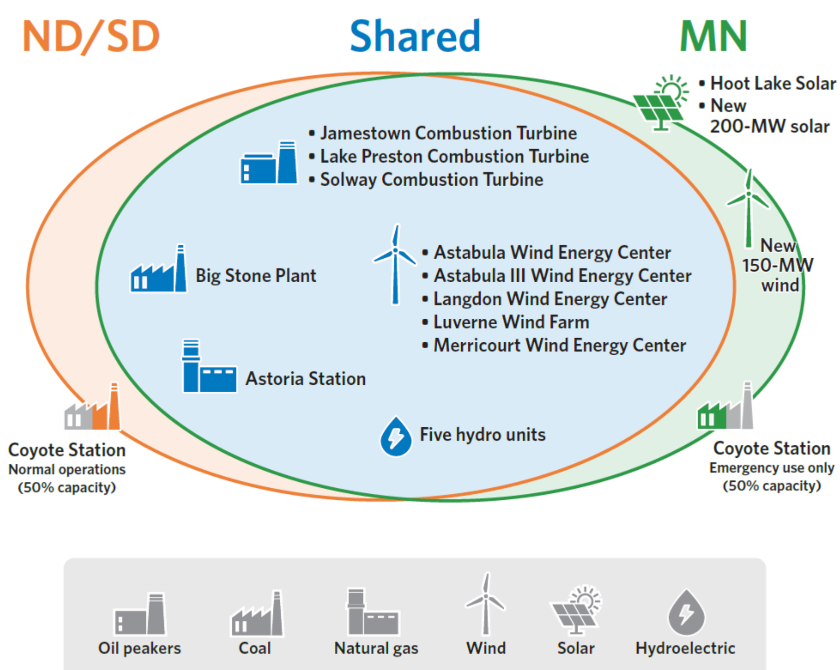


Figure 2: Proposed



In sum, differing legal frameworks and policy prerogatives between the jurisdictions we serve require that we adopt jurisdictional planning. This approach to planning does not replace traditional integrated system planning; instead, it modifies our traditional approach to resource planning to accommodate critical differences between our jurisdictions.

2. **Should the Commission approve, modify, or reject Otter Tail's Minnesota Preferred Plan with Available Maximum Emergency (AME) as presented in the Company's December 15, 2023, Supplemental Filing?**

The Commission should approve Otter Tail's Minnesota Preferred Plan with AME as presented in the Company's December 15, 2023, supplemental filing. The Minnesota Preferred Plan has two primary components: (1) designating the Minnesota allocated portion of Otter Tail's ownership interest in Coyote Station as an AME resource, and (2) adding 200 MW of solar and 150 MW of wind generation by 2032 that will be wholly allocated to the Minnesota jurisdiction. These components work together to promote compliance with Minnesota policy goals and legal requirements while also providing our Minnesota customers a key capacity backstop.

Minnesota Preferred Plan – Coyote Station AME Designation

As we noted in our December 15, 2023, supplemental filing an AME designation for the Minnesota-allocated portion of Coyote Station provides significant reliability and economic benefits while reducing the plant's carbon emissions and advancing Otter Tail toward compliance with the CFS. In addition, designating the Minnesota-allocated portion of Coyote Station as an AME resource does not foreclose any future course of action concerning Coyote Station, which enables Otter Tail to adjust to future developments for the benefit of Minnesota customers.

The AME designation for Coyote Station would apply to the Minnesota allocated share of Otter Tail's 35 percent ownership interest in the plant. This equates to approximately 70 MW. Designating this portion of the plant to be offered as an AME resource would result in that 70 MW of the plant's output not being dispatched under normal system conditions, but to remain available if MISO declares a Maximum Generation (Max Gen) Event; a situation where the plant's full energy output is necessary to support system reliability. The applicable MISO tariff requires AME resources to be available within two hours of a Max Gen Event declaration.

Coyote Station is uniquely situated to be an AME resource. Ordinarily, a coal plant would be incapable of starting from an off-line condition in that short time. Since the remainder of Coyote Station that is not operating under AME would be regularly offered into the market,[18] the plant is expected to be online and operating in market conditions preceding a Max Gen Event declaration. So while the operating characteristics of a coal plant are not normally well suited for AME operation, the unique circumstances of Otter Tail's partial ownership in a jurisdictionally allocated plant make AME a viable option.

The MISO market also plays a critical role in allowing the AME option to work for Coyote Station. While the plant is a single generator and has operating characteristics that cannot be separated (such as a minimum level of output), the plant is offered into the MISO market distinctly by each owner for their share of the total plant. Otter Tail's ownership represents 150 MW total and this amount is currently offered into MISO as if it were a stand-alone generator. Otter Tail will implement AME by approximately dividing this amount in half, one half to serve Minnesota customers and the other to serve North and South Dakota customers.[19] The Minnesota share will be offered as an AME resource allowing for clear dispatch signals and clear accounting for any potential hours when MISO calls for AME resources to operate.

AME at Coyote Station will result in emissions from Coyote Station being reduced on behalf of Minnesota customers by 99.8 percent based on the expected few hours of operation under AME. This is a specific and measurable reduction of up to a half million tons of CO2 per year, assuming AME operation of 20 hours per year. At the same time Coyote Station will remain available to maintain reliability when MISO needs it most and will therefore capture capacity revenues in seasonal capacity auctions. Savings from avoided fuel purchases will also support investments in new renewable generation we have outlined in our Minnesota Preferred Plan with AME.

In our December 15, 2023, supplemental filing we referenced discussions with MISO and the Independent Market Monitor concerning the use of an AME designation in the MISO tariff as applied to the Minnesota-allocated portion of the plant. These discussions identified that the Commission would need to explicitly order the limitation of operations at Coyote Station so that Coyote Station could be designated as an AME Resource; this is due to the requirement that such an operating limit must be established by regulation.[20] Otter Tail recently received MISO confirmation that an order from the

[18] The portion of the plant not operating under an AME designation are Otter Tail's share of the plant serving North Dakota and South Dakota, and the shares of the plant owned by the other co-owners.
[19] Allocations will be made using the allocation percentages and method in effect at the time of the allocation.
[20] *See* MISO Tariff § 39.2.5 (stating as follows with respect to AME): An Emergency Commitment Status indicates that the Resource is an AME Resource and that the Transmission Provider is authorized to commit the Resource only under an Emergency condition for the Hour. The Emergency Commitment Status will not be available to any Resource unless it has satisfied the conditions set forth in this Section 39.2.5.b.xxvi. An Outage Commitment Status indicates the Resource is not available for commitment

Commission setting an operating limit consistent with AME would in fact suffice as an operating limit established by regulation. This confirmation is enclosed as **Attachment 2** to this filing.[21]

Finally, we summarized the merits of an AME designation for Coyote Station in our December 15, 2023, supplemental filing:

> …AME is anticipated to be a valuable tool for Otter Tail, until it withdraws from Coyote Station or the plant is retired, as it undertakes to plan its system on a bifurcated basis because it will allow the Company to plan for the Minnesota-specific share of Coyote Station with increased optionality. AME at Coyote Station will allow the Company to retain Coyote Station's capacity, thereby providing an important reliability benefit, and will help the Company ensure that it remains compliant with market monitoring regulations and its contractual obligations to the co-owners of Coyote Station. With respect to reliability, Coyote Station helps Otter Tail, as a winter-peaking system, mitigate substantial risk resulting from volatility in weather patterns, changes to MISO capacity accreditation standards, increased load on the Otter Tail system, capacity deficits across the industry and MISO in particular, and increased renewables onto the grid with the passage of the IRA. In other words, it provides capacity and an energy hedge in the face of serious reliability concerns.[22]

during the Hour due to a planned or forced outage. A Not Participating Commitment Status indicates the Market Participant will not operate a Resource that is otherwise available. The Not Participating Commitment Status will not be available to any Resource that has all or a portion of its capacity designated as a Capacity Resource. In order to submit an Offer with an Emergency Commitment Status, a Resource must meet one of the following conditions: i) the AME Resource has an operating limit established by regulation (e.g, permits or federal and state laws or regulations) where the AME Resource can only be accessed during an Emergency to preserve its reliability value; ii) the Offer is based on a demonstrated severe energy limit, including but not limited to a fuel shortage affecting the Resource's capability to respond to three days of Emergency conditions; or, iii) the operating configuration of the Resource is inconsistent with "good utility practice" due to potential damage to equipment that is significant and difficult to quantify. Each of these conditions are further described in Business Practice Manual -009 Market Monitoring and Mitigation. A Market Participant for a Resource which does not satisfy any of these conditions may designate a Resource as an AME Resource and use the Emergency Commitment Status through consultation with the IMM as set forth in section 64.3.d of Module D.).

[21] "From MISO Legal's perspective, an order of the Minnesota PUC establishing an operating limit would satisfy the provision in Section 39.2.5.b.xxvi that requires "i) the AME Resource has an operating limit established by regulation (e.g, permits or federal and state laws or regulations) where the AME Resource can only be accessed during an Emergency to preserve its reliability value." Such an order would fall within the intent of the AME provision, plus Otter Tail has received the support of the IMM. So, under these circumstances MISO would allow the resource to use AME status." *See* Attachment 2.

[22] Otter Tail Supplemental Fling, December 15, 2023, pp. 5-6.

What we described then remains the case today. It is in the public interest to designate the Minnesota-allocated portion of Otter Tail's Coyote Station ownership interest as an AME resource.

Minnesota Preferred Plan - Renewable Resource Additions

The second component of our Minnesota Preferred Plan with AME addresses jurisdictional differences in renewable resource selections while promoting Otter Tail's compliance with the recently enacted CFS. The CFS (Minn. Stat. § 216B.1691, subd. 2g) provides the following:

> *Subd. 2g.* ***Carbon-free standard.*** *In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:*

(1)	*2030*	*80 percent for public utilities; 60 percent for other electric utilities*
(2)	*2035*	*90 percent for all electric utilities*
(3)	*2040*	*100 percent for all electric utilities.*

In sum, Otter Tail must generate or procure carbon free electricity sufficient to serve 100 percent of its Minnesota retail electric sales by 2040, with intermediate compliance thresholds before that date, including an 80 percent threshold by 2030. The CFS allows utilities to comply with the CFS through the acquisition of renewable energy credits (RECs).[23] However the nature and scope of this alternative compliance mechanism has been disputed in this docket and is slated for future Commission consideration.[24]

[23] *See* Minn. Stat. § 216B.1691, subd. 4 (b).
[24] *See In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon Free Standard under Minn. Stat. § 216B.1691*, MPUC Docket No. E999/CI-23-151.

The proposed renewable resource additions included in the Minnesota Preferred Plan with AME put the Company on a trajectory toward compliance with the CFS with limited reliance on REC purchases. This is noteworthy considering that Otter Tail's CFS compliance is ostensibly more challenging than other Minnesota investor-owned utilities because Otter Tail lacks a carbon free baseline provided by nuclear generation or significant hydro-electric generation.[25]

We detailed these proposed renewable resource additions in Table 1 of our December 15, 2023, supplemental filing, noting that the precise timing of the additions would need to be reasonably flexible:

	Minnesota Preferred Plan with AME
Year	
2023	Hoot Lake Solar
2024	
2025	Wind Repowers 200 MW Surplus Solar*
2026	Astoria Onsite Fuel* 100 MW Generic Wind*
2027	
2028	
2029	AME at Coyote
2030	
2031	
2032	50 MW Generic Wind
Wind	150
Solar	200
Battery	0
Total	350

The following table shows the resultant renewable energy position Otter Tail would be in following the addition of 200 MW of solar and 150 MW of wind assigned wholly to its Minnesota customers.

[25] Otter Tail has hydro generation, but the electricity provided by these plants is minor.

Table1

	MN Only Resource Additions **200 MW Solar & 150 MW Wind**		
	2030 (80%)	**2035 (90%)**	**2040 (100%)**
MN Retail Sales (GWh)	2,736	2,704	2,682
CFS Requirement (GWh)	2,189	2,434	2,682
MN Carbon Free Generation (GWh)	1,833	1,833	1,833
RECs Needed (GWh)	356	601	849

Assuming these new resources are in service prior to 2030, Otter Tail would still be slightly short of the 80 percent target by 2030 by 356 GWh. This gap would be met by REC purchases.

The following Table 2 shows that if Otter Tail were to add 300 MW of solar and 200 MW of wind wholly allocated to Minnesota, it could satisfy the 80 percent renewable generation standard by 2030 without relying on RECs.

Table 2

	MN Only Resource Additions **300 MW Solar & 200 MW Wind**		
	2030 (80%)	**2035 (90%)**	**2040 (100%)**
MN Retail Sales (GWh)	2,736	2,704	2,682
CFS Requirement (GWh)	2,189	2,434	2,682
MN Carbon Free Generation (GWh)	2,228	2,228	2,228
RECs Needed (GWh)	-39	206	454

Under the Minnesota Preferred Plan with AME the cost and benefits of these renewable resource additions would be allocated wholly to Minnesota. Absent such an allocation, the lack of jurisdictional consensus on the need for and prudence of these renewable resource additions would preclude their implementation and undermine the Company's efforts to comply with Minnesota policy as expressed in the CFS.

3. **Should the costs and benefits of renewable projects identified in Otter Tail's Minnesota Preferred Plan with AME be wholly allocated to Minnesota customers?**

Yes, these projects are needed to serve Minnesota customers for compliance with Minnesota policy as reflected by the CFS and to replace the energy lost from Minnesota's share of Coyote Station after the transition to AME.

The MISO energy and capacity markets provide the tools necessary to accurately track the costs and benefits of individual resources. From a capacity perspective, Otter Tail will continue to have a system-wide capacity requirement referred to as its Planning Reserve Margin Requirement (PRMR). Minnesota customers will be responsible for paying for their share of the PRMR at the capacity auction clearing price as is currently the practice. Conversely, Minnesota customers will receive capacity payments for their allocated shares of existing resources and 100 percent of the new renewable resources identified in Otter Tail's Minnesota Preferred Plan with AME. Allocating all capacity revenue from these renewables directly to Minnesota customers through the Minnesota fuel clause will ensure that North and South Dakota customers do not receive any capacity benefits from resources they are not paying for.

Similarly, energy revenues from all resources in MISO are transparently tracked through existing MISO processes. Each resource in MISO has its own generation pricing node that clears at its own unique locational marginal price (LMP) for each hour. All energy revenues received from resources that are wholly allocated to Minnesota will flow back to Minnesota customers through the Minnesota fuel clause. Energy costs and revenues of existing resources will continue to be allocated to each jurisdiction through the same process already in place.

4. **Should the Commission authorize OTP to begin the process of withdrawing from Coyote Station in the event the Company is required to make major, non-routine capital investments in the plant?**

Yes. The Commission should authorize Otter Tail to commence the process of withdraw from Coyote Station in the event that Otter Tail is required to make a major, non-routine capital investment in the plant. Our position on this point has not changed with the introduction of the Minnesota Preferred Plan with AME. We have requested this authority to ensure we can move ahead with clear direction and authority from the Commission should such an investment be required.

Material, Non-Routine Capital Investment

In our prior filings we have explained that a material non-routine capital investment should be distinguished from routine capital investments necessary for the plant to operate safely, reliably, and in compliance with current regulations. As a baseline a large capital investment that could cause us to withdraw from Coyote Station would differ qualitatively and quantitively from routine capital investments the co-owners have made in Coyote Station in the past and which are projected to be made in the future to operate the plant safely, reliably and in compliance with current law. Each year the Coyote Station co-owners develop a ten-year routine capital plan with contingencies that would serve as a baseline in our analysis. These type of routine capital investments would need to be made even if Coyote Station's operating life were significantly reduced to maintain the plant's safety, reliability, and compliance up to the final day of operations.

While we can't predict the timing and nature of a material, non-routine capital investment, we anticipate the most likely scenarios involve investments required to comply with federal environmental regulations, whether Regional Haze standards or the EPA's proposed greenhouse gas rules under section 111(d) of the Clean Air Act. We understand that the EPA's final action on North Dakota's Regional Haze State Implementation Plan may be completed by November 2024 pursuant to a proposed consent decree filed with the D.C. Court of Appeals.[26] This development does not alter our Comments. Otter Tail and its co-owners would assess the EPA's decision and its anticipated compliance costs in due course as we have discussed in this docket.

Commence the Process of Withdrawal

The authority Otter Tail requests is to commence the process of withdrawal from the Minnesota-allocated portion of Otter Tail's ownership interest in Coyote Station.[27] Having this authority would enable Otter Tail to quickly move forward with discussions with Coyote Station co-owners and stakeholders regarding the appropriate resolution were Otter Tail required to make a material, non-routine capital investment in Coyote Station.

We anticipate this process and related discussions with co-owners and stakeholders would include an evaluation of (1) Otter Tail divesting its ownership shares in the plant to another co-owner or third-party which would assume Otter Tail's current obligations, and secure releases from those obligations as necessary in favor of the acquiring party, (2) Otter Tail seeking authority from the North Dakota PSC to reallocate to North Dakota the portion of Otter Tail's ownership interest in the plant now allocated to Minnesota, or (3) some other arrangement that would achieve withdrawal of the Minnesota share in an equitable manner. There may also be scenarios where the size, nature and timing of the required investment causes the Coyote Station co-owners to deem it necessary to initiate the wind down of plant operations and to seek early termination of the lignite supply agreement that is part of the mine-mouth framework of the plant.

We recognize that each of these scenarios will require additional proceedings before the Commission to address the appropriate treatment of Minnesota's interests and

[26] See 89 Fed. Reg. 22141, March 29, 2024.
[27] We believe this authority is sufficient for Minnesota purposes if Otter Tail deemed it necessary to withdraw from Coyote Station as a whole.

obligations in any scenario involving Otter Tail's withdrawal from Coyote Station.[28] Our request does not presuppose the outcome of those proceedings. Instead our request is intended to ensure that we can move quickly and confidentially with our co-owners and stakeholders should we be required to make a large, non-routine capital investment.

5. **Should the Commission approve Otter Tail's proposal to add onsite liquified natural gas (LNG) fuel storage at Astoria Station in 2027?**

Yes, the Commission should approve Otter Tail's proposal to add on-site liquefied natural gas (LNG) storage at Astoria Station. The record is well developed.[29] LNG fuel storage at Astoria Station addresses the factors the Commission considers when evaluating resource options, demonstrating the project is in the public interest.[30]

Our prior filings have detailed the impact of extreme winter events on natural gas price volatility and reliability seen during Winter Storm Uri in February 2021 and Winter Storm Elliot in December 2022. Winter Storm Uri's impacts are now well documented. At its peak, Winter Storm Uri left millions of customers without electricity, renewable generation was at times not available, natural gas availability was at times limited, and electricity market prices and natural gas prices were at times extremely high.[31] Winter Storm Uri highlighted natural gas volatility and associated intra-day price risk; a risk caused by the fact that Otter Tail must buy day ahead natural gas for Astoria Station and offer the plant's output to MISO well in advance of MISO clearing Otter Tail's offer. Depending on how MISO clears the Company's offer, the Company may need to secure

[28] Otter Tail assumes that, should it formally withdraw from Coyote Station, it would still be allowed to recover from Minnesota customers its stranded costs and a return on those stranded costs. Minn Stat 216B.16, subd. 6. *See also In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E017/CI-23-375, in which the Commission is considering questions related to stranded costs.

[29] We have addressed the merits of dual fuel, and then specifically LNG fuel storage at Astoria Station in the following filings: Otter Tail Initial Filing September 1, 202, pp. 53-58; Supplemental Filing and Request for Changes in Procedural Schedule October 14, 2022, pp. 3-5; Supplemental Comments, November 4, 2022; Reply Comments, February 1, 2023; Otter Tail Supplemental Filing, March 31, 2023; Supplemental Comments Concerning Astoria Station On-Site LNG Fuel Storage, June 23, 2023; Reply Comments, October 30, 2023, pp. 36-37; 48-49.

[30] Under Minn. Rule 7843.500 (b) the Commission evaluates resource options on their ability to: (a) maintain or improve the adequacy and reliability of utility service; (b)keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; (c) minimize adverse socioeconomic effects and adverse effects upon the environment; (d) enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and (e) limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

[31] Winter Storm Uri impact on the areas served by ERCOT and SPP "caused numerous outages, derates or failures to start at electric generating plants scattered across the region. The Texas grid operator (Electric Reliability Council of Texas or ERCOT) ordered a total of 20,000 MW of rolling blackouts in an effort to prevent grid collapse; this represents the largest manually controlled load shedding event in U.S. history. More than 4.5 million people in Texas lost power – some for as long as four days. Tragically, the loss of electricity caused the deaths of numerous Texans." FERC News Release, November 16, 2021 available at https://www.ferc.gov/news-events/news/final-report-february-2021- freeze-underscores-winterization-recommendations.

additional natural gas at then prevailing market rates or sell back unused gas.[32] This risk is borne by Otter Tail customers through the Company's fuel clause. On-site fuel storage alleviates this risk.

During Winter Storm Elliot Otter Tail experienced: (1) a forced outage at Astoria Station due to lack of fuel supply on the Northern Border Pipeline, (2) extreme natural gas pricing of $150/MMBtu, and (3) MISO committing Astoria for reliability purposes under a unit offer utilizing approximately $120/MMBtu natural gas costs even though locational marginal pricing (LMP) at Astoria Station was relatively low at the time. Otter Tail customers were largely spared from negative consequences during this event due to strong regional wind generation that kept Otter Tail LMP pricing low. Absent strong wind generation, the economic consequences for Otter Tail's customers could have been much more dire. On-site LNG fuel storage would have allowed Otter Tail to continue operating Astoria Station, demonstrating the value of fuel assurance for this key capacity resource.

On-site LNG fuel storage at Astoria Station also addresses the risk of MISO capacity accreditation reductions; a risk demonstrated during Winter Storm Elliot when Otter Tail was forced to put Astoria Station in a forced outage due to a lack of fuel supply. Otter Tail expects MISO to reduce Astoria Station's capacity accreditation by approximately 50 MW for a period of three years. While Otter Tail has adequate capacity, the reduction in accreditation reduces the amount of capacity Otter Tail can offer into the capacity market; an opportunity cost for our customers. In the case of Winter Storm Elliot, onsite fuel storage would have provided Astoria Station a stable fuel resource at a known cost allowing the unit to operate and avoid risks to the plant's capacity accreditation.

The risks of future extreme events should not be discounted. The increasing frequency of these disruptive events was recently noted by Federal Energy Regulatory Commission's (FERC) acting chair Willie Phillips, who commented that Winter Storm Elliot was the fifth winter storm event in the past 11 years. Chair Phillips urged plant owners to take prompt action to avoid power disruptions caused by future disruptive weather events.[33]

In addition to addressing natural gas market volatility, reliability impacts, and accreditation reductions, on-site LNG provides an energy hedge value for our customers. Without the ability to call on Astoria Station for dual fuel capability (and therefore run the facility at a pre-determined energy price), Otter Tail has utilized energy purchases at the

[32] Otter Tail customers were not exposed to this risk during Winter Storm Uri, in part because Astoria Station was not yet in commercial service.

[33] FERC Chair Phillips made these comments at FERC June 15, 2023, Open Meeting which addressed FERC's review of Winter Storm Elliot. https://ferc.gov/news-events/events/june-15-2023-open-meeting-06152023 Media summaries of FERC's open meeting include "FERC chair to power plant owners: Act now to protect grid" Energy Wire, June 16, 2023. Chair Phillips comments urged generation owners to adopt NERC cold weather preparedness recommendations.

Otter Tail load zone to hedge against high priced, natural gas-driven markets during the winter months of December, January, and February. This winter energy hedge purchase could likely be significantly reduced or eliminated with installation of on-site LNG fuel storage. On-site LNG fuel storage also supports the clean energy transition envisioned by Minnesota energy policy. Having an on-site LNG fuel supply reduces the risk of a severe reliability event or price spike that would undermine public support for renewable energy.

Otter Tail has carefully assessed options to on-site LNG fuel storage, including financial hedging instruments, call options, pipeline alternatives, and other storage options including battery storage. None of the other options adequately address the risks associated with extreme events or provide fuel assurance benefits of on-site fuel storage at an acceptable cost.[34]

Otter Tail recognizes the proposed cost of the LNG fuel project is significant, and that the insurance value provided by LNG fuel storage is difficult to calculate. That said, the Commission can consider the DOC's assessment that traditional cost/benefit metrics often are ill-suited for reliability projects.[35] The Commission can note that the proposed modifications to Astoria Station are intended to provide the plant fuel assurance, a key MISO reliability attribute, and that the reliability aspects of the project warrant approval even if traditional cost/benefit metrics are difficult to determine. That being said, Otter Tail has provided an analysis on the cost effectiveness of fuel storage/dual fuel at Astoria Station that indicates the potential for significant net benefits from the project assuming there will be future extreme weather events.[36] Also, with respect to cost concerns, Otter Tail does not object to the Commission imposing a soft cap on recovery as proposed by Staff.[37]

The Commission should be skeptical of arguments to defer action on this issue until the Company's next IRP cycle. Any perceived benefits of deferring this issue do not outweigh the risk of delay, given the risk of extreme weather events and the anticipated benefits of on-site fuel storage. To be clear, however, Otter Tail's ability to proceed with

[34] *See* Otter Tail Supplemental Comments Concerning Astoria Station On-Site Fuel Storage, June 23, 2023, pp. 6-12.

[35] "In summary, refurbishing Astoria is not justified solely based on the economic benefits as calculated by OTP. However, it is not unusual for projects undertaken for reliability purposes to fail a benefit/cost test; that is why reliability standards are treated as a minimum that must be met rather than being a question of cost-effectiveness. The question at hand can be viewed as 'is OTP's Revised Proposal sufficiently related to a reliability standard.' Considering all of the risks, the Department concludes that the Revised Proposal, while not directly connected to any existing reliability standard, is sufficiently related to reliability and related risks to make an economic test of lesser importance." DOC Comments, December 30, 2022, p. 8. At the time of the DOC's Comments Otter Tail has not specified LNG fuel storage as favored approach for dual fuel capability. The point made by the DOC, however, remains relevant.

[36] Otter Tail Supplemental Comments, November 4, 2022, pp. 15-16; Otter Tail Comments Concerning Astoria Station On-Site LNG Fuel Storage, January 23, 2023, pp 15-17.

[37] Staff Briefing papers issued May 4, 2023 include Staff option 5: "Order that cost recovery for the proposal is limited to the Company's estimate provided in its November 4, 2022 Supplemental Comments, unless Otter Tail proves in a future proceeding that additional cost recovery is in the public interest."

the development and implementation of this system resource requires the support of all our jurisdictions. We are actively pursuing that support.[38]

6. Should the Commission find that Otter Tail's current resource acquisition process is sufficient and need not be modified?

Yes. The Commission should find that Otter Tail current resource acquisition process is sufficient. Otter Tail's current acquisition process is a flexible, competitive, and cost-effective process that we have successfully used in prior projects, the most recent of which are the 150 MW Merricourt Wind Project and our 49.9 MW Hoot Lake Solar Project. This flexible, competitive process allows Otter Tail to evaluate projects in various stages of development, as well as varying project structures (PPA, build-transfer, and self-built) while collaborating with developers to explore potential opportunities. We also evaluate greenfield sites and surplus interconnection facilities to ensure our customers are getting the best value.

In our experience this flexible competitive process allows us to move quickly to take advantage of opportunities as they arise and to adjust to market changes, which is important for a small utility like Otter Tail. Otter Tail lacks the market presence of other Minnesota investor-owned utilities that regularly evaluate significantly more projects than we do. A prescribed, more formalized approach to resource acquisition may be more suitable where there is a high volume and steady cadence of projects to evaluate. We have relatively few projects, so each resource acquisition is unique. In this environment our customers are best served by a flexible, nimble approach that allows Otter Tail to take advantage of opportunities provided by the market.

We have described our flexible competitive acquisition process in compliance filings in our last resource planning docket.[39] The process weighs multiple factors in evaluating projects:

(i) cost of wind energy to Otter Tail customers;
(ii) indication of site commitment;
(iii) status of generation interconnection request;
(iv) location of interconnection and impact of delivery to Otter Tail customer including potential project curtailment;
(v) project permitting status;

[38] The LNG fuel storage system at Astoria Station will be a system resource the costs of which will be allocated among our respective jurisdictions. Otter Tail is currently seeking an advanced determination of prudence (ADP) for the LNG storage system from the North Dakota PSC in Case No. 23-066. Otter Tail anticipates a decision in that docket by mid-2024, and possibly as early as mid-April, 2024.
[39] Compliance Filing, April 7, 2020, and July 1, 2020, *In the Matter of Otter Tail Power Company's 2017-2031 Resource Plan* Docket No. E017/RP-16-386.

(vi) anticipated commercial operation date to ensure utilization of the tax incentives;
(vii) evidence of wind turbine supply;
(viii) anticipated reliability of proposed equipment;
(ix) evidence of wind resource;
(x) developer's experience in developing wind farms; and
(xi) other public interest benefits.[40]

These factors are considered in a competitive setting. For example, in our Merricourt Wind Project Otter Tail undertook a solicitation process to probe the market for wind projects and to assess project options. Otter Tail solicited wind project proposals from a host of experienced national wind developers. Otter Tail received ten proposals representing a total of seven different wind projects and six different developers. The proposals ranged from 99 MW power purchase agreements to 200 MW build-transfer arrangements with ultimate Otter Tail ownership. To ensure a reasonable comparison across the spectrum of proposals, Otter Tail calculated a levelized cost of energy for varied project life sensitivities. The turnkey, build-transfer Merricourt Project proposal had the lowest levelized cost of energy. [41]

This process has produced excellent results for our customers, most recently in our Hoot Lake Solar Project, which the OAG described as "the lowest-cost solar project the Commission has approved to date by a large margin."[42] The Commission recognized the effectiveness of our process in that docket, declining to adopt DOC recommendations mandating a more rigid, formal process:

> While the Commission appreciates the Department's close scrutiny of Otter Tail's acquisition process, the Commission concurs with Otter Tail that its competitive bidding process and the evaluation of the proposals it received were reasonable and prudent, consistent with the Commission's directives, and resulted in the least-cost solar resource available.[43]

We understand and appreciate the comments made by the DOC and others in this docket recommending that Otter Tail use a more formal process that includes among other

[40] Compliance Filing, July 1, 2020, at p.4, *In the Matter of Otter Tail Power Company's 2017-2031 Resource Plan* Docket No. E017/RP-16-386.
[41] *Petition for Approval of the Merricourt Wind Project,* Docket No. E017/M-17-279, pp.10-11.
[42] Order Approving Petition, Authorizing Allocation of Output & Costs, Authorizing Cost Recovery, and Requiring Compliance Filings, April 29, 2021, *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project* Docket No. E-017/M-20-844, p.4.
[43] Id.

things independent auditors, formalized requests for proposals, and a prescribed competitive bidding procedure.[44] We share the DOC's goal of securing the most cost-effective projects for customers. The record, however, demonstrates that Otter Tail's competitive flexible process is the best way to achieve this goal.

Other Topics Open For Comment:

- ***Has OTP provided enough information for the Commission to determine that designating Coyote Station as an AME Resource and allocating all costs to Minnesota is in the best interests of Otter Tail's Minnesota customers?***

As a point of clarification, Otter Tail's proposal to designate the Minnesota allocated share of the Company's ownership interest in Coyote Station as an AME resource does not include or contemplate allocating all costs to Minnesota as suggested above. We described cost allocation for a Coyote Station AME designation in our December 15, 2023, supplemental filing, where we noted the following:

> With the designation of Otter Tail's Minnesota-allocated share of Coyote Station as an AME Resource, Otter Tail reasonably anticipates that the energy available to Minnesota customers will decrease and that the costs of operating Coyote Station allocated to Minnesota customers will also decrease. With respect to costs, although Otter Tail believes that Minnesota rates should continue to reflect the Minnesota-allocated share of Otter Tail's fixed costs for owning and operating the plant, the variable costs of operation should not be attributed to Minnesota except when the plant is called upon by MISO in emergency situations. These avoided costs would be a savings realized by Minnesota customers and would primarily consist of the portion of fuel that is variable. Based on actual and forecasted data, Otter Tail anticipates Minnesota customers can realize Coyote Station-related savings in a range of $6.9 to 7.9 million annually through the AME designation beginning in 2029.[45]

Under the above-referenced framework our Minnesota customers will be responsible for the costs and benefits of designating and operating the Minnesota

[44] To be clear, our competitive flexible acquisition process does not preclude use of competitive bidding; the process is flexible. For example in response to information request we have described the competitive bidding process we intend for key aspects of the Astoria Sation LNG fuel storage project. *See* Otter Tail response to IR-MN-PUC 008.
[45] Otter Tail Supplemental Comments, December 15, 2023, pp. 6-8.

share of Coyote Station as an AME. Our Minnesota customers would continue to pay in rates costs associated with maintaining and operating the plant as an AME resource. These costs include a return on rate base, fixed operating and maintenance costs, and fixed fuel cost. Our Minnesota customers would also pay for any variable fuel costs associated with energy dispatched during an emergency.

At the same time, our Minnesota customers would be allocated the benefits from the AME designation, including the reduced costs of variable fuel and variable operating and maintenance costs (such as reagents) for energy not dispatched due to AME, continued receipt of capacity auction revenue, and capacity accreditation for the Minnesota jurisdictional share of Coyote Station. The benefits of energy dispatched from the plant such as MISO market revenues and FTRs would be allocated to the jurisdiction supporting such dispatch.

In many respects our Minnesota customers' costs and benefit allocation is that associated with a peaking plant, which is what the Minnesota-allocated portion of Coyote Station effectively operates as under an AME designation. In the context of an existing resources, our Minnesota customers continue to retain value currently reflected in rates while achieving significant emission reductions. All of the foregoing does not alter existing rates, and the variable costs benefits to be allocated to our Minnesota customers are addressed through the Company's fuel clause.

What financial issues that should be addressed as part of this proceeding?

Otter Tail believes that it has addressed relevant financial issues related to this proceeding. However, we have taken note of comments made during the January 4, 2024, hearing concerning renewable resource additions allocated wholly to Minnesota. Specifically, comments made by Commissioners during the hearing suggested a desire that Minnesota allocated projects should - if reasonably practicable - be located in Minnesota. We do not disagree. The Commission could require Otter Tail to provide a reasonable preference for Minnesota locations for projects to be wholly allocated to Minnesota customers. This would require Otter Tail to demonstrate that it evaluated Minnesota options and provide a rationale for selecting or rejecting a Minnesota-located project. Of course it is inherently difficult to define a price at which a Minnesota located project is not reasonable in relation to projects located in other jurisdictions, and we would not attempt to create a specific metric on this point. While siting projects in the state can create economic benefits for the host community and area, a lower cost project that translates to low electric rates can benefit all of Otter Tail's customers within Minnesota. The point of the reasonable preference would be to ensure Otter Tail fairly and fully considers Minnesota located projects and identifies a basis for or against selection.

Does AME address other risks discussed in the record, such as market energy price risk environmental regulations risk to Minnesota ratepayers?

Yes, offering Minnesota's share of Coyote as an Available Max Emergency (AME) resource addresses multiple risks to the benefit of Minnesota customers. The risks mitigated by an AME designation for Coyote Station include the following items.

1. *Energy Price Risk* - Vertically integrated utilities such as Otter Tail purchase their hourly load from MISO at their load zone(s) and sell their generation resources at the individual generation pricing nodes. Although there is variance in locational marginal prices (LMPs) between the load zone node and generation nodes due to congestion and losses, the marginal energy component of the LMP is consistent across the MISO footprint. If a utility has adequate owned and contracted resources in place to match its load, generation revenues will match the cost to purchase its load. In situations where load is greater than available owned and contracted generation resources, the balance of the load is served with market purchases at whatever the market price is for those hours. It is likely that LMPs will be high during emergency events when AME resources will be called on to operate. AME will provide Minnesota customers with additional energy backstop to hedge against high energy prices during emergency events.

2. *Capacity Price Risk* - Recent projections provided by MISO have pointed to potential capacity shortfalls starting in the 2028 timeframe. In the event there is not enough capacity across MISO to meet requirements, the capacity auction will clear at the Cost of New Entry (CONE), similar to what was seen in Planning Year 2022/2023. This poses a serious risk to load serving entities that do not have enough capacity to meet their own needs. Keeping Coyote Station as an AME resource instead of an early withdrawal will provide Minnesota customers with an additional 60-70 MW of capacity credit to help mitigate this risk. This risk is further increased given the accreditation rule changes contemplated by MISO. The amount of accreditation resources will receive as well as the amount of margin that will be required is unknown. Our current estimates show capacity length for our Minnesota jurisdiction with Coyote Station under AME treatment, but rules changes, specifically changes relate to renewable resource accreditation under MISO's Direct Loss of Load (DLOL) proposal could impact these projections.

3. *Environmental Risk* - Offering Minnesota's share of Coyote Station as an AME resource will reduce carbon emissions attributed to Minnesota customers between 400,000 to 500,000 tons. In its recently approved guidelines, the EPA assessed the societal cost of carbon at over $200 per ton. Using this assumption, Otter Tail's AME proposal reduces roughly $80 million of environmental risk per year compared to continued operation of Coyote under normal operation.

4. *Regulatory Cost Risk* - Reducing carbon emissions by 400,000 tons at Coyote Station will also reduce the risk faced by Minnesota customers of a regulatory cost of carbon being imposed in the future. The Commission recently approved a future regulatory cost of carbon assumption of $5 - $75 per ton starting in 2028. Using the mid-point of $40 per ton, reducing carbon emissions by 400,000 tons would result in $16 million in savings for Minnesota customers.

5. *Jurisdictional Dispute Risk* - Designating the Minnesota allocated share of Coyote Station an AME designation allows Otter Tail to continue its ownership interest in Coyote Station while operating the plant consistent with the differing legal frameworks and policy prerogatives of our jurisdictions. Other parties to this docket have urged the Commission to take action, such as ordering a full withdrawal from Coyote Station – or more limited actions intended to produce that result that could be perceived as extending Minnesota's policy prerogatives beyond its borders. Doing so may risk jurisdictional conflict and potential inter-state litigation. Designating the Minnesota share of Coyote Station limits this risk.

6. *Otter Tail Commercial Risk*- We have noted in our prior filings that withdrawing from Coyote Station is a complex endeavor implicating contractual obligations among the Coyote Station co-owners, who in turn have contractual obligations to the owner and operator of the lignite mine serving the plant and related contractual obligations to the mine's lenders. In any scenario where Otter Tail is required to exit the plant by a date certain, or otherwise exit in a manner that is not aligned with the interest of other stakeholders, there is an increased the risk of contractual claims and disputes. Designating the Minnesota allocated portion of Coyote Station as an AME resource limits this risk, while also allowing time for greater certainty on federal environmental standards which may make many of the contractual risks moot.

What are the local job impacts associated with AME compared to other alternatives?

There will be minimal local job impacts by the implementation of the AME status at Coyote Station. There will be lower coal demand at the coal mine. Due to this reduced demand, the mine will consider staffing and overtime needs when developing their mining plan. There will be reduced output from Coyote Station, however, because the plant will continue to operate (with reduced output) and be needed at all hours of the day, the reduced demand at the plant is anticipated to have minimal local job impacts. There may be delays or extensions between wash outages or maintenance overhauls as a result of lower plant output, and that would require fewer contractors to come to the plant because of extension between overhaul intervals and Otter Tail and the co-owners will continue to discuss this during the normal course of operation and oversight. Alternatives to AME that involve Otter Tail withdrawing from its Minnesota allocated share in the plant are also not likely to result in significant job impacts, as the plant would presumably continue to operate at full capacity.

Should the Commission consider opening a new, separate docket to address jurisdictional cost allocation issues for OTP?

Otter Tail does not believe that it is necessary for the Commission to open a new separate docket to address jurisdictional cost issues. The record in this docket is sufficient for the Commission to approve Otter Tail's Minnesota Preferred Plan with AME.

The allocation of cost and benefits from designating the Minnesota share of Coyote Station as an AME resource is described in this filing and our December 15, 2023 supplemental filing. A benefit of the AME designation for Coyote Station is that additional proceedings are not required to effectuate the cost and benefit allocations described above. There is no need to change current rates, and the Company's fuel clause addresses changes in fuel use. Similarly a separate docket concerning cost allocations is not needed for the renewable resource additions included in the Minnesota Preferred Plan with AME. Those resources are premised on allocation of all costs and all benefits to the Minnesota jurisdiction. In that respect there are no cost allocation issues to address in a new separate docket.

In the future the Commission may need to address jurisdictional cost allocation issues if Otter Tail partially or fully withdraws from its ownership interest in Coyote Station. Some of these issues will likely be addressed in existing dockets, such as in Otter Tail's annual depreciation docket, and the Commission is separately addressing many of these issues in Docket No. CI-23-375. Therefore we do not believe it necessary for the

Commission to create a new separate docket to examine jurisdictional cost (and benefit) allocations.

Are there other issues or concerns related to this matter?

Otter Tail believes the Commission's Notice of Comment Period identifies the issues required to further develop the record consistent with the Commission's directive discussed during the January 4th hearing. Therefore at this time we do not have other issues or concerns to address in this filing.

III. CONCLUSION

Based on the forgoing, Otter Tail respectfully requests that the Commission issue an order approve without modifications the parties comprehensive Settlement Agreement dated April 1, 2024. If the Commission declines to adopt the Settlement Agreement as presented, Otter Tail requests a Commission order (1) approving the Company's Minnesota Preferred Plan with AME, (2) authorizing Otter Tail to withdraw from Coyote Station in the event the Company is required to make a material, non-routine capital investment in the plant, (3) approving Otter Tail's LNG fuel storage project for Astoria Station, (4) authorizing Otter Tail to add the renewable resources identified in the Company's Minnesota Preferred Plan with AME, and allocate those renewable resources wholly to Minnesota, and (5) finding that Otter Tail's current competitive, flexible acquisition process is sufficient for the projects authorized by the Commission in this docket.

Dated: April 3, 2024

Respectfully submitted,

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Otter Tail Integrated Resource Plan (2021) and Supplemental Integrated Resource Plan (2023) Review and Analysis

Prepared for:

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Otter Tail IRP and Supplemental IRP Review
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EXECUTIVE SUMMARY

This report presents to the North Dakota Public Service Commission (ND PSC) the findings of CDG Engineers' (CDG) comprehensive review of Otter Tail Power Corporation's Integrated Resource Plans (IRPs) in response to the ND PSC's commitment to responsible energy management and regulation. The review encompasses both the 2021 IRP and the 2023 Supplemental IRP and makes several recommendations.

The analysis highlights several key findings and recommendations:

Alternate Least-Cost Preferred Plan: CDG does not recommend the Otter Tail Preferred Plan because it does not reflect the least cost plan and would be impacted by the other recommendations in this report. CDG recommends that the ND PSC request that Otter Tail modify its Preferred Plan to remove solar additions in the five-year action plan period (2024-2028), remove the plan to take the initial steps of adding 200 MW of wind generation in the 2029 timeframe, model the system with Coyote Station through 2040, and after 2029 modify its Preferred Plan to more closely align with the alternative least-cost plan referred to as the ND Alternate Preferred Plan. This plan does not add any new unplanned resources in the five-year action plan period. The plan also provides a lower NPVRR from 2023-2037 by $57 Million and longer-term reliability compared with Otter Tail's Preferred Plan.

Surplus Energy Restrictions: Otter Tail models surplus transmission available to new resources by collocating with existing resources, but restricts this surplus to zero-capacity wind and solar, and solar with capacity. This approach overlooks MISO market risks, fails to effectively hedge prices or optimize the dispatch of the existing generation fleet and fails to consider other resources that could be less costly. The replacement generation for retiring resources similarly does not include a comprehensive portfolio of resources.

Coyote Station Retirement: During the 2023-2037 IRP period, keeping Coyote Station operational was the least-cost plan by more than $10 Million compared with the base case of closing it in 2028. Additionally, CDG performed reliability modeling which also supports maintaining Coyote Station in operation. Continued participation in Coyote Station is recommended for resource planning. Otter Tail suggested retaining Coyote through 2040 in their Preferred Plan; however, in the modeling Otter Tail assumes that Coyote Station retires in 2028 and selects resources accordingly. For expansion planning Otter Tail should assume and select resources based on the continued operation of Coyote Station.

Load Following Generation Options: CDG noted that broadening the assessment of load following generation options, such as partnerships with other utilities in ownership of a combustion turbine and Power Purchase Agreements (PPAs), will improve resource planning.

Modeling Extreme Weather Events: Including modeling for the effects of extreme weather events on load forecasts, fuel availability, fuel prices, and purchase power price forecasts will provide insights into system reliability and cost. CDG did a stochastic analysis of Otter Tail's system as a potential method to quantify these risks. This analysis showed that operating Coyote through 2040 and the ND Alternate Preferred Plan reduced Loss of Load Hours (LOLH).

Production Cost Model Dispatch: Running a production cost model with a full dispatch will provide a more accurate representation of the value of dispatchable and storage resources, better optimize the resource mix, and develop more reliable cost estimates.

NPVRR Reporting: Otter Tail compares scenarios using the NPVRR (Net Present Value of Revenue Requirement) from 2023-2050 as the basis for determining the least cost plan. It is more appropriate to use the NPVRR for the IRP period 2023-2037 rather than 2023-2050 to compare scenarios. This comparison uses the most accurate and actionable forecast data.

Market Purchase Assumptions: Modifying market purchase assumptions and implementing a market price depth curve will provide a more accurate representation of market interactions and their impact on resource planning.

Renewable Modeling Enhancement: CDG provided recommendations for improving renewable modeling including using the renewable price updates presented by Otter Tail at the November 20, 2023, Informal Hearing, monitoring MISO Direct Loss of Load (DLOL) accreditation, accounting for repowering costs or degradation, and properly addressing curtailments.

PRMR Calculation: Otter Tail acknowledged that their calculation for the MISO Planning Reserve Margin Requirement (PRMR) is not correctly implemented in the EnCompass model. This affects the expansion planning and NPVRR calculations.

INTRODUCTION/BACKGROUND

On June 8, 2023, the North Dakota Public Service Commission (ND PSC), in its ongoing commitment to the regulation of public utilities, engaged the services of CDG Engineers (CDG) to undertake a comprehensive review of the Otter Tail Power Corporation (Otter Tail) Integrated Resource Plan (IRP) filed September 1, 2021, and the 2023 Supplemental Integrated Resource Plan filed on March 31, 2023. On November 20, 2023, the ND PSC held an Informal Hearing with Otter Tail to review Otter Tail's updated modeling. In the engagement with the ND PSC, CDG Engineers undertook a multifaceted project, focusing on key areas that are pivotal to the state's energy planning efforts. This initiative aimed to ensure the affordable build-out of resources with a focus on the reliability, resilience, and affordability of North Dakota's energy infrastructure.

The initial work focused on data requirements and model development. CDG worked closely with ND PSC staff to define the information to replicate and run additional scenarios of the Otter Tail system. CDG then proceeded to develop a model that accurately replicated the outcomes presented in the Otter Tail IRP.

Collaborating closely with PSC staff, CDG Engineers selected appropriate scenarios and sensitivities to assess the reliability and resilience of the Otter Tail portfolio. CDG also assessed the cost implications of the Otter Tail Preferred Plan under varying conditions. In addition to these scenarios, CDG modeled alternative scenarios and generation options to provide a comprehensive view of the base case and Preferred Plan. These scenarios and sensitivities were evaluated based on each scenario's NPVRR, while taking into consideration factors such as unserved energy, curtailments, and unserved capacity.

CDG Engineers rigorously assessed the Otter Tail IRP and Supplemental IRP in alignment with North Dakota's IRP rules as specified in North Dakota Administrative Code (NDAC) Chapter 69-09-12. This review involved a thorough comparison of these plans against the state's regulatory requirements. Any inconsistencies or omissions within the Otter Tail IRP were documented.

This report presents the findings of CDG's comprehensive review, offering a detailed analysis of Otter Tail's IRP and the accompanying 2023 Supplemental IRP. It assesses the plans' compatibility with state IRP rules and evaluates their adherence to established best practices in the industry. Furthermore, this report outlines several recommendations and insights from the analysis in development of a more cost-effective resource build-out.

APPLICABLE STATUTES AND RULES

The ND PSC introduced updated Resource Plans and Cybersecurity rules, designated as NDAC Chapter 69-09-12, which became effective on January 1, 2023. These new regulations represent a significant step forward in ensuring the reliability and security of energy resources within the state.

Compliance with ND PSC Resource Plans

CDG's review has revealed notable discrepancies between Otter Tail's IRP and the prevailing ND PSC rules. Otter Tail's IRP, published in 2021, references the previous rules under North Dakota Century Code Chapter 49-05-17, which are now obsolete based on the updated regulations. Otter Tail claims that this was discussed with commission staff and that it was acknowledged that they would not be meeting all the required criteria. Subsequent sections of this report will delve deeper into the specifics of Otter Tail's IRP and evaluate its compatibility with the ND PSC's Resource Plans, providing recommendations for corrective actions where necessary to ensure compliance with the ND PSC rules.

LOAD FORECASTING

Load Forecast Accuracy Values

NDAC Section **69-09-12-04(3)(h)** requires that resource plans include "the accuracy of the peak demand and energy forecasts compared to the previous integrated resource plan forecasts and an explanation for the causes of any deviation". However, Otter Tail's IRP does not provide an analysis of historical load forecast accuracy.

Otter Tail provided CDG with its load forecast. The demand and load forecast and actuals are shown in Table 1 and Table 2. The energy load forecast is within 5% of the actual load in all years except 2022 where there was a new large load not included in the prior forecasts. The demand forecasts were within 3% of the actual demand in all years except 2020.

Table 1 - Load Forecasts and Actual Load (GWh)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
As Forecasted in Year 2018	4,773	4,953	4,790	4,748	4813					
As Forecasted in Year 2019		4,966	5,009	5,017	5,010	5,023				
As Forecasted in Year 2020			4,893	4,955	4,904	4,907	4,906			
As Forecasted in Year 2021				5,679	5,747	5,750	5,777	5,805		
As Forecasted in Year 2022					5,676	5,643	5,642	5,649	5,652	
As Forecasted in Year 2023						5,699	5,741	5,716	5,746	5,757
Actuals	4,999	4,785	4,793	5,547						

Table 2 - Demand Forecasts and Actual Demand (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
As Forecasted in Year 2018	820	822	824	826	828					
As Forecasted in Year 2019		798	801	803	806	808				
As Forecasted in Year 2020			804	807	811	814	818			
As Forecasted in Year 2021				739	743	747	751	754		
As Forecasted in Year 2022					768	771	774	778	781	
As Forecasted in Year 2023						770	781	784	787	789
Actuals	806	714	805	798						

Planning Reserve Margin

NDAC Section **69-09-12-03(2)** requires that resource plans identify the resources needed to meet forecasted capacity and energy needs, including a reserve requirement. The Planning Reserve Margin Requirement (PRMR) as defined by MISO and Otter Tail plays a vital role in ensuring grid reliability. This review has identified that Otter Tail has misapplied the PRMR in Otter Tail's EnCompass model, which has a substantive effect on the expansion plan and NPVRR. This effect ranges from 13.4 MW in 2023 to over 20 MW in the final year of the Supplemental IRP. The PRMR as calculated by Otter Tail and the actual winter coincident peak as correctly modeled are shown in Figure 1.

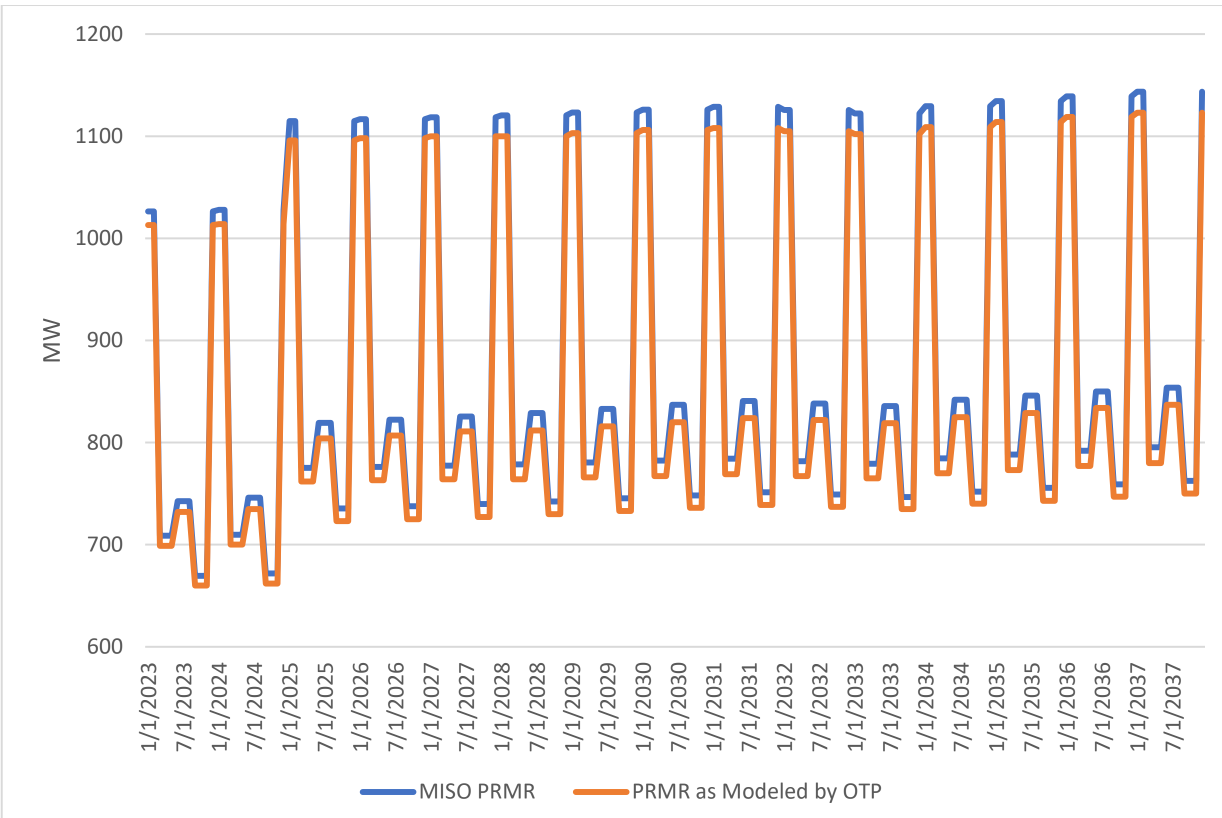


Figure 1 - Planning Reserve Margin

The effect of this discrepancy moves the year that Otter Tail's coincident peak is greater than its existing resources up from 2034 to 2029. This results in a different expansion plan and would likely affect Otter Tail's decision in selecting a Preferred Plan. CDG's modeling correctly applied the PRMR to all its resource expansions.

As shown in Figure 1, the planning reserve margin is heavily influenced by the winter period. This makes the winter peak load and winter accreditation important for load serving purposes. Figure 2 and Table 3 show Otter Tail's winter firm capacity compared with their winter coincident peak. As depicted, the first year that requires additional capacity is 2029.

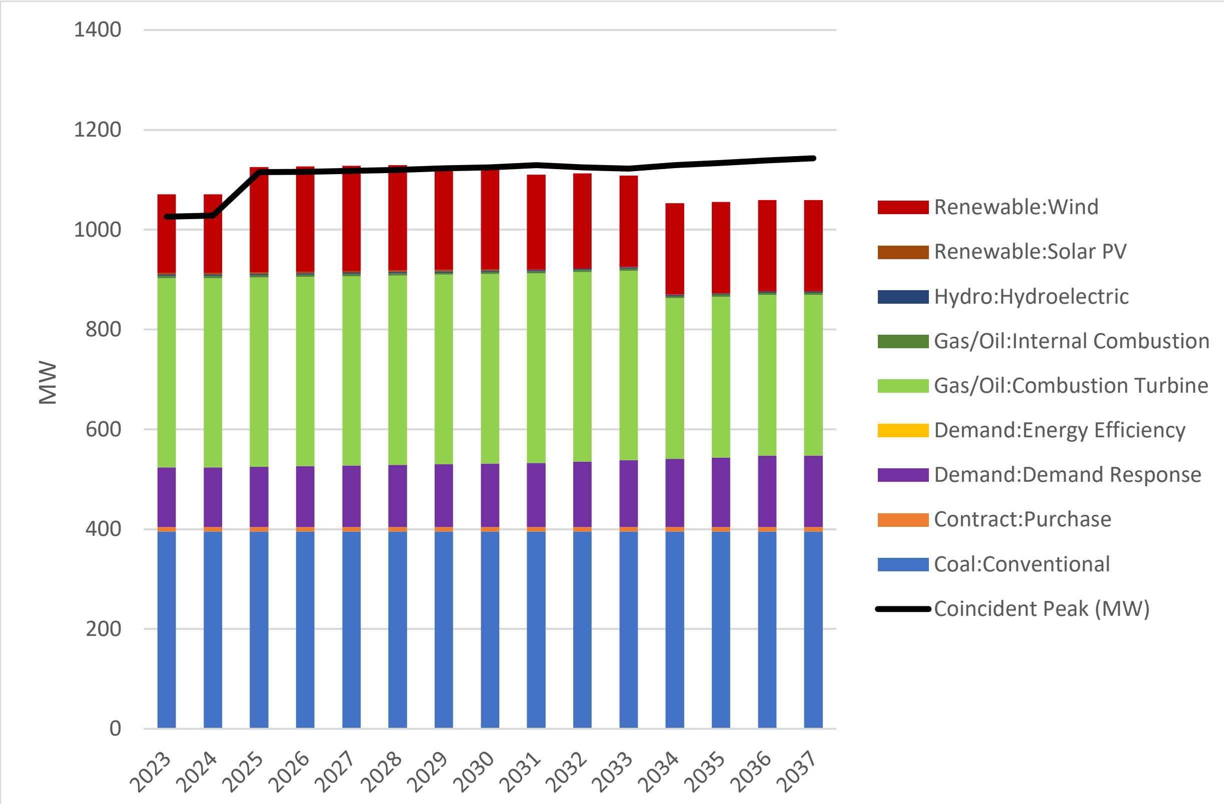


Figure 2 - Planning Reserve Margin Requirement and Existing Generation Firm Capacity

Table 3 - Coincident Peak and Existing Firm Capacity

	Coincident Peak (MW)	Existing Firm (MW)	Excess/Deficit
2023	1,026	1,070	44
2024	1,028	1,070	42
2025	1,115	1,125	10
2026	1,116	1,126	10
2027	1,118	1,128	10
2028	1,120	1,129	9
2029	1,123	1,122	-1
2030	1,125	1,123	-2
2031	1,129	1,112	-17
2032	1,125	1,115	-10
2033	1,122	1,111	-11
2034	1,129	1,056	-73
2035	1,134	1,058	-76
2036	1,139	1,062	-77
2037	1,143	1,062	-81

RESOURCE AND PROJECT REVIEW

CDG reviewed Otter Tail's IRP modeling and noted opportunities for different modeling techniques and modeling instances that do not follow ND PSC IRP rules.

Load Following Generation

The modeled natural gas resource options are limited to a single unit LM6000 aeroderivative combustion turbine and a 248 MW "Firm Dispatchable" resource which mimics Otter Tail's Astoria Station. These options are limited and could be supplemented by smaller dispatchable options like Reciprocating Internal Combustion Engines (RICE), sharing the output of a larger turbine, or purchasing load following capacity as a PPA. These partnering opportunities are required to be evaluated under the NDAC Sections **69-09-12-04(3)(b)** and **69-09-12-04(3)(c).**

Surplus/Replacement Transmission Availability

Otter Tail has identified 400 MW of surplus interconnection between 2025-2032, an additional 600 MW of surplus interconnection after 2032, and 150 MW of replacement interconnection after 2032. The initial 400 MW of surplus interconnection is limited to 150 MW of solar with capacity credit and 250 MW of solar with zero capacity credit.

The options shown in Table 4 were adapted from a table provided by Otter Tail.

Table 4 - Assumed Surplus and Replacement Capacity in Otter Tail IRP

Timeframe	Resource	Type	Maximum in Timeframe	Total MWs	Total MWs by Type
After 2032, Post IRA	25 MW Battery	Replacement	2	50	150
	25 MW Solar		2	50	
	50 MW Wind		1	50	
	50 MW Wind	Surplus	6	300	600
	25 MW Solar		12	300	
2025-2032 Only	25 MW Solar		10	250	400
	25 MW Solar with Capacity Credit		6	150	

The initial 400 MW of surplus interconnection is assumed to be spread across all of Otter Tail's current points of interconnection solely owned by Otter Tail. These points and rights are shown in Table 5.

Table 5 - Assumed Interconnection Rights in Otter Tail IRP

Resource	Interconnection Rights (MW)
Merricourt	150
Ashtabula	48
Ashtabula III	62.4
Langdon I	40.5
Luverne	49.5
Astoria	284.5
Jamestown 1 & 2	29, 29
Lake Preston	29
Solway	50

The 600 MW of surplus interconnection assumes pairing resources with complementary existing generation. In this way the surplus generation additions are a mechanism for reducing fuel costs at existing stations rather than offering capacity. This capacity is limited to only generic solar and wind resources.

Finally, the 150 MW replacement interconnection comes from the retirement of the Jamestown 1/2, Lake Preston, and Solway CTs. This replacement interconnection is limited to wind, solar and battery generation despite the generation replacing existing CT resources.

It is unclear why the resources able to use this excess transmission capacity are limited to solar, wind, and battery. The value of the transmission is also unclear based on the relative pricing of generic generation. Generic wind is priced at $48.5/MWh where replacement wind is priced at $35/MWh implying a value of $13.5/MWh. However, generic solar is priced at $47/MWh, where replacement solar is priced at $40/MWh implying a value of $7/MWh. Finally, generic battery storage is priced at $180/kW-yr, where replacement battery storage is priced at $140/kW-yr, implying a value of $40/kW-yr.

CDG compared the cost of the remodeled Otter Tail Base Case (corrected for PRMR) and assuming a 2040 Coyote exit to the same case with gas units added as resource options. CDG modeled generic CT options with a negative fixed cost of $40/kW-yr to reflect the value of using replacement or surplus transmission interconnection. Along with the CT options that Otter Tail modeled, CDG also modeled a 1/4-size H-Class CT option (62 MW), a 1/2-size H-Class CT option (144 MW), and a RICE unit (21 MW). The expansion plan for this scenario includes 144 MW of new CT generation and is shown in Table 6. Therefore, restricting surplus and replacement to only solar, wind, and storage without considering other resources is more costly and is not be recommended.

Table 6 - Expansion Plan for Generation Agnostic Replacement Generation

		Remodeled Base Case (Corrected for PRMR)	Same Case with Generation Agnostic Replacement/Surplus Generation
Withdraw from Coyote 12/31/2040	**NPVRR ($000)**	1,907,771	1,890,291
	2023	Hoot Lake Solar	Hoot Lake Solar
	2024		
	2025	Wind Repowers	Wind Repowers
	2026		
	2027		
	2028	**25** MW Solar – Surplus+Cap ITC	
	2029		
	2030		
	2031	**25** MW Solar - Surplus+Cap, ITC **50** MW Wind - Generic, PTC	**50** MW Wind - Generic, PTC
	2032	**125** MW Solar - Surplus, ITC **125** MW Solar - Surplus+Cap, ITC **150** MW Wind - Generic, PTC	**250** MW Solar - Surplus, ITC **150** MW Solar - Surplus+Cap, ITC **50** MW Wind - Generic, PTC
	2033		**144** MW Firm Dispatchable
	2034		
	2035		
	2036		
	2037		

Renewable Options

Otter Tail modeled several wind and solar resources. They modeled different costs associated with transmission access and the availability of Inflation Reduction Act (IRA) tax credits.

The renewable projects are subject to curtailments and within the model, the curtailments reduce the PPA price, which is not commonly a feature of PPA contracts. Often because of contractual agreements and tax credit effects, the buyer must pay the PPA price for curtailed generation. When CDG modeled the Preferred Plan to assume Otter Tail paid for curtailed generation, the NPVRR is increased by $4.5 Million. The way Otter Tail modeled curtailments encourages the selection of these renewable PPA resources, because allowing for free curtailments understates the true cost of a PPA.

Otter Tail has modeled the IRA with the PTC/ITC tax savings ending in 2032. However, the IRA allows for safe harboring projects under construction several years after the expiration of the ITC/PTC, which allows for projects to be deferred, yet still qualify for the benefit. Without this recognition, in many of Otter Tail's scenarios, significant wind and solar generation is added exactly when these benefits expire (i.e., 2032) in order capture these benefits. Therefore, to be consistent with the IRA, these tax credits should be extended through at least 2034 before phasing them out. When the IRA tax credits were extended through 2034, the Preferred Plan defers 250 MW of solar and 150 MW of wind to the year 2034. This new expansion plan resulted in an NPVRR savings of $5.7 Million.

The overall effect of the modeling choices by Otter Tail discussed in this section favored the addition of solar, wind, and storage resources earlier in the Otter Tail expansion planning.

Updated Renewable Pricing

Otter Tail presented updated modeling at the Informal Hearing on November 20, 2023. At this hearing, Otter Tail presented the cost of renewable energy. The PPA price for solar energy and the fixed cost for battery projects were increased based on Otter Tail's discussions with developers. As shown in Table 7 the costs increased 30% on average compared to the base modeling assumptions.

Table 7 - Fixed and PPA Cost Changes for Storage and Solar

Resource	Input	New Cost	Existing Cost	Difference
25 MW Battery	Fixed Costs ($000/yr)	$5,375	$4,300	25%
25 MW Battery, ITC	Fixed Costs ($000/yr)	$4,125	$3,300	25%
25 MW Replacement Battery	Fixed Costs ($000/yr)	$4,125	$3,300	25%
25 MW Surplus Battery, ITC	Fixed Costs ($000/yr)	$3,750	$3,000	25%
25 MW Solar - Generic	Energy Costs ($/MWh)	$65	$47	38%
25 MW Solar - Generic, ITC	Energy Costs ($/MWh)	$45	$39	15%
25 MW Solar - Replacement	Energy Costs ($/MWh)	$60	$40	50%
25 MW Solar - Surplus	Energy Costs ($/MWh)	$60	$40	50%
25 MW Solar - Surplus, ITC	Energy Costs ($/MWh)	$40	$32	25%
25 MW Solar - Surplus+Cap, ITC	Energy Costs ($/MWh)	$40	$32	25%

When CDG tested the effect of this updated pricing on the ND Alternate Preferred Plan, discussed later, it found that the model added 25 MW less solar generation in 2034. This was in a plan that already significantly reduced the number of renewable units and added a portion of a conventional combustion turbine.

Accreditation for Existing and New Resources

Otter Tail used MISO's 2023/2024 Loss of Load Expectation (LOLE) study as the basis for its renewable accreditation for 2023-2030 and MISO's Regional Resource Assessment (RRA) for the years after 2030. The values in Table 8 are reproduced from Table 4-3 from Otter Tail's Supplemental IRP filing.

Table 8 - PY23-24 UCAP MISO Accreditation (%)

	Summer	Fall	Winter	Spring
Wind (current)	18	23	40	23
Solar (current)	45	25	6	15
Battery (current)	82	68	82	76
Wind (2031)	18	21	37	12
Solar (2031)	23	18	1	17
Battery (2031)	82	68	82	76
Wind (2041)	16	21	26	12
Solar (2041)	18	20	11	11
Battery (2041)	100	100	97	64

After the Supplemental IRP was filed, MISO produced a preliminary view of accreditation under a Direct Loss of Load (DLOL) methodology. Figure 3 depicts a MISO presentation showing DLOL accreditation results for the resource expansion plan that meets its members decarbonization and resource goals. As shown in Figure 3, solar is much lower in both the summer and winter periods when compared with the current accreditation methodology (i.e., PY23-24 on the figure), and the accreditation largely declines through time as additional solar is added to the system. The changes to the DLOL and the uncertainty of accreditation demonstrate a risk of relying on solar to fulfill capacity requirements.

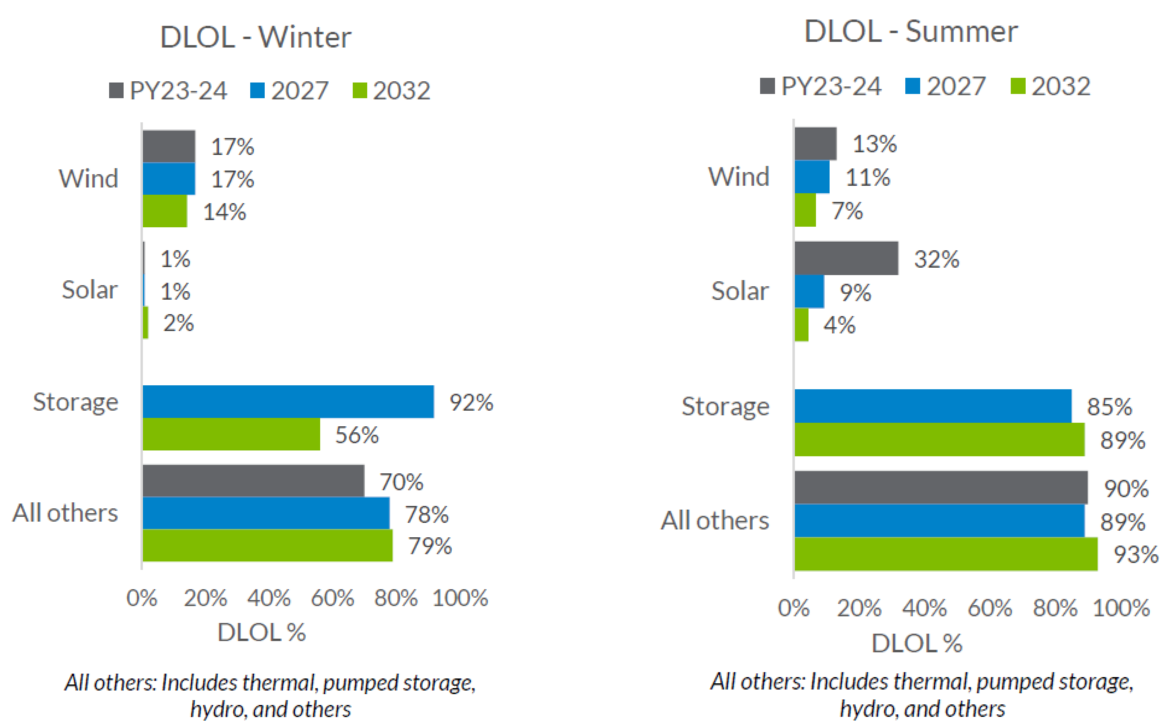


Figure 3 – MISO DLOL Preliminary Accreditation

MODELING AND EXPANSION PLANS

CDG developed an EnCompass model to verify Otter Tail's results and evaluate alternative scenarios and input assumptions. CDG received Otter Tail's EnCompass model files and developed a new database using the same version of EnCompass. CDG replicated Otter Tail's expansion plan model and scenarios and proceeded to develop an alternative model based on North Dakota policy preferences and integrated resource plan rules.

Planning Reserve Margin Update

The first major change CDG made was to correct the PRMR as discussed in the Load Forecasting section. CDG applied this correction to all modeling runs and scenarios, unless otherwise stated.

Otter Tail's Base Case (corrected for the PRMR) is also referenced as the remodeled Otter Tail Base Case scenario. This scenario does not assume any regional haze upgrades to the Coyote Station, assumes a 2040 exit date, introduces zero-capacity renewable resources and resource restrictions as discussed.

Coyote Station Retirement Assumption

Otter Tail provides modeling for a 2040 Coyote exit and a 2028 Coyote exit, and that modeling is replicated where shown to show the effects of an early retirement of the plant. However, despite Otter Tail's narrative discussing retaining Coyote Station the base case and preferred plan modeling in the filing assumes a 2028 retirement. In the remodeled Otter Tail Base Case (corrected for the PRMR) and the remodeled Otter Tail Preferred Plan, CDG uses a 2040 retirement for Coyote Station as a base assumption.

Production Cost Runs

When modeling its system, Otter Tail simulated its generation dispatch using a typical week without using the "No Commitment" option (i.e., not optimized over 8760 hours per year) with a full capacity expansion optimization. This is appropriate for determining the capacity expansion, but it does not provide a full hourly view of the system dispatch. In other words, Otter Tail did not optimize their resource expansion across all 8760 hours.

"No Commitment", according to the Encompass software literature, ignores the minimum capacity constraint and estimates the number of units online for a resource by dividing the total generation by the maximum capacity and outputs a continuous dispatch. This means that rather than performing a unit commitment for each available unit, the model will add a fraction of a unit based on the relative economics of the plant, while ignoring some of the commitment rules for the plant. By contrast, CDG used the "Full Commitment" option across all 8760 hours of the year and selected its plans based on all the resource dispatch characteristics. Therefore, CDG's modeling better accounts for the value of dispatchable and storage resources and this, in turn, provides a more accurate NPVRR. Table 9 shows the impact of performing a production cost run on the NPVRR for the remodeled Otter Tail Base Case (corrected for the PRMR). Both runs use the same expansion plan which assumed a 2040 Coyote exit.

Table 9 – NPVRR Difference for Expansion Plan and Production Cost Run

	($000s)
No Commitment Run 2023-2050	$2,771,929
Full Commitment Run 2023-2050	$2,737,429
Difference	$34,500

Net Present Value of Revenue Requirements Period

Otter Tail compared each scenario's NPVRR with one another using the full expansion planning simulation period from 2023-2050 rather than the IRP period from 2023-2037. Choosing a longer period for economic comparisons exacerbates the effects of generic growth of prices, loads, and generation costs and can affect the resources added to serve load for up to 37 years in the future. Relying on these estimates in the later years increases the uncertainty of the estimates and the cost of the resource mix.

For example, all generic and existing thermal generation resources' fixed and variable costs increase by 2% per year each year. Additionally, generic thermal resources' capital costs increase by 1% per year each year, while the cost of wind, solar, and storage resources stay flat throughout the expansion plan period. This skews the costs and NPVRR in the later years as the uncertainty of the costs are compounded through time.

Unless Otter Tail has a rationale for using this longer-term view, it is more appropriate and consistent with standard practice to calculate the NPVRR over the same period as the period over which the resources were selected (i.e., 2023-2037). CDG calculated the NPVRR using this period (2023-2037) to more accurately reflect the operating and capital costs of the system during the period for which the IRP was filed. This method better reflects the ND PSC rules to evaluate scenarios and sensitivities on a consistent and comparable basis.

Spot Market Interaction

Otter Tail does not allow market sales in its resource plans, which is appropriate for a long-term expansion planning model. Otter Tail models up to 1000 MW of firm market energy purchases and 250 MW of market capacity purchases. Otter Tail is part of the MISO market and has access to significant amounts of energy through that market; however, modeling 1000 MW of potential purchases against a peak demand that ranges from

1026-1143 MW is risky. While Otter Tail modeled market capacity purchases, no capacity purchases are purchased in any scenario.

Otter Tail could account for this risk by modeling an increase in market prices with an increase in the demand for such purchases. CDG modeled the first 300 MW of energy purchases at 100% of market price, the next 300 MW at 110% of market price, and the last 400 MW at 120% of market price. CDG did not develop a market price curve based on actual generation and market purchase data, so this should be considered an example of one. When CDG introduced this market price curve to the remodeled Otter Tail Base Case (corrected for the PRMR), CDG discovered that an upward market price curve reduced market purchases by an average of 6.5% and increased the NPVRR by $7.2 Million during the IRP period, as shown in Table 10. It is recommended that Otter Tail quantify the risks of increasing market purchase costs as the demand increases. Reliance on market purchases without appropriately valuing the cost can skew the resource selection to intermittent resources.

Table 10 – NPVRR and Annual Purchases with and without Purchase Price Curves

	NPVRR ($000s)	Average Annual Purchases (GWh)
Otter Tail Base Case (corrected for the PRMR)	1,907,771	1,651
Otter Tail Base Case (corrected for the PRMR) w/Purchase Price Curve	1,915,011	1,543
Difference	7,241	108

Reliance on Market Purchases

While Otter Tail maintains sufficient capacity to serve its PRMR, a significant portion of the energy within its IRP scenarios is provided by market purchases. For example, the percent of load served by purchases from the remodeled Otter Tail Base Case (corrected for the PRMR) simulation are shown in Figure 4. In this case, Otter Tail purchases an average of 23.8% of its load from the market, even when Coyote is extended through 2040. The amount of market purchases decline in 2032 after additional resources are brought online. This compares with 24.8% of market purchases over the same period in Otter Tail's base case that retires Coyote in 2028. Retiring Coyote in 2028 would therefore only exacerbate Otter Tail's exposure to market purchases. This effect is most clear both plans add resources in 2032, where there are 22% higher market purchases when Coyote retires in 2040.

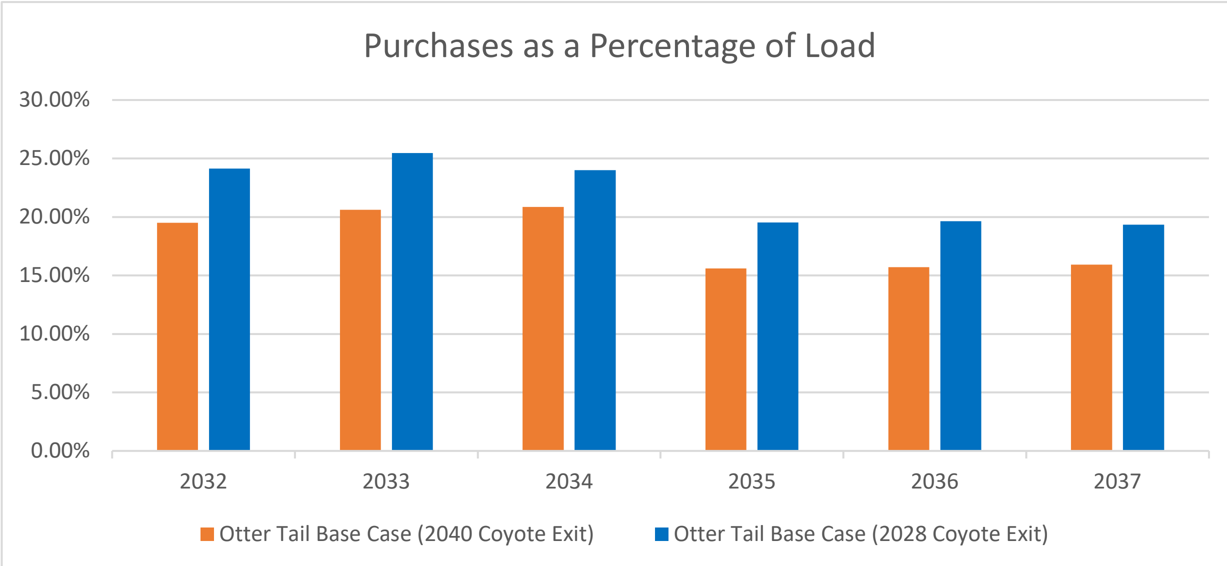


Figure 4 - Purchases as a Percentage of Load for the remodeled Otter Tail Base Case (corrected for the PRMR)

Scenario Analysis

With these changes CDG reran all the scenarios that Otter Tail ran in their Supplemental IRP as described in Appendices F and I of the Supplemental IRP. These simulations used the same inputs as were used by Otter Tail in their modeling. The only changes in this update are that the PRMR is corrected as described in the Load Forecasting section and that CDG used production cost models for the years of the IRP (2023-2037) as the basis for the NPVRR.

Otter Tail's sensitivity runs modified specific inputs as described below to show their effects on the base case.

- **NGEM -50%/50%/100%** - modifies the natural gas and electricity market prices by -50%, 50%, and 100%.
- **Regional Haze Mid** - additional cost for compliance of the Coyote station under increased regional haze regulations. Assumes the addition of an SNCR (selective non-catalytic reduction system).
- **Regional Haze High** - additional cost for compliance of the Coyote station under increased regional haze regulations. Assumes the addition of an SCR (selective catalytic reduction system).
- **Load +10%/25%** - increased load by 10%/25% in all years.
- **Renewable High** – increased capital costs for wind, solar and storage resources.
- **Renewable Low** – assumes a 40% investment tax credit.
- **High/Low Accred** – changes the firm capacity assumed for solar, storage, and wind resources to 25 % higher in the high case and 50% lower in the low case.
- **Carbon Tax** – assumes a carbon tax increasing from 7 to 54 $/ton from 2026-2050.

None of the scenarios modeled include externalities. Otter Tail's modeling also specifically excludes externalities associated with carbon costs, emissions reductions, and renewable energy standards. The NPVRR associated with the scenarios that were reran are shown in Table 11. The associated expansion plans generated by CDG in its modeling are shown in Appendix B. The expansion plans generated in the Otter Tail modeling are included in Appendix C. It should be noted that Otter Tail did not specifically assess the risks of each scenario and sensitivity as required by the NDAC Section **69-09-12-03(8),** so they equally weighted them in their comparisons.

Table 11 also includes some scenarios that CDG ran that were not included in the Supplemental IRP. These scenarios reflect a combination of sensitivities.

As shown in Table 11, the 2040 Coyote retirement option has a lower NPVRR in 10 of 22 of Otter Tail's scenarios and 10 of 15 Otter Tail scenarios that do not include regional haze regulations. The scenarios that retire Coyote in 2028 that have a lower NPVRR than a retirement in 2040 assume higher natural gas, higher renewable resource pricing, or do not assume regional haze regulations. Scenarios where the NPVRR for the 2028 Coyote exit are greater than the 2040 exit are shaded in blue. Additional scenarios were run that include regional haze costs and assume high load growth, lower renewable accreditation, and higher natural gas pricing. In these scenarios, continued participation in the Coyote station through 2040 has a lower cost than retiring the station in 2028 even when regional haze regulations are assumed. Based on these scenarios, continued participation in the Coyote Station is recommended.

Table 11 - NPVRR Calculation for 2040 and 2028 Coyote Exit Scenarios

	Withdraw from Coyote 12/31/2040	**Withdraw from Coyote 12/31/2028**	**2028 Difference from 2040 Exit NPVRR**
	NPVRR ($000)	NPVRR ($000)	($000)
Otter Tail Base Case (corrected for the PRMR)	1,907,771	1,917,916	10,145
Preferred Plan	1,925,485	1,920,005	-5,480
NGEM+50%	2,103,861	2,109,633	5,772
NGEM+100%	2,245,469	2,256,895	11,425
NGEM-50%	1,490,135	1,475,260	-14,875
Regional Haze Mid Cost	1,950,927	1,913,369	-37,558
Regional Haze Mid Cost - NGEM+100%	2,289,316	2,256,895	-32,421
Regional Haze High Cost	1,971,482	1,913,369	-58,113
Regional Haze High Cost - NGEM+100%	2,304,855	2,256,895	-47,960
Load+10%	2,118,651	2,128,822	10,171
Load+10% - NGEM+100%	2,493,555	2,512,347	18,792
Load+25%	2,472,261	2,524,103	51,843
Load+25% - NGEM+100%	2,905,885	2,944,866	38,981
High Accred	1,903,472	1,879,835	-23,637
Low Accred	1,981,366	2,025,697	44,331
Carbon Tax	2,135,058	2,057,495	-77,563
Renew High Cost	1,916,322	1,948,735	32,413
Renew High Cost - NGEM+100%	2,350,153	2,408,349	58,196
Renew Low Cost (40% ITC)	1,903,311	1,901,701	-1,610
Regional Haze High Cost – Low Accred	2,045,301	2,025,697	-19,604
Regional Haze High Cost - Load+25%	2,534,782	2,524,103	-10,679
Regional Haze High Cost - Renew High Cost	1,980,901	1,948,735	-32,167
ADDITIONAL SCENARIOS RAN			
Regional Haze High, Low Accred, Load +25, NGEM +100%	3,345,702	3,374,424	28,721
Regional Haze Mid, Low Accred, Load +25, NGEM +100%	3,336,576	3,374,424	37,847
Regional Haze High, Low Accred, Load +10, NGEM +100%	2,831,705	2,885,939	54,234
Regional Haze Mid, Low Accred, Load +10, NGEM +100%	2,805,124	2,885,939	80,815

PREFERRED PLAN

NDAC Section **69-09-12-03 (1)** requires, Otter Tail to define a "Preferred Plan". As stated in the Supplemental IRP Otter Tail's Preferred Plan:

> *"replaces our Initial Preferred Plan in its entirety, presents actions that: (a) will ensure that Otter Tail has the resources necessary to continue to provide reliable, low-cost electricity to meet customers' needs, while avoiding adverse impacts; (b) comply with the requirements of applicable statutes and rules, including the Minnesota Clean Energy Law; (c) preserve flexibility to respond to risks in a fluid and uncertain planning environment; and (d) account for differing policies in each of the three states we serve while preserving the customer benefits of system-wide planning and networked assets for a small utility.*
>
> *(a) modifying Astoria Station to add LNG fuel storage capability; (b) adding solar and wind resources, including approximately 200 MW of solar generation and approximately 200 MW of wind generation (in addition to repowering our existing wind facilities—excluding Merricourt) and (c) retaining Coyote Station in our generation portfolio pending the need for any significant, non-routine capital investment that may be required to continue operating the plant."*

The full section of the Supplemental Integrated Resource Plan related to the Otter Tail Preferred Plan is included in this report as Appendix A.

Part of the Otter Tail Preferred Plan includes adding LNG to the Astoria Station. This change is not modeled and the addition of it is not a capacity addition; therefore, CDG does not discuss it in this report. This proposed addition is discussed in case number PU-23-066.

Otter Tail mentions in their preferred plan that they recommend "retaining Coyote Station in our generation portfolio pending the need for any significant, non-routine capital investment that may be required to continue operating the plant." However, Otter Tail assumed a 2028 Coyote retirement date when it selected resources for both its as-filed base case and its as-filed Preferred Plan. CDG then re-modeled these "as-filed" plans assuming a 2040 Coyote Station exit while matching Otter Tail's as-filed resource expansions to obtain accurate NPVRRs of keeping Coyote operational through 2040. Table 12 depicts Otter Tail's as-filed Base Case (scenario 1) and the as-filed Preferred Plan (scenario 2). The filed Base Case and Preferred Plans are modeled as an hourly production cost simulation with a 2040 Coyote exit and assume Otter Tail's other resource constraints.

CDG then re-ran Otter Tail's base case using the same inputs per the supplemental IRP, but also introduced additional thermal generation options for replacement resources and partial gas CTs for the model to select, removed zero-capacity surplus resources, assumed a 2040 Coyote exit, and extended ITC/PTC tax credits. This case is labeled the ND Alternate Preferred Plan (scenario 3).

Each scenario in Table 12 assumes a corrected PRMR, calculates NPVRR over the period 2023-2037, and assumes a 2040 Coyote retirement.

Table 12 – Expansion Plans for Base Case and Preferred Plans

Scenario #		**1**	**2**	**3**
Scenario Name		***Otter Tail Base Case (As Filed)***	***Otter Tail Preferred Plan (As Filed)***	***ND Alternate Preferred Plan***
	NPVRR ($000)	*1,966,608*	1,949,704	1,892,485
Delta From Scenario 2	**($000)**	*16,904*	-	-57,219
	2023	*Hoot Lake Solar*	Hoot Lake Solar	Hoot Lake Solar
	2024			
	2025	*Wind Repowers*	Wind Repowers	Wind Repowers
	2026			
	2027		**100** MW Solar – Surplus+Cap, ITC	
	2028		**50** MW Solar – Surplus, ITC **50** MW Solar – Surplus+Cap, ITC	
	2029	**50** MW Solar – Surplus+Cap, ITC ***300** MW Wind – Generic, PTC*	**200** MW Wind – Generic, PTC	
	2030		**100** MW Solar – Surplus, ITC	
	2031	**25** MW Surplus Battery, ITC	**150** MW Wind – Generic, PTC	**50** MW Wind – Generic, PTC
	2032	***150** MW Solar – Surplus, ITC* **100** MW Solar – Surplus+Cap, ITC **25** MW Surplus Battery, ITC ***100** MW Wind – Generic, PTC*	**100** MW Solar – Surplus, ITC **25** MW Surplus Battery, ITC	
	2033			**144** MW Firm Dispatchable
	2034			**150** MW Solar Surplus+Cap, ITC **250** MW Wind – Generic, PTC
	2035			
	2036			
	2037			

As a result of Otter Tail optimizing its base case and preferred plan around the assumption of a 2028 Coyote Station exit rather than keeping it operational through 2040, both the as-filed Base Case and the as-filed Preferred Plan have a higher NPVRR than the ND Alternate Preferred Plan.

The ND Alternate Preferred Plan's (scenario 3) NPVRR is $57 Million less than the Otter Tail Preferred Plan (scenario 2). Over the 5-year action plan through 2028, the ND Alternate Preferred Plan selects no resources, while Otter Tail includes in its Preferred Plan 200 MW of solar and then prepares to add 200 MW of wind the following year. These resources were not selected to serve needs consistent with North Dakota policy or to fulfill a capacity or energy need. The ND Alternate Preferred Plan selects none of these resources and results in a lower NPVRR.

Furthermore, the ND Alternate Preferred Plan was allowed to select higher capacity credit CTs as replacement resources instead of forcing the model to select either wind, solar, or storage resources after 2032. By allowing the model to select higher capacity credit CTs after 2032, the model will not select any of the uneconomic solar resources earlier in the model in anticipation that the capacity deficit can be cured with a later dispatchable resource addition. Furthermore, because the ITC and PTC are extended through 2034, the final generation addition is deferred from 2032 to 2034 as the model can defer investment and not build as much generation early on to secure the tax credits.

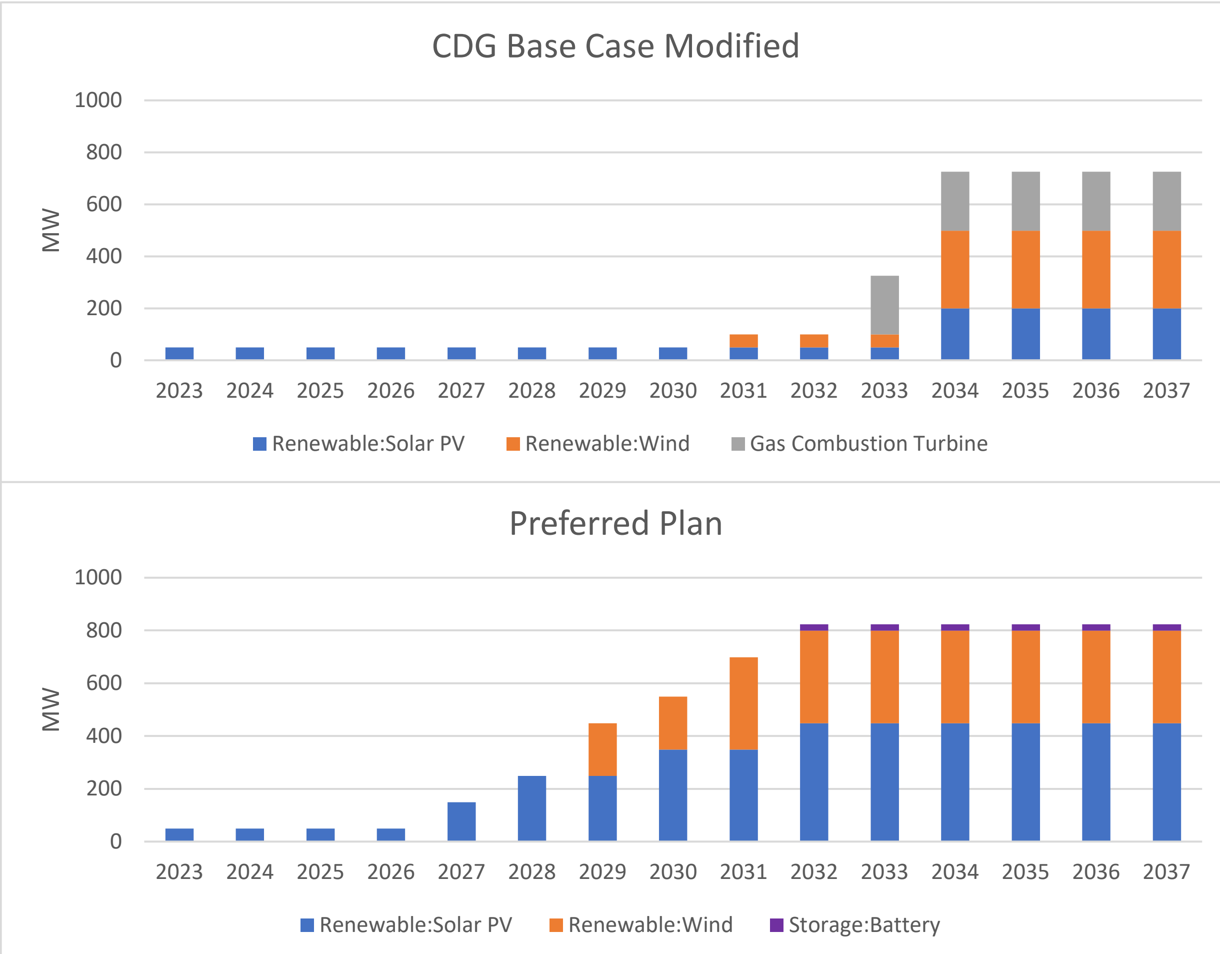


Figure 5 & 4 - Nameplate Capacity Generation Additions (MW) by Scenario

Overall, CDG has found that the Otter Tail Preferred Plan adds more generation earlier and is more expensive on an NPVRR basis than the ND Alternate Preferred Plan. The changes between the Otter Tail Preferred Plan and ND Alternate Preferred Plan are due to decisions made by Otter Tail to not optimize the resource expansion based on least cost, to restrict the selection of replacement resources, to not consider a full suite of resource options, and to not build resources when they are not needed for capacity or energy needs due to modeling under the assumption that Coyote Station will retire in 2028 instead of 2040. This is inconsistent with the NDAC Section **69-09-12-03(3)** that requires that utilities select resources "representing the least-cost plan".

Because the Otter Tail Preferred Plan does not represent the least cost plan and builds more generation than is required to meet the PRMR, this strongly indicates that the additional solar and wind resources were added to satisfy requirements outside of the objectives of the ND PSC IRP rules. The NDAC Section **69-09-12-03(6)** requires that "the North Dakota Preferred Plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities." The Otter Tail Supplemental IRP describes four risks and uncertainties that affected its Preferred Plan:

- Modeling Changes
- Capacity Accreditation Questions
- Otter Tail's Capacity Position Relative to Load Growth
- Recent Volatility in MISO Energy Markets and Natural Gas Markets

Otter Tail describes the potential risks but did not quantify or model the risks. For instance, Otter Tail's models introduced restrictions on the type of resources the model was able to select while ignoring analysis that would be consistent with North Dakota's energy preferences and the impact the preferred portfolio could have on reliability during extreme weather events as demonstrated in the next section. Otter Tail also did not assess its exposure to the market purchases.

Furthermore, adding solar resources only increases cost through the planning period and largely increases cost beyond the planning period. This adds not only cost to the plan, but also potentially additional risk to the portfolio because MISO is in the process of developing new accreditation around the proposed DLOL approach. Additional risk is also added given the significant number of solar resources in MISO's interconnection queue, and the potential impact from a decline in on-peak energy prices. Currently, solar resources make up 52% of the MISO queue.

Finally, by using an assumed 2028 Coyote exit to create the capacity expansion Otter Tail is inconsistent with the language referring to retaining Coyote Station in its generation portfolio and as a result contributes to the overbuild of generation within the action plan period and beyond 2029.

Extreme Weather Modeling/Reliability Modeling

NDAC Section **69-09-12-04(3)(i)** requires that utilities assess the reliability and resource adequacy of resource plans during extreme weather events. This assessment should include quantitative metrics for the size, frequency, duration, and timing of capacity shortfalls during extreme weather conditions. Otter Tail's IRP performed no such modeling. Without this modeling, Otter Tail cannot judge the adequacy of their planning for such scenarios. Attention in this area is crucial to ensure that its energy infrastructure can withstand extreme weather conditions.

CDG developed a stochastic model of Otter Tail's system parameterized on historical data from 2020-2023 for prices, loads, and outages. This period was inclusive of two of the more impactful extreme weather events. For this analysis, market *energy* purchases were limited to 500 MW, which is roughly half of Otter Tail's peak load. This limit helps to reflect the effects of extreme weather, outages, and generation variability on the system. CDG ran this model for 300 iterations for the load year 2035 using the generation additions from the ND Alternate Preferred Plan scenario and two Otter Tail Preferred Plans: one with a 2040 Coyote exit (Otter Tail Preferred Plan) and another with a 2028 exit (Otter Tail Preferred Plan (2028 Coyote Exit)).

This method is a framework that can be used to show the reliability risk associated with the variability in prices, loads, and generation on Otter Tail's ability to serve load. Figure 6 shows the distribution of Loss of Load Hours (LOLH) for the three scenarios. The Otter Tail Preferred Plan with a 2028 Coyote withdrawal had the most hours of LOLH observed, while the ND Alternate Preferred Plan had the fewest.

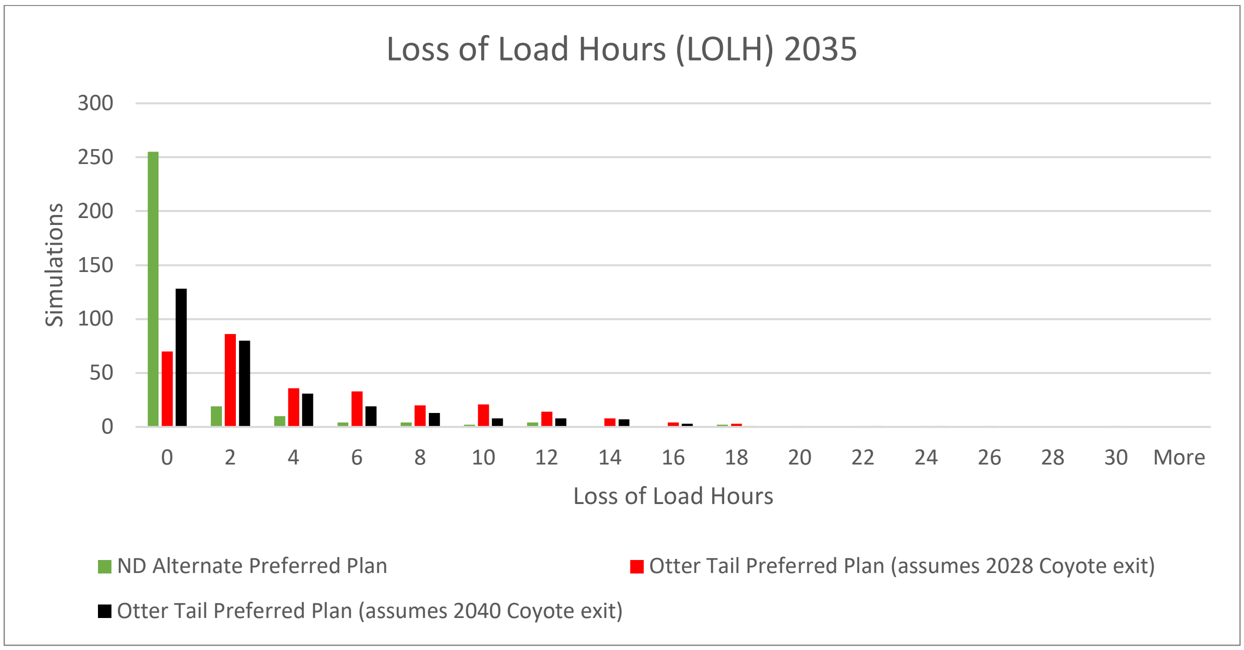


Figure 6 - Distribution of Loss of Load Hours with Stochastic Simulation

The analysis also shows the effect of prices, loads, and outage distributions on system cost. Figure 7 shows the distribution of revenue requirements for the three scenarios. Revenue requirements include fuel, operations and maintenance expense, purchases, contract costs, fixed costs, carrying costs, depreciation, and allowed return. The ND Alternate Preferred Plan's 2035 expected revenue requirement is $4 Million less than Otter Tail's Preferred Plan assuming Coyote is retired in 2040 and $6 Million less assuming it retires in 2028. Similarly, the ND Alternate Preferred Plan's expected 2034 revenue requirement has a 95% chance of not exceeding $216 Million, which is $5 Million less than the Preferred Plan assuming Coyote is retired in 2040 and $7 Million less assuming it retires in 2028. This demonstrates that the ND Alternate Preferred Plan has lower cost along with less risk of exceeding that cost across multiple scenarios of prices, loads, and outages.

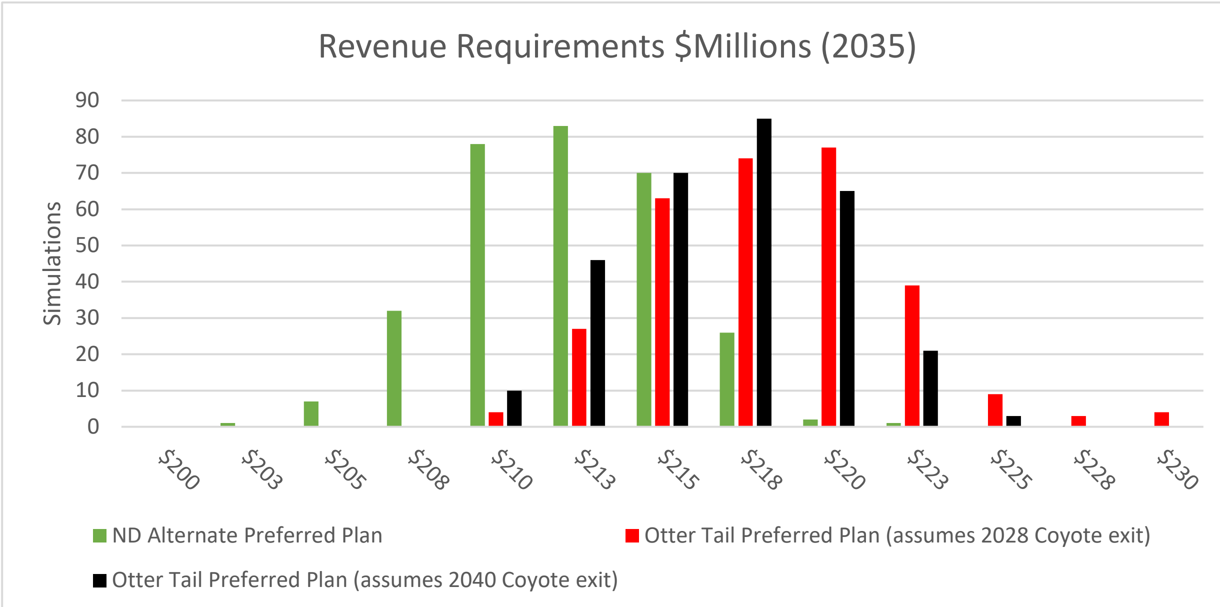


Figure 7 - Distribution of Revenue Requirements with Stochastic Simulation

CONCLUSION/RECOMMENDATIONS

CDG Engineers reviewed Otter Tail's IRP, Supplemental IRP, and associated modeling to determine whether the IRP complies with ND PSC rules, follows best industry practices, and selected the least-cost portfolio for ratepayers. The analysis has revealed both strengths and areas for improvement within the IRPs. Through replicating Otter Tails modeling and performing its own modeling, CDG determined that the Otter Tail Preferred Plan adds more generation than is necessary to meet its PRMR and is more costly than the ND Alternate Preferred Plan. The Otter Tail Preferred Plan relies heavily on solar resources (earlier than even its base case), which provide little or no capacity towards its PRMR. These additions as well as the preparation of adding 200 MW of wind the year after its 5-year action plan is not economic. The ND Alternate Preferred Plan adds none of these resources and at a lower cost and with fewer LOLH in a reliability analysis.

CDG determined that Otter Tail's resource planning can benefit from adjustments and enhancements to better align with ND PSC rules and industry standards. The following recommendations aim to address the identified issues and enhance the reliability, transparency, and compliance of Otter Tail's IRPs, ultimately contributing to the sustainable and affordable development of North Dakota's energy infrastructure.

1. Least-Cost Preferred Plan: CDG's analysis, integrating the suggested measures, resulted in the ND Alternate Preferred Plan, a genuine least-cost expansion plan. It is recommended that the ND PSC request that Otter Tail modify its Preferred Plan to remove the solar additions in the five-year action plan period, not take the initial steps to add 200 MW of wind in 2029 and modify its plan after 2029 to more closely align with the ND Alternate Preferred Plan. This plan avoids introducing new unplanned resources within the five-year action plan period, a $57 million lower NPVRR from 2023-2037 and enhanced long-term reliability. The ND Alternate Preferred Plan and the analysis contained within this report support these recommendations.

2. Solar Resources in the Action Plan: The ND Alternate Preferred Plan does not include any new solar resources before 2034. Based on this outcome it is recommended that North Dakota reject the new solar resources included in the five-year action plan period of the Otter Tail preferred plan and reject taking the initial steps to add 200 MW of wind in the 2029 timeframe.

3. Coyote Station Retirement Option: The analysis conducted reveals that in 10 out of 22 scenarios, and particularly in 10 of 15 scenarios excluding regional haze regulations, the option of retaining Coyote Station results in a lower NPVRR. In the least cost simulation, continuing to utilize Coyote Station has a lower NPVRR by over $10 Million compared to the equivalent simulation with a 2028 exit. Based on these findings, it is recommended that Otter Tail continues participation in Coyote Station as a prudent choice in its resource planning. The continued operation of Coyote Station should be the base assumption for expansion plan modeling used in Otter

Tail's preferred plan in keeping with their objective of retaining Coyote Station in their generation portfolio pending any significant capital expense.

4. Surplus and Replacement Resource Restrictions: Otter Tail models surplus transmission available from collocating complementary new resources and/or using unused transmission allocations from existing resources or replacements for retiring resources. Otter Tail restricts the surplus generation to zero-capacity wind and solar and solar with capacity. Restricting resource options, either as replacement or surplus, does not represent an attempt to effectively hedge market prices, optimize the dispatch of the existing generation fleet, or to select a least-cost resource plan. The replacement generation available from retiring resources only adds one dispatchable option (up to 50 MW of batteries). Otter Tail should consider surplus and replacement transmission available for all types of resources rather than restricting the options to wind, solar, and storage. The ND Alternate Preferred Plan is agnostic toward the technology for surplus and replacement resources and furthermore adds natural gas resources as replacement options.

5. Load Following Generation Options: Otter Tail should develop a resource plan that better reflects ND energy policy by considering a broader range of load following generation options. This could include partial natural gas projects representing partnerships with other utilities and Power Purchase Agreements (PPAs). A more comprehensive assessment of load following options will improve resource planning. In the ND Alternate Preferred Plan, partial units were considered, and a partial combustion turbine was selected as a resource in the least-cost plan.

6. Modeling of Extreme Weather Events: Otter Tail should model the effects of extreme weather events on load forecasts, fuel availability, fuel prices, and purchase power price forecasts. This will ensure that its energy infrastructure is adequately prepared for extreme conditions, enhancing grid resilience. When CDG modeled the effects of an energy purchase limited system, the ND Alternate Preferred Plan had a lower number of LOLHs than the Otter Tail Preferred Plan assuming a 2040 Coyote exit and the Otter Tail Preferred Plan assuming a 2028 exit. This analysis supports the finding that keeping Coyote operational through 2040 contributes to the reliability of the resource plan.

7. Production Cost Model Dispatch: Otter Tail should run a production cost model with a full dispatch for each expansion plan. A full dispatch will more accurately represent and capture the value of dispatchable and storage resources, leading to a more reliable NPVRR upon which to select a resource plan. This type of analysis is essential to fully evaluate the reliability and operations of the system.

8. Market Purchase Assumptions: Otter Tail should modify its market purchase assumptions to lower the number of purchases available and/or implement a market price depth curve to reflect the effect on prices as more purchases are made each

hour. This will provide a more accurate representation of market interactions and their impact on resource planning.

9. PRMR Calculation: CDG recommends that Otter Tail correct its PRMR calculation in the EnCompass model. The PRMR impacts the expansion plan and the NPVRR of all scenarios. Otter Tail should rerun the scenario expansion plans with an accurate PRMR to ensure reliability in resource planning.

10. NPVRR Reporting: CDG recommends that Otter Tail use an NPVRR period of 2023-2037 rather than 2023-2050. This better aligns with the planning horizon of the IRP and would use the most reliable data in the study for price and load forecasts.

11. Historical Load Forecast Accuracy: To better quantify the risks associated with load forecast errors, Otter Tail should provide an assessment of the accuracy of historical load and demand in its future IRPs. This will enhance transparency and ensure stakeholders can assess the reliability of its load forecasts.

12. Renewable Modeling Enhancement: Otter Tail should enhance its modeling of renewables by:

    a. Monitoring MISO DLOL accreditation and incorporating forecasts into future IRPs.

    b. Properly accounting for curtailments within the production cost model for renewables.

    c. Monitoring the timing and amount of Investment Tax Credits and Production Tax Credits for renewable projects for better planning.

    d. Using renewable prices presented at the November 20, 2023, Informal Hearing.

These recommendations aim to enhance the accuracy, transparency, and compliance of Otter Tail's Integrated Resource Plans with ND PSC rules and industry best practices. By implementing these suggestions, Otter Tail can make more informed decisions regarding its energy infrastructure, ensuring reliability and sustainability in North Dakota's energy landscape, while selecting the least-cost resource plan consistent with North Dakota's energy policy.

APPENDIX A

Supplemental IRP Preferred Plan

3 Supplemental Preferred Plan

The Supplemental Preferred Plan

Our Supplemental Preferred Plan, which replaces our Initial Preferred Plan in its entirety, presents actions that: (a) will ensure that Otter Tail has the resources necessary to continue to provide reliable, low-cost electricity to meet customers' needs, while avoiding adverse impacts; (b) comply with the requirements of applicable statutes and rules, including the Minnesota Clean Energy Law; (c) preserve flexibility to respond to risks in a fluid and uncertain planning environment; and (d) account for differing policies in each

[7] ND PSC Case No. PU-21-380. In North Dakota, the plan is filed pursuant to North Dakota Century Code §§ 49-05-04.4 and 49-05-17.
[8] In addition to addressing MISO's seasonal capacity construct and the Inflation Reduction Act we also noted our intent to address changes in MISO Planning Resource Auction (PRA) prices and capacity projections and Otter Tail load forecast changes that have occurred since our Initial Filing.
[9] *In the Matter of Otter Tail Power Company Advance Prudence Application – Astoria Station Onsite Fuel Inventory System*, ND PSC Case No. PU-23-066.

of the three states we serve while preserving the customer benefits of system-wide planning and networked assets for a small utility.

The Company has determined that it can best satisfy those goals by: (a) modifying Astoria Station to add LNG fuel storage capability; (b) adding solar and wind resources, including approximately 200 MW of solar generation and approximately 200 MW of wind generation (in addition to repowering our existing wind facilities—excluding Merricourt) and (c) retaining Coyote Station in our generation portfolio pending the need for any significant, non-routine capital investment that may be required to continue operating the plant. Our analysis indicates that this combination of actions will provide flexibility, reduce costs, and maintain and enhance the resiliency of our system.

Table 3-1 provides the preferred 15-year resource plan for both the Base Case and our Supplemental Preferred Plan. The Table includes the resource selection and net present value of revenue requirements (NPVRR) both with and without externalities.

Our five-year action plan to add 200 MWs of solar in the 2027/2028 timeframe and to begin activities to add 200 MW of wind in the 2029 timeframe is not altered by any actions we may take concerning Coyote Station. As shown below, if Otter Tail were to withdraw from Coyote Station, in a future resource planning proceeding we would likely request authority to add 100 MW of solar and 150 MW of wind in the 2030/2031 timeframe.

Supplemental Table 3-1 – Supplemental Preferred Plan Summary

	No Externalities		with Externalities	
	Base Case	Preferred Plan*	Base Case	Preferred Plan*
2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
2024				
2025	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers
2026	Astoria Onsite Fuel	Astoria Onsite Fuel	ria Onsite Fuel50 MW Gen W	Astoria Onsite Fuel
2027		100 MW Sur Solar		100 MW Sur Solar
2028		100 MW Sur Solar		100 MW Sur Solar
2029	50 MW Sur Solar 250 MW Gen Wind	200 MW Gen Wind	150 MW Gen Wind	200 MW Gen Wind
2030		100 MW Sur Solar		100 MW Sur Solar
2031	25 MW Sur Battery	150 MW Gen Wind	25 MW Sur Battery	150 MW Gen Wind
2032	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	25 MW Sur Battery 150 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery
2033				
2034				
2035				
2036				
2037				
NPVRR	$2,714,497	$2,724,103	$3,152,731	$3,199,210

*Resource additions in 2030 and 2031 are to be determined. 100MW Surplus Solar and 150 MW Generic Wind are needed if Otter Tail withdraws from Coyote at year end 2028.

As provided in the table above, the NPVRR for the Supplemental Preferred Plan is slightly higher than the optimal EnCompass solved Base Case. Our Supplemental Preferred Plan represents a balanced and reasonable approach to addressing the concerns of our regulators and varied stakeholders, which complies with all legal requirements and allows the Company to continue providing reliable, low-cost electricity to meet our customers' needs.

Graphs 3-1 to 3-4 show Otter Tail's position within MISO's current capacity construct for all seasons through 2037 – considering scenarios with Coyote Station included and removed from the resource stack.

Graph 3-1: Supplemental Preferred Plan Accredited Winter Capacity and - PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Graph 3-2: Supplemental Preferred Plan Accredited Spring Capacity and PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Graph 3-3: Supplemental Preferred Plan Accredited Summer Capacity and PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

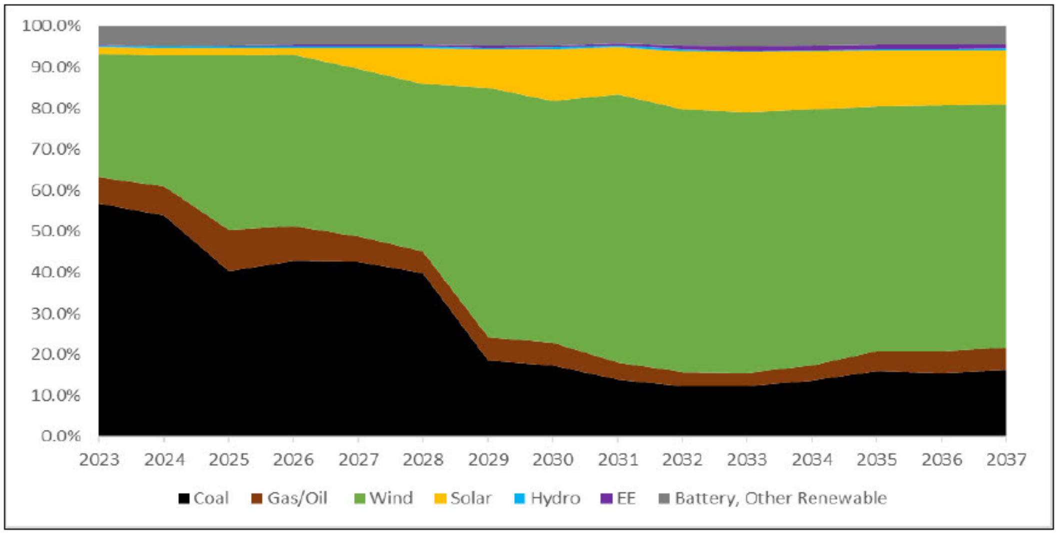
Graph 3-4: Supplemental Preferred Plan Accredited Fall Capacity and PRMR

[PROTECTED DATA BEGINS…

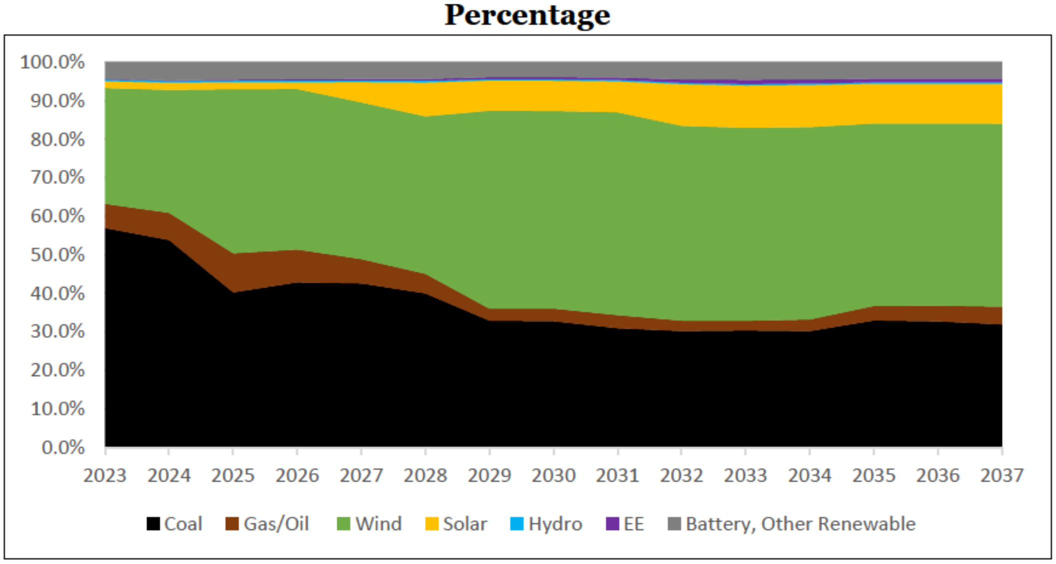
…PROTECTED DATA ENDS]

Graph 3-5 shows the expected energy mix through 2037 for Otter Tail's Supplemental Preferred Plan, considering scenarios with Coyote Station included through 2040 and not included beginning in 2029 (this data is based on Encompass generator output in runs not considering externalities).

Graph 3-5: Supplemental Preferred Plan (Coyote 2028) Energy Generation Percentage



Graph 3-6: Supplemental Preferred Plan (Coyote 2040) Energy Generation Percentage



Otter Tail's approach to planning recognizes that modeling and a corresponding NPVRR analysis, while important, is not the end of the analysis. As noted in our Initial Filing, the Company has historically advocated for what we describe as a "least cost" resource plan. However, the selection of such a plan has always involved more than just selecting the lowest cost option under a single forecasted scenario. Instead, Otter Tail analyzes numerous potential scenarios in a range of possible "futures." By considering a variety of scenarios, the Company's goal has always been to go beyond a single "least cost" consideration to also consider the various *risks* that are inherent in any plan so that we can arrive at a plan that has the greatest likelihood of being "least cost" under the broadest range of possible futures. It might therefore be more accurate to say that Otter Tail's resource planning has been focused on finding the "least cost/least risk" plan. The Supplemental Preferred Plan is such a plan.

Our Supplemental Preferred Plan closely tracks our Initial Preferred Plan. The primary difference concerns Coyote Station. In our Initial Preferred Plan we stated the following:

> In fact, the economic analyses supporting the Preferred Plan is compelling. In almost every scenario and permutation analyzed, the results are clear: It is no longer in customers' best interest for Otter Tail to continue to participate as an owner in Coyote Station. This outcome is true regardless of any future compliance obligation or potential change in law. Should significant investments need to be made at Coyote Station for environmental compliance purposes, the economic analysis is even more compelling.[10]

Based on material changes that have occurred since our Initial Filing we believe our customers are better served by the Company remaining an owner in Coyote Station pending a need for significant investments in the plant, which would most likely be necessary for environmental compliance purposes.[11] Should we determine it necessary to withdraw from Coyote Station, our goal is to do so expeditiously while minimizing potential adverse impacts. Consequently, Otter Tail is seeking authority in its Supplemental Preferred Plan to withdraw from its ownership interest in Coyote Station in the event Otter Tail is required to make a significant, non-routine capital investment in the facility. Pending such a development, Otter Tail believes it prudent not to

[10] Initial Filing at p. 6.
[11] This possibility arises from the EPA's Regional Haze Rule. In its planning, the Company is treating the need for capital investments to comply with that rule as a possibility; however, to be clear, Otter Tail is not taking the position that such capital investments should be required, nor are we providing an estimate of the likelihood of such outcome.

prematurely withdraw from its ownership in Coyote Station, recognizing that our ownership in Coyote Station will be reevaluated in our next resource plan filings.

The risks and uncertainties that inform our view of Coyote Station (discussed in more detail later in this Supplemental Filing) include the following:

- Modeling Changes - In our Initial Filing, there were few scenarios where it was economic to remain in Coyote Station beyond 2028. In nearly every case, even when externalities were not included, the modeling supported withdrawing from Coyote Station. In our updated modeling there are now additional scenarios that support remaining in Coyote Station. These scenarios include a high renewable energy cost scenario and a low renewable accreditation scenario.
- Capacity Accreditation Questions - There remain significant questions about MISO's capacity accreditation for generation resources. MISO is considering several proposals for capacity accreditation and as of the date of this Supplemental Filing it is unclear which standard MISO will adopt.[12]
- Otter Tail's Capacity Position Relative to Load Growth – Otter Tail's updated modeling includes the addition and projected addition of large loads. Some of these loads are agricultural processing facilities similar to what we have seen historically, albeit with different methods, intended to produce carbon neutral products; others are atypical in nature for Otter Tail, such as data processing customers. We expect continued interest from customers in these industries, which could affect our overall capacity position.
- Recent Volatility in MISO Energy Markets and Natural Gas Markets - While we expect these markets to return to more normal conditions in our forecasts, the extreme volatility in these markets that occurred after our Initial Filing demonstrates that forecasting will always have an inherent amount of uncertainty and risk.

[12] Also note that on March 21, 2023, MISO received an order from the Federal Energy Regulatory Commission (FERC) establishing a show cause proceeding in FERC Docket EL23-46-000 regarding Seasonal Accredited Capacity (SAC) ratios for Schedule 53 resources. FERC's order dated March 17, 2023 states that MISO "appears to be violating its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) by failing to update its system-wide Unforced Capacity (UCAP)/Intermediate Seasonal Accredited Capacity (ISAC) ratio (Ratio) for the 2023/24 Planning Resource Auction despite having updated ISAC values for certain resources." In response to FERC's order, MISO will be recalculating the SAC ratios, which is expected to result in reduced SAC values for individual market participants on an aggregate basis. We do not anticipate this development having a material impact on our Supplemental Fling.

- MISO Capacity Position & Regional Resource Assessment –Since our Initial Filing MISO has shifted from capacity surplus to capacity shortfall, and MISO modeling indicates near term capacity risk. MISO's Local Resource Zone 1 of which Otter Tail has 99 percent of its customers, is not isolated from this risk.

In the current planning environment, having Coyote Station part of the Company's portfolio provides a cost-effective hedge against market volatility, unresolved accreditation questions, forecasting uncertainties and related risk of errors, and unforeseen developments. This is a cautious and measured approach that preserves flexibility and limits risk pending more clarity on several fronts.

There is no doubt there will be differences of opinions among our stakeholders, some of whom may view our Supplemental Preferred Plan as a significant departure from our Initial Preferred Plan on the issue of Coyote Station. We do not think that is the case. Our position with respect to Coyote Station tracks closely to that detailed in our Initial Filing; our Supplemental Preferred Plan should be viewed as a cautious pause pending further developments.

Otter Tail's goal is to keep customers' interests in the forefront of this analysis. We know we share this goal with each of our three Commissions. Our Supplemental Preferred Plan strikes a balance between several planning objectives - including arriving at a diversified mix of generation resources that assures reliability, rate stability, environmental responsibility, and the flexibility to respond to risks and opportunities in this rapidly changing environment.

As we noted in our Initial Filing any withdrawal from Coyote Station is complex and challenging. Coyote Station is a key baseload resource for the plant's co-owners. Additionally, Otter Tail is the current operator of the plant and is relied upon by the co-owners for the plant's safe and efficient operation. Further, Coyote Station is a mine-mouth lignite plant, with the adjacent mine serving the plant. There are significant differences between mine mouth plants such a Coyote Station and delivered fuel plants that affect any withdrawal analysis. Appendix K provides a summary of these differences.

The mine is owned by Coyote Creek Mining Company, LLC, a subsidiary of the North American Coal Corporation, which is not affiliated with any of the Coyote Station co-owners. Finally, Coyote Station is a key source of jobs and tax base in Mercer County and North Dakota. These challenges will require thoughtful consideration and management should circumstance make it necessary to withdraw from Coyote Station.

Table 3-2 below summarizes the key actions in the Supplemental Preferred Plan. Each of the items listed is discussed in greater detail in subsequent sections of this filing.

Table 3-2: Otter Tail 2023-2029 Detailed Action Plan

Year	Actions
2023	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. Wind Equipment Upgrades (in service 2024 & 2025)[13]: Secure necessary siting amendments, equipment and contracting for construction. Onsite Fuel at Astoria Station: Development Activities: Engage engineering firm to complete sufficient design to support permitting, regulatory approvals, and Engineering, Procurement, and Construct (EPC) bid packages. Enter into EPC and fuel supply agreements.
2024	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar (in-service 2027): Development Activities: Secure land, MISO interconnection, Preliminary Design Permitting Onsite Fuel at Astoria Station: EPC contractor completes detailed design, manufacturing and

[13] We reference the repowering of our wind facilities in the Supplemental Preferred Plan to provide a full picture of our efforts to develop cost effective generation and the impact of the IRA. Repowering of these facilities is subject to separate regulatory proceedings outside of this Supplemental Preferred Plan.

Year	Actions
	construction begins.
2025	<u>Monitor Possible Withdrawal from Coyote Station:</u> Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. <u>100 MW Solar (in-service 2028):</u> Development Activities: Secure land, MISO interconnection, Preliminary Design Permitting <u>Onsite Fuel at Astoria Station:</u> Construction
2026	<u>Monitor Possible Withdrawal from Coyote Station:</u> Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. <u>100 MW Solar (in-service 2027):</u> Final design and contracting <u>200 MW Wind (in-service 2029):</u> Development Activities: Secure land, MISO interconnection, Preliminary Design, Permitting
2027	<u>Monitor Possible Withdrawal from Coyote Station:</u> Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. <u>100 MW Solar</u> 2027 Commercial operation <u>100 MW Solar (in-service 2028):</u> Final design and contracting <u>200 MW Wind (in-service 2029):</u> Secure necessary equipment and contracting for construction
2028	<u>Monitor Possible Withdrawal from Coyote Sation:</u> Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital

Year	Actions
	investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar 2028 Commercial operation 200 MW Wind (in-service 2029): Construction
2029	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 200 MW Wind: 2029 commercial operation

APPENDIX B

Scenario Output

CDG Modeled Scenario 2023 Base Case
Coyote Retirement Date 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	25	-	-	25	250	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	25	-	-	75	400	-	-	-	-	-

CDG Modeled Scenario Preferred Plan
Coyote Retirement Date 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	100	100	-	-	-	100	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	100	100	200	-	-	125	-	-	-	-	-

CDG Modeled Scenario NGEM+50%
Coyote Retirement Date 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	50	50	-	-	50	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	400	-	50	50	-	-	50	100	-	-	-	-	-

CDG Modeled Scenario NGEM+100%
Coyote Retirement Date 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-	-	150	50	-	50	-	-	-	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	550	50	-	50	-	-	-	75	-	-	-	25	-

CDG Modeled Scenario NGEM-50%
Coyote Retirement Date 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	-	-	25	-	-	-	-	-	-

CDG Modeled Scenario RH Mid Cost
Coyote Retirement Date 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	25	-	-	-	325	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	25	-	-	50	475	-	-	-	-	50

CDG Modeled Scenario RH Mid Cost - NGEM+100%
Coyote Retirement Date 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-
Gen Wind	-	-	150	50	-	50	-	-	-	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	550	50	-	50	-	-	25	50	-	-	-	-	-

CDG Modeled Scenario RH High Cost
Coyote Retirement Date 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	200	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	25	-	-	275	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	25	-	50	475	-	-	-	-	-

CDG Modeled Scenario	RH High Cost - NGEM+100%														
Coyote Retirement Date	2040														
Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-	-	150	-	-	50	-	-	-	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	550	-	-	50	-	-	-	125	-	-	-	-	-

CDG Modeled Scenario	Load+10%														
Coyote Retirement Date	2040														
Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	150	-	-	-	50	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	150	-	-	-	-	-	-	200	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	300	-	-	-	50	-	50	250	-	25	-	50	-

CDG Modeled Scenario: Load+10% - NGEM+100%
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Gen Wind	-	-	200	-	-	50	-	-	50	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	600	-	-	50	-	-	50	175	-	-	-	-	-

CDG Modeled Scenario: Load+25%
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-
Sur Battery	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	300	-	50	-	50	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	125	-	25	-	-	-	-	175	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	450	25	75	-	50	-	50	225	-	-	50	-	-

CDG Modeled Scenario: Load+25% - NGEM+100%

Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	25	50	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	400	-	-	-	-	-	100	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	25	-	-	-	75	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	850	-	-	25	-	-	100	125	-	-	-	-	-

CDG Modeled Scenario: High Accred

Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	50	-	-	-	25	300	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	50	-	-	-	25	500	-	-	-	-	-

CDG Modeled Scenario: Low Accred
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	350	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	50	-	-	-	-	50	500	-	-	-	-	50

CDG Modeled Scenario: Carbon Tax
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	300	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	150	225	25	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	150	225	25	-	-	50	300	-	-	-	-	-

CDG Modeled Scenario: Renew High Cost
Coyote Retirement Date: 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	-	-	50	50	-	-	-	-	-

CDG Modeled Scenario: Renew High Cost - NGEM+100%
Coyote Retirement Date: 2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-	-	50	-	-	50	-	-	-	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	150	-	50	-	-	-	-	100	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	200	-	50	50	-	-	-	275	-	-	-	-	-

CDG Modeled Scenario: Renew Low Cost (40% ITC)
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	75	75	75	25	-	-	-	150	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	75	75	75	25	-	-	50	300	-	-	-	-	-

CDG Modeled Scenario: RH High Cost - LowAccred
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	350	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	50	-	-	-	-	50	500	-	-	-	-	50

CDG Modeled Scenario: RH High Cost - Load+25%
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	300	-	50	-	100	-	-	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	125	-	25	-	-	-	-	175	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	475	-	75	-	100	-	-	225	-	-	-	50	-

CDG Modeled Scenario: RH High Cost - Renew High Cost
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	-	-	50	50	-	-	-	-	-

CDG Modeled Scenario: 2023 Base Case
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	25	-	-	25	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	300	-	50	-	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	75	-	-	25	225	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	75	325	-	75	250	-	-	-	-	-

CDG Modeled Scenario: Preferred Plan
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	200	-	150	-	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	100	100	-	100	-	100	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	49	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	100	100	200	100	150	125	-	49	-	-	-

CDG Modeled Scenario NGEM+50%

Coyote Retirement Date 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	25	25	-	-	-	-	-
Gen Wind	-	-	-	-	50	50	250	-	-	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	400	-	50	50	250	-	25	125	-	-	-	-	-

CDG Modeled Scenario NGEM+100%

Coyote Retirement Date 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	25	25	-	-	-	-	-
Gen Wind	-	-	150	-	-	50	150	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	550	-	-	50	150	-	75	125	-	50	-	-	-

CDG Modeled Scenario: NGEM-50%
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	289	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	-	-	-	-	-	289	-	-	-

CDG Modeled Scenario: Load+10%
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-
Gen Wind	-	-	150	-	-	-	200	-	-	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	125	-	25	-	-	-	-	175	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	275	-	25	-	250	-	-	325	-	-	50	-	-

CDG Modeled Scenario: Load+10% - NGEM+100%

Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	25	50	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-
Gen Wind	-	-	200	-	-	50	200	-	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	100	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	600	-	-	50	250	-	50	150	-	-	-	-	-

CDG Modeled Scenario: Load+25%

Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	200	-	-	-	-	-	100	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	150	-	-	-	-	-	-	250	-	-	-	-	-
GASCT	-	-	-	-	-	-	289	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	350	-	-	-	289	-	100	400	-	-	-	-	-

CDG Modeled Scenario: Load+25% - NGEM+100%

Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	75	-	50	50	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	400	-	-	-	200	-	-	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	25	-	-	-	150	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	850	-	-	25	200	-	-	250	-	-	-	-	-

CDG Modeled Scenario: High Accred

Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	200	-	100	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	25	-	25	25	-	200	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	25	-	225	25	100	300	-	25	-	-	-

CDG Modeled Scenario	Low Accred
Coyote Retirement Date	2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	-	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	400	-	-	-	-	-
GASCT	-	-	-	-	-	-	289	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	289	-	-	550	-	-	-	-	-

CDG Modeled Scenario	Carbon Tax
Coyote Retirement Date	2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	25	25	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	300	50	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	150	175	-	-	-	-	75	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	150	175	-	300	50	75	150	-	-	-	-	50

CDG Modeled Scenario: Renew High Cost
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	-	-	-	400	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	-	-	-	-	-	-	-	400	-	-	100	-	-

CDG Modeled Scenario: Renew High Cost - NGEM+100%
Coyote Retirement Date: 2028

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	50	50	-	-	-	-	-
Gen Wind	-	-	100	-	-	-	500	-	100	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	300	50	100	-	-	-	-	300	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	400	50	100	-	500	-	150	450	-	-	-	-	-

CDG Modeled Scenario: Renew Low Cost (40% ITC)
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	25	-	25	-	-	-	-	-	-
Gen Wind	-	-	-	-	-	-	200	100	50	50	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	75	75	50	-	-	-	-	200	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	75	75	50	-	225	100	75	250	-	-	-	-	-

CDG Modeled Scenario: Low Accred, Load +25, NGEM +100%
Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-		-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-		-	-	-	50	-	-		-	-	-	-	-
Gen Wind	-	-	200	-	-	-	250	-	-	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	200	25	75					100	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	400	25	75	-	300			200	-	-	-	-	-

CDG Modeled Scenario: Regional Haze High, Low Accred, Load +25, NGEM +100%
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-
Gen Wind	-		200	-	-		50	-	-	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-		200	125	-	-	-		25	50	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	400	125		-	50		25	225	-	-	-	-	-

CDG Modeled Scenario: Regional Haze Mid, Low Accred, Load +25, NGEM +100%
Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Gen Wind	-		200	-	-	50	-	-	50	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-		-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-		-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-		-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-		-	-	-	-	-
Sur Solar	-		225	25	50	-	-	-	-	100	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-		-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	425	25	50	50			50	300	-	-	-	-	-

CDG Modeled Scenario: Low Accred, Load +10, NGEM +100%

Coyote Retirement Date: 2028

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-
Gen Wind	-		200	-	50	-	50	-	-	150	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-		150	150	25	25	100	-	-	150	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	350	150	75	25	150			350	-	-	-	-	-

CDG Modeled Scenario: Regional Haze High, Low Accred, Load +10, NGEM +100%

Coyote Retirement Date: 2040

Nameplate (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-		25	25							-	-	-	-	-
Gen Wind	-		250			50				100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-		150							200	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	425	25		50				300	-	-	-	-	-

CDG Modeled Scenario	Regional Haze Mid, Low Accred, Load +10, NGEM +100%
Coyote Retirement Date	2040

Nameplate (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gen Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Battery	-	-	25	25	-	-	-	-	-	-	-	-	-	-	-
Gen Wind	-	-	200	50	-		50	-	-	100	-	-	-	-	-
Rep Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gen Solar	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rep Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sur Solar	-	-	125	25	-	-	-	-	-	200	-	-	-	-	-
GASCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	49	-	350	100		-	50			300	-	-	-	-	-

APPENDIX C

Otter Tail Sensitivity Summary

Appendix I: Sensitivity Summary
Page 1 of 4

NPVRR Comparison			A	A.1	B	C	D	E	F	G	H	I	J
IRP Refresh No Externalities Included			2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,742,670	$2,764,110	$2,999,270	$3,163,944	$2,173,232	$2,798,479	$3,218,073	$2,818,342	$3,236,851	$3,025,644	$3,495,792
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,714,497	$2,724,103	$2,972,047	$3,164,174	$2,131,738	$2,714,497	$3,164,174	$2,714,497	$3,164,174	$3,011,694	$3,502,295
	2028 Difference from 2040 Exit NPVRR	($000)	-$28,173	-$40,007	-$27,223	$230	-$41,494	-$83,982	-$53,899	-$103,845	-$72,677	-$13,950	$6,503

Annual Resource Additions - Exit Coyote 12/31/2040		A	A.1	B	C	D	E	F	G	H	I	J
		2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
3	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4	2024											
5	2025	Wind Repowers	Wind Repowers	Wind Repower 400 MW Sur Solar	Wind Repower 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers 75 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind
6	2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 75 MW Sur Solar	Astoria Onsite Fuel
7	2027		100 MW Sur Solar	50 MW Gen Wind								
8	2028		100 MW Sur Solar							50 MW Gen Wind		50 MW Gen Wind
9	2029		200 MW Gen Wind		50 MW Gen Wind			50 MW Gen Wind			50 MW Gen Wind	
10	2030											
11	2031			50 MW Gen Wind							50 MW Gen Wind	
12	2032	325 MW Sur Solar 200 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	150 MW Gen Wind	100 MW Gen Wind		350 MW Sur Solar 200 MW Gen Wind	100 MW Gen Wind	325 MW Sur Solar 200 MW Gen Wind	100 MW Gen Wind	150 MW Sur Solar 150 MW Gen Wind	50 MW Sur Battery 25 MW Gen Solar 150 MW Gen Wind
13	2033											
14	2034											
15	2035											
16	2036											
17	2037										50 MW Rep Wind	

Annual Resource Additions - Exit Coyote 12/31/2028		A	A.1	B	C	D	E	F	G	H	I	J
		2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
18	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19	2024											
20	2025	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 75 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind
21	2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 75 MW Sur Solar	Astoria Onsite Fuel
22	2027		100 MW Sur Solar	50 MW Gen Wind								
23	2028		100 MW Sur Solar									50 MW Gen Wind
24	2029	50 MW Sur Solar 300 MW Gen Wind	200 MW Gen Wind	250 MW Gen Wind	150 MW Gen Wind		50 MW Sur Solar 300 MW Gen Wind	150 MW Gen Wind	50 MW Sur Solar 300 MW Gen Wind	150 MW Gen Wind	50 MW Sur Battery 250 MW Gen Wind	25 MW Sur Battery 200 MW Gen Wind
25	2030		100 MW Sur Solar									
26	2031	25 MW Sur Battery	150 MW Gen Wind	50 MW Gen Wind	100 MW Gen Wind		25 MW Sur Battery	100 MW Gen Wind	25 MW Sur Battery	100 MW Gen Wind	50 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind
27	2032	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	50 MW Sur Battery 50 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind		25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	50 MW Gen Battery 175 MW Sur Solar 100 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind
28	2033											
29	2034					248 MW Firm Dispatchable						
30	2035											
31	2036										25 MW Rep Battery	
32	2037			50 MW Rep Wind								25 MW Rep Solar

NPVRR Comparison			K	L	M	N	O	P	Q	R	S	T	U
IRP Refresh No Externalities Included			25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$3,501,204	$4,029,495	$2,725,995	$2,848,225	$3,118,304	$2,843,108	$3,434,742	$2,728,735	$2,924,406	$3,574,435	$2,919,805
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$3,534,590	$4,048,011	$2,674,770	$2,885,307	$2,983,391	$2,880,639	$3,476,938	$2,695,743	$2,885,307	$3,534,590	$2,880,639
	2028 Difference from 2040 Exit NPVRR	($000)	$33,386	$18,516	-$51,225	$37,082	-$134,913	$37,531	$42,196	-$32,992	-$39,099	-$39,845	-$39,166

Annual Resource Additions - Exit Coyote 12/31/2040			K	L	M	N	O	P	Q	R	S	T	U
			25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
3		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4		2024											
5		2025	Wind Repowers 125 MW Sur Solar 250 MW Gen Wind	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 150 MW Sur Solar 50 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 100 MW Sur Solar 250 MW Gen Wind	Wind Repowers
6		2026	Astoria Onsite Fuel 25 MW Sur Battery 25 MW Sur Solar 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 125 MW Sur Solar	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 25 MW Sur Battery	Astoria Onsite Fuel 25 MW Sur Battery 50 MW Gen Wind	Astoria Onsite Fuel
7		2027	50 MW Gen Wind			50 MW Sur Solar	250 MW Sur Solar		50 MW Sur Solar	225 MW Sur Solar	25 MW Sur Solar	25 MW Sur Battery 50 MW Gen Wind	
8		2028				50 MW Sur Battery	25 MW Sur Solar		50 MW Gen Wind	25 MW Sur Solar	25 MW Sur Battery		
9		2029	25 MW Sur Battery	50 MW Gen Wind								50 MW Sur Solar	
10		2030											
11		2031	50 MW Gen Wind	25 MW Sur Battery								50 MW Gen Wind	
12		2032	175 MW Sur Solar 100 MW Gen Wind	50 MW Gen Battery 100 MW Gen Solar 100 MW Gen Wind	325 MW Sur Solar 200 MW Gen Wind	325 MW Sur Solar 150 MW Gen Wind	300 MW Gen Wind	100 MW Gen Wind	100 MW Sur Solar 150 MW Gen Wind	150 MW Sur Solar 200 MW Gen Wind	350 MW Sur Solar 150 MW Gen Wind	200 MW Sur Solar 100 MW Gen Wind	100 MW Gen Wind
13		2033											
14		2034	50 MW Rep Battery									50 MW Rep Battery	
15		2035				50 MW Rep Wind					50 MW Rep Wind		50 MW Rep Wind
16		2036						50 MW Rep Wind					
17		2037	50 MW Rep Wind									50 MW Rep Wind	

Annual Resource Additions - Exit Coyote 12/31/2028			K	L	M	N	O	P	Q	R	S	T	U
			25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
18		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19		2024											
20		2025	Wind Repowers 150 MW Sur Solar 150 MW Gen Wind	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 150 MW Sur Solar 50 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers
21		2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 125 MW Sur Solar	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel
22		2027				100 MW Sur Solar	200 MW Sur Solar		75 MW Sur Solar	225 MW Sur Solar	100 MW Sur Solar		
23		2028		25 MW Gen Solar		50 MW Sur Solar			50 MW Gen Wind	25 MW Sur Solar	50 MW Sur Solar	25 MW Gen Solar	
24		2029	248 MW Firm Dispatchable	25 MW Sur Battery 50 MW Gen Battery 75 MW Gen Solar 200 MW Gen Wind	125 MW Sur Solar 150 MW Gen Wind		300 MW Gen Wind		200 MW Gen Wind	25 MW Sur Battery 200 MW Gen Wind		25 MW Sur Battery 50 MW Gen Battery 75 MW Gen Solar 200 MW Gen Wind	
25		2030			25 MW Sur Solar								
26		2031	50 MW Gen Wind	50 MW Gen Battery 50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Wind		50 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind		50 MW Gen Battery 50 MW Gen Wind	
27		2032	250 MW Sur Solar 200 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind	175 MW Sur Solar 150 MW Gen Wind	250 MW Sur Solar 200 MW Gen Wind	50 MW Sur Battery 75 MW Sur Solar 100 MW Gen Wind	250 MW Gen Wind	50 MW Sur Battery 150 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar 150 MW Gen Wind	250 MW Sur Solar 200 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind	250 MW Gen Wind
28		2033											
29		2034				248 MW Firm Dispatchable					248 MW Firm Dispatchable		
30		2035											
31		2036						50 MW Rep Wind					50 MW Rep Wind
32		2037							50 MW Rep Wind				

From: Steve Clay <SClay@misoenergy.org>
Sent: Wednesday, March 6, 2024 11:07 AM
To: Donofrio, Lauren D. <ldonofrio@otpco.com>
Cc: Amy Thurmond <AThurmond@misoenergy.org>; Darrin Lahr <dlahr@misoenergy.org>
Subject: Confidential Otter Tail Question re AME status

Good morning, Lauren,

I am the responsible attorney at MISO for the AME resource category. Amy Thurmond forwarded your question to me and I have had a chance to review all of the correspondence.

From MISO Legal's perspective, an order of the Minnesota PUC establishing an operating limit would satisfy the provision in Section 39.2.5.b.xxvi that requires "i) the AME Resource has an operating limit established by regulation (e.g, permits or federal and state laws or regulations) where the AME Resource can only be accessed during an Emergency to preserve its reliability value." Such an order would fall within the intent of the AME provision, plus Otter Tail has received the support of the IMM. So, under these circumstances MISO would allow the resource to use AME status.

Thanks, and plus let me know if you need anything further on this.

Steven Clay

Senior Corporate Counsel
2985 Ames Crossing Road | Eagan, MN 55121
sclay@misoenergy.org

www.misoenergy.org

CERTIFICATE OF SERVICE

RE: In the Matter of Otter Tail Power Company's 2022-2036 Resource Plan Docket No. E017/RP-21-339

I, Kim Ward, hereby certify that I have this day served a copy of the following, or a summary thereof, on Will Seuffert and Sharon Ferguson by e-filing, and to all other persons on the attached service list by electronic service or by First Class Mail.

Otter Tail Power Company
Comments

Dated this **3rd** day of **April, 2024**.

<u>/s/ KIM WARD</u>
Kim Ward
Lead Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8268

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Laura	Bishop	Laura.Bishop@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_21-339_21-339
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_21-339_21-339
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-339_21-339
Brooke	Cunningham	Health.Review@state.mn.us	Minnesota Department of Health	PO Box 64975 St. Paul, MN 55164-0975	Electronic Service	No	OFF_SL_21-339_21-339
Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters	700 Olive Street St. Paul, MN 55130	Electronic Service	No	OFF_SL_21-339_21-339
Kristin W	Duncanson	kw.duncanson@gmail.com		57746 Highway 30 Mapleton, MN 56065	Electronic Service	No	OFF_SL_21-339_21-339
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-339_21-339
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-339_21-339
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_21-339_21-339
Barb	Freese	bfreese@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company	PO Box 496 Fergus Falls, MN 56538-0496	Electronic Service	Yes	OFF_SL_21-339_21-339
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-339_21-339
Julie	Goehring	julie@redriverbasincommission.org		708 70 Ave NW Moorhead, MN 56560	Electronic Service	No	OFF_SL_21-339_21-339
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-339_21-339
Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club	2101 Webster St Ste 1300 Oakland, CA 94612	Electronic Service	No	OFF_SL_21-339_21-339
Nathan	Jensen	njensen@otpco.com	Otter Tail Power Company	215 S. Cascade St. Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339
Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.	11 East Superior St Ste 125 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-339_21-339
William D	Kenworthy	will@votesolar.org	Vote Solar	332 S Michigan Ave FL 9 Chicago, IL 60604	Electronic Service	No	OFF_SL_21-339_21-339
Kate	Knuth	kate.knuth@gmail.com		2347 14th Terrace NW New Brighton, MN 55112	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Randy	Kramer	rlkramer89@gmail.com	Water and Soil Resources Board	42808 Co. Rd. 11 Bird Island, MN 55310	Electronic Service	No	OFF_SL_21-339_21-339
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339
Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-339_21-339
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-339_21-339
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-339_21-339
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339
Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Debra	Opatz	dopatz@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-339_21-339
Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND	81 E Little Canada Road St. Paul, MN 55117	Electronic Service	No	OFF_SL_21-339_21-339
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Stephan	Roos	stephan.roos@state.mn.us	MN Department of Agriculture	625 Robert St N Saint Paul, MN 55155-2538	Electronic Service	No	OFF_SL_21-339_21-339
Nathaniel	Runke	nrunke@local49.org	International Union of Operating Engineers Local 49	611 28th St. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_21-339_21-339
John	Saxhaug	john_saxhaug@yahoo.com		3940 Harriet Ave Minneapolis, MN 55409	Electronic Service	No	OFF_SL_21-339_21-339
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-339_21-339
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-339_21-339
Cary	Stephenson	cStephenson@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	Yes	OFF_SL_21-339_21-339
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	Yes	OFF_SL_21-339_21-339
Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 St. Paul, MN 55104	Electronic Service	Yes	OFF_SL_21-339_21-339
Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club	Environmental Law Program 1536 Wynkoop St Ste 200 Denver, CO 80202	Electronic Service	No	OFF_SL_21-339_21-339

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-339_21-339