MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	May 28 and May 30, 2024		**Agenda Item ***1**
Company	Otter Tail Power Company (OTP or Company)		
Docket No.	E017/RP-21-339		
	In the Matter of Otter Tail Power's 2023-2037 Integrated Resource Plan		
Issues	Should the Commission approve, modify, or reject OTP's Minnesota Preferred Plan with AME? Should the Commission approve OTP's Settlement Agreement? Should the Commission require OTP to initiate a competitive bidding process to acquire resources? Should the Commission cap rate recovery for OTP's Astoria Station onsite-storage project, if approved? When should OTP file its next IRP?		
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✓**Relevant Documents**	**Date**
Otter Tail Power, Initial Filing (Public and Non-Public)	September 1, 2021
Otter Tail Power, Supplemental Filing (Public and Non-Public)	October 14, 2022
Otter Tail Power, Supplemental Comments (Public and Non-Public)	November 4, 2022
Department of Commerce, Comments (Public and Non-Public)	December 30, 2022
IUOE Local 49 and NCSRC of Carpenters, Comments	December 30, 2022
LIUNA Minnesota and North Dakota, Comments	December 30, 2022

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

✓ **Relevant Documents**	**Date**
Office of the Attorney General, Comments (Public and Non-Public)	December 30, 2022
Clean Energy Organizations, Reply Comments	February 1, 2023
Office of the Attorney General, Reply Comments	February 1, 2023
Otter Tail Power, Reply Comments	February 1, 2023
Otter Tail Power, Supplemental Letter	February 16, 2023
Otter Tail Power, Supplemental Resource Plan (Public and Non-Public)	March 31, 2023
Otter Tail Power, Appendices C, D, I, K	March 31, 2023
Otter Tail Power, Appendix F	March 31, 2023
Otter Tail Power, Errata	April 25, 2023
Clean Energy Organizations, Comments (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Attachment 1 (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Attachment 2	September 13, 2023
Clean Energy Organizations, Attachment 3	September 13, 2023
IUOE Local 49 and NCSRC of Carpenters, Comments	September 13, 2023
Department of Commerce, Comments	September 13, 2023
Office of the Attorney General, Comments (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Corrected Attachment 1 (Public and Non-Public)	September 29, 2023
LIUNA, Reply Comments	October 30, 2023
Otter Tail Power, Reply Comments (Public and Non-Public)	October 30, 2023
Clean Energy Organizations, Reply Comments (Public and Non-Public)	October 30, 2023
Office of the Attorney General, Reply Comments	October 30, 2023
Staff Briefing Papers	December 20, 2023
Otter Tail Power, Settlement Agreement	April 2, 2024
Clean Energy Organizations, Supplemental Comments (Public and Non-Public)	April 3, 2024
Clean Energy Organizations, Attachment 1 to Supplemental Comments	April 3, 2024
Otter Tail Power, Comments	April 3, 2024
Office of the Attorney General, Comments (Public and Non-Public)	April 3, 2024
Otter Tail Power, Reply Comments	April 17, 2024
Clean Energy Organizations, Reply Comments	April 17, 2024

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BACKGROUND

At the January 4, 2024, agenda meeting, the Commission met to discuss Otter Tail Power Company's (OTP or the Company) Integrated Resource Plan (IRP), which was initially filed on September 1, 2021 (Initial Filing) and updated on March 31, 2023 (Supplemental IRP).

However, because OTP filed an alternative proposal on December 15, 2023, which included (1) a new bifurcated planning concept that would separate Minnesota-specific resource additions from OTP's other jurisdictions and (2) a new plan for Coyote Station, the Commission determined that it could not make a decision on the full resource plan without additional comment from parties. Therefore, the Commission directed Staff to issue a *Notice of Comment Period* to further develop the record on OTP's newly-proposed resource plan.

The Notice was issued on January 18, 2024, and sought comments on the following issues:

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

2. Should the Commission approve, modify, or reject OTP'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 OTP'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 OTP's proposal to add onsite liquified natural gas (LNG) fuel storage at Astoria Station in 2027?

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

The Notice also opened the following topics 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 OTP'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 and 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?

On April 2, 2024, OTP filed a Settlement Agreement, which OTP stated "is intended to resolve all issues among the Parties and provide for a recommended decision to the Commission."[1] The parties to the Settlement Agreement are:

- OTP;
- Department of Commerce, Division of Energy Resources (Department);
- International Union of Operating Engineers Local 49 (IUOE Local 49);
- Laborers' International Union of North America (LIUNA); and
- North Central States Regional Council of Carpenters (Carpenters).

Notably, the Clean Energy Organizations (CEOs)[2] and the Office of the Attorney General – Residential Utilities Division (OAG) declined to agree to the terms of the Settlement Agreement.

On April 3, 2024, OTP, CEOs, and OAG filed comments in response to the Commission's *Notice of Comment Period*. On April 17, 2024, OTP and the CEOs filed reply comments.

Staff notes that the December 22, 2023, Staff Briefing Papers discussed OTP's Initial Filing and Supplemental IRP, party comments, including an alternative plan proposed by the CEOs, and OTP's and CEOs' EnCompass modeling. Staff will not repeat that information here, except where it is necessary for context and clarification relevant to the Decision Options in these briefing papers.

INTRODUCTION

I. Key Resources in the Action Plan

The five main resources (both existing and new) most relevant to the Commission's decision at this juncture are:[3]

- Coyote Station;
- Big Stone Plant;
- Astoria Station;
- New Solar; and

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[1] OTP, Settlement Agreement, p. 1.

[2] The CEOs are comprised of Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy.

[3] OTP included a 25 MW battery proposal in the 2031-32 timeframe in the Supplement IRP, but the Company removed the resource in its December 15, 2023, because it was no longer needed with Coyote Station operating under the AME designation.

- New Wind.

A. Coyote Station

Coyote Station is a 427 megawatt (MW) lignite-mine mouth facility located near Beulah, North Dakota that is co-owned by:

- OTP (35%);[4]
- Northern Minnesota Municipal Power Agency, who is represented by Minnkota (30%);
- Montana-Dakota Utilities Co. (25%); and
- Northwestern Energy (10%).

Coyote Station commenced service in 1981 and has a depreciable life that has been extended at various times during the life of the plant, the last time being in 2013 when the depreciable life was extended until 2041.[5] In 2012, the owners entered into a 25-year lignite supply agreement (LSA) with Coyote Creek Mining Company to supply Coyote Station with lignite from a new mine.

In previous filings, OTP urged the Commission to consider the complexities of contractual agreements with other co-owners. For instance, OTP stated that Coyote Station "is a key baseload resource for the plant's co-owners," and as a "mine-mouth lignite plant, with [an] adjacent mine serving the plant," there are important differences than delivered fuel plants like Big Stone.[6] Additionally, the co-owners "are parties to a 1978 transmission facilities agreement (TFA)[7] that predates the formation of Regional Transmission Organizations," and "early retirement would likely require the co-owners to negotiate ownership and transmission service rights currently addressed by the TFA."[8]

In reply comments filed on October 30, 2023, OTP emphasized that the Company "has no unilateral right to withdraw from Coyote Station,"[9] but rather each Coyote Station co-owner has a right to terminate the Coyote Station Plant Ownership Agreement upon not less than five years advance notice. (Staff notes that this five-year requirement alone makes the 2028 early exit scenario modeled in previous filings infeasible.)

[4] OTP became the operating agent of Coyote Station in July 1998.

[5] *In the Matter of Otter Tail Power Company's Request for Approval of its Five-Year Depreciation Study*, Docket No. E017/D-13-795, Order (April 7, 2014).

[6] Updated IRP, p. 13.

[7] OTP stated, "The primary purpose of the TFA was to facilitate the coordinated and efficient construction of transmission facilities needed to deliver the Coyote Station's electricity. The co-owners share in maintenance costs for commonly-owned assets and do not do so for discretely-owned assets."

[8] OTP reply comments, p. 36.

[9] OTP reply comments, p. 32.

Thus, to withdraw from its ownership interest in Coyote Station, OTP must either (1) divest its ownership shares to another co-owner or third-party and secure releases from those obligations or (2) terminate the co-tenancy in the plant under the ownership agreement. In either case, OTP stated, termination of the Plant Ownership Agreement does not cause the automatic termination of the LSA.

OTP also urged the Commission to consider the costs to withdraw from Coyote. OTP explained that there are two general cost categories to withdrawal: (1) undepreciated net book value, and (2) early termination costs under the LSA. OTP's economic analysis developed for the Initial Filing assumed a "conservative estimate" of $68.5 million to withdraw from Coyote Station at the end of 2028.[10] This includes an assumed $21.7 million estimate for the LSA under a 2028 buy-out scenario. The table below shows OTP's estimate of Coyote withdrawal costs under the 2028 exit.

Table 1. OTP Share of Coyote Station Estimated Foreseeable Withdrawal Costs

	Forecast (in $millions)	
Coyote Station	**YE 2040**	**YE 2028**
Book Value (non-land accts 311-316)*	(13.4)	33.4
2041 Decommissioning/Salvage**	13.4	13.4
LSA Early Termination Costs	0	21.7
Total For Withdrawal	**0**	**68.5**

* Project Book Balances in 2023: March 31, 2023: $58.31M, YE 2023: $55.21M
**This is the Coyote End of Life book value collected and accumulated in the current depreciation rates for the decommissioning of the plant.

The CEOs argued in previous comments that retaining ownership in Coyote Station is not in the interests of OTP's ratepayers or the environment. Table 2 provides a summary of OTP's sensitivity results,[11] which compare the cost or savings (in Present Value Revenue Requirement, or PVRR, terms) of a 2028 Coyote exit to a 2040 Coyote exit. Savings, in red, indicate that the 2028 exit is cheaper.

The modeling results show that exiting Coyote by 2028 is least-cost under all sensitivities that consider environmental externalities and the vast majority of sensitivities that exclude environmental externalities. Staff also notes that early exit was less expensive by a large margin with or without externalities under every scenario which considered Regional Haze compliance costs, which Staff highlighted in green.

[10] Note: Does not include any: (1) ancillary costs of withdrawal such as loss of plant-related transmission rights or other operational matters; (2) any potential costs of disputes; (3) any unforeseen liabilities.

[11] CEOs September 13, 2023 comments, p. 18.

Table 2. OTP Sensitivities A-U, PVRR Comparisons of 2028 vs. 2040 Plans

		Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
	Scenario Name	**No Externalities Included**	**Externalities Included**
A	2023 Base Case	($28,173)	($105,154)
A.1	Preferred Plan	($40,007)	($113,264)
B	Natural Gas & Energy Markets (NGEM) +50%	($27,223)	($80,510)
C	NGEM +100%	$230	($54,033)
D	NGEM -50%	($41,494)	($106,873)
E	Regional Haze (RH) Mid Cost	($83,982)	($155,499)
F	RH Mid Cost NGEM +100%	($53,899)	($1,096,581)
G	RH High Cost	($103,845)	($179,189)
H	RH High Cost NGEM +100%	($72,677)	($1,115,381)
I	10% Increased Load	($13,950)	($104,668)
J	10% Increased Load NGEM +100%	$6,503	($64,565)
K	25% Increased Load	$33,386	($97,300)
L	25% Increased Load NGEM +100%	$18,516	($45,720)
M	High Renewable Accreditation	($51,225)	($114,143)
N	Low Accreditation	$37,082	($26,297)
O	Carbon Tax	($134,913)	
P	Renewable High Cost	$37,531	($85,272)
Q	Renewable High Cost NGEM +100%	$42,196	($24,053)
R	Solar and Battery Low Cost (40% ITC)	($32,992)	($113,658)
S	Low Accreditation RH High	($39,099)	($93,888)
T	25% Increased Load RH High	($39,845)	($164,207)
U	Renew High Cost RH High	($39,166)	($158,931)

Among the 7 out of the 22 futures in the No Externalities case which show that continuing to operate Coyote until 2040 is least-cost, the CEOs argued that these sensitivities used "extreme assumptions," because they assume: (1) a 100% increase in both gas prices and energy market prices; (2) a 10-25% increase in load; (3) exceedingly high renewable energy costs; and (4) low renewable resource accreditations.

Importantly, OTP did not model any scenarios which considered costs for the EPA Greenhouse Gas (GHG) Power Plant Rule or the Mercury and Air Toxics (MATS) Rule. These regulations are important to consider, however, given that:

- In 2021, Coyote Station emitted SO_2 at a rate at least eight times higher than any coal plant in Minnesota or South Dakota.

- In 2021, Coyote Station emitted NO_X at a rate at least <u>three and a half times</u> higher than any coal plant in Minnesota or South Dakota.[12]

- In 2022, Coyote Station emitted mercury at a rate approximately <u>three to five times</u> higher than any other coal plant in Minnesota and South Dakota.

- The EPA proposes reducing allowable mercury emissions from lignite-fired plants to 1.2 lb/TBtu, which is well-below Coyote's 2022 emission rate of 2.28 lb/TBtu.[13,14]

Regarding the timing of regulations, the CEOs noted that OTP may be required to comply with these rules by 2028 for Regional Haze, by 2028 or 2031, depending on the compliance pathway for the GHG standard, and by 2027 but possibly as early as 2025 for the MATS.[15]

The CEOs also discussed public health concerns associated with OTP's coal plants. Attachment 2 to CEOs' initial comments is the PSE Healthy Energy report (PSE Report), which describes the human health impacts from continuing to operate Coyote Station and Big Stone. According to the CEOs, PSE found that Coyote Station emits significantly more NO_X, SO_2, and $PM_{2.5}$ than Big Stone – in fact, twenty times more SO_2 and $PM_{2.5}$.[16,17] PSE found that public health impacts from both plants extend across multiple states; as shown below, "it is clear that although neither coal plant is located in Minnesota, Minnesotans are unquestionably bearing the adverse health consequences of the continued operation of these plants."[18]

[12] CEOs initial comments, p. 32.

[13] CEOs initial comments, p. 35.

[14] 88 Fed. Reg. 24,857.

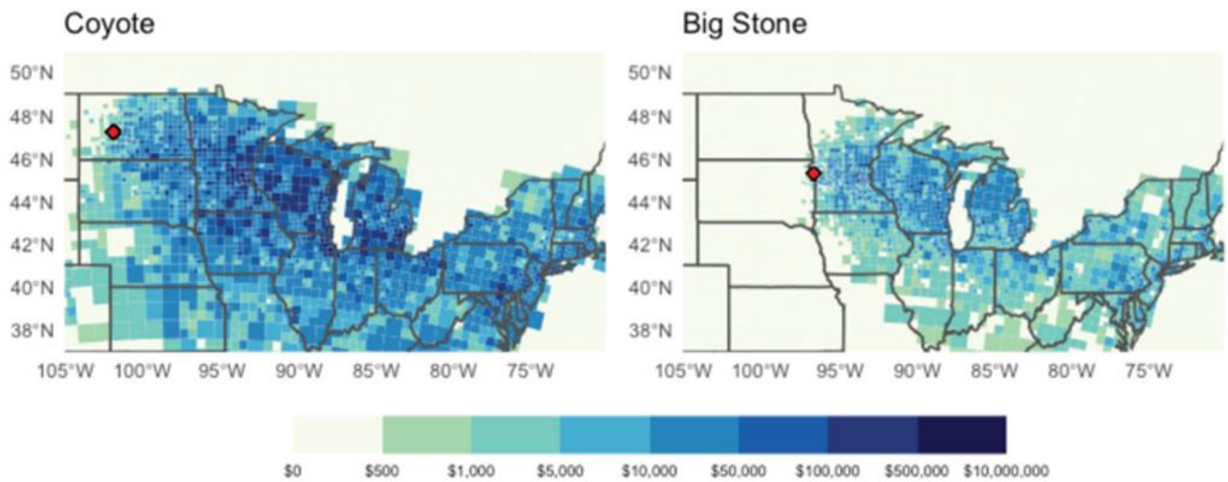
[15] CEOs initial comments, pp. 28-29.

[16] This is because Coyote burns lignite coal, which is the lowest grade of coal, and requires more coal to be burned to generate the same amount of electricity as hard coal like bituminous or subbituminous (Big Stone utilizes subbituminous). Lignite also tends to have higher amounts of sulfur and ash content.

[17] CEOs initial comments, p. 86.

[18] CEOs initial comments, p. 89.

Figure 1. Annual total $PM_{2.5}$ public health impacts of Coyote Station and Big Stone



The OAG, like the CEOs, pointed to OTP's own modeling to argue that the early Coyote exit scenario was in the best interests of OTP's ratepayers, regardless of whether major upgrades were needed to comply with the Regional Haze Rule. The OAG noted that in the Initial Filing, retaining ownership in Coyote was economic in only two sensitivities. In the Updated IRP, even when environmental externalities were excluded, withdrawing from Coyote by 2028 showed once again to be least-cost. Therefore, the OAG recommended that the Commission direct OTP to withdraw from Coyote Station by 2028 as originally proposed in the Company's Initial Filing.

The OAG also noted that withdrawing from Coyote Station could be less expensive than OTP estimates. This is because "all of the scenarios Otter Tail analyzed assume full rate recovery of early termination fees under the LSA and a return on the remaining undepreciated plant balance," which the OAG believes are unreasonable assumptions. For instance, OTP assumed that $21.7 million in LSA early termination costs and a return on Coyote Station's remaining book value will be recovered by ratepayers, and therefore this recovery is part of the PVRR calculation. However, the OAG does not believe these costs should be included in the PVRR, so without them "the case for early withdrawal becomes even stronger."[19]

B. Big Stone Plant

Big Stone is a 475 MW sub-bituminous coal-fired power plant located near Milbank, South Dakota. The plant is co-owned by:

- OTP (53.9%);
- Montana Dakota Utilities Co. (22.7%); and
- Northwestern Energy (23.4%).

In 2015, Big Stone was retrofitted with an Air Quality Control System (AQCS) for SO_2, NO_X, and

[19] OAG comments, p. 9.

mercury control.

According to OTP, Coyote and Big Stone have similar market operating complexities. For example, both plants can be dispatched by either MISO or SPP, and both have contractual obligations that require partners to take their minimum share of the plant whenever another owner calls for dispatch. Additionally, both plants are capable of being placed on economic commitment.

Having said that, OTP noted four key differences between Coyote Station and Big Stone Plant:

1. "Big Stone is a delivered-fuel plant where we only pay for coal that we take—as contrasted with Coyote where we have a fixed component in the fuel cost."

2. "Big Stone's AQCS, with capital intensive state-of-the-art SO_2 and NO_X controls, is already in place."

3. "While the Company would have sufficient capacity resources after withdrawal from Coyote Station, replacing Otter Tail's interest in Big Stone would require the addition of another large dispatchable resource (likely a gas Combustion Turbine)."

4. "Big Stone has recently been operated more frequently on economic dispatch, which reduces the hours it operates in a market below its production costs."[20]

One of the CEOs' criticisms of OTP's modeling is that the Company did not examine any early retirement dates for Big Stone. The CEOs conducted EnCompass modeling which showed that OTP's plan to retain an ownership stake in Big Stone until 2046 is not in the public interest. CEOs' EnCompass modeling shows that exiting Big Stone in 2030 (in addition to exiting Coyote in 2028) and adding more wind and battery storage will cost less, reduce regulatory risk, and greatly reduce externalities compared to OTP's plan to depend on Big Stone until 2046.

C. Astoria Station

Astoria Station is a natural gas-fired, simple cycle combustion turbine (CT), with a summer rating of 245 MW and a winter capability of 286 MW. Astoria Station is located in South Dakota at the intersection of the Northern Border Pipeline and the Big Stone South to Brookings transmission line. The CT was designed with fast-start capability, allowing it to achieve 80% load within 10 minutes of a start command. Astoria is several times larger than OTP's other CTs and has the lowest variable O&M costs.[21] Astoria Station became operational in February 2021.

Prior filings 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

[20] Updated IRP, p. 35.

[21] For generic, H-Class CTs used in its EnCompass modeling, OTP used the same variable O&M as Astoria.

2022. For instance, Uri highlighted intra-day price risk, and during Elliot, OTP was forced to put Astoria Station in a forced outage due to a lack of fuel supply. OTP noted that as a result of this outage, OTP expects MISO to reduce Astoria Station's capacity accreditation by approximately 50 MW for a period of three years. OTP continued:

> 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 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.[22]

The OAG argued that OTP's dual-fuel proposal would increase ratepayer costs while "doing little or nothing to increase Astoria Station's capacity accreditation or improve system reliability." The OAG further argued that the Company's economic analysis "greatly overstates the proposal's benefits as a hedge against high market prices." The OAG cited the Department's December 30, 2022, comments, which concluded that "refurbishing Astoria is not justified solely based on the economic benefits as calculated by OTP."

CEOs recommended the Commission defer a decision on dual fuel at Astoria until OTP's next IRP. CEOs argued that "there is no imminent need for this addition while Otter Tail is still operating two large dispatchable resources." While CEOs recognized that OTP may have a need for firm dispatchable capacity and fuel assurance once it no longer includes multiple large dispatchable generators, this type of "insurance policy" is currently premature.[23]

D. Resource Additions (Solar and Wind)

Throughout various Company-filings, OTP's EnCompass modeling consistently selected roughly 100-200 MW of solar and 100-200 MW of wind in or around the five-year action plan, although the timing varied depending on the sensitivity and inclusion of environmental externalities. Table 3 below shows OTP's three action plans by filing. As noted above, OTP's Minnesota Preferred Plan with AME is OTP's third proposed plan and is the only plan that assigns

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[22] OTP April 3, 2024 comments, pp. 17-18.

[23] CEOs initial comments, p. 91.

Minnesota ratepayers 100% of the cost for renewable resources.

Table 3. OTP Initial Filing Preferred Plan, Action Plan

	Initial Filing Action Plan (9/1/21)[24]	Updated IRP (3/31/23)[25]	MN Preferred Plan with AME (12/15/23)[26]
2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
2024	Provide five-year advance notice of termination of Coyote Station Plant Ownership Agreement by January 1, 2024		
2025	150 MW Surplus Solar	Wind Repowers	Wind Repowers 200 MW Surplus Solar
2026	Onsite Fuel oil at Astoria	Onsite LNG at Astoria	Astoria Onsite LNG 100 MW Generic Wind
2027	100 MW Surplus Wind	100 MW Surplus Solar	
2028	Withdrawal from Coyote Station (-149 MW)	100 MW Surplus Solar	
2029		200 MW Generic Wind	AME at Coyote

Of note, OTP modeled "Wind Repowers"[27] as a fixed unit in all modeling runs; the repowerings do not need any action or approval from the Minnesota Commission in this IRP.

Also, Table 3 refers to "surplus" and "generic" resources. "Surplus" and "generic" are differentiated as follows:

> Surplus interconnection resources are built alongside an existing resource and share the interconnection rights while not exceeding the total output of the existing interconnection.[28]

Because they connect at an existing site and share available interconnection rights, surplus resources are assumed to have no network upgrade cost. For this reason, EnCompass selected surplus solar up to the maximum available surplus interconnection capacity rather than generic

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24 OTP Initial Filing, Table 6-1: Preferred Plan Resource Summary, p. 75.

25 OTP Supplemental Resource Plan, Supplemental Table 3-1 – Supplemental Preferred Plan Summary, p. 7.

26 OTP December 15, 2023 Supplemental Filing, Table 1: Minnesota Preferred Plan with AME, p. 8.

27 The repowered facilities are the Langdon, Ashtabula, Luverne and Ashtabula III wind farms in North Dakota, which are assumed to improve the net capacity factor from roughly 40% to 50% at each wind farm, providing about 167 gigawatt-hours (GWh) of incremental wind output annually.

28 OTP March 31, 2023, Updated IRP, p. 32.

solar.

A "generic" resource is the typical capacity expansion modeling unit that has no location, which is assigned a network upgrade cost, and assumed to go through the MISO queue process.

Under all three plans, OTP proposed surplus solar—meaning OTP assumes additional solar will be located adjacent to an existing site. However, OTP proposed generic wind in the Supplemental IRP and Minnesota Preferred Plan with AME.

II. Changes to OTP's Preferred Plans

In the Initial Filing, OTP stated:

> 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.[29]

In the Supplemental IRP, OTP stated that the Initial Filing's proposal reflected the Company's EnCompass analysis; however, OTP discussed new developments contributing to an uncertain planning landscape that OTP believes warrants continued operation of Coyote Station, such as:

1. MISO's transition to a seasonal resource adequacy construct and capacity requirements that increased planning reserve margins above the quantities included in the Initial Filing;
2. MISO's projection for capacity deficits and recent volatility in energy markets, as well as warnings from MISO, FERC, and NERC about the rapid pace of thermal unit retirements;
3. load additions and changes in Otter Tail's load forecast;
4. the enactment of the Inflation Reduction Act (IRA); and
5. Minnesota's adoption of the 2040 Carbon-Free Standard (CFS).

Considering these factors, OTP believes Coyote Station is needed to provide "a cost-effective hedge against market volatility, unresolved accreditation questions, forecasting uncertainties and related risk of errors, and unforeseen developments."[30]

OTP acknowledged that continued operation of Coyote Station carried certain risks as well, in particular with respect to environmental regulations. Therefore, in light of current planning uncertainties, OTP sought authority 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

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[29] Petition, pp. 6-7.

[30] Updated IRP, p. 13.

facility."[31]

At the January 4, 2024, agenda meeting, the Commission asked OTP to clarify a "material, non-routine capital investment." In the Company's April 3, 2024, comments, OTP explained the distinction between "routine" and "non-routine" capital investments:

- **Routine** capital investments are required to maintain the plant's safety, reliability, and compliance up to the final day of operations even if Coyote Station's operating life were significantly reduced.

- **Non-routine** capital investments may involve investments required to comply with federal environmental regulations, such as Regional Haze standards or the EPA's proposed greenhouse gas rules under section 111(d) of the Clean Air Act.

According to OTP, the Company's December 15, 2023, supplemental filing (Bifurcated IRP Proposal) intended to:

1. inform the Commission of the Company's efforts to balance the interests of the jurisdictions it serves; and
2. propose a bifurcated IRP that implements the Minnesota Preferred Plan with AME.

The Bifurcated IRP Proposal explained that it could designate the Minnesota share of Coyote Station (70 MW) as an Available Maximum Emergency (AME) resource, which would essentially operate the unit as a CT that would dispatch during emergency conditions:

> Through discussions with MISO and the Independent Market Monitor, Otter Tail has identified the Available Maximum Emergency (AME) resource designation in the MISO tariff[32] as a means through which it potentially could limit the dispatch

[31] Updated IRP, p. 11.

[32] MISO Tariff § 39.2.5 states 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 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

> of the approximately 70 megawatts (MW) of Coyote Station capacity attributable to Minnesota customers to emergencies and dispatch it distinctly from Otter Tail's remaining share and that of other owners. These discussions also 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 due to the requirement that such operating limit must be established by regulation.
>
> AME Resources are resources that are called upon only in the event of a Maximum Generation (Max Gen) event, such as in the cases of extreme heat, cold, or other extreme events. If MISO anticipates a capacity shortage, it can declare a Max Gen event, which declaration would call on emergency resources including those with AME status to operate.[33]

Minn. Rule 7843.0500, subpart 3 requires the Commission to consider several factors when evaluating IRPs. Generally, these are reliability, rate and bill impacts, socioeconomic and environmental impacts, utility flexibility, and risk management. The table below lists the evaluation criteria and summarizes OTP's explanation of why the Minnesota Preferred Plan with AME meets each of the Commission's criteria.

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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.).

[33] OTP December 15, 2023 letter, pp. 3-4.

Table 4. Commission Factors to Consider when Evaluating Resource Plans

Evaluation Criteria	Otter Tail Rationale
- maintain or improve the adequacy and reliability of utility service;	- AME designation for the Minnesota-allocated portion of Coyote Station ensures a key capacity resource amid reliability concerns and planning uncertainty. - Dual fuel capability at Astoria Station will provide fuel assurance to ensure the plant can be dispatched even during extreme conditions.
- keep customers' bills and the utility's rates as low as practicable	- AME designation for Coyote Station reduces annual plant variable costs for Minnesota customers.
- minimize adverse socioeconomic effects and adverse effects upon the environment;	- Minnesota renewable resources are needed to comply with the CFS. - Nearly all carbon emissions attributable to the Minnesota-allocated share of Coyote Station will be eliminated.
- enhance the utility's ability to respond to financial, social, and technological changes	- AME preserves OTP's ability to adjust during its energy transition without foreclosing any options or making any irreversible decisions at Coyote Station.
- limit the risk of adverse effects on the utility and customers from factors it cannot control.	- Fuel assurance at Astoria Station provides a price hedge against volatility in energy markets and intraday pricing risk, which was experienced during recent winter storms.

SETTLEMENT AGREEMENT

I. Terms of the Settlement

On April 1, 2024, five parties entered into the Settlement Agreement:

- OTP;
- the Department,
- the Carpenters,
- Local 49; and
- LIUNA.

According to OTP, the Settlement "is intended to resolve all issues among the Parties and provide for a recommended decision to the [Minnesota Commission]."

The terms of the Settlement, Sections A.1 – A.9, are listed below:

A. Recommendations to the Commission

The Parties recommend that the Minnesota Public Utilities Commission approve Otter Tail's Minnesota Preferred Plan with AME as follows:

1. Approve the proposal to operate the MN share of Coyote Station as a capacity resource as soon as is reasonably possible to the extent that the solar resources contemplated in Section A.3, below are available to replace the energy from Coyote Station as follows:

    a. When ordered by the MN Public Utilities Commission, Otter Tail will designate the Minnesota jurisdictional share (as determined by annual allocation process) of Coyote Station's capacity based on the then-in-use jurisdictional allocation methods (approx. 70 MW as of 2023) as an "Available Maximum Emergency" (AME) resource beginning as soon as March 1, 2026.

    b. The costs and benefits of designating and operating the Minnesota Share of Coyote Station as an AME will be borne and received by customers residing in Minnesota. Such costs include the return of and return on rate base, fixed operating and maintenance costs, fixed fuel cost, any variable fuel costs associated with energy dispatched during an emergency, and any lost financial transmission rights attributable to the MN share of energy dispatched from the plant. Such benefits include reduced costs of variable fuel and variable operating 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.

    c. Otter Tail will inform the Commission of the status of solar projects contemplated under this agreement and recommend replacement energy solutions accompanying AME implementation, including hedging options, as necessary until the projects reach commercial operation.

2. Authorize Otter Tail to begin the process of withdrawing from the Minnesota share of Coyote Station if Coyote Station is required to make a material, non-routine capital investment in the plant. OTP will, within 90 days of such occurrence, submit notice to the Commission in a changed circumstance filing which will identify the event creating the need for the filing and a recommendation from Otter Tail with respect to the best option to pursue in light of the changed circumstance. OTP will also annually file with the Commission a listing of all capital projects with a total plant cost over $30 million.

3. Find that the resources specified by Otter Tail in its proposed Minnesota Preferred Plan with AME will help Otter Tail meet its Minnesota's system capacity and Minnesota customers' energy requirements. Further, Minnesota policy supports the addition of additional carbon free energy resources for Minnesota customers on Otter Tail's system beyond those that Otter Tail proposed in its Minnesota Preferred Plan with AME.

Therefore, between 2024-2030, Otter Tail will endeavor to develop the following carbon-free energy projects by the dates described, provided that all costs and benefits of such projects will be allocated to Minnesota customers, only. The carbon free projects are: (a) No less than 200 MW and up to 300 MW of solar resources with a commercial operation date of November 1, 2027, or as soon as practicable thereafter; (b) No less than 150 MW and up to 200 MW of wind resources with a commercial operation date of December 31, 2029 or as soon as practicable thereafter.

4. For renewable resource projects to be allocated solely to Minnesota under this Settlement, Otter Tail will give reasonable preference to projects located in Minnesota.

5. OTP will work with organized labor stakeholders to ensure that resource acquisitions and investments maximize the availability of high-quality employment and career opportunities for local workers by prioritizing investment in the utility's service territory and plant host communities, and the state of Minnesota through the employment of local workers and use of registered apprenticeship programs that have a proven track record of developing local and diverse skilled workforce.

6. Otter Tail will include in its next IRP modeling and resource options including mid and long-duration energy storage systems.

7. Otter Tail's proposal to add on-site LNG storage at its Astoria Natural Gas Facility, a jurisdictionally shared resource, is reasonable and prudent to protect system reliability and provide price protection for customers.

8. Otter Tail will file its next Minnesota IRP no later than May 15, 2026 in which Otter Tail will develop a plan which assumes Otter Tail will withdraw from the Minnesota share of Coyote Station as of December 31, 2031; provided that Otter Tail may present additional plans for consideration based on a comprehensive resource planning analysis.

9. Otter Tail's current resource project selection process results in selection of prudent projects. However, to ensure greater transparency into Otter Tail's resource selection process, Otter Tail will provide in its renewable resource eligibility filings a full narrative description and financial analysis demonstrating that the project selected was competitively superior to other alternatives available to the Company. The Company and DOC shall jointly develop relevant data points and fields for this analysis.

II. Parties Opposed to Settlement Terms

A. CEOs

1. Summary of CEOs' Position

CEOs maintain their position from prior rounds of comments that withdrawing from Coyote

Station by the end of 2028 and Big Stone by 2030 continues to be the best course of action.

Staff provides a summary of the CEOs' main arguments below:

1. **Existing Coyote by 2028 has consistently shown to be least-cost, with or without environmental costs**. According to the CEOs, addressing the Coyote question is the most urgent issue posed by this IRP. The evidence in this record supporting an early exit from Coyote is "abundant and clear."

2. **Battery resources would be cheaper than AME**. The CEOs provided an alternative plan, which is identical to OTP's new AME plan, except that it replaces the Minnesota portion of Coyote Station with 75 MW of battery resources in 2029. Specifically, the "CEO Alternative Plan with Battery" proposes:
    - At least 200 MW of solar resources as soon as feasible, wholly-allocated to Minnesota (the model selects this resource in 2025);
    - At least 150 MW of wind in 2026, but no later than 2029, wholly-allocated to Minnesota;
    - 75 MW of energy storage resources of at least four-hour duration by 2029, wholly-allocated to Minnesota; and
    - Withdrawal from the Minnesota share of Coyote Station by December 31, 2028.

3. **The record on AME is undeveloped**. The evidence in the record supporting AME is insubstantial. Some examples of missing information include:
    - Nowhere in the record has OTP compared its AME Plan to its 2040 Preferred Plan or 2028 Preferred Plan under <u>constant modeling assumptions</u>, which makes it challenging to compare modeling results. The Commission should consider that there is a lack of quantitative evidence supporting AME but a robust record supporting withdrawal from Coyote.
    - OTP did not conduct an hourly, 8760 analysis in EnCompass to calculate GHG emission reductions; OTP merely provided a rough approximation.
    - OTP did not explain why it needs two "insurance policies" at both Astoria and Coyote Station.
    - OTP did not examine alternative capacity resources that could serve the same emergency purposes as AME.
    - There is no certainty surrounding when AME status will begin or end.
    - OTP did not explain how the AME plan addresses the regulatory risk OTP's customers face from continuing to depend on Coyote.
    - OTP did not explore the broader implications of bifurcated system planning.

4. **Otter Tail overstates the benefits and understates the costs of AME**. OTP overstates the benefits of AME – in particular GHG reductions – while understating the risks and costs. According to CEOs, Minnesota customers would still pay "significant operational costs for Coyote under Otter Tail's AME plan."

5. **Bifurcated planning is unnecessary**. Addressing Minnesota's share of Coyote and new Minnesota-only resources does not require system bifurcation as the new default planning practice.

6. **Modifications to the AME proposal are needed**. If the Commission decides to pursue AME, modifications are needed to protect Minnesota customers. CEOs recommend the Commission:
   - Require that OTP seek approval before making any large, non-routine capital expenditure at Coyote Station.
   - Condition any approval on an agreement by OTP to refund any payments by Minnesotans later found to be unjust or unreasonable.
   - Establish back-up requirements in case AME cannot be implemented.
   - Require OTP to begin planning now for resources that will replace Coyote by the end of 2031 at the latest.

2. Where the CEOs Agree on the Settlement

if the Commission decides to approve Otter Tail's AME Plan, the CEOs appear to agree with terms 4, 5, 6, and 9 as worded. The CEOs can support provisions 1a, 2, 3, and 8 with modifications.

- A.1a: OTP's capacity expansion modeling shows that new wind and solar in 2025 and 2026 is least-cost; thus, CEOs recommend an order point that would require AME to begin in 2026 or as soon as replacement renewable energy resources can be brought online.

- A.2: OTP should be required to get pre-approval from the Commission for any large, non-routine capital investment in Coyote Station. CEOs agree that an annual filing documenting capital projects at Coyote is appropriate but question whether the $30 million total plant (e.g., $10.5 million for OTP) threshold is appropriate, or if the cost threshold should be lowered.

- A.3: CEOs support at least 200 MW of solar and at least 150 MW of wind, with all costs and benefits allocated to Minnesota customers only. However, the CEOs recommend two modifications to this term:

    a. The solar addition should be completed as soon as possible, but no later than December 31, 2027, and the wind addition should be ordered to occur as soon as possible but no later than December 31, 2029.

    b. Hybrid projects should be considered.

- A.8: OTP should model Minnesota's withdrawal from Coyote "as a fully explored scenario that is tested against various sensitivities (as opposed to the withdrawal run being one sensitivity performed on a no-withdrawal proposal).”

3. Where the CEOs Disagree

Even if the Commission approves AME, CEOs do not support:

- A.1b: CEOs do not support OTP’s proposed allocation of costs under the AME proposal because Coyote Station has significant fixed costs, and there should be no presumption that Minnesota ratepayers should continue to bear these costs if Minnesota’s share is put on AME designation.

- A.7—CEOs do not support on-site LNG at Astoria, especially if the AME plan is approved.

The CEOs emphasized that if A.1 and A.7 are adopted, Minnesota ratepayers will be required to continue to pay for fixed costs at the Coyote plant and its jurisdictional share of on-site storage at Astoria on top of the entire cost of at least 350 MW of new renewable projects.

B. OAG

The OAG argues three main points:

1. The Commission should not approve OTP’s proposal to designate Coyote Station as an emergency-only resource.

2. Due to the ratepayer risks associated with further investments in Astoria Station, the Commission should impose a hard cap on rate recovery if it approves the Astoria LNG project.

3. The Commission should place certain conditions on the acquisition process for the resources that it approves to help ensure that they are procured at the lowest reasonable cost.

Unlike the CEOs, the OAG did not file reply comments supporting, opposing, or recommending modifications to the terms of the Settlement Agreement. However, the OAG’s comments referred to OTP’s modeling to support their position that an early exit date for Coyote Station was prudent, and the OAG reiterated several ratepayers concerns with the Astoria LNG project.

The OAG explained that the Company’s modeling both in the Initial Filing and Supplemental IRP showed that withdrawing from Coyote in 2028 would be cost-effective under most future scenarios. In the AME filing, OTP failed to compare the cost of AME to other capacity resources; based on the OAG’s review of five other resource options – Coyote with and without AME, Astoria with and without on-site storage, and a generic peaking plant – the OAG found AME to be the most expensive on both a $/MW and $/MWh basis. If Coyote Station is placed on AME status, and if the costs and benefits for replacement resources are to be wholly-allocated to Minnesota ratepayers, the OAG believes this only heightens the importance of a cost-competitive bidding process.

MAIN ISSUES IN THE APRIL 3, 2024 COMMENTS

As noted previously, the Commission's *Notice of Comment Period* set initial and reply comment deadlines at April 3, 2024, and April 17, 2024, respectively. Only OTP, CEOs, and the OAG filed comments in response to the Notice. In this section, Staff will elaborate on some of the key issues mentioned in the previous section.

I. Need for Jurisdictional System Planning

OTP pointed to differences in modeling requirements, North Dakota law prohibiting the consideration of externalities and Minnesota law requiring them, and Minnesota's adoption of the CFS as reasons why bifurcated, jurisdictional system planning is needed.

OTP also attached to their April 3, 2024, comments an evaluation report of OTP's IRP conducted by CDG Engineers' (CDG) for the North Dakota Public Service Commission (ND PSC). CDG does not recommend any resources to be added in the five-year action plan (2024-2028).[34]

CEOs do not believe that approval of a resource plan with the AME Plan requires bifurcating the planning process from here on out, as Otter Tail suggests. According to the CEOs:

> System-wide modeling can provide a baseline for the Commission and parties to understand the scale of need overall, and the most cost-effective tools to achieve it. If concerns about jurisdictional cost allocation persist, systemwide modeling can be compared with state-specific modeling that more accurately reflects state policy. To resolve this issue in this IRP, <u>CEOs suggest that the Commission direct Otter Tail to engage with the Department of Commerce and other parties prior to the filing of its next IRP</u> to discuss how best to ensure a resource plan that recognizes the ongoing jurisdictional differences between the states but that also provides complete information regarding the Company's resource needs and planning direction.[35]

The OAG did not take a position on whether OTP should adopt bifurcated system planning for future IRPs, but the OAG expressed concerns that "all replacement resources [for Coyote Station] will be paid for solely by Minnesota ratepayers,"[36] while Minnesota could have to pay

[34] CDG recommends the ND PSC: 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; and model the system with Coyote Station through 2040. Additionally, CDG determined that the first year that requires additional capacity is 2029. Also, OTP's resource options are limited and could be supplemented by smaller dispatchable options.

[35] CEOs comments, p. 19.

[36] OAG comments, p. 16.

for two other fossil fuel resources that are not needed or prudent.

II. Minnesota Preferred Plan with AME

Table 5 shows OTP's proposed expansion plan under the Minnesota Preferred Plan with AME. Note that the Minnesota solar and wind appear in 2025 and 2026, respectively, while AME status begins in 2029.

Table 5. Minnesota Preferred Plan with AME

Year	Resource Addition
2023	Hoot Lake Solar
2024	
2025	Wind Repowers 200 MW Surplus Solar
2026	Astoria on-site fuel 100 MW Generic Wind
2027	
2028	
2029	AME at Coyote
2030	
2031	
2032	50 MW Generic Wind
Total Wind	**150 MW**
Total Solar	**200 MW**

The renewable resource additions will enable CFS compliance with limited reliance on REC purchases, which OTP claims is important because the Company "lacks a carbon-free baseline provided by nuclear generation or significant hydro-electric generation."

OTP assumes Coyote Station will be called upon as an AME resource 20 hours per year.
To calculate avoided CO_2 emissions, OTP compared 20 hours of operation to Coyote Station's average historical capacity factor of 65%. Under these assumptions, OTP estimates energy output at Coyote Station will be reduced by 400,000 MWh annually, which equates to 488,000 tons of avoided CO_2 per year.

OTP believes that as an AME resource, Coyote Station will insulate Minnesota customers from several risks. OTP's April 3, 2024, comments describe how AME at Coyote Station will mitigate:

- Energy price risk;
- Capacity price risk;
- Environmental risk;
- Regulatory cost risk;
- Jurisdictional dispute risk; and

- Commercial risk.

Staff notes that the CEOs' reply comments addressed OTP's claims about how Coyote Station will benefit ratepayers as a risk management strategy. In the table below, Staff summarizes OTP's discussion and the CEOs' response.

Table 6. Coyote Station and Risk Management

	OTP	CEOs
Energy price risk	LMPs will likely 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.	Replacing Minnesota's share of Coyote with a 75 MW battery resource provides sufficient energy availability in peak winter conditions, including days with low wind output. CEOs modeled a four-hour lithium-ion battery, and EFG's production cost analysis demonstrated that the CEOs' plan provided enough energy to meet OTP Minnesota customer demand in each hour, even in challenging winter conditions.
Capacity price risk	Keeping Coyote Station as an AME resource will provide Minnesota customers with an additional 60-70 MW of capacity credit, which is increasingly valuable given the accreditation rule changes contemplated by MISO.	Battery storage may maintain or increase Otter Tail's winter season accredited capacity relative to AME under MISO's new Direct Loll-of-Load (DLOL) accreditation method.[37]
Environmental risk	Offering Minnesota's share of Coyote Station as an AME resource will avoid approximately 488,000 tons of CO_2 emissions annually.	The CEOs found that AME will lower emissions by only 277,000 tons of CO_2 per year, approximately a 9% reduction at the plant. The CEOs used "hourly generation over three historical years," whereas OTP used "annual estimated capacity factors." In other words, OTP calculated AME impacts by using "an across-the-board decrease," which is not how AME will work. CEOs continued that delaying plant's retirement even by one year could outweigh emissions reductions resulting from AME over the remainder of Coyote's life.
Regulatory cost risk	The Commission's CO_2 regulatory cost range is \$5 - \$75 per ton starting in 2028. Using the mid-	OTP did not acknowledge the "imminent regulatory cost risks facing Coyote Station" on regional haze, the GHG Power Plant Rule, and

[37] The CEOs cited MISO's final DLOL proposal for Planning Year 23-24 in which storage resources could receive a 91% class-average accreditation compared to 73% for coal, which the CEOs claimed was reflective of the relatively poorer performance of coal resources in the winter.

	point of $40 per ton, the estimated CO_2 emissions reduction will save ratepayers roughly $16 million.	the MATS rule.
Jurisdictional dispute risk	Designating the Minnesota share of Coyote Station limits the jurisdictional conflict and potential interstate litigation.	The CEOs did not ask the Commission to order a full withdrawal from Coyote Station. The CEOs recommend "that the Commission approve withdrawal from the Minnesota portion of Coyote as part of Otter Tail's resource plan for serving its Minnesota customers," which "is what Otter Tail originally sought in this proceeding as well."
Commercial risk	Any scenario where OTP is required to exit the plant by a date certain increases the risk of contractual claims and disputes.	OTP's business risks associated with Coyote Station "are not the responsibility of Minnesota customers or regulators to resolve," and it was OTP's decision in 2012 to enter into a long-term LSA for Coyote without the Commission's approval. Moreover, the CEOS "challenge the presumption that its customers must pay for risks that Otter Tail unilaterally took on."

Overall, the CEOs do not believe that AME is a substitute for withdrawal from Coyote Station. Rather, it is a means of delaying withdrawal, at a cost to Minnesota customers. The CEOs cite at least three problems with deferring a final decision on an exit date at Coyote:

1. OTP's modeling demonstrates that the longer that Minnesota ratepayers are tied to the plant, the more they will pay;

2. The longer a decision on Coyote's end date is deferred, the more likely it is that a withdrawal or retirement decision will have to be made on short notice and with potentially greater ramifications for ratepayers;

3. Deferral to the next IRP will only mean the Commission has to consider the same evidence and arguments again in the next IRP process.

To elaborate on the CEOs' first claim listed above, the CEOs provided the following table showing the PVRR of three scenarios: (1) No-Coyote, No-AME; (2) designating the Minnesota share of Coyote as AME from 2029-2031, withdrawing thereafter; and (3) designating the Minnesota share of Coyote Station on AME through 2040. The results show that No-Coyote, No-AME is the least expensive, and the incremental costs of AME through 2031 is $25 million. The most expensive scenario was AME through 2040, which resulted in $70 million in incremental costs.

Table 7: Minnesota Customers' Costs of Coyote Plans (PVRR, $mil, excluding CO_2 regulatory costs)

	No AME, withdraw 2028	AME 2029-2031, then withdraw	AME 2029-2040, then withdraw
Portfolio PVRR (2023-2050, $mil)	$1,249	$1,274	$1,319
PVRR compared to 2028 exit (2023-2050, $mil)		+$25	+$70

The CEOs stated that these results are not surprising given the consistent modeling finding "that the longer Minnesota customers are involved in Coyote Station, the more they will pay for electricity."

The CEOs found that AME is also more expensive than alternative resources which perform similar functions. The CEO's compared the cost of continuing to operate 70 MW of Coyote Station as an AME resource against four available capacity resources or hedges – a new CT, MISO's planning auction, a recent capacity purchase made by OTP, and battery storage – and the CEOs determined that AME is the most expensive of these options.

III. CEOs Alternative Minnesota Preferred Plan with Battery

According to the CEOs, the CEO Alternative Plan with Battery (1) is cheaper than OTP's AME Plan, (2) provides the same (and potentially more) winter accredited capacity, (3) meets OTP's peak winter energy needs in every hour, and (4) is aligned with Minnesota policy.

CEOs asked its experts at Energy Futures Group (EFG) to develop a plan with the same resource additions as OTP's Minnesota Preferred Plan with AME, except OTP would exit from the Minnesota portion of Coyote by 2029 and add 75 MW of four-hour duration battery resources. Note that while the CEOs continue to believe that the best course of action is for OTP to also exit Big Stone by 2030, for the purposes of AME-specific modeling, the CEO Plan with Battery scenario kept Big Stone as an operational unit.

EFG's EnCompass results demonstrate that the Alternative CEO Plan with Battery is slightly cheaper on a PVRR basis than AME, even before considering either externalities or CO_2 regulatory costs. While the cost difference is not large – just 1.6% – what the modeling shows is that replacing Coyote's capacity MW-for-MW with a battery is likely to be cost-neutral or result in cost savings for customers, and it would shift to a carbon-free resource that will deliver long-term reliability benefits.

Importantly, EFG found that the CEOs Alternative Plan with Battery can meet OTP's peak demand needs <u>in every hour even during extreme conditions</u>. EFG examined the hourly dispatch of the Minnesota portion of OTP's system on the two peakiest winter days in 2029, assuming one peak day (on January 12, 2029) with strong renewable energy generation and a second peak day (on January 26, 2029) with low renewable energy generation. On both days, the Alternative CEO Plan with Battery can meet the energy needs of OTP's Minnesota customers <u>with owned resources</u> in every hour.

The CEOs added that the record remains underdeveloped since the Company first proposed AME on December 15, 2023, which "contained no modeled analysis of the financial, environmental, or reliability impacts of the AME plan as compared to the other plans that Otter Tail itself or CEOs have put forward."[38] According to the CEOs, the CEOs analysis "remain[s] the most robust quantitative analysis of the Company's AME proposal and alternatives in this proceeding."[39]

OTP refuted the CEOs' analysis on several fronts:

First, OTP argued that "[t]here are no material cost savings resulting from the CEO Alternative Plan with Battery, but it would expose Minnesota customers to numerous risks, specifically during long-duration emergency events."

Second, OTP argued that the CEOs' PVRR analysis failed to capture the insurance value provided by Coyote Station with AME, among other benefits.

Third, OTP disagreed with the CEOs that battery storage will maintain or increase winter season accredited capacity relative to AME. OTP contended that "[t]he CEOs battery claims do not account for future MISO accreditation changes that are likely as more wind and solar come on-line."[40] The CEOs' DLOL battery storage capacity accreditation analysis considers only the 2023-2024 Planning Year, but long-term battery resource accreditation could decline significantly.[41]

OTP continued that a 2028 withdrawal is infeasible, since OTP does not have a unilateral ability to withdraw and would require "termination of the plant ownership agreement on five years advance written notice."[42] Moreover, any transfer or sale of the Minnesota share of the plant could result in unfavorable terms, and transferring the Minnesota-allocated portion of Coyote to North Dakota "requires consent and approval of the North Dakota Public Service Commission, which is not assured."[43]

[38] CEOs April 3, 2024 comments, p. 20.

[39] CEOs April 17, 2024 reply comments, p. 2.

[40] OTP reply, pp. 4-5.

[41] Otter Tail showed MISO estimates five-years out (2027) and ten-years out (2032) under both the current and proposed DLOL accreditation methodology to show that battery storage may have a higher winter accreditation initially, but over time it is forecasted to decrease significantly. This occurs due to longer expected unserved energy events occur, which limit the assumed 4-hour ability to fully charge and discharge across the duration of events.

[42] OTP reply, p. 9.

[43] OTP reply, p. 9.

IV. Financial Issues

A. Coyote Station

OTP emphasized that its Minnesota Preferred Plan with AME is not a separation of its system. OTP stated that "[t]he 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." OTP added that the AME proposal "does not preclude future shared resources when need and timing align among our jurisdictions."[44] The graphic below depicts how resources are shared currently and under the AME proposal. Hoot Lake Solar is currently the only resource wholly-allocated to Minnesota.

Figure 1. Current

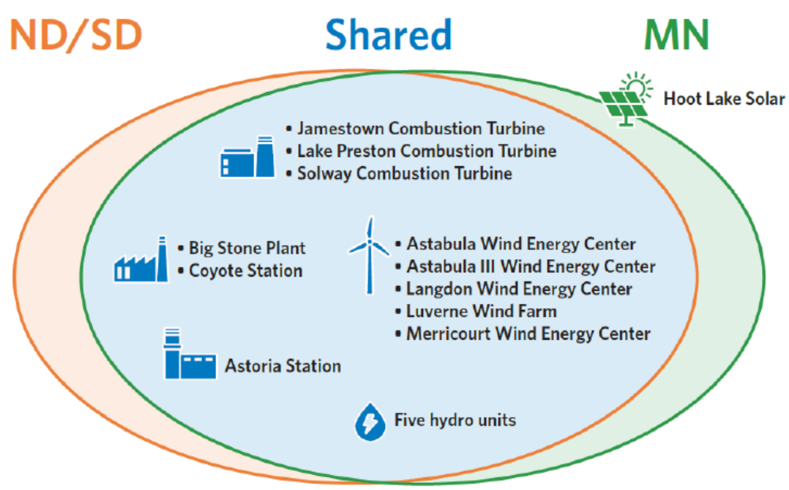
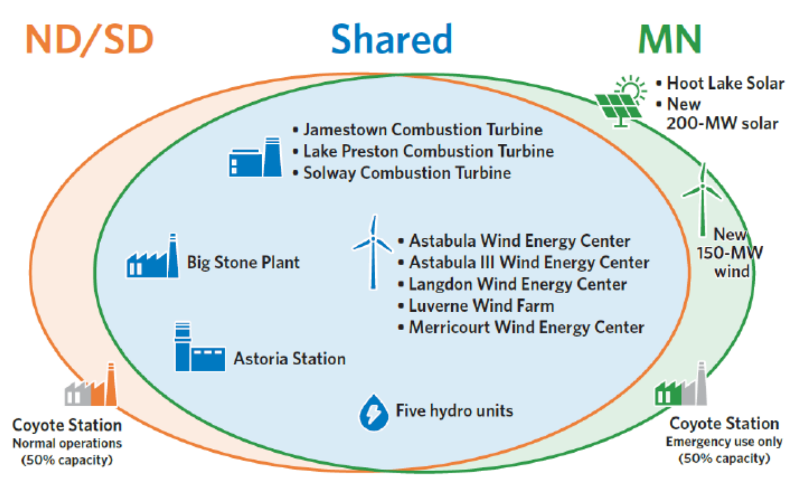


Figure 2. Shared



44 OTP April 3, 2024 comments, p. 6.

According to OTP, "[t]he MISO energy and capacity markets provide the tools necessary to accurately track the costs and benefits of individual resources."[45] Because each resource in MISO has its own generation pricing node that clears at its own unique locational marginal price (LMP) for each hour, OTP will be able to track and account for the costs and benefits associated with each resource in the Minnesota Preferred Plan with AME.

As discussed previously, Coyote Station is currently offered into the MISO market distinctly by each owner for their share of the total plant. Under the Minnesota Preferred Plan with AME, OTP will establish an additional commercial pricing node for the OTP-MN share of Coyote Station, which will be offered as an AME resource. This will allow "for clear dispatch signals and clear accounting for any potential hours when MISO calls for AME resources to operate,"[46] and the OTP-MN share can be "accounted for distinctly from the OTP-Dakota's share."

Energy costs and revenues of existing resources will continue to be allocated to each jurisdiction through the same process already in place. Under the Minnesota Preferred Plan with AME, "<u>all energy revenues</u> received from resources that are <u>wholly allocated to Minnesota</u> will flow back to Minnesota customers <u>through the Minnesota fuel clause</u>."

Minnesota customers will also receive capacity payments for the Minnesota-allocated share of existing resources (including Coyote Station) and <u>100% of the capacity payments for new renewable resources</u> wholly-allocated to Minnesota.

A breakdown of what Minnesota customers will pay versus what they receive under the Minnesota Preferred Plan with AME is shown in the table below.

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[45] OTP April 3, 2024 comments, p. 14.

[46] OTP April 3, 2024 comments, p. 9.

Table 8. Breakdown of what Minnesota Customers will Pay and Receive under AME Plan

	Minnesota customers will pay	Minnesota customers will receive
Capacity	- Minnesota's share of the PRM requirement at the capacity auction clearing price	- Capacity payments for the allocated share of Coyote Station - Capacity payments for 100% of the new renewable resources identified in the Minnesota Preferred Plan with AME. Capacity revenue from renewables will go through the Minnesota fuel clause.
Energy	- Costs associated with maintaining and operating the plant as an AME resource, including a return of and return on rate base, fixed O&M costs, and fixed fuel cost. - Variable fuel costs associated with energy dispatched during an emergency. - Lost FTRs attributable to the MN share of energy dispatched from the plant.	- Reduced costs of variable fuel and variable O&M costs for energy not dispatched due to AME - MISO market revenues and FTRs when Coyote Station is dispatched

The OAG does not support the AME proposal since "the available evidence suggests that a 2028 exit would be more beneficial to ratepayers and to society than placing Coyote Station on AME status." However, the OAG suggested that the Commission could lessen the ratepayer impact by "limiting the fixed fuel costs that Otter Tail recovers through rates." Because fuel-cost recovery is beyond the scope of this docket, the Commission could:

1. refer the reasonableness of Coyote Station's fuel costs to an appropriate docket, such as Otter Tail's annual fuel-clause docket or

2. allow interested parties to raise the issue in an appropriate proceeding.

CEOs proposed several Minnesota ratepayer protections in the event the Commission approves OTP's AME proposal:

1. **Require Otter Tail to seek prior Commission approval of any large, non-routine capital investment in Coyote Station.** The CEOs believe this is appropriate because OTP has not made any commitment or guarantee that Minnesota ratepayers will not bear these costs if the co-owners or other jurisdictions prefer to pay to keep the plant operational.

2. **Require Otter Tail to explicitly agree to refund to its Minnesota ratepayers any charges made under the AME proposal that the Commission finds in a future rate case or other**

proceeding to have been unjust or unreasonable. The CEOs argued that "the Commission cannot make an unqualified presumption that the costs Minnesotans would incur under the AME proposal are just and reasonable. There is simply no support for it in this record and, there is substantial evidence that requiring Minnesota to continue to pay all Coyote's operational costs other than its variable costs would be unjust and unreasonable, particularly given the high level of fixed costs. Putting the burden on Otter Tail to remedy any overcharge is appropriate given the lack of evidence supporting the economic prudence of this proposal."[47]

3. **Establish back-up requirements in case the AME proposal cannot be implemented.** Otter Tail acknowledges the possibility that the proposal may prove impossible to implement, and Otter Tail will conduct a fatal flaw analysis to ensure that the AME designation can be implemented as envisioned. The problem is that Otter Tail has offered no alternative in the event that AME cannot be implemented. The CEOs recommend that Otter Tail submit a filing within four months of the date of its order in this docket with the results of the fatal flaw analysis, including formal written approvals by the IMM, MISO, and Coyote's co-owners.

4. **Require AME to commence as soon as feasible, at least seasonally.** CEOs argued that it would be in Minnesota customers' benefit if AME could be deployed sooner than 2029 and that the replacement solar and wind could be brought online as soon as possible.

    a. Staff notes that OTP's response to PUC Information Request No. 7 stated that it would be possible to place a partial OTP share of Coyote Station under AME on a seasonal basis <u>in 12 months or less</u>. However, because replacement energy would be needed at least in the summer and winter (OTP expects it can cover spring and fall energy needs over the next five years), OTP would need to implement AME <u>on a seasonal basis until 2027</u>, once the solar and wind are in-service.

5. **Require Otter Tail to plan for adding resources to replace Coyote Station by December 31, 2031 at the latest.** The CEOs argued that until Otter Tail exits from Coyote Station, "Otter Tail's Minnesota customers remain partially dependent on an aging coal plant likely to face major capital costs in order to stay open."[48] The Commission should find that, regardless of whether AME is implemented, it would not be reasonable or in the public interest for Minnesota ratepayers to continue to pay for or depend on Coyote Station beyond 2028.

B. Astoria Station

The OAG expressed concerns over such a significant investment in Astoria Station, a new fossil

[47] CEOs comments, p. 39.

[48] CEOs comments, p.

fuel facility, which the OAG argued could face stranded cost risk if the plant needed to retire early. The OAG noted that Astoria will not be fully depreciated until 2056, and the onsite storage upgrades (assuming a minimum design life of 30 years) may not be fully depreciated until 2057. The OAG argued that OTP did not address the unrecovered plant balance that will remain if Astoria is forced to retire earlier than planned, if, for example, future regulations make gas-fired peaking plants like Astoria cost-prohibitive.

The OAG recommends that if the Commission approves the Astoria LNG project:

> it should make clear that approval here does not guarantee Otter Tail full recovery of its investment if Astoria Station retires early; rather, post-retirement recovery will be addressed in a future rate case if the plant has to be abandoned before the end of its useful life. Further, if the project is approved, the Commission should cap the costs that may be recovered from ratepayers.[49]

The Commission should require Otter Tail to <u>implement a hard cap on recovery of capital costs, with a 90/10 sharing of any savings below the cap</u>. This means that Otter Tail will absorb cost overruns, but if the project comes in under budget, 90% of the savings are shared with ratepayers, and 10% of the savings are retained by the Company.[50] The OAG believes this is reasonable because Otter Tail's current cost estimate has already been increased so significantly since the proposal was first introduced in the Initial Filing.

OTP objected to the OAG's recommendation, stating it "is effectively a request to (1) eliminate or significantly limit the rebuttable presumption of prudency that normally attaches to projects approved in an IRP order, and (2) inappropriately incorporate a hind-sight prudency analysis to the project." While OTP acknowledged that circumstances can change, the OAG's recommendation would "condition the approval of a project with the explicit risk of non-recovery should future circumstances limit the life of a resource." OTP continued:

> Utilities need reasonable assurance of recovery when projects are approved. If approval and rate recovery came with significant caveats dependent on future events few projects could ever proceed.

OTP also opposed the OAG's recommended hard cap proposal and 90/10 shared savings mechanism:

> The OAG's hard cap proposal is unreasonable and unworkable. Assuming for analysis that Otter Tail put the Astoria Station LNG Fuel Storage Project into service below the project cost approved by the Commission (i.e. under budget), Otter Tail would have no basis to seek recovery for project costs it did not incur,

[49] OAG comments, p. 11.

[50] OAG comments, p. 12.

> and there would be no savings for Otter Tail to retain or distribute to customers. Otter Tail's customers would receive the full benefit of the under-budget cost from the fact there would be fewer project costs to recover. On the other hand, if project costs exceed the hard cap, Otter Tail would not have the ability to demonstrate to the Commission that those costs, while more than the initial projected cost, are nevertheless necessary and prudent, as would be the case in if a soft cap was in place. There is no basis to adopt the hard cap proposed by the OAG.

V. Resource Acquisition Process

The OAG stated that OTP's proposal to wholly allocate costs of renewable resources to Minnesota "heighten[s] the importance of a carefully designed procurement process to protect ratepayers from paying too much for Coyote's replacement resources."[51]

The OAG supported the Department's proposal outlined in their initial comments, which recommended "that the Commission approve a bidding process for OTP's future resource acquisitions that are larger than 100 MW and last longer than five years."[52] The OAG recognized OTP's opposition to a formal process in previous comments, especially over (1) the need to create an internal firewall between the bid selection and bid review teams if submitting a company bid and (2) the use an independent auditor, but the OAG believes these are two necessary steps to a neutral process.

OTP responded that a flexible, competitive process will allow the Company to take advantage of opportunities as they arise and adjust to market changes. Also, as a small utility, OTP "lacks the market presence" of other Minnesota investor-owned utilities that regularly evaluate significantly more projects than OTP does, and OTP generally has relatively few projects to evaluate.

Staff notes that at the January 4, 2024, agenda meeting the Commission asked OTP about bidding out components for the Astoria LNG project. Therefore, Staff asked OTP to describe how the components for the Astoria LNG project will be bid out. OTP responded:

> Otter Tail intends to execute the project with two major procurements. One procurement will be for the supply and installation of all equipment and materials and the other will be for a fuel supply.
>
> As part of the development of the project, a significant amount of engineering and evaluation, such as geotechnical investigations and pipeline sizing, has been completed. This amount of engineering will allow Otter Tail, with support from the same development engineer consultant, to develop a request for proposal

[51] OAG comments, p. 16.

[52] Department September 13, 2023 comments, p. 35.

> package that will be bid on a fixed price basis. No less than three bidders will be utilized during the bidding phase and Otter Tail has been engaged with potential bidders throughout development to ensure there is interest in the project.
>
> The fuel supply will also be competitively bid, and Otter Tail has been engaged with potential bidders for the fuel supply. Otter Tail intends to request proposals for the fuel supply early in the project before the first planned delivery. This approach will allow the potential bidders to acquire delivery equipment or upgrade production facilities as required to serve Otter Tail's needs on a reasonable timeline, thus ensuring the most cost-effective bids.[53]

Consistent with OTP's response above, the OAG recommends that OTP must use a minimum of three bidders for both major components of the project (equipment and fuel).

STAFF DISCUSSION

As noted in the Introduction section, the December 20, 2023, Staff briefing papers included a summary of OTP's Initial Filing and Supplemental IRP, party comments, and Staff analysis, and Staff will not repeat that analysis here. Instead, Staff will refer to relevant portions of the December 20, 2023, briefing papers where applicable to these Decision Options.

Also, the organization of the discussion below tracks the organization of Sections A.1.-A.9. of the Settlement Agreement, which, generally stated, recommend the Commission:

1. approve the Minnesota share of Coyote Station as an AME resource.
2. authorize OTP to begin the process of withdrawing from the Minnesota share of Coyote Station if Coyote Station is required to make a material, non-routine capital investment.
3. find that the resources in the Minnesota Preferred Plan with AME, including 200-300 MW of solar by 2027 and 150-200 MW of wind by 2029, are required to meet the CFS.
4. allocate the costs and benefits of renewable resource projects solely to Minnesota.
5. have OTP work with organized labor stakeholders when developing the projects.
6. have OTP include mid- and long-duration resource options in its next IRP modeling.
7. approve on-site LNG storage at its Astoria Natural Gas Facility.
8. set a deadline for OTP's next Minnesota IRP no later than May 15, 2026.
9. find that OTP's current resource selection process results in prudent projects.

I. Sections A.1 and A.2: Coyote Station as an AME Resource

Setting aside for the moment the merits of the Settlement, Staff believes that the Settlement fails to capture many of the nuances of the record that would be useful and informative to future Commission proceedings. Therefore, Staff believes it would be helpful for the Commission's order to include findings of fact that could be used when referring back to this

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[53] OTP response to PUC Information Request No. 8.

IRP process at a future time. Also, based on the analysis in the record, Staff believes it would be appropriate for the Commission to authorize OTP to take multiple actions at Coyote Station, rather than include OTP's proposal which merely contemplates possibly beginning a process at some point in the future.[54]

Specifically, Section A.2 of the Settlement asks the Commission, in part, to:

> Authorize Otter Tail to begin the process of withdrawing from the Minnesota share of Coyote Station if Coyote Station is required to make a material, non-routine capital investment in the plant …

This language merely asks the Commission to authorize (not require) OTP to begin a process (not take a specific action) at Coyote in the event an unspecified "material" and "non-routine" investment is required in the future. In addition, or as an alternative, to this excerpted portion of Section A.2, the Commission could adopt a more specific, direct finding that better reflects the quantitative analysis across the full record, but does not rise to a requirement that may encounter jurisdictional problems.

Since the modeling in the record so heavily favored a Coyote early exit scenario, the Commission could simply add "authorize Otter Tail to withdraw from Coyote Station by 2031" (with 2031 accounting for the fact that a 2028 exit is infeasible due to the five years' advance notice under OTP's Plant Ownership Agreement) to its decision. This could be a clearer way of stating that the record supports a Coyote withdrawal without requiring OTP to divest from the plant.

A. Commission Findings and Conclusions

Minn. R. 7843.0500, subp. 1 (Commission Review of Resource Plans) states, in part, that when issuing a decision, the Commission should include findings of fact and conclusions:

> **Subpart 1. Decision.**
>
> Based upon the record, which is the information filed with the commission in the resource plan proceeding of a utility, including responses to information requests, the commission shall issue a decision consisting of findings of fact and conclusions on the utility's proposed resource plan and the alternative resource plans . . .

Minn. R. 7843.0600, subp. 2 (Relationship to Other Commission Processes) states the facts and conclusions in the Commission's decision constitutes *prima facie* evidence in related Commission proceedings:

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[54] Staff notes that OTP is unique in its preference that the Commission to use the word "authorize" in its order, rather than the "require," which is the norm for Xcel and Minnesota Power.

> **Subp. 2. Resource plan findings of fact and conclusions.**
>
> The findings of fact and conclusions from the commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related commission proceedings, including, for example, rate reviews, conservation improvement program appeals, depreciation certifications, security issuances, property transfer requests, cogeneration and small power production filings, and certificate of need cases. In those proceedings, the commission's resource plan decision constitutes *prima facie* evidence of the facts stated in the decision. This subpart does not prevent an interested person from submitting substantial evidence to rebut the findings and conclusions in another proceeding.

Staff agrees with the CEOs and OAG that the quantitative analysis supporting AME is limited at best, especially when compared to the robust modeling supporting the Coyote early exit scenarios. As Staff stated in the December 20, 2023, briefing papers, while OTP's concerns regarding seasonal resource adequacy and contractual complexities with other Coyote co-owners are reasonable, there is a dubious ratepayer benefit of operating Coyote over the long-term (which OTP recognizes), and the plant has unquestionable adverse effects on the environment:

> Staff believes the following conclusions can be drawn based on the record:
>
> - The economic case for continuing to operate Coyote Station is not persuasive. In both the No Externalities and Externalities Included modeling runs, and in both the Initial Filing and the Updated IRP, the majority of sensitivities indicate that exiting Coyote sooner rather than later is least-cost.
> - The risk of environmental compliance costs at Coyote Station is very high, and under no scenario does investing in environmental controls appear to be cost-effective.
> - Even though Coyote Station is located in North Dakota, public health concerns apply to Minnesota.
> - However, OTP demonstrated that it faces a capacity risk under the SAC to meet its winter and spring PRMR. Additionally, Staff believes OTP raised important considerations regarding OTP's share of the foreseeable withdrawal costs at Coyote Station, which include undepreciated net book value and early termination costs under the LSA.

Below, Staff will briefly summarize these four bullet points.

1. No-Externalities and Externalities-Included Sensitivities

Regarding the No-externalities and Externalities-included modeling runs, OTP compared in EnCompass its Preferred Plan under a 2028 Coyote exit to 2040 Coyote exit with and without environmental externalities. OTP's results found that the 2028 Coyote exit was less expensive than the 2040 exit by $40 million without externalities. When externalities were included, the 2028 Coyote exit was less expensive than the 2040 Coyote exit by $113.3 million. The table below shows values from Appendix I of OTP's Supplemental IRP:

Table 9. PVRR Comparison of 2028 Coyote Withdrawal to 2040 Continued Operation

No Externalities	**Preferred Plan (NPVRR, $000)**	**2028 Difference from 2040 Exit NPVRR ($000)**
Withdraw from Coyote 12/31/2040	$2,764,110	
Withdraw from Coyote 12/31/2028	$2,724,103	-$40,007
Externalities	**Preferred Plan (NPVRR, $000)**	**2028 Difference from 2040 Exit NPVRR ($000)**
Withdraw from Coyote 12/31/2040	$3,312,474	
Withdraw from Coyote 12/31/2028	$3,199,210	-$113,264

At the January 4, 2024, Commission meeting, OTP noted that one reason for the jurisdictional disagreement on optimal resource plans was that OTP's base case did not include any renewable additions in the 2020s. While it is true that the base case delayed the acquisition of renewables, Staff notes that according to OTP's modeling results from Appendix I, the No-externalities base case showed that the 2028 Coyote exit was still less expensive than the 2040 Coyote exit (by $28.2 million), and the base case still added 325 MW of surplus solar and 200 MW of wind in 2032. In other words, regardless of the inclusion of externalities, the least-cost path forward generally included an early exit from Coyote paired with a combination of solar and wind.

2. Environmental Regulatory Compliance Risk

Regarding environmental regulatory compliance risk, the December 20, 2023, Staff briefing papers also noted that OTP's base assumption was that Regional Haze compliance costs and CO_2 regulatory costs are zero, but according to OTP's sensitivity analysis:

> the Company quantified Regional Haze and CO_2 regulatory costs, and under every scenario, with and without externalities, withdrawing from Coyote by 2028 was least-cost, and savings ranged from roughly $84-$179 million [as shown by the table below]:

Table 10. PVRR Comparison of Regional Haze and CO_2 Cost Scenarios to Preferred Plan

	Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
Scenario Name	**No Externalities Included**	**Externalities Included**
Preferred Plan	($40,007)	($113,264)
Regional Haze (RH) Mid Cost	($83,982)	($155,499)
RH High Cost	($103,845)	($179,189)
Carbon Tax	($134,913)	

Staff then quoted the CEOs' comments, which stated that OTP ignored the EPA GHG Power Plant Rule and MATS even though:

- In 2021, Coyote Station emitted SO_2 at a rate at least <u>eight times</u> higher than any coal plant in Minnesota or South Dakota.
- In 2021, Coyote Station emitted NO_X at a rate at least <u>three and a half times</u> higher than any coal plant in Minnesota or South Dakota.[55]
- In 2022, Coyote Station emitted mercury at a rate approximately <u>three to five times</u> higher than any other coal plant in Minnesota and South Dakota.
- The EPA proposes reducing allowable mercury emissions from lignite-fired plants to 1.2 lb/TBtu, which is well-below Coyote's 2022 emission rate of 2.28 lb/TBtu.[56,57]

3. Public Health Impacts

Regarding adverse effects on the environment and public health, the December 20, 2023, Staff briefing papers stated:

> Attachment 2 to CEOs' initial comments is the PSE health and equity report (PSE Report), which describes the human health impacts from continuing to operate Coyote Station and Big Stone. According to the CEOs, PSE found that Coyote Station emits significantly more NO_X, SO_2, and $PM_{2.5}$ than Big Stone – in fact,

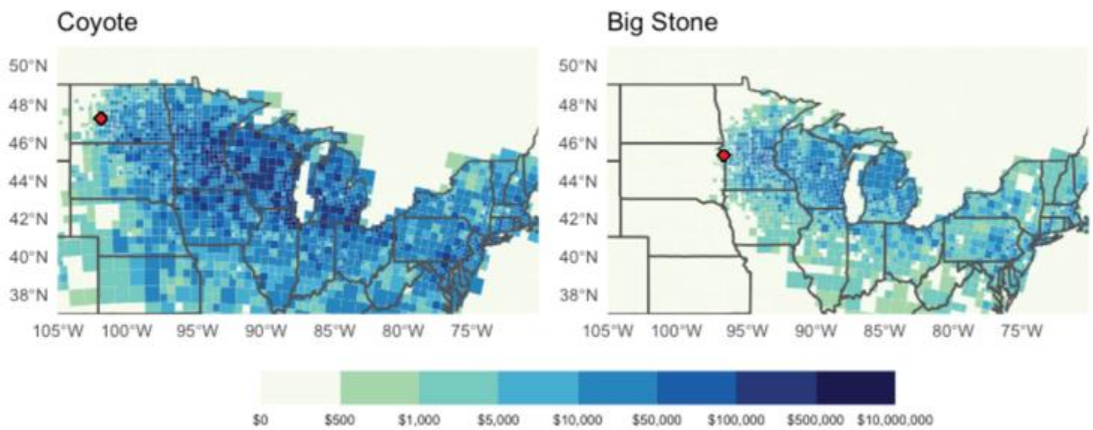
55 CEOs initial comments, p. 32.

56 CEOs initial comments, p. 35.

57 88 Fed. Reg. 24,857.

twenty times more SO_2 and $PM_{2.5}$.[58,59] PSE also found that public health impacts from both plants extend across multiple states. As shown below, "it is clear that although neither coal plant is located in Minnesota, Minnesotans are unquestionably bearing the adverse health consequences of the continued operation of these plants."[60]

Figure 3. Annual total $PM_{2.5}$ public health impacts of Coyote Station and Big Stone



With these facts in mind, one question before the Commission is whether the Settlement Agreement sufficiently captures this record evidence so that it can be used as "evidence in related Commission proceedings." From Staff's perspective, more is needed to inform future Commission proceedings, especially because Staff believes OTP overstates the extent to which Coyote early exit and replacement renewables is due to the CFS and environmental externalities in IRP modeling; neither the Settlement, nor OTP's April 3, 2024, comments recognize the broad range of no-externalities cases in which exiting Coyote was least-cost or the financial risk involved with continuing to operate a high-polluting, aging coal plant that will be 60 years old by 2040. Therefore, Staff offers some findings that may be included in the Commission's decision:

- OTP's modeling showed that withdrawing from Coyote Station in 2028 was less expensive than continuing to operate the plant until 2040 under 15 out of 22 No-Externalities scenarios and 22 out of 22 Externalities-included scenarios.[61]

- All of OTP's Regional Haze and CO_2 regulatory cost modeling scenarios in the Initial Filing

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[58] This is because Coyote burns lignite coal, which is the lowest grade of coal, and requires more coal to be burned to generate the same amount of electricity as hard coal like bituminous or subbituminous (Big Stone utilizes subbituminous). Lignite also tends to have higher amounts of sulfur and ash content.

[59] CEOs initial comments, p. 86.

[60] CEOs initial comments, p. 89.

[61] Staff briefing papers, p. 45 (Table 24) and CEO's September 13, 2023, comments, p. 18 (Table 1).

and Supplemental IRP found that, with or without externalities, exiting Coyote Station by 2028 was least-cost.

- OTP's analysis of its Preferred Plan showed that the 2028 Coyote exit was less expensive than the 2040 exit by $40 million without externalities. When externalities were included, the 2028 Coyote exit was less expensive than the 2040 Coyote exit by $113.3 million.[62]

By authorizing OTP to withdraw from Coyote Station by 2031, based on the factors discussed above, Staff asserts there is no need for a material, non-routine capital investment to be the trigger to begin a process to withdraw from the plant. OTP's proposed language implies that operating Coyote Station until 2040 would be least-cost unless a material, non-routine capital upgrade is required, and Staff does not agree the record supports this conclusion.

Staff also notes that Section A.2 of the Settlement Agreement would require OTP to "annually file with the Commission a list of all capital projects with a total plant cost over $30 million," which the Company stated would provide "transparency and insight into Coyote Station capital projects."[63] Staff finds this threshold confusing and unsupported by other evidence. First, this implies that if, hypothetically OTP invests $29 million of new capital into Coyote Station, the Company would not report it to the Commission, and Staff does not understand why (a) the Company chose $30 million or (b) would not report it in a filing. Second, it is unclear if these new capital investments OTP might be alluding to are in the EnCompass modeling. Third, a Commission finding that the least-cost plan is to withdraw by 2028 may result in greater scrutiny in future Commission proceedings as to why OTP made these $30+ million investments.

As a final note, OTP's April 3, 2024, comments referred to the CDG modeling report prepared for the ND PSC, which showed that some Regional Haze scenarios continued to operate Coyote as the least-cost plan. Staff believes CDG used a highly questionable methodological approach to find this result, which is discussed below, and the results appear intended to obfuscate OTP's overwhelming modeling results on Regional Haze.

CDG stated that "the 2040 Coyote retirement option has a lower NPVRR in 10 of 22 of Otter Tail's scenarios and <u>10 of 15 Otter Tail scenarios that do not include regional haze Regulations</u>." It should be noted that CDG added four Regional Haze runs, which bundled together OTP's Regional Haze assumptions with only the inputs that generally favored continued operation of Coyote Station. In OTP's model, continued operation of Coyote Station until 2040 was economic when (1) renewable accreditation was low; (2) load growth was high; and (3) when natural gas and energy market (NGEM) prices were high. CDG's additional scenarios simply combined these three specific assumptions into four Regional Haze scenarios.

[62] OTP Supplemental IRP, Appendix I: Sensitivity Summary, Pages 1 and 3.

[63] OTP, April 17, 2024, reply comments, p. 13.

CDG did not balance these out with the possibility that these inputs could go in the other direction. From Staff's perspective, CDG's additional modeling runs provide no value to the question of environmental compliance risk.

CDG's table is shown below, with all Regional Haze scenarios highlighted in yellow. Note that the four rows at the bottom are CDG's additional scenarios, and these scenarios flip the cells from all red (i.e, early exit is always least-cost) to all blue (i.e., operation of Coyote until 2040 is always least-cost).

[Intentionally blank]

Table 11. CDG Report

Scenario	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

B. Authorizing the AME Plan

OTP stated that based on discussions with MISO and the IMM, “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.”[64] Given (a) the Commission’s limited authority to require OTP to exit Coyote Station, (b) the passage of time that has rendered a 2028 exit infeasible, and (c) OTP’s winter and summer capacity position, Staff believes the AME proposal is a fine compromise for Coyote Station until the next IRP; after all, the alternative to no-AME appears to be continued operation of Coyote at historic levels, which the record does not indicate is in Minnesota ratepayers’ or the public interest.

Having said that, Staff notes that Section A.1 of the Settlement Agreement states that OTP will only operate Coyote Station as a capacity resource “to the extent that the solar resources contemplated in Section A.3, below are available to replace the energy.” In the next section, Staff will discuss its concerns with OTP’s proposed solar plan.

II. Section A.3 – Replacement Resources under the Minnesota Preferred Plan with AME

Section A.3 of the Settlement Agreement asks the Commission to find that the resources under the Minnesota Preferred Plan with AME are needed to meet Minnesota’s system capacity requirements, Minnesota customers’ energy requirements, and Minnesota policy requirements. These resources include:

- 70 MW of Coyote Station designated as AME;
- On-site fuel storage at Astoria Station by 2027;
- No less than 200 MW and up to 300 MW of solar by November 1, 2027; and
- No less than 150 MW and up to 200 MW of wind by December 31, 2029.

At this point, it is worth mentioning points of context raised by the CEOs and the OAG. The CEOs stated:

> It is also important to put the incremental cost of AME (lost energy revenue) in the context of the Company’s full proposal, which asks Minnesota customers to pay for AME, the entire cost of 350 MW of renewable energy projects, and the Minnesota share (46.6%) of the on-site LNG storage proposal at Astoria.[65]

The OAG stated:

> the OAG emphasizes that Otter Tail’s proposal to place the Minnesota share of Coyote Station on AME status, and its related proposal to bifurcate resource-planning between Minnesota and the Dakotas, would mean that all replacement

[64] OTP, April 3, 2024, comments, p. 9.

[65] CEOs, April 3, 2024, comments, p. 30.

> resources will be paid for solely by Minnesota ratepayers.[66]

Staff adds that the size of the proposed acquisitions relative to the size of OTP's system is important to consider in the context of Minnesota ratepayer impacts. OTP frequently refers to itself as a small utility, not to be compared to a utility like Xcel, and the 49.9 MW Hoot Lake Solar and 150 Merricourt Wind acquisitions were very large considering OTP's size. The Settlement Agreement contemplates solar acquisitions four to six times the size of Hoot Lake Solar by 2027 and a wind acquisition about the size of Merricourt by 2029. Staff is concerned that the rate and bill impacts to Minnesota ratepayers have not been sufficiently examined. The CEOs' comments also referred to the underdeveloped record on the AME proposal:

> Otter Tail's Preferred Plan with AME, filed December 15, 2023, contained no modeled analysis of the financial, environmental, or reliability impacts of the AME plan as compared to the other plans that Otter Tail itself or CEOs have put forward … Given that the AME plan includes several novel approaches to resource planning and operations (at least novel for Minnesota), CEOs believe the proposal demands greater scrutiny rather than less.[67]

A. Rate Impacts to Minnesota Customers

PUC Information Request No. 3 asked OTP to compare the PVRR of the Minnesota share of the March 31, 2023, Preferred Plan with the PVRR of the Minnesota share of the MN Preferred Plan with AME. OTP's response forecasted that the Minnesota share of the MN Preferred Plan with AME has a PVRR that is approximately <u>4% higher</u> than the PVRR of the Minnesota share of the Supplemental IRP developed for the March 31, 2023 filing. According to OTP's response to PUC Information Request No. 12, the PVRR of North Dakota's share, however, is estimated to <u>decrease</u> by 0.2% relative to the Supplemental IRP.

Table 12. PVRR Comparison of Supplemental IRP to AME by Jurisdiction

Jurisdiction	March 2023 IRP	December 2023 AME Plan PVRR	Difference
Minnesota share	$1,290,563	$1,319,208	+4%
North Dakota share	$1,473,547	$1,471,148	-0.2%

OTP clarified that this increase in the PVRR will not increase rates because the December 2023 calculation included a higher Minnesota sales forecast. This is not a comforting response because OTP did not provide a rate impact analysis to support this explanation. Moreover, what OTP appears to be stating is that the PVRR cannot be compared across OTP's filings to make inferences about the rate impacts of the AME plan, which was also echoed in the CEOs'

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66 OAG April 3, comments, p. 16.

67 CEOs, April 3, 2024, comments, p. 20.

comments.[68] This is concerning because, to Staff's knowledge, there is no Minnesota ratepayer impact analysis of the AME plan compared to a baseline that assumes jurisdictionally-allocated costs.

B. Solar Price Uncertainty

Per the Settlement Agreement, designating the Minnesota share of Coyote as an AME resource is contingent upon acquiring solar resources contemplated in Section A.3 of the Settlement (200-300 MW of solar by 2027). However, there does not appear to be a comprehensive and conclusive resource planning analysis to support why at least 200 MW of solar by 2027 must replace reduced output at Coyote.

First, OTP's EnCompass analysis did not always add replacement resources under the 2028 Coyote exit scenario; the timing of resource additions was impacted by, among other things, the inclusion of externalities, renewable costs, natural gas prices, and load growth. For instance, according to Appendix I of the Supplemental IRP, OTP's no-externalities, 2028 Coyote exit base case, EnCompass selected 50 MW of surplus solar and 300 MW of generic wind in 2029.

Second, OTP anticipates that AME will not be implemented until 2029, although Staff agrees with the CEOs that OTP did not provide a clear beginning or end date for AME status. Nevertheless, OTP stated that "[i]n spring and fall seasons, Otter Tail expects to have sufficient energy resources available throughout the next five years," but when replacement energy resources are in-service, "Coyote could be offered as an AME resource during all seasons."[69] With this information, Staff is unable to tell whether a minimum of 200 MW of solar wholly-allocated to Minnesota is needed to either match and offset 70 MW of expected output from Coyote Station or ensure energy adequacy.

Moreover, there appears to be enough uncertainty with respect to the current price of solar to raise doubts about whether solar – at least in the amount OTP proposes – is the most prudent investment at this time. According to the CDG report submitted to the ND PSC:

> On November 20, 2023, the ND PSC held an Informal Hearing with Otter Tail to review Otter Tail's updated modeling … 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 <u>based on Otter Tail's discussions with developers</u>. As shown in Table 7 the <u>costs increased 30% on average compared to the base modeling assumptions</u>.[70]

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[68] The CEOs stated that ""nowhere has Otter Tail compared its AME Plan to its 2040 Preferred Plan or 2028 Preferred Plans under constant modeling assumptions."

[69] OTP response to PUC Information Request No. 7.

[70] OTP April 3, 2024, comments, Attachment 1, Page 13 of 69.

Staff notes that OTP's Minnesota Preferred Plan with AME included surplus solar, and according to the CDG report OTP stated that the levelized cost of surplus solar has increased 50% relative to previous assumptions.

Table 13. Excerpt of CDG Report, Updated Cost Difference of Solar Prices

Resource	Input	New Cost	Existing Cost	Difference
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%

While ideally the Commission's order could identify a specific price point at which solar is a cost-effective acquisition for ratepayers, it is not clear from the record where that price threshold is. The record certainly does not indicate that adding solar at any cost is prudent. In fact, no solar was added during the planning period under OTP's Renewable High Cost sensitivity.

For these reasons, the Commission may consider modifications to Section A.3, which as written commits Minnesota ratepayers to at least 200 MW and up to 300 MW of solar by 2027. OTP's comments about conversations with developers indicating higher solar prices may justify waiting until OTP brings forward a petition for approval of actual projects before finding 200 MW of solar is prudent. Therefore, Staff offers the following decision option language, which would authorize OTP to file a petition for approval of cost-effective solar in the future rather than committing ratepayers to a certain amount of new solar at this time:

> Authorize Otter Tail to file a petition for approval with the Minnesota Public Utilities Commission for the cost-effective acquisition of solar resources identified in the Company's Minnesota Preferred Plan with AME. Require that any petition shall contain updated load forecasts, updated capacity expansion modeling on a system-wide and Minnesota-specific basis, and estimated rate impacts to Otter Tail's Minnesota customers.

To be clear, the purpose of this alternative option is not to suggest solar is cost-prohibitive. The point is that Staff's understanding of Section A.3 is a conclusive determination that at least 200 MW of solar wholly-allocated to Minnesota is in the ratepayers' interests; because Staff has concerns about the current price and 100% allocation to Minnesota, the Staff alternative would allow OTP to move forward with solar acquisition in a way that minimizes downside financial risk to OTP's Minnesota ratepayers.

Other ways the Commission could address solar price uncertainty is by reducing the low end of the range from 200 MW of solar to an amount the Commission deems appropriate, or, as the next section will explain, open the resource selection process to more carbon-free resources, similar to an all-source competitive process but with CFS-qualifying resources only.

C. CFS

OTP's April 3, 2024, comments stated that the need for bifurcated system planning was because:

> North Dakota's legal framework for determining the prudency of resource additions is "<u>need plus least cost</u>" 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. In contrast, Minnesota employs a "<u>in the public interest</u>" standard 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.[71]

OTP continued that the costs and benefits of renewable projects identified in OTP's Minnesota Preferred Plan with AME should be wholly allocated to Minnesota customers because "<u>these projects are needed to serve Minnesota customers for compliance with Minnesota policy as reflected by the CFS</u> and to replace the energy lost from Minnesota's share of Coyote Station after the transition to AME."[72]

Staff notes that OTP's Preferred Plan in the Initial Filing contemplated exiting Coyote Station by 2028 before the CFS was passed. After the CFS was signed into law, OTP filed a letter following the Commission's February 2, 2023, agenda meeting (which discussed the IRP procedural schedule) explaining:

> Otter Tail is uniquely (and well) positioned to comply with this 100 percent carbon-free obligation. We have significant renewable generation already in our fleet relative to the quantity of energy we deliver to our Minnesota customers. Right now, with our current generation fleet, we have enough renewable generation to cover about 54 percent of our energy sales to Minnesota customers. This is before we add the Hoot Lake Solar project, currently under construction. After Hoot Lake Solar comes on-line later in 2023, the 54 percent will increase to 57 percent.[73]

In OTP's Supplemental IRP, the Company provided a summary table of CFS compliance under three different scenarios, shown below, which assumed different compliance levels depending on how RECs could be allocated across jurisdictions. Assuming OTP can allocate RECs generated

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[71] OTP, April 3, 2024, comments, p. 4.

[72] OTP, April 3, 2024, comments, p. 13.

[73] OTP, February 16, 2023.

in other states for CFS compliance, OTP projected that, without any new resources (i.e., Hoot Lake Solar and wind repowers only), OTP will be able to cover 65% of its energy sales to Minnesota customers for CFS compliance by 2030 (bold, italicized font).

Table 14. CFS Compliance under Preferred 2040 Plan[74]

MN REC Forecast	Current: No HLS, No Repowers	2023 w/HLS	2025 w/HLS & Repowers	2030 Preferred Plan	2035 Preferred Plan	2040 Preferred Plan
MN covered by MN RECs	25%	28%	31%	51%	55%	55%
MN covered by MN/ND RECs	50%	53%	59%	100%	109%	109%
MN covered by MN/ND/SD RECs	54%	57%	***65%***	110%	120%	120%

While the calculations above show that OTP still has a remaining compliance need, when reviewing the record in its totality, the CFS is far from the only reason OTP has sought solar and wind; moreover, the tenor of OTP's claimed urgency to meet the CFS has amplified dramatically throughout the Company's filings, and Staff is not aligned with OTP's current stance that it needs to abandon system-based planning in order to incorporate CFS compliance.

Staff also asserts that OTP's proposed renewable plan will vastly exceed the amount of energy it needs to replace reduced output at Coyote. The table below includes the resources in the Minnesota Preferred Plan with AME (not including the Astoria LNG project) and shows that new solar will replace the reduced energy output at Coyote on a nearly 1:1 basis. However, note that the CEOs refuted OTP's estimate of energy and emissions reductions at Coyote, finding that applying AME to historical data "would have led to an average annual reduction of 224,907 MWh."[75]

Table 15. Average annual energy output by resource

Resource	Capacity Factor	Average annual energy output (MWh)
70 MW Coyote	65%	400,000
200 MW solar	20%	350,400
150 MW wind	50%	657,000

In total, the estimated annual output from 350 MW (at the minimum) of renewable energy contemplated by the Settlement Agreement leads to 1,007,400 MWh per year, which could be considered excessive. While the record strongly supports that, on a system-wide basis, some

[74] Updated IRP, Table 4-6: Minnesota Clean Energy Law Compliance Breakdown (Coyote 2040), p. 28.

[75] CEOs, April 3, 2024, comments, p. 24.

combination of solar and wind is needed and least-cost, as noted above, several factors can impact the timing and the optimal mix of solar versus wind.

Considering these factors, the Commission may direct OTP to initiate a carbon-free resource selection process, similar to a renewable all-source process. Staff's rationale for suggesting this approach is that (a) if the need for bifurcated planning is driven mostly by CFS compliance, and (b) if the goal is to accrue carbon-free MWh at the lowest possible cost, then it would make sense to allow all carbon-free sources compete in order to achieve the lowest price per REC. Two considerations for designing such a process could be:

1. Should the process identify a need in nameplate capacity terms, or in an amount of energy needed?

2. Should the targeted amount of carbon-free energy seek to match the expected reduction in energy output for the Minnesota share of Coyote Station or an estimated amount of RECs needed to comply with the CFS?

Staff offers the following decision option for the carbon-free resource selection process; since Staff has no strong position on how the Commission may address the two questions above, the draft language below simply uses both OTP's and CEOs' estimates for expected annual energy output reduction at Coyote to establish a range.

> Direct Otter Tail to initiate a competitive resource selection process that seeks approximately 250,000 – 400,000 MWh of annual carbon-free energy to be in-service by 2029. Otter Tail shall seek all resources that qualify as carbon-free under Minn. Stat. § 216B.1691, subd. 1a.

III. Sections A.4, A.5, A.6, and A.8 – Location, Local Workers, and OTP's Next IRP

Sections A.4, A.5, A.6, and A.8 of the Settlement Agreement state:

- A.4 – For renewable resource projects to be allocated solely to Minnesota under this Settlement, Otter Tail will give reasonable preference to projects located in Minnesota.

- A.5 – OTP will work with organized labor stakeholders to ensure that resource acquisitions and investments maximize the availability of high-quality employment and career opportunities for local workers by prioritizing investment in the utility's service territory and plant host communities, and the state of Minnesota through the employment of local workers and use of registered apprenticeship programs that have a proven track record of developing local and diverse skilled workforce.

- A.6 – Otter Tail will include in its next IRP modeling and resource options including mid and long-duration energy storage systems.

- A.8 – Otter Tail will file its next Minnesota IRP no later than May 15, 2026 in which Otter Tail will develop a plan which assumes Otter Tail will withdraw from the Minnesota share of Coyote Station as of December 31, 2031; provided that Otter Tail may present additional plans for consideration based on a comprehensive resource planning analysis.

As noted above, the CEOs can support these provisions in the event the Commission decides to approve OTP's AME proposal. However, the CEOs "urge the Commission to require that Otter Tail model Minnesota's withdrawal from Coyote as a fully explored scenario that is tested against various sensitivities (as opposed to the withdrawal run being one sensitivity performed on a no withdrawal proposal)."[76]

Staff does not oppose these terms but notes that they are either vague or reflect actions that OTP should be doing in IRP and resource acquisition anyway. For example, it would be surprising and probably highly-criticized if OTP did not consider either mid- and long-duration energy storage systems or a Coyote withdrawal scenario in its next IRP. Also, it would seem that Section A.5 is already required under Minn. Stat. § 216B.2422, subp 4a, which concerns local job creation.

Having said that, the Commission may wish to further explore Section A.4 (location in Minnesota) and A.8 (Coyote withdrawal plan), which Staff will discuss below:

First, regarding Section A.4 of the Settlement Agreement, it is unclear what the term "reasonable preference" means. OTP has already described the challenges of going through the MISO queue process and the relative cost benefits of surplus solar, so OTP's position seems to be that it would be unreasonable to locate resources in Minnesota.

This issue was discussed at the January 4, 2024, agenda meeting, so following the agenda meeting, Staff sent OTP an information request asking whether the Company would support <u>a Commission requirement</u> that new renewable projects must also be located in Minnesota. OTP did not provide a yes or no answer, but their response laid out the reasons why OTP could ultimately locate a project in another state despite giving "reasonable preference" to Minnesota projects:

> Otter Tail is part of MISO and seeks generation resources located in MISO Zone 1 with a preference for generation resources located in Otter Tail's service territory. <u>Further limiting the location of the generation resources may unnecessarily limit available options and hinder low-cost projects for our customers</u>.
>
> One primary constraint for projects at this time is transmission interconnection. It is currently estimated to take 3-4 years to get through the standard MISO interconnection process. In addition to the time, the costs associated with the interconnect are uncertain until the last stages due to projects in the queue

[76] CEOs, April 17, 2024, reply comments, p. 12.

> dropping out and new transmission coming online. This means projects selected in the near term either already have interconnection rights or are far enough along in the process to have confidence in the cost requirements. <u>Limiting our project selection to only the Minnesota subset of those available projects compounds the challenge of achieving optimal projects.</u>
>
> If the Commission orders us to focus our efforts on siting projects in Minnesota, Otter Tail will seek to comply with the best projects available.[77]

Regarding A.8, Staff agrees with the CEOs that OTP should do a much better job exploring the feasibility of a Coyote Station withdrawal plan in its next IRP. Staff notes that OTP's arguments made in its Supplemental IRP and after about contractual complexities with co-owners and challenges with the LSA were difficult to comprehend because it was OTP who first proposed a 2028 exit plan in the Initial Filing. Nevertheless, what is clear from the current positions among the parties is that EnCompass modeling generally points to an early Coyote exit; what is less developed is how OTP can address the contractual and jurisdictional issues the Company claims to have.

IV. Section A.7 – On-site Fuel at Astoria Station

The December 20, 2023, Staff briefing papers stated:

> Staff does not have a strong position on whether the Commission should approve onsite fuel at Astoria, but the threshold issue seems to be (a) balancing OTP's reasons for seeking dual fuel capability at Astoria, which are valid, with (b) the significant cost associated with the project.
>
> On the one hand, Staff agrees with OTP that having backup fuel will protect against natural gas price volatility and availability, and events such as the 2014 Polar Vortex and Winter Storms Uri and Elliot revealed potentially significant adverse consequences that may arise during such events.
>
> Further, Staff shares OTP's concern regarding seasonal resource adequacy under the SAC, and onsite dual fuel capability at Astoria may greatly improve the likelihood of the plant receiving a high, stable capacity value.
>
> On the other hand, the OAG highlighted important ratepayer considerations associated with the retrofit, essentially arguing that OTP cannot receive a blank check to mitigate risk. Staff agrees with the OAG that the Commission should be mindful of the magnitude of OTP's cost estimate.
>
> Either way, Staff believes the record is sufficiently developed for the Commission

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[77] OTP response to PUC Information Request No. 4.

> to make a decision in this proceeding, and furthermore, a Commission decision one way or another is probably helpful in that it enables OTP to move forward with regulatory certainty. Additionally, the cost-benefit considerations of dual fuel capability at Astoria do not seem to depend on the path forward at Coyote; OTP stated in its Initial Filing that the Company's analysis "supports dual fuel at Astoria Station regardless of the course of action on Coyote Station."[78]
>
> For these reasons, Staff does not support the CEOs' position to delay a decision on Astoria until the next IRP.
>
> Overall, Staff believes OTP provided a reasonable proposal to address several present-day risks – both financial and safety-related – that support approving LNG at Astoria; however, the Commission can reasonably decide that the costs are excessive, deny the proposal without prejudice, and require that OTP continue to explore other, less-expensive options to address those risks.
>
> Finally, Staff does not believe there are any apparent conflicts with either the Minnesota Renewable Preference Statute or greenhouse gas (GHG) emissions goal. LNG will be a backup fuel source to be used under extreme conditions and for a very specific purpose; further, when LNG is dispatched, it may offset other natural gas plants that may otherwise dispatch in MISO, thus producing minimal net GHG emissions.

OTP noted in its April 3, 2024, comments that, as a consequence of being required to place Astoria on forced outage during Winter Storm Elliot, OTP "expects MISO to reduce Astoria Station's capacity accreditation by approximately 50 MW for a period of three years."[79] As Staff's December 20, 2023, briefing papers discussed, dual fuel capability should enable Astoria to receive a stable capacity value, and mitigating capacity accreditation risk will be an important aspect of the project.

Staff disagrees with CEOs' contention that OTP did not explain the need "to acquire two insurance policies at the same time." Staff believes the term "insurance policy" is an overgeneralization, and OTP provides several reasons why on-site storage at Astoria is needed and why AME at Coyote is needed for different reasons. Regardless of whether the Commission agrees with those reasons, OTP discusses the benefits of dual fuel and the benefits of AME in very distinct ways.

V. Section A.9 – Resource Acquisition

Staff addressed OTP's opposition to a Commission-approved competitive bidding process in the

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[78] Initial Filing, p. 8.

[79] OTP April 3, 2024, comments, p. 17.

Staff briefing papers:

> the Department recommended the Commission approve a competitive bidding process similar to the resource acquisition process the Commission approved in Minnesota Power's 2021 IRP. That proposed process is outlined on page 36 of the Department's September 13, 2023, comments and on pages 60-61 of these briefing papers. The OAG supported the Department, as did the CEOs, but with one modification: to reduce the minimum size of storage acquisitions that would trigger a competitive bidding process (since storage resources are typically smaller in size than other resources).
>
> In reply comments, OTP opposed the Department's recommendation to initiate a competitive bidding process largely by citing the Commission's order in the Hoot Lake Solar docket, in which the Commission stated:
>
>> 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.[80,81]
>
> Staff believes this excerpt from the Commission's order and citation in OTP's reply comments requires additional context because OTP did not mention the five years leading up to this order.
>
> To start, the Commission's 2017 IRP Order required that OTP procure 30 MW of solar by about 2020. OTP was also required to file its next IRP by June 3, 2019. In OTP's ensuing extension requests, the Company reported little progress in its ability to acquire a physical solar asset, and the Company repeated its intention to purchase S-RECs until a cost-effective solar project emerged. That was until the Commission's second IRP extension request, in which the Commission expressed some frustration with OTP's lack of a solar acquisition coupled with its request for another year to file an IRP. The Commission's December 30, 2019, IRP extension order stated:
>
> while Otter Tail's filing stated that it had procured enough solar renewable energy credits to satisfy the Minnesota Solar Energy Standard for 2020 and 2021, it also stated that its intention was to use SRECS until a solar energy project can be shown

80 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.

81 OTP reply comments, pp. 52-53.

> to be part of a least cost resource plan. The Commission finds that Otter Tail needs to be more proactive in its approach to compliance . . . The Commission will require the Company to, by June 1, 2020, have completed a competitive-bidding process to procure the approximately 30 MW or more of installed solar capacity needed to satisfy its resource plan.[82]
>
> The Hoot Lake Solar petition was filed on November 25, 2020, about 6 months after the deadline for OTP to complete a competitive bidding process.
>
> When considering the complete history of the events which led to Hoot Lake Solar, which was approved nearly four years after the Commission's 2017 IRP Order, the events leading up to Hoot Lake Solar was not as seamless as the Company makes it appear. Moreover, just because Hoot Lake Solar is a cost-effective resource does not, by itself, prove that the Department's recommendation would be bad for OTP customers. OTP repeated why Hoot Lake Solar is a good project, but the Company did not directly explain why Hoot Lake Solar could not have been bid into a process like the one the Department recommends.

Staff's position on resource acquisition is unchanged; Staff understands why OTP would want full control over resource acquisition, but Staff believes there are benefits to a formal competitive bidding process, such as having a more contained and possibly competitive process. As described above, OTP took several years to acquire Hoot Lake Solar and came to a point where the Commission had to order OTP to complete the process by a date certain.

Ultimately, if the Commission wishes to define certain parameters of the resource selection process, this can be accomplished without as many specified steps as Minnesota Power's or Xcel Energy's formal processes, but more specificity than what OTP proposes.

VI. Big Stone Plant

While Big Stone is not part of the Settlement Agreement, the CEOs continue to recommend exiting the plant by 2030. Staff's position on Big Stone Plant remains unchanged from the December 20, 2023, briefing papers, in which Staff discussed the hourly analysis run by its modeling expert, EFG. Staff discussed that EFG's analysis indicated Coyote Station could be removed from the model, and OTP would make minimal market purchases even during winter peak days with low wind output. However, when both Coyote and Big Stone were out of the model, OTP's market purchases during winter peak days reached 17-21%, which Staff argued reflected extreme market exposure:

> If OTP were to withdraw from one of its coal plants, that coal plant would clearly be Coyote Station, and Staff believes the record shows that withdrawing from Coyote Station and Big Stone would fail to meet several of the Commission's IRP

[82] Docket No. 16-386, OTP 2016 IRP, Commission Order (December 30, 2019), pp. 4-5.

evaluation criteria. Therefore, Staff agrees with OTP that the Commission should not require any operational changes to Big Stone as part of this proceeding, and at least three areas of the record support this conclusion:

1. The CEOs’ 2031 hourly analysis found that on winter peak days with Coyote Station and Big Stone removed from the plan, market purchases accounted for 17%-21% of OTP’s hourly demand on average, which in Staff’s view fails to provide sufficient energy availability and proper risk management.

2. Staff is concerned about seasonal capacity risk in the event that neither Coyote nor Big Stone is part of OTP’s generation portfolio. As noted previously, OTP’s Planning Year 2023-’24 winter PRM was 25.5%, and its winter PRMR was 1,117 MW. Together, Coyote Station and Big Stone amount to slightly over 400 MW of accredited winter capacity, or roughly one-third of OTP’s winter accredited capacity.

3. In 2015, the Commission approved a $364 million AQCS project at Big Stone, and Staff shares OTP’s concerns over the rate impacts of adding replacement energy and capacity at Big Stone on top of the remaining value of the AQCS.

DECISION OPTIONS

Settlement Agreement (OTP, Department, Carpenters, IUOE Local 49, LIUNA)

1. Approve without modifications the parties comprehensive Settlement Agreement dated April 1, 2024.

OR, If the Commission declines to adopt the Settlement Agreement as presented:

2. Approve Otter Tail's Minnesota Preferred Plan with AME.

3. Authorize 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.

4. Approve Otter Tail's LNG fuel storage project for Astoria Station.

5. Authorize 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.

OR

   a. Authorize Otter Tail to file a petition for approval with the Minnesota Public Utilities Commission for the cost-effective acquisition of solar resources identified in the Company's Minnesota Preferred Plan with AME. Require that any petition shall contain updated load forecasts, updated capacity expansion modeling on a system-wide and Minnesota-specific basis, and estimated rate impacts to Otter Tail's Minnesota customers. (Staff alternative)

6. Find that Otter Tail's current competitive, flexible acquisition process is sufficient for the projects authorized by the Commission in this docket.

AND/OR

   a. Direct Otter Tail to initiate a competitive resource selection process that seeks approximately 250,000 - 400,000 MWh of annual carbon-free energy to be in-service by 2029. Otter Tail shall seek all resources that qualify as carbon-free under Minn. Stat. § 216B.1691, subd. 1a. (Staff alternative)

Office of the Attorney General

7. Find that Otter Tail's proposal to place Coyote Station on AME status is not in the public interest.

8. If the Astoria Station onsite-storage project is approved, cap rate recovery at Otter Tail's current cost estimate, with a 90/10 sharing of any savings below the cap.

9. For resource acquisition:
    a. If the Astoria onsite-storage project is approved, require Otter Tail to use a minimum of three bidders for both major components of the project (equipment and fuel); and
    b. For other approved resources, require the Company to use the bidding process recommended by the Department.

Clean Energy Organizations

10. Approve the resources in the Alternative CEO Plan with Battery, which are designed to serve Minnesota Otter Tail customer energy needs only and include:
    a. At least 200 MW of solar resources to be acquired as soon as feasible;
    b. At least 150 MW of wind to be acquired in 2026, and no later than 2029;
    c. 75 MW of energy storage resources of at least four-hour duration to be acquired by 2029; and
    d. Withdrawal from the Minnesota share of Coyote Station by December 31, 2028.

OR, if the Commission approves AME:

11. Find that based on the record in this docket, it would not be prudent for Otter Tail to make a large, non-routine capital investment in Coyote, and therefore Otter Tail may not recover from Minnesota ratepayers the costs of a large, non-routine capital investment in Coyote unless it obtains the Commission's approval prior to making that investment.

12. Obtain from Otter Tail its explicit agreement that, if the Commission finds in a future proceeding that Minnesota ratepayers have paid more for Coyote during its AME status than is just and reasonable, Otter Tail will refund the overpayment to its Minnesota ratepayers.

13. Require Otter Tail to submit a filing within four months of the date of its order in this docket with the results of its AME fatal flaw analysis. The filing should describe Otter Tail's efforts to obtain formal written approvals of the proposal by the MISO Independent Market Monitor, by MISO regarding tariff compliance, by Coyote's co-owners, and by any other parties that could block the AME plan. The filing should attach those approvals or explain why they have not been obtained.

14. Find that, if AME is found to be infeasible, it is not reasonable or in the public interest for Minnesota ratepayers to continue to pay for or depend on Coyote Station past 2028.

15. Require Otter Tail to submit a new IRP within six months of a finding that the AME plan

cannot proceed. Such a finding can be established the Commission, by Otter Tail, or evidenced by a rejection of the plan by MISO, the Independent Market Monitor, or any other party with power to block the plan.

Or, in alternative to 14 and 15:

16. Require Otter Tail to move forward with the following resource acquisitions consistent with the Alternative CEO Plan with Battery, which are designed to serve Minnesota Otter Tail customer energy needs only:
    a. 200 MW of solar resources to be acquired as soon as feasible;
    b. 150 MW of wind to be acquired in 2026, and no later than 2029;
    c. 75 MW of energy storage resources of at least four-hour duration to be acquired by 2029;
    d. Withdrawal from the Minnesota share of Coyote Station by December 31, 2028.

17. Require Otter Tail to commence AME status at Coyote, as modified in this order, as soon as feasible. If Otter Tail is unable to commence AME status at least seasonally by 2026 and year-round by 2027, it will submit a filing to the Commission explaining why not and identifying the soonest feasible time when it could commence AME status.

18. Require Otter Tail in its next IRP to:
    a. include in its reference case scenario the replacement resources necessary to allow Otter Tail to end the AME arrangement and cease Minnesota's dependence on Coyote Station entirely by the end of 2031; and
    b. include a scenario that would include the replacement resources necessary to allow Otter Tail to end the AME arrangement and cease Minnesota's dependence on Coyote Station entirely by the end of 2028.

19. Find that it may be economic for Otter Tail to add more wind, solar and/or battery storage resources than specified above, especially in light of potential changes to its energy needs, capacity position, or market circumstances. Otter Tail should actively assess market conditions and project availability to bring forward economic resources when feasible and by no later than the dates specified.

20. Require Otter Tail to begin planning now for a Big Stone withdrawal by 2030, and to present a plan in its next Minnesota IRP that withdraws from Big Stone by no later than the end of 2030. The plan should demonstrate that Otter Tail is taking proactive steps to keep a 2030 exit on the table and is exploring the economic value of retiring the plant, including consulting with co-owners on the issue.

21. Defer a decision on Otter Tail's Astoria LNG proposal until the Company's next IRP.

22. Direct Otter Tail in its net IRP to:
    a. Include an analysis of the costs of its preferred plan and its comparative plans

under the full range of regulatory and externality costs specified by the Commission in its order in docket 22-236. This analysis should include emissions both inside and outside Minnesota to the extent they are associated with generation used to serve Minnesota customers.

b. Present modeling runs that allow a reasonable amount of both market purchases and sales.
c. Conduct production cost modeling to obtain more detailed information to develop the portfolio PVRRs and to evaluate the dispatch of resources during specific periods of time, including during periods of challenging system conditions.
d. Include an analysis of the health and equity impacts of its preferred plan.
e. Include an assessment of energy efficiency, demand flexibility, and energy storage options, especially in comparison with the addition of on-site fuel storage at its Astoria facility.

23. Order Otter Tail to submit its next IRP by two years from the date of this order.

24. Require Otter Tail to engage with the Department of Commerce and other parties prior to filing its next IRP to discuss the issue of bifurcated planning and how best to ensure a resource plan that recognizes ongoing jurisdictional differences between states but that also provides complete information regarding the Company's resource needs and planning direction.