ENERGY FUTURES GROUP

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Economic and Policy Analysis of Energy, Environment and Equity

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A Clean Energy Alternative for Otter Tail Power

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1 Clean Energy Organizations' EnCompass Modeling Runs

Energy Futures Group and Applied Economics Clinic were asked to conduct an independent technical review of Otter Tail Power's Supplemental Integrated Resource Plan ("IRP"), making corrections, as deemed appropriate in our professional opinions, to Otter Tail Power's EnCompass modeling assumptions, and exploring alternative combinations of unit retirements and additions that would better fit the policy preferences outlined in Commission orders and state statutes.

The following sections discuss the modifications that we made to Otter Tail Power's ("OTP") EnCompass database to perform the Clean Energy Organizations ("CEO") modeling runs.

Our modeling approach was to examine three portfolios with different capacity expansion plans:

1) A rerun of OTP's Preferred Plan ("Revised OTP Preferred 2040 Plan"), using our corrected modeling assumptions. This includes OTP's modeling assumption that the Company withdraws from Coyote in 2040 and Big Stone continues to operate until its retirement in 2046;

2) A rerun of OTP's 2028 Coyote Withdrawal Plan ("Revised OTP 2028 Plan"), using our corrected modeling assumptions.[1] In this plan, OTP withdraws from Coyote in 2028 and Big Stone continues to operate until its retirement in 2046;

3) An all renewable and battery storage expansion plan ("CEOs Preferred Plan") that includes a 2028 withdrawal date from Coyote and a 2030 withdrawal date from Big Stone.

We evaluated these portfolios under a central set of assumptions that involved making certain corrections and changes to Otter Tail Power's modeling assumptions, along with updating the cost of new renewable and storage resources, as discussed in greater detail below.

The EnCompass modeling described in this report demonstrates that a portfolio of renewable and battery storage resources with OTP withdrawing from Coyote in 2028 and Big Stone in 2030 shows reduction in both the Present Value of Revenue Requirements ("PVRR") and carbon emissions compared to OTP's Preferred Plan ("Revised OTP Preferred 2040 Plan") and its 2028 Coyote Withdrawal Plan ("Revised OTP 2028 Plan").

1.1 Updates and Other Corrections to Otter Tail Power's EnCompass Modeling

The changes we made to Otter Tail Power's modeling are discussed in the sections that follow. Except where otherwise noted, these changed inputs went into modeling of all three expansion plan portfolios.

[1] The Company presented two preferred plans in its supplemental IRP, one that withdrew from Coyote in 2040 and one that withdrew from the plant in 2028. Ultimately, OTP chose the 2040 withdrawal plan. Thus, to avoid confusion, when we refer to OTP's preferred plan, we are only referring to the plan with the 2040 withdrawal.

1.1.1 Changes to Otter Tail Power's Wind, Solar, and Battery Storage Cost Assumptions

We developed alternative resource costs for wind, solar PV, and battery storage resources that were modeled for all portfolios that we present in this report. The decision to model alternative resource costs was primarily driven by concerns that OTP's base case costs were too low in the short term and too high in the long term.

In the short-term, we addressed the recent increase in clean energy costs driven in large part by a long and expensive interconnection approval process and supply chain constraints that have persisted after the covid-19 pandemic.[2] To capture this recent trend, we relied on OTP's high case costs in the short-term but assumed that costs would rebalance by 2029. This is a reasonable assumption as there is a concerted effort to break up the "log jam" of new resources by mitigating interconnection obstacles, including at the RTO and federal levels, and a massive federal effort to increase domestic clean energy manufacturing which will boost supply and improve stability during trade disruptions.

The Federal Energy Regulatory Commission ("FERC") recently ruled under Order 2023 unanimously to improve the interconnection process nationwide.[3] Mere months prior to FERC's issuance of Order 2023, MISO initiated its own interconnection reform effort in an attempt to remove the logjam of interconnection requests, primarily by ensuring that such requests are closer to being commercially ready at the time generators join the interconnection queue. MISO is currently adjusting its proposed reforms to better align with Order 2023, and once it has proceeded through the stakeholder process, MISO is attempting file its proposal with FERC this year, and before the launch of the next interconnection queue cycle.

Additionally, the first tranche of Long Range Transmission Planning lines ("LRTP Tranche 1") includes 18 transmission lines with expected commercial operation dates between 2028-2030. Three lines are located wholly or partially within Minnesota and improve connections between Minnesota and neighboring states. MISO modeling indicates that these lines will help bring on 14.4 GW[4] of new renewable energy capacity in Local Resource Zone 1 (including most of Minnesota along with parts of North Dakota, South Dakota, western Wisconsin, and eastern Montana) by 2039. It is worth noting that this projection is also based on MISO's Future 1, which is a more conservative estimate of future

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[2] LevelTen Energy, PPA Price Index: Executive Summary, Q2 2023. Available at: https://www.leveltenenergy.com/ppa

[3] Id. Concurring opinion of Commission Christie. p.1

[4] MISO, *MISO Futures Report*, page 56, April 2021, updated December 2021, *available at* https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf, showing cumulative resource additions for each LRZ as a result of Tranche 1, and based on MISO's projections using Future 1. Note that LRZ 1 does not include extreme southwestern Minnesota.

renewables growth than Future 2A, the latter of which MISO is currently using to model transmission expansion for LRTP Tranche 2.

In the first nine months since the passage of the IRA, more than 100 new clean energy manufacturing facilities or expansions were announced in the U.S., including new wind, solar, battery manufacturing plants.[5] While some of these facilities will not begin production until 2025 or later, a majority have announced production dates by the end of 2024.[6] It is reasonable to assume this activity will continue and contribute to reduced supply chain constraints by the end of the decade, if not before.

The re-balancing of prices by 2029 and onward relies on our medium to long-term forecast, which is based on the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) from 2022, using the "conservative" or high-priced case from this source (rather than the "reference" or base case). Our price forecast also used OTP's assumed interconnection costs for wind ($500 per kW[7]), solar ($200 per kW[8]), and battery storage ($1.14 per kW-mo[9])—as well as the Company's assumed annual capacity factors for wind (50 percent) and solar (24 percent).[10] We added one resource that OTP did not model: a ten-hour lithium-ion battery, using the same NREL ATB 2022 source for those costs.

In our medium to long-term price forecast, we adjusted the tax credits that were available for clean energy resources. In modeling the Inflation Reduction Act ("IRA"), OTP implemented the 30 percent investment tax credit (ITC) for solar and battery storage projects and 100 percent of the production tax credit ("PTC") for wind. The Company assumed that these were available for projects that began operation by 2032, then were unavailable for those that began operation in 2033 and beyond.[11] This treatment of tax credits is too conservative in two ways: 1) the PTC is now available to solar PV projects as well, and can make solar cheaper than using the ITC; and 2) the IRA tax credits are going to be available for projects that start operation well after 2032. To address these issues, shown below in Table ***1***, we implemented the PTC for new solar PV and assumed that IRA tax credits would only start to decline after 2035, finally disappearing for projects coming-online in 2039—rather than in 2033 as OTP assumed.

[5] https://www.canarymedia.com/articles/clean-energy-manufacturing/the-us-climate-law-is-fueling-a-factory-frenzy-heres-the-latest-tally
[6] *Id.*
[7] OTP Supp IRP, Appendix F, Figure 2
[8] OTP Supp IRP, Appendix F, Figure 3
[9] Company response to IR CEO-077
[10] OTP Supp IRP, Appendix F, p. 4
[11] Id.

Table 1: Tax Credit Availability by Operation Date

Begin operation	OTP ITC (% of capital costs)	CEO ITC (% of capital costs)	OTP PTC (% of full payment)	CEO PTC (% of full payment)
2032	30%	30%	100%	100%
2033	0%	30%	0%	100%
2034	0%	30%	0%	100%
2035	0%	30%	0%	100%
2036	0%	23%	0%	75%
2037	0%	15%	0%	50%
2038	0%	8%	0%	25%
2039	0%	0%	0%	0%

Per the IRA, both the ITC and PTC will be available for projects that start construction by 2035, thus allowing for lead time to start operations in subsequent years and receive the credit.[12] Even that timeline is the *fastest* this phase-out could begin because the tax credits will only start to decline in 2035 if the U.S. power sector achieves 75 percent reduction in 2022 greenhouse gas emissions by 2032.[13] If that requirement is not achieved, the decline in tax credits is delayed and the full credits remain in place until the emission target is met. Our assumed IRA tax credits are thus more accurate than OTP's but could end up being conservative if the power sector does not reduce greenhouse gas emissions 75% by 2032.

The resulting new resource costs, shown below, match OTP's high costs for 2025 and 2026 and then costs re-balance between 2027 and 2029 to meet the long-term cost trajectories from NREL; all costs incorporate corrections to the IRA tax credits. With these changes, our costs are higher than OTP's base case in at least the short-term—or as late as 2032 in the case of solar PV—and substantially lower than OTP's wind and four-hour battery storage costs in the medium to long-term.

[12] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818. Sections 13701 and 13702.
[13] Id.

Figure 1: New Wind Costs (levelized nominal $/MWh)

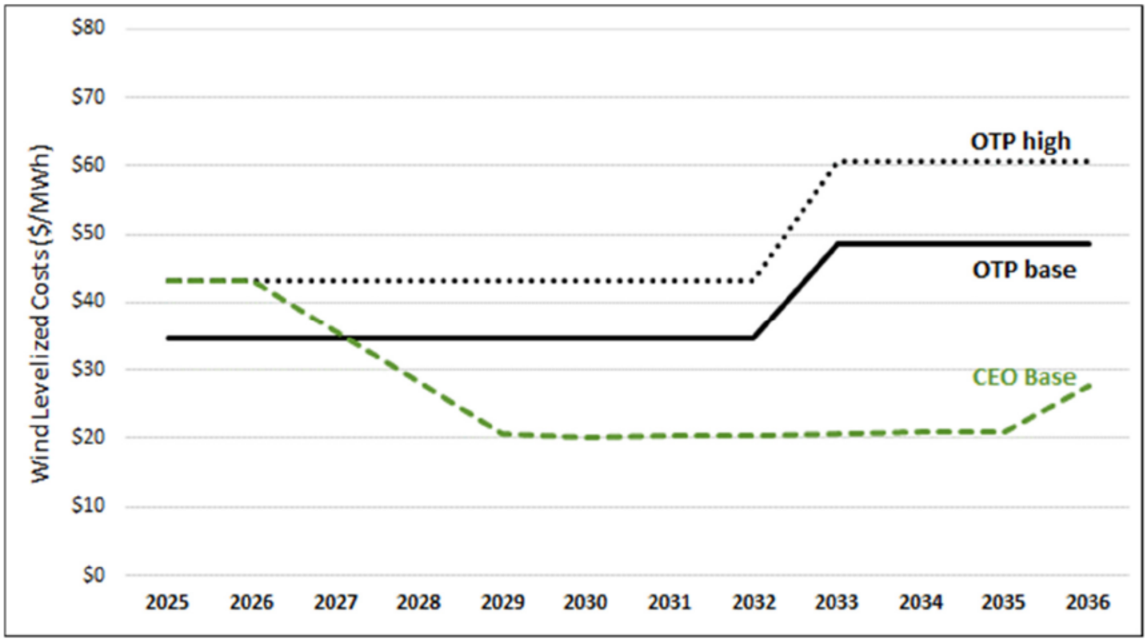


Figure 2: New Solar PV Costs (levelized nominal $/MWh)

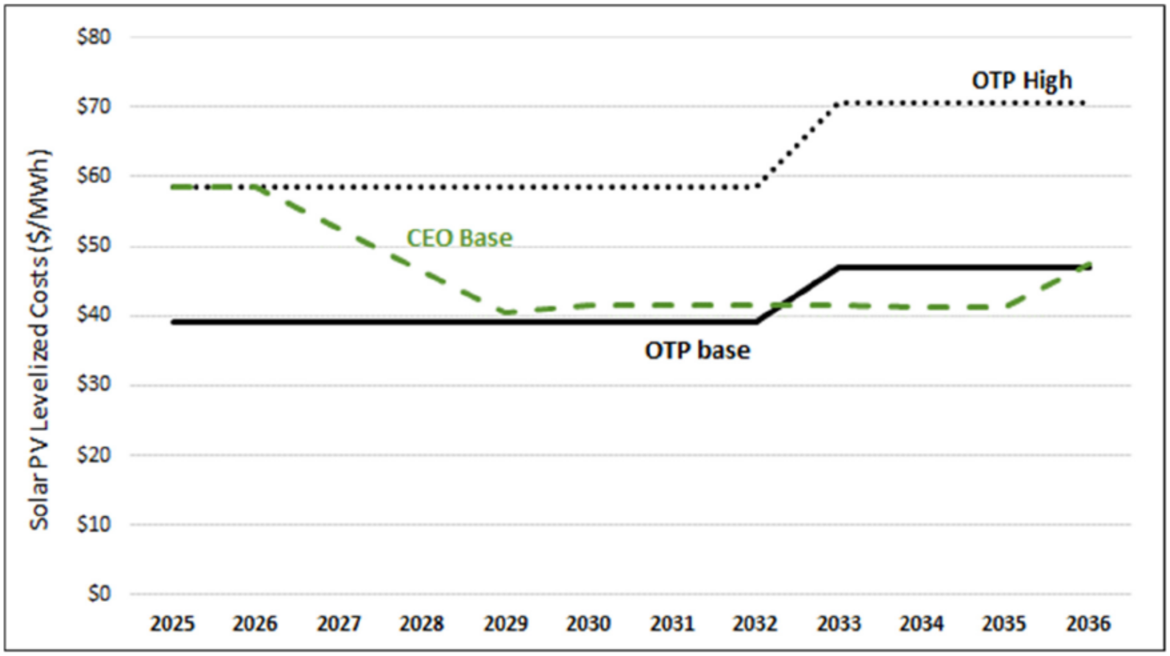
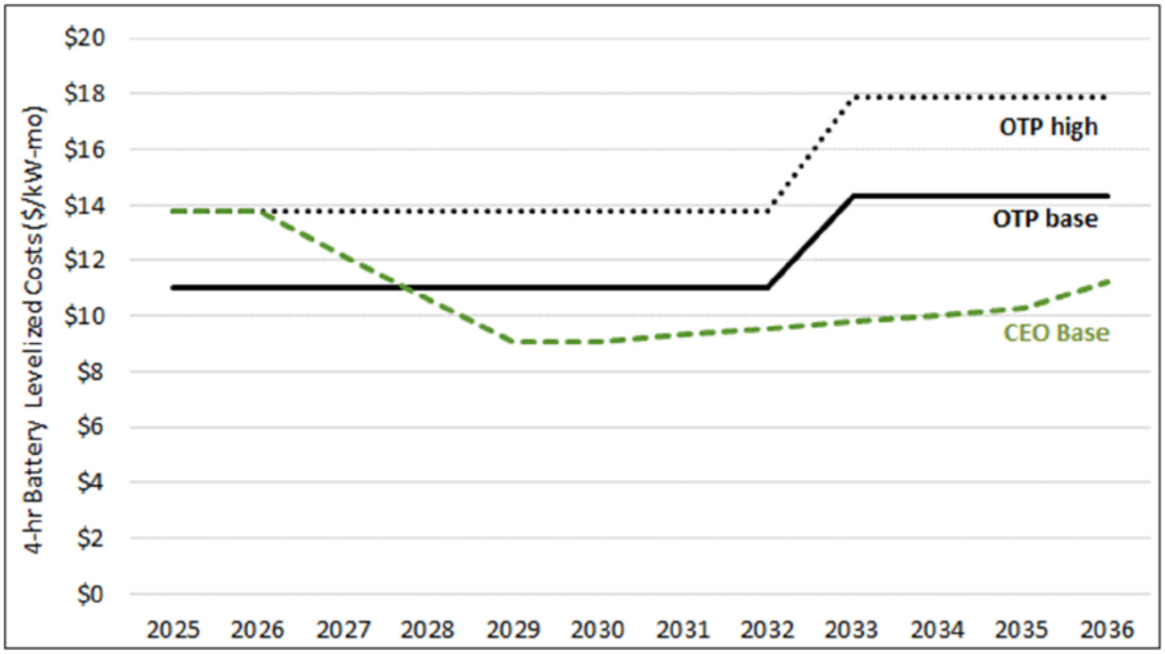


Figure 3: New 4-hr Battery Storage Costs (levelized nominal $/kW-month)



Our costs used in EnCompass are presented below in Figure 4. These show the new wind, solar PV, and battery resources that were considered in our expansion plans. Those without additional interconnection costs were used to mirror OTP's "surplus" and "replacement" resources that have access to an existing interconnection.

Figure 4: CEO New Resource Costs

	CEO Base Case - Levelized Costs (nominal $)						
	Wind ($/MWh)	Wind w/ interconnection ($/MWh)	Solar ($/MWh)	Solar w/ interconnection ($/MWh)	4-hr Battery ($/kW-mo)	4-hr Battery w/ interconnection ($/kW-mo)	10-hr Battery w/ interconnection ($/kW-mo)
2025		$43	$48	$59	$13	$14	
2026		$43	$48	$59	$13	$14	
2027		$36	$44	$52	$11	$12	
2028		$28	$39	$46	$10	$11	
2029	$13	$24	$35	$40	$9	$10	
2030	$12	$24	$36	$42	$9	$10	$22
2031	$13	$24	$36	$42	$9	$10	$22
2032	$13	$24	$36	$42	$10	$11	$23
2033	$13	$24	$36	$41	$10	$11	$23
2034	$13	$24	$36	$41	$10	$11	$24
2035	$13	$25	$35	$41	$10	$11	$24
2036	$20	$31	$42	$47	$11	$12	$26

1.1.2 New Resource Constraints

OTP modeled three categories of new wind, solar, and battery storage resources in the Supplemental IRP:[14]

(1) Generic resources that would be built at a new generation site;
(2) Surplus interconnection resources that would be added alongside an existing generation facility;[15]
(3) Replacement resources that would reuse the existing interconnection rights of a facility that is retiring.

Table ***2*** below shows the annual and cumulative constraints that OTP applied to the generic, surplus, and replacement resources in the model.

[14] OTP Supp IRP, Appendix F, p.4.
[15] The resources would operate in such a manner that the generation of both resources does not exceed the existing interconnection level for the original facility.

Table 2. OTP's New Resource Constraints

	Time Period	Annual MW	Cumulative MW
Generic (with IRA)	**2025-2032**		
Solar		500	500
Wind		1000	1000
Battery		500	500
Generic	**2033-2050**		
Solar		250	500
Wind		500	1000
Battery		250	500
Surplus (with IRA)	**2025-2032**		
Solar		250	250
Wind		0	0
Battery		50	50
Surplus	**2033-2050**		
Solar		300	300
Wind		300	300
Battery		0	0
Surplus and Capacity (with IRA)	**2025-2032**		
Solar		150	150
Wind		0	0
Battery		0	0
Replacement	**2033-2050**		
Solar		50	50
Wind		50	50
Battery		50	50

For the CEOs Preferred Plan, we adjusted a number of the assumptions OTP made regarding the availability and level of new resources to ensure that the EnCompass inputs reflected the full suite of actually available options so that constraints imposed in the model would not limit resource selection. The changes that we made for the CEO modeling include:

(1) Raising the solar generic constraint to 1000 MW on a cumulative basis throughout the entire planning period;
(2) Allowing the model to add up to 1000 MW of generic wind per year and on a cumulative basis throughout the entire planning period;
(3) Revising the annual generic battery storage constraint to 500 MW annually and 1000 MW on a cumulative basis throughout the entire planning period;

(4) Placing a global constraint on replacement resources to allow the model to optimize the selection of up to 150 MW of replacement wind, solar, and battery storage resources between 2033-2041, rather than being limited to 50 MW of each resource.
(5) Adjusting the replacement resource options available to the model, to demonstrate the potential for a resource plan that both exits and retires the coal plants and utilizes the valuable interconnection rights at both plants.

We raised the cumulative generic solar and battery storage constraints from 500 MW to 1,000 MW for symmetry with wind. The other changes to constraints for wind and battery storage were made to apply a uniform set of constraints across the planning period rather than having different capacity limits before and after 2032. This was done for modeling simplicity and because 2032 is no longer an inflection point in clean energy resource costs due to our adjustments to the IRA tax credits phase-out.

Regarding replacement resources available to EnCompass, OTP assumed 150 MW would be available starting in 2033 [Trade Secret Data Begins]

[Trade Secret Data Ends]. As described above, CEOs adjusted the way this was modeled to allow EnCompass to choose up to 150 MW total without being limited to 50 MW of each resource. In our modeling runs with the 2028 Coyote withdrawal and 2030 Big Stone withdrawal, we added additional replacement wind, solar, and battery options to the data set. This was done to evaluate the potential value of these interconnection rights—e.g., would EnCompass select those resources as part of a least-cost resource plan? We also calculated the costs of the same portfolio assuming these additions are generic rather than replacement resources by adding the interconnection costs back in. Thus, the CEOs Preferred Plan considers the potential that OTP is not able to reuse the interconnection rights at Coyote and Big Stone.

The Coyote replacement resource was modeled as a global cap of 150 MW, which could be met through solar, wind, and/or battery storage. For Big Stone we modeled up to 250 MW of replacement resources, including a fixed decision for the model to add 150 MW of four-hour battery storage. The model was then allowed to optimize the remaining 100 MW by choosing between replacement solar, wind, and/or additional battery storage resources.

We included this fixed battery storage build because OTP currently has no storage resources and OTP's Preferred Plan only includes a 25 MW surplus battery before 2038. It is reasonable to assume that, in the event of a transition away from coal, OTP would need additional battery resources to provide reliability services and complement its renewable generation. Moreover, capacity expansion modeling does not always capture the full value of energy storage for energy arbitrage,[16] ancillary services,[17] or flexibility[18] benefits. As a result, capacity expansion models may miss important aspects of economic value that battery storage resources can provide.

1.1.3 MISO Market Exchange

In capacity expansion and production cost models, a market exchange is typically simulated by including assumptions on the level of imports and exports a utility can make in any given hour. In the EnCompass modeling, OTP included the assumption that it could import up to [Trade Secret Data Begins] [Trade Secret Data Ends] in any hour over the entire planning period. However, OTP also assumed that it would not be able to engage in any market sales over the entire planning period. For the CEO modeling, we revised this assumption and allowed the model to have the ability to sell up to [Trade Secret Data Begins] [Trade Secret Data Ends] in any given hour for symmetry with the import limit. We included this modeling assumption to be in alignment with how OTP would operate its system given the economics of its own resources and market prices.

In order to ensure that the model would not over rely on either market purchases or sales, we added a second level constraint that limited the annual level of market purchases and sales to 25% of OTP's annual energy requirements. For example, this limit was set to be 1,698 GWh for 2025.

1.1.4 Regulatory Cost of Carbon and Externality Costs

OTP's Supplemental IRP included modeling runs with and without externalities and the Regulatory Cost of Carbon. For the runs performed with the Regulatory Cost of Carbon and externality costs, OTP included the cost of both as a dispatch adder for the thermal units. The approach we have typically seen Minnesota utilities take is to model the Regulatory Cost of Carbon as a dispatch adder. Externality costs, on the other hand, are typically added to the Present Value of Revenue Requirements ("PVRR") as a post-processing step outside of the model so that a Present Value of Societal Costs ("PVSC") can be

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[16] Average hourly price forecasts, which are the basis for dispatch decisions in EnCompass, have significantly less variability than 5-minute pricing in the real-time market, which is the price signal that a battery would follow for arbitrage opportunities. It is difficult to quantify the impact this will have on a battery resource's net revenue in production cost modeling, but this issue is recognized by industry leaders including researchers at the Department of Energy National Laboratories, resource planners at Portland General Electric, and 5Lakes Energy. See: U.S. DOE Training "State of the Art Practices for Modeling Storage in Integrated Resource Planning," October 12, 2021; Portland General Electric, 2016 IRP, Chapter 8, p. 236 for discussion of PGE's real time modeling approach for operational value; and 5Lakes Energy Technical Workshop: Integrating Batteries into Resource Planning, April 13, 2022 (included as Attachment 3 to CEO comments).

[17] In its 2021 IRP, the Northern Indiana Public Service Company ("NIPSCO") evaluated the sub-hourly ancillary services of resources, including battery storage. NIPSCO's analysis found that the sub-hourly energy and ancillary services value was projected to be highest for battery storage resources (See the NIPSCO 2021 IRP, page 244). In Its 2022 IRP, DTE also evaluated the ancillary service benefits of battery storage resources (See the testimony of Witness Mikulan, page 57 in Case No. U-21193).

[18] In its 2022 IRP, DTE evaluated the flexibility of battery storage resources (See the testimony of Witness Mikulan, page 64 in Case No. U-21193).

presented. The approach we took included sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), and particulate matter ("PM2.5") externality costs in the calculation of the PVSC. We did not include any carbon externalities in the PVSC calculation but rather calculated those separately based on the social cost estimates from the Environmental Protection Agency.[19] Table 3 provides an overview of how we treated the Regulatory Cost of Carbon and externality costs for the CEO modeling.

Table 3. Regulatory and Externality Application

Category	Modeled in EnCompass	Cost Treatment
Regulatory Cost of Carbon	Dispatch Adder	Included in the EnCompass PVRR
Externality Costs	No Dispatch Adder	SO_2, NOx, and PM2.5 externalities added to the PVRR to calculate the Partial PVSC outside of the model. Carbon externality costs are not included in the PVSC, but calculated separately.

Our modeling includes the Median value of the Regulatory Cost of Carbon as a dispatch adder. The SO_2, NOx, PM2.5, and CO_2 externality costs are considered outside of the model, and unlike OTP, we apply them to all units, both inside and outside the state, but only to 50% of Otter Tail's emissions to reflect the fact that 50% of their energy serves Minnesota customers. We also included the assumption that the Regulatory Cost of Carbon and externality costs would increase throughout the planning period at OTP's assumption for inflation, which is 2%.

The last modification we made related to the Regulatory Cost of Carbon and externality costs is to remove the externality and carbon regulation costs that OTP included for MISO market purchases. This simplifies the analysis and avoids having to make long-term predictions about the average carbon intensity of MISO purchases or the effect of a regulatory cost on the price of those purchases.

In OTP's IRP filing, there were seven sensitivities under the "No Externalities" assumptions which resulted in OTP's 2028 Preferred Plan having a higher PVRR when compared to OTP's 2040 Preferred Plan. We reran these sensitivities with only the mid-range Regulatory Cost of Carbon as a dispatch adder, and this resulted in OTP's 2028 Preferred Plan having a lower PVRR when compared to OTP's 2040 Preferred Plan in all seven sensitivities.

[19] We applied the EPA social costs to carbon emissions in response to the 2023 amendments to Minn. Stat. Section 216.2422, subd. 3.

1.1.5 Astoria Capacity Factor Limit

In some of the early years in the planning period, the model was opting to operate the Astoria unit at a high capacity factor. In order to manage the model's reliance on the Astoria unit and reflect more typical combustion turbine operations, we added an annual capacity factor limit of 25% in our modeling runs.

1.1.6 Battery Storage Input Changes

For the generic, surplus, and replacement battery resource options, we made three changes to how those resources were modeled by OTP:

(1) Allowed the model to select the new battery storage resources as partial units.
(2) Removed the MWH dispatch adder[20] that OTP applied to all battery storage resources.
(3) Set the minimum capacity of the battery storage resources to 0.1 MW[21]

We allowed the model to select the new battery storage resources as partial units to reflect the modular nature of battery storage resources. We also removed the dispatch adder because we were not in agreement with OTP's rationale for including it in the model.[22] We also revised the minimum capacity of the battery storage resource to allow the model to be able to dispatch the battery storage resources at any level greater than 0 MWh and less than the total energy storage for the resource, rather than only allowing battery resources to dispatch at the maximum capacity as OTP had modeled.[23]

1.1.7 Withdrawal Dates for Coyote and Big Stone

OTP's supplemental IRP included modeling runs that included either a 2028 or 2040 withdrawal date for Coyote. For purposes of our modeling, we compared the CEOs Preferred Plan with OTP's Preferred Plan with 2040 withdrawal ("Revised OTP Preferred 2040 Plan"), and its 2028 Coyote Withdrawal plan ("Revised OTP 2028 Plan").

[20] The model sees a dispatch adder input as an additional cost to dispatch the resource. Capacity expansion models typical see the dispatch cost of a resource as the fuel and any non-fuel variable operations and maintenance costs. When a dispatch adder is also set for a resource, this can either be a standalone cost for non-fuel resources or an additional cost for fuel resources.

[21] Initial production cost runs were resulting in an error message and further investigation into the cause of the error led us to realize that it was being caused by the min capacity input for the battery storage resources. The battery storage resources were set to have a minimum capacity equal to the maximum capacity which meant that the resources could only dispatch at the maximum capacity level.

[22][Trade Secret Data Begins]

. [Trade Secret Data Ends]

[23] See footnote 14.

OTP did not perform any modeling runs in the Supplemental IRP that considered a withdrawal date for Big Stone before 2046. We typically see withdrawal/retirements modeled by either allowing the capacity expansion model to optimize the retirement date for units or specific scenarios are modeled with hardcoded retirement dates. OTP did not use either approach to evaluate a withdrawal/retirement date for Big Stone as all of OTP's modeling assumed that Big Stone would continue to operate until 2046. The CEOs Preferred Plan models a 2030 withdrawal from Big Stone.

As noted in section 1.1.2, CEOs offered EnCompass the option to select replacement resources at both coal facilities to represent the potential for reusing interconnection rights in a retirement scenario. However, we also evaluate the portfolio's costs assuming these additions are generic. Thus, the CEOs Preferred Plan contemplates and is valid in a scenario where OTP is not able to reuse the interconnection rights at Coyote or Big Stone.

1.1.8 Cost of Curtailment for New Wind and Solar Resources

OTP modeled new wind and solar costs on a levelized cost of energy basis. This means that the cost was developed based on an assumption around an expectation of how much energy the resources will generate. We added an input within EnCompass to ensure that the model captured the cost of the total energy produced from the renewable resources, including any curtailed energy.

2 CEO Modeling Methodology

The changes described above were then applied to the three resource portfolios presented in this report. This approach was chosen to allow for an apples-to-apples comparison of costs for the Coyote and Big Stone decisions. Comparing the CEO Preferred Plan to the Revised OTP Preferred 2040 Plan shows the impacts of early versus late withdrawal from both Coyote and Big Stone. Comparison of the CEOs Preferred Plan to the Revised OTP 2028 Plan isolates the impacts of early exit from Big Stone alone because both plans include the early withdrawal from Coyote in 2028. Table 4 shows a breakdown of the specific changes made to the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan.

Table 4. CEO Modeling Changes Summary

Modeling Changes	CEOs Preferred Plan	Revised OTP Preferred 2040 Plan	Revised OTP 2028 Plan
CEO Renewables and Storage Costs	✓	✓	✓
Coyote specific replacement resources	✓	-	-
Big Stone specific replacement resources	✓	-	-
Revisions to new resource constraints	✓	-	-
Market Import/Export Assumptions	✓	✓	✓
CEO Approach for Regulatory Cost of Carbon and externality costs	✓	✓	✓
Astoria capacity factor limit	✓	✓	✓
Battery storage partial units	✓	-	-
Remove battery storage dispatch adder	✓	✓	✓
Revise battery storage minimum capacity	✓	✓	✓
Coyote Withdraw 2028	✓	-	✓
Big Stone Withdraw 2030	✓	-	-
Curtailment Costs	✓	✓	✓

The resource expansion plans and cost comparisons that result from these runs are discussed in Section 3.

2.1 Setting up the CEO Modeling Runs

The primary model runs we performed are described in this section.

The Revised OTP Preferred 2040 Plan and the Revised OTP 2028 Plan include the same resource build decisions that OTP modeled for these plans in the IRP. For the CEOs Preferred Plan, we included the fixed resource decisions that were specified by OTP for 2027 through 2032 included in the Revised OTP 2028 Plan. These resources, along with the resource builds for the Revised OTP Preferred 2040 Plan are shown in Table 5 below. We then allowed the model to optimize for additional resources subject to the modeling input changes outlined in Section One for the CEOs Preferred Plan.

Table 5. New Resource Builds (2027-2032)

New Resource	Year Added	MW Added in Revised OTP 2028 Plan	MW Added in Revised OTP Preferred 2040 Plan
Surplus and Capacity Solar	2027	100	100
Surplus and Capacity Solar	2028	50	50
Surplus Solar	2028	50	50
Generic Wind	2029	200	200
Surplus Solar	2030	100	0
Generic Wind	2031	150	0
Surplus Solar	2032	100	100
Surplus Battery	2032	25	25

OTP's modeling approach for the Supplemental IRP was to only perform capacity expansion runs and not pass the portfolios developed in the capacity expansion step through the production cost capability within EnCompass. In order to perform capacity expansion modeling, capacity expansion models typically need to do time sampling[24] to manage the problem size and run time. This means that EnCompass performs the capacity expansion step with simplified dispatch using time sampling and then maps the results onto the entirety of each year. Portfolios are then typically put through the production cost modeling step where the resource portfolio is fixed and dispatched under more granular unit commitment and dispatch across all 8760 hours in each year of the planning period. We typically see utilities perform both capacity expansion and production cost modeling in their resource plan filings, as the production cost step allows for more granular detail of unit commitment and dispatch for developing costs of resource portfolios.

CEOs performed production cost runs of the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan to ensure that we would be able to provide the most granular information about portfolio costs and to allow the plans to be compared on an apples-to-apples cost basis.

[24] It is common for the time sampling to be representative weeks or on and off-peak days.

3 CEO Modeling Results

3.1 Capacity Expansion Portfolio Results

Figure 5 shows a comparison of the cumulative installed capacity in MWs from 2027 to 2050 for the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan. The main differences in the resource additions in the three plans are:

(1) The CEOs Preferred Plan includes an additional 150 MW of replacement wind for the Coyote withdrawal in 2028;
(2) The CEOs Preferred Plan includes 300 MW of additional generic wind resources in 2029;
(3) The CEOs Preferred Plan includes the withdrawal from Big Stone in 2030 and replacement resources consisting of 150 MW of 4-hour battery storage and 100 MW of wind. The Revised OTP 2028 Plan and the Revised OTP Preferred 2040 Plan continue to operate Big Stone until 2046 and then the model selects the "firm dispatchable"[25] resource after Big Stone retires.

Figure 5. Cumulative Installed Capacity (MW) Between 2027 and 2050

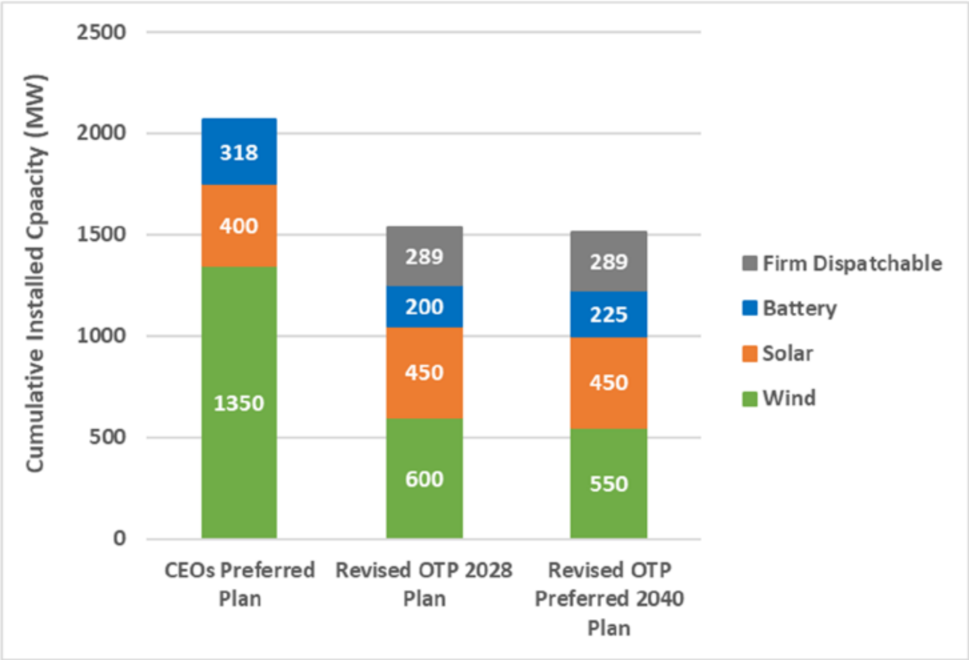


Table 6 below shows the annual installed capacity additions and withdrawals for the CEOs Preferred Plan between 2027 and 2032.

[25] This resource is modeled with the characteristics of a Combustion Turbine, but it is labeled as "Firm Dispatchable" in the EnCompass modeling.

Table 6. CEOs Preferred Plan Near Term Resource Additions and Withdrawals (2027-2032, Installed Capacity, MW)

	2027	2028	2029	2030	2031	2032
New Resource Additions:						
Surplus and Capacity Solar	100	50	0	0	0	0
Surplus Solar	0	50	0	100	0	100
Replacement Wind Coyote	0	0	150	0	0	0
Generic Wind	0	0	500	0	150	0
Replacement Wind Big Stone	0	0	0	0	100	0
Replacement Battery Storage Big Stone	0	0	0	0	150	0
Surplus Battery Storage	0	0	0	0	0	25
Withdraw:						
Coyote		-150				
Big Stone				-256		

Table 7, Table 8, and Table 9 show the winter accredited capacity for OTP's existing and new resource mix for the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan, respectively, between 2027 and 2040.

Table 7. Existing and New Resources in the CEOs Preferred Expansion Plan (Winter Accreditation, MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Existing Resources:														
Coal	396	396	253	253	0	0	0	0	0	0	0	0	0	0
Combustion Turbine	384	384	384	384	384	384	384	326	326	326	326	326	285	285
Contract	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Wind	211	211	202	202	190	190	183	183	183	183	183	183	183	183
Solar	3	3	3	3	0	0	0	0	0	0	0	0	0	0
Demand Response	123	125	126	127	129	131	134	137	139	143	143	143	143	143
Total Existing	**1128**	**1129**	**980**	**981**	**714**	**717**	**712**	**657**	**660**	**664**	**664**	**664**	**623**	**623**
New Resources:														
Solar	6	9	9	9	2	2	2	2	2	2	2	2	2	2
Wind	0	0	262	262	333	333	342	342	389	389	389	389	389	389
Battery Storage	0	0	0	0	123	146	146	146	146	146	146	146	146	146
Total New	**6**	**9**	**271**	**271**	**458**	**480**	**489**	**489**	**536**	**536**	**536**	**536**	**536**	**536**
Total	**1134**	**1139**	**1251**	**1252**	**1172**	**1197**	**1202**	**1147**	**1196**	**1200**	**1200**	**1200**	**1158**	**1158**

Table 8. Existing and New Resources in the Revised OTP 2028 Plan (Winter Accreditation, MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Existing Resources:														
Coal	396	396	253	253	253	253	253	253	253	253	253	253	253	253
Combustion Turbine	384	384	384	384	384	384	384	326	326	326	326	326	285	285
Contract	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Wind	211	211	202	202	190	190	183	183	183	183	183	183	183	183
Solar	3	3	3	3	0	0	0	0	0	0	0	0	0	0
Demand Response	123	125	126	127	129	131	134	137	139	143	143	143	143	143
Total Existing	**1128**	**1129**	**980**	**981**	**968**	**970**	**966**	**911**	**913**	**917**	**917**	**917**	**876**	**876**
New Resources:														
Solar	6	9	9	9	2	2	2	2	2	2	2	2	2	2
Wind	0	0	81	81	130	130	130	130	130	130	130	148	148	148
Battery Storage	0	0	0	0	0	23	23	23	23	23	23	64	64	64
Total New	**6**	**9**	**90**	**90**	**131**	**154**	**154**	**154**	**154**	**154**	**154**	**213**	**213**	**213**
Total	**1134**	**1139**	**1070**	**1071**	**1099**	**1124**	**1119**	**1064**	**1067**	**1071**	**1071**	**1130**	**1089**	**1089**

Table 9. Existing and New Resources in the Revised OTP Preferred 2040 Plan (Winter Accreditation, MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Existing Resources:														
Coal	396	396	396	396	396	396	396	396	396	396	396	396	396	396
Combustion Turbine	384	384	384	384	384	384	384	326	326	326	326	326	285	285
Contract	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Wind	211	211	202	202	190	190	183	183	183	183	183	183	183	183
Solar	3	3	3	3	0	0	0	0	0	0	0	0	0	0
Demand Response	123	125	126	127	129	131	134	137	139	143	143	143	143	143
Total Existing	**1128**	**1129**	**1122**	**1123**	**1110**	**1113**	**1108**	**1053**	**1056**	**1060**	**1060**	**1060**	**1018**	**1018**
New Resources:														
Solar	6	9	9	9	2	2	2	2	2	2	2	2	2	2
Wind	0	0	81	81	74	74	74	74	74	74	74	74	93	93
Battery Storage	0	0	0	0	0	23	23	23	23	23	23	23	23	23
Total New	**6**	**9**	**90**	**90**	**76**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**117**	**117**
Total	**1134**	**1139**	**1212**	**1213**	**1185**	**1211**	**1206**	**1151**	**1154**	**1158**	**1158**	**1158**	**1135**	**1135**

3.2 Present Value Revenue Requirement ("PVRR") and Partial Present Value Societal Cost ("PVSC") Cost Results

In this section we provide the PVRR and the partial PVSC cost results for the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan. To calculate the Partial PVSC results, we performed a post-processing step to adjust the revenue requirements calculated within EnCompass to account for the Minnesota Public Utility Commission's estimates of the externality costs of SO_2, NOx, and PM2.5 emissions. However, these PVSC results do not reflect any CO_2 externality costs which are discussed in section 3.4 (and which is why these are designated as only *Partial* PVSC costs).

The externality costs of emissions need to be added outside of the model since those costs are not part of the optimization within EnCompass. This is the typical approach to externalities since in reality they are not reflected in a utility's revenue requirement and would not affect dispatch. (We note that OTP took a different approach. OTP's modeling runs labeled "Externalities Included" included both the Regulatory Cost of Carbon and the externality costs as dispatch adders, which means these costs are included in the PVRR reported from EnCompass for these runs. However, OTP's modeling only applied externalities to a fraction of its emissions, excluding all CO_2 externalities from emissions outside of Minnesota— so the cost of emissions from Coyote and Big Stone were not counted in OTP's PVRR).

Table 10, below, shows the PVRR and Partial PVSC[26] net present value ("NPV") for the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan for the planning period 2023 - 2050. The PVRR category reports the PVRR from EnCompass, including the PUC's mid-range Regulatory Cost of Carbon, in addition to out-of-model adjustments for the interconnection cost of new generic battery resources and OTP's wind congestion adder for generic wind resources. The Partial PVSC column adds the externality costs of SO_2, NOx, and PM2.5 to the PVRR.

Table 10. PVRR and Partial PVSC Results for CEO Modeling ($000)

Plan	PVRR	Partial PVSC[27]
CEOs Preferred Plan	$2,196,616	$2,338,702
Revised OTP 2028 Plan	$2,822,359	$2,977,053
Revised OTP Preferred 2040 Plan	$3,012,835	$3,289,636

[26] The externalities were only applied to half of Otter Tail's emissions to focus on the impact of energy serving OTP's Minnesota energy requirements (OTP Supp IRP, Supplemental Table 5-1, page 33).

[27] The PVSC includes the externality costs for SO_2, NOx, and PM2.5 from OTP's thermal resources.

Since the CEO modeling runs allowed for the consideration of market sales, we wanted to also reflect the PVRR for the three plans when market sales revenue is not included in the PVRR calculation. Table 11 shows the PVRR and Partial PVSC results for each portfolio when sales revenue is not considered.

Table 11. PVRR and Partial PVSC Results for CEO Modeling ($000) No Sales Revenue

Plan	PVRR	Partial PVSC[28]
CEOs Preferred Plan	$2,808,893	$2,950,980
Revised OTP 2028 Plan	$3,032,574	$3,187,269
Revised OTP Preferred 2040 Plan	$3,215,976	$3,492,778

We also evaluated what the cost impact might be on the CEOs Preferred Plan if OTP did not have the ability to locate the wind and battery storage replacement resources for Coyote and Big Stone at those facility locations. We modified the wind and battery storage resources to reflect the costs as if they were generic resources located at a new site. Table 12 below provides an overview of how we modified the wind and battery storage resource cost assumptions to move from replacement to generic resources for this evaluation.

Table 12. Wind and Battery Storage Cost Modifications for CEOs Generic Resources Scenario

	Wind	Battery Storage
Remove IRA Bonus Adder	✓	✓
Include Interconnection Cost	✓	✓
Wind Congestion Adder	✓	Not Applicable

Table 13 shows the PVRR results when we consider the cost impact of not being able to locate the wind and battery storage replacement resources included in the CEOs Preferred Plan at the Coyote and Big Stone locations.

[28] The PVSC includes the externality costs for SO_2, NOx, and PM2.5 from OTP's thermal resources.

Table 13. PVRR Results with and without Replacement Interconnection Option at Coal Sites ($000)

Plan	PVRR	Difference from Revised OTP Preferred 2040 Plan	Difference from Revised OTP 2028 Plan
CEOs Preferred Plan	$2,196,616	$(816,219)	$(625,743)
CEOs Preferred Plan - Generic Resources	$2,296,579	$(716,256)	$(525,780)
Replacement Interconnection and Energy Community Resources Value	$(99,963)		-

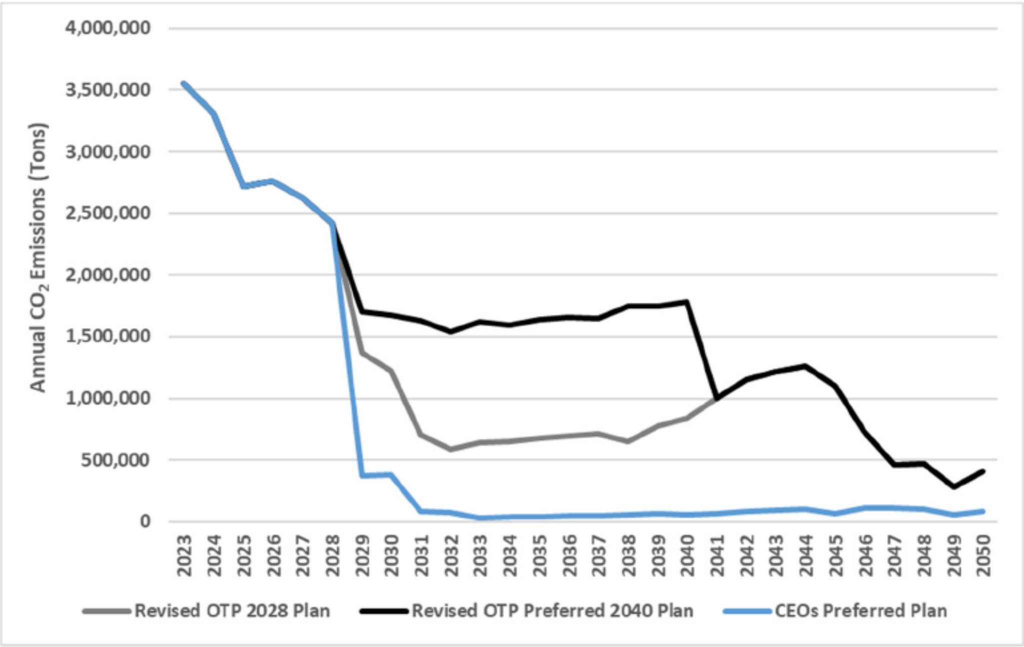
3.3 Carbon Emissions

The level of carbon emissions reduction between the CEOs Preferred Plan and the two Otter Tail plans is another important factor to consider when evaluating them. Table 14 provides the cumulative CO_2 emissions comparison between the three plans when only considering the emissions from OTP's existing and planned resources in the portfolio over the planning period (2023-2050). Table 14 also includes the cumulative emissions for each portfolio between (2023-2030) and (2031-2040) to show the emissions impact for each decade. Table 14 does not reflect the additional carbon emissions associated with MISO purchases, and our modeling shows these emissions would be much higher under either of OTP's plans than under the CEOs Preferred Plan. Figure 6 shows the annual carbon emissions comparison between the plans when considering emissions from OTP's thermal resources.

Table 14. Cumulative Carbon Emission Comparison (Tons)

Plan	Cumulative (2023 -2050)	CO_2 Avoided by CEOs Plan	Cumulative (2023-2030)	CO_2 Avoided by CEOs Plan	Cumulative (2031-2040)	CO_2 Avoided by CEOs Plan
CEOs Preferred Plan	19,573,688	-	18,157,494	-	538,494	-
Revised OTP 2028 Plan	35,024,275	15,540,587 **44%**	19,993,298	1,835,804 **9%**	6,935,981	6,397,487 **92%**
Revised OTP Preferred 2040 Plan	45,483,683	25,909,995 **57%**	20,776,229	2,618,735 **13%**	16,611,216	16,072,722 **97%**

Figure 6. Annual Carbon Emission Comparison for OTP Thermal Resources in Each Plan (Tons)



3.4 EPA Social Cost of Carbon

We also evaluated the CEOs Preferred Plan, the Revised OTP Preferred 2040 Plan, and the Revised OTP 2028 Plan under the Environmental Protection Agency's ("EPA") new estimates[29] for the social cost of carbon.

The EPA provides estimates for the social cost of carbon across three different discount rate scenarios (2.5%, 2.0%, and 1.5%), as the social cost of carbon is the discounted future damages of carbon emissions—discounted back to the year of emission. For instance, the 2030 social cost of carbon represents the future damages discounted back to 2030. Thus, when calculating the NPV of the social cost of carbon under the EPA estimates, we discounted each year's social costs from the year of emission back to 2023 to get a 2023 net present value. To do this, we used the EPA discount rates rather than OTP's weighted average cost of capital ("WACC")[30] to be consistent with the EPA's discounting of post-emission year damages. Since the PVRR and Partial PVSC rely on OTP's WACC for discounting, and the EPA social cost of carbon is utilizing different discount rates, we are presenting the NPV of the social cost of carbon as a separate cost calculation to the PVRR and Partial PVSC.

[29] Retrieved from https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf

[30] We also are presenting the NPV of the social cost of carbon separately since it is based on a real discount rate and the PVRR's of OTP's plans are based on a nominal discount rate.

Table 15 shows the NPV of the social cost of carbon calculated for the three plans under the three different discount rates used by the EPA for the energy serving Otter Tail's entire system, including Minnesota, North Dakota, and South Dakota load. Table 16 shows the NPV of the social cost of carbon only for the energy serving the Minnesota load. Since the Minnesota portion of OTP's total energy requirements is 50%,[31] the social cost of carbon presented in Table 16 is half the costs in Table 15 .

Table 15. Social Cost of Carbon NPV[32] (2023-2050, Real 2023 $000) for Minnesota, South Dakota and North Dakota

	Discount Rate		
Plan	**2.50%**	**2%**	**1.50%**
CEOs Preferred Plan	$2,255,667	$3,767,486	$6,799,245
Revised OTP 2028 Plan	$3,838,419	$6,615,549	$11,902,248
Revised OTP Preferred 2040 Plan	$4,929,013	$8,570,859	$15,391,060

Table 16. Social Cost of Carbon NPV (2023-2050, Real 2023 $000) for Minnesota

	Discount Rate		
Plan	**2.50%**	**2%**	**1.50%**
CEOs Preferred Plan	$1,127,834	$1,883,743	$3,399,622
Revised OTP 2028 Plan	$1,919,210	$3,307,774	$5,951,124
Revised OTP Preferred 2040 Plan	$2,464,507	$4,285,430	$7,695,530

Table 17 and Table 18 below show the cumulative emissions and social cost of carbon NPVs for Coyote (cumulative emissions from 2029 to 2040) and Big Stone (cumulative emissions from 2031 to 2046), respectively, in the Revised OTP Preferred 2040 Plan. The NPV represents an approximation of the additional social cost of carbon for operating Coyote and Big Stone past the withdrawal dates included in the CEOs Preferred Plan.

[31] Otter Tail supplemental IRP, p. 33
[32] The NPVs presented in the table are reduced by the NPV of the Carbon Regulatory cost in each of the plans to reflect the partial internalization of those externalities.

Table 17. Carbon Emissions (Tons) and Social Cost of Carbon NPV for Coyote (Real 2023 $000) in the Revised OTP Preferred 2040 Plan for Minnesota[33]

		Discount Rate		
	Cumulative Emissions	2.50%	2%	1.50%
Coyote, 2029 - 2040	11,935,323	$663,608	$1,177,452	$2,070,090

Table 18. Carbon Emissions (Tons) and Social Cost of Carbon NPV for Big Stone (Real 2023 $000) in the Revised OTP Preferred 2040 Plan for Minnesota[34]

		Discount Rate		
	Cumulative Emissions	2.50%	2%	1.50%
Big Stone, 2031 - 2046	9,571,250	$517,883	$924,940	$1,635,754

[33] The externalities were reduced by half to focus on the impact of energy serving OTP's Minnesota energy requirements (OTP Supp IRP, Supplemental Table 5-1, page 33).
[34] The externalities were reduced by half to focus on the impact of energy serving OTP's Minnesota energy requirements (OTP Supp IRP, Supplemental Table 5-1, page 33).

4 Production Cost Modeling Hourly Analysis

As a supplemental step to the production cost modeling runs, we also reviewed the hourly detailed output for the year 2029 and 2031 for the CEOs Preferred Plan to assess its performance under challenging winter conditions. We selected the year 2029 and 2031 for evaluation since 2029 is the first year after the withdrawal from Coyote in the CEOs Preferred Plan and the Revised OTP 2028 Plan, and 2031 is the first year without Big Stone in the CEOs Preferred Plan.

For the hourly analysis, we focused on evaluating the winter hours with the highest peak demand and lowest wind generation. Thus, these would be the most difficult circumstances for winter reliability in the modeling. As we started reviewing results from these runs, we realized that in many hours the model was choosing MISO market purchases over the dispatch of some of OTP's existing resources for economic purposes. During these periods, the hourly market prices were lower than the dispatch price for any of OTP's thermal units.

Since we wanted to focus this hourly look at how OTP's system would dispatch during periods of high demand or lower wind generation, we made a couple of modifications to the modeling inputs to ensure that all of OTP's resources would dispatch before the model turned to market purchases. In order to execute this in EnCompass, we allowed OTP's demand response resources[35] to be called on and we also modified the market price forecast to raise the market price to ensure that it would be higher than the highest-cost unit in OTP's fleet of resources.

The following sections will provide more detail on the results for 2029 and 2031.

4.1 2029 Hourly Analysis

Figure 7 illustrates the dispatch of OTP's system on one of the winter peak days we evaluated for 2029. This dispatch reflects OTP's system with Coyote offline and the new solar and wind resources from the CEOs Preferred Plan online. On this day, the model is dispatching both Big Stone and Astoria with additional generation from the existing and new renewable resources. In almost every hour, the OTP system is exporting to the MISO market (as shown by generation above the dotted line which represents Otter Tail's demand) and is in a capacity surplus position. It is also important to note that OTP has an additional 350 MW of peaking units and approximately 130 MW of winter demand response resources that did not need to be called upon in this particular example.

[35] OTP modeled two distinct demand response resources in the EnCompass database for the Minnesota and North Dakota jurisdictions. Since there are two separate resources, there may be periods when the model dispatches both programs at the same time or it may choose to dispatch them separately at different time periods in the day.

Figure 7. Example Winter Peak Day on January 5th, 2029 (MW)

[Trade Secret Data Begins]

[Trade Secret Data Ends]

Figure 8 illustrates the dispatch of OTP's system on one of the winter peak days that also coincides with low output from the new[36] generic and replacement wind resources. For this day, we modified the market price forecast and allowed the demand response resources to dispatch to see what the dispatch would look like if OTP utilized its own resource capacity before turning to market purchases. Market purchases for this day on average account for 2% of OTP's hourly demand.

[36] In EnCompass, OTP modeled an hourly shape for each existing wind resource and applied one wind shape to all new wind resources. This analysis focuses on days with lower output from the new wind resources.

Figure 8. Example Winter Peak Day and Lower Wind Output on January 26th, 2029 (MW)

[Trade Secret Data Begins]

[Trade Secret Data Ends]

4.2 2031 Hourly Analysis

Figure 9 illustrates the dispatch of OTP's system on one of the winter peak days we evaluated for 2031. Upon review, the market price forecast for this day provided by OTP was lower than expected, and so not all of OTP's resources were dispatched. We needed to make modifications to the market price forecast and the demand response resources to see what dispatch would look like if OTP dispatched its resources before turning to market purchases (the model otherwise preferred market purchases as lower cost). These changes better reflect the scenario we are seeking to investigate – a winter peak day with potentially limited supply and, therefore, high market prices. On this day, the model is utilizing the demand response and battery storage resources in the early morning hours. Market purchases in the later afternoon hours help with charging the battery storage resources so that the battery storage resources are available in the later evening hours before the uptick in wind generation. Market purchases for this day on average account for 21% of OTP's hourly demand.

Figure 9. Example Winter Peak Day on January 31st, 2031 (MW)

[Trade Secret Data Begins]

[Trade Secret Data Ends]

Figure 10 illustrates the dispatch of OTP's system on January 18th, which is a both a winter peak day and lower wind generation day for the new wind resources in the CEOs Preferred Plan. Here, we also needed to make modifications to the market price forecast and the demand response resources to ensure the model was utilizing all of OTP's resources before turning to market purchases. In this example, OTP is dispatching all the peaking units, calling on the Minnesota and North Dakota demand response resources at different points in time, and utilizing excess solar generation to help charge the battery storage resources so that they can discharge in the later evening hours. Market purchases for this day on average account for 17% of OTP's hourly demand.

Figure 10. Example Winter Peak Day and Lower Wind Output on January 18th, 2031 (MW)

[Trade Secret Data Begins]

[Trade Secret Data Ends]

This hourly production cost modeling analysis allowed us to investigate how the existing and planned resources in the CEOs Preferred Plan would perform under challenging winter conditions, i.e., peak load and low wind generation. The CEOs Preferred Plan was able to meet the peak demand in every hour of the high stress periods evaluated for this analysis.

5 EnCompass Modeling Recommendations

In this section, we offer several modeling recommendations for OTP to consider for future IRP filings.

5.1.1 Carbon Emission Rate Assigned to Market Purchases

OTP included assumptions about the carbon emission rate associated with market purchases in the model. However, the emission rate was assumed to be a static value over the entire planning period of 2023-2050. We recommend that for future IRPs, OTP consider evaluating an emission rate that declines through the planning period to reflect increases in penetration of renewable resources, retirement of thermal resources with higher emission rates, and the decarbonization of the electric system.

5.1.2 Market Price Forecasts for Regulatory Carbon Cost Cases

In Appendix F, OTP described in its source for the electric market price forecast used as an input for the EnCompass model:

> *Otter Tail used the Wood Mackenzie July 2022 North American Power Service as the basis for the market energy prices used in this resource plan. Otter Tail applied the Wood Mackenzie forecasted monthly on-peak and off-peak energy prices to an hourly profile to reflect the hourly variability/volatility of the energy market.*[37]

In future IRPs, we would recommend that OTP develop additional market price forecasts for the modeling runs that include the Regulatory Cost of Carbon as a dispatch adder. Without having a market price forecast that reflects the Regulatory Cost of Carbon, there is an asymmetry modeling OTP's system with the Regulatory Cost of Carbon included as a dispatch adder, which can cause the model to prefer market purchases more than it otherwise might. This issue is further exacerbated by the modeling approach that OTP took for this IRP since the externality modeling runs performed by OTP included both the Regulatory Cost of Carbon and externality costs as a dispatch adder for thermal units.

5.1.3 Evaluating Sales

OTP's modeling for the Supplemental IRP included an assumption that OTP would be able to import from the market in any given hour of the planning period, but there were no market sales allowed. We understand that sometimes modelers need to impose constraints or limits within the model, however, we typically see utilities include a market representation that includes both imports and sales. In order to reflect a more accurate depiction of how OTP's system would operate, we recommend that in future IRPs, OTP include modeling runs that include a representation of both market purchases and sales.

[37] OTP Supp IRP, Appendix F, p.11.

5.1.4 Demand Response Resources

OTP included its existing demand response resources in the EnCompass database as a resource. However, the inputs were configured in a way that prevented the model from being able to dispatch these resources. This assumption seems to contrast with the information that was provided on the historical operation of OTP's demand response programs in response to CEO IR 048 Att. 1. We recommend that for future IRPs, OTP allow demand response resources to be dispatched in the modeling under operational constraints that reflect the parameters of the program, i.e., limits on the number of calls per day/week/month/year and on the duration of calls.

5.1.5 Production Cost Modeling

We recommend that for future IRPs OTP conduct both capacity expansion and production cost modeling. Since there is commitment and dispatch simplification that must happen in the capacity expansion modeling step to manage run times, we believe that including the production cost modeling step will provide OTP with more detailed information to use for the development of the portfolio PVRRs and to evaluate the dispatch of resources during specific periods of time such as the analysis presented in Section 4. We also were able to discover the issue with the minimum capacity of the battery storage units discussed in Section 1.1.6 because of an error message we received when running the production cost modeling step.