State of Minnesota
Before the Public Utilities Commission

Katie Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph Sullivan	Commissioner
John Tuma	Commissioner

In the Matter of Minnesota Power's
Application for Approval of its 2021-2035
Integrated Resource Plan

Docket No. E-015/RP-21-33

Comments of the Citizens Utility Board of Minnesota

I. Introduction

The Citizens Utility Board of Minnesota ("CUB") welcomes the opportunity to comment on Minnesota Power's ("Company") 2021 Integrated Resource Plan ("IRP" and "Plan"). CUB a is a nonprofit organization that advocates on behalf of residential ratepayers for affordable clean energy and consumer protections in utility service. In addition to advocating for consumers before the Commission and at the Legislature, CUB provides Minnesotans with information on how to reduce their utility bills and directs them to appropriate resources. These Comments were prepared with the assistance of Strategen,[1] and they are based on a review and analysis of the Company's assumptions, inputs, and methodology. The comments provided evaluate the Company's approach and determine whether the IRP serves the best interest of ratepayers.

We applaud Minnesota Power's commitment to deliver carbon-free electricity by 2050 while maintaining reliable, affordable power for its customers.[2] However, we have several concerns with the manner in which the Company considered its resource options in this IRP. The goal of an IRP is to establish a plan that ensures that customers' needs are met in a reliable and least-cost way while complying with all relevant Minnesota statutes. As these comments will demonstrate, the Company's assumptions and modeling choices are flawed and require further evaluation by the Commission. Considering the Company's unique customer base, the Company's carbon-free commitment and the urgency of the clean energy transition, the economic uncertainty facing ratepayers, and the Company's responsibility to continue to provide reliable and low-cost services, the Commission must take care in this process to ensure that Minnesota Power is prudently managing its risks and choosing a least-cost path for customers.

The Plan's lack of consideration of resources other than thermal generation to replace Boswell Energy Center Units 3 and 4 ("BEC 3 and 4") is highly problematic. The very purpose of an IRP is to run various

[1] Strategen is a globally connected, impact-driven firm that helps clients envision, accelerate, and create the clean energy future. Strategen is a minority- and woman-owned business headquartered in Northern California, with offices in Portland, Oregon, and Brisbane, Australia.
[2] In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan Docket No. E015/RP-21-33, February 1, 2021, p. 1.

portfolios under a range of conditions to identify a least-cost, least-risk path. By restricting the types of resources that can replace a significant size of the Company's generation portfolio, the Company is inappropriately limiting potential cost-effective resource options.

Another significant issue is the Plan's reliance on a scenario that includes a regulatory cost that does not reflect the utility's actual operating conditions and thus will not accurately reflect reality. As we will explain, applying a regulatory cost impacts the merit order of dispatch, and so the Company's model chooses to reduce coal unit dispatch, which in turn reduces the environmental impacts of the coal units. Consequently, the model chooses to significantly reduce the capacity factor of BEC 3 and 4 but to keep the units online for capacity purposes. In reality, there is no regulatory mechanism in place that would restrain Minnesota Power's dispatch of its thermal fleet, and, as such, the utility is most likely to run the thermal units at a higher capacity, leading to the scenario with the highest environmental and ratepayer costs for customers of the Company's examined scenarios.

These comments reflect the Citizens Utility Board's analysis of Minnesota Power's proposed IRP. We include limited preliminary recommendations based on that analysis. We may provide further recommendations regarding resource options in reply comments after reviewing modeling presented by the Department of Commerce and other intervenors.

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II. Comments

A. Environmental Adders and the Impacts to Boswell Energy Center 3 and 4

i. Minnesota Power's inclusion of regulatory costs in its modeled dispatch decisions creates an unrealistic projection of BEC dispatch.

As part of the Order Establishing the 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, the Minnesota Public Utilities Commission required electric utilities to model certain environmental cost scenarios.[3] CUB is supportive of the Commission's requirement for the utilities to model various environmental and regulatory cost conditions to better understand the relative costs and risks of portfolios under various futures. However, we want to highlight that unless the Company operates its generation fleet as it is modeled, which the Company is neither required nor likely to do, then the IRP could result in real-world operations that are both higher emission and higher cost than the model suggests.

a. Background

Minnesota Power's Preferred Plan retires BEC 3 in 2029 and maintains BEC 4 until 2035.[4] The Company also modeled various retirement dates for BEC 3 and 4 to determine if earlier retirements dates were more appropriate (its "Alternative Power Supply Portfolios" or "Swim Lane alternatives"). The alternatives include:

1. "Preferred Plan", which retires BEC 3 in 2029, also called the "2021 Plan" and the "PrefPlan Case;"
2. Expedited Retirement of BEC 3 (2025) and BEC 4 (2030), also called the "FastExit Case;"
3. Early3, which retires BEC 3 in 2025.
4. Early4, which retires BEC 4 in 2030.
5. Base Case, also called the "Status Quo," which does not include the early retirement of BEC 3 and 4.

In compliance with the Commission's Estimate of Future Carbon Dioxide Regulation Costs, the Company also modeled the four Commission-ordered environmental cost scenarios, plus two additional scenarios, in its Capacity Expansion and Swim Lane Comparative Analyses. The four Commission-ordered environmental future scenarios include:[5]

1. CLE1S: Incorporate, for each year of a generator's expected operating life, the low end of the range of environmental costs for CO2 as approved by the Commission in its Environmental Cost Order;

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[3] Docket Nos. E999/CI-07-1199 and E999/DI-19-406 (Sep. 30, 2020).
[4] Minnesota Power, 2021 Integrated Resource Plan, p. 68.
[5] Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket Nos. E999/CI-07- 1199 and E999/DI-19-406 (Sep. 30, 2020).

2. CHE1S: Incorporate, for each year of a generator's expected operating life, the high end of the range of environmental costs for CO2 as approved by the Commission in its Environmental Cost Order;

3. CLER1S: Incorporate the low end of the range of environmental costs for CO2 but substitute, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations ($5 per short ton) in lieu of environmental costs as approved by the Commission in its Environmental Cost Order;

4. CHER1S: Incorporate the high end of the range of environmental costs for CO2 but substitute, for planning years after 2024, the high end of the range of regulatory costs for CO2 regulations ($25 per short ton) in lieu of environmental costs, as approved by the Commission in its Environmental Cost Order;

The two additional scenarios that were not required by the Commission include:

5. CREF1S (reference): reference case that included "medium" environmental costs prior to 2025 and $15/ton regulation costs after 2024;

6. CCUST1S: no environmental cost and no carbon regulation cost throughout the planning horizon.

b. Modeling approach

The Company applied a two-step approach for determining its Preferred Plan for retiring BEC 3 and 4 and identifying replacement resources. First, the Company conducted a Capacity Expansion Analysis for each BEC retirement scenario, to determine which resources should be added to the portfolio and when. Second, for each environmental future, the Preferred Plan and Swim Lane alternatives were put through 37 sensitivities to test the main drivers for resource decisions (the "Swim Lane Comparative Analysis").[6]

Regarding the environmental future scenarios, it is helpful to understand how the environmental and regulatory costs are included in the model and how each impacts the results. Environmental costs are added to the total supply costs after the units have dispatched. As such, an environmental cost does not have any impact on the merit order of dispatch in the model. The environmental costs are simply the summation of the negative externality costs. CLE1S and CHE1S are the two scenarios that include only an environmental cost. The regulatory costs, on the other hand, are included in the utility's cost of operations and have an impact on the merit order of dispatch. The model pretends that there is an actual cost of emissions that the Company will have to pay. Scenarios CLER1S, CHER1S, and CREF1S incorporate regulatory costs beginning in 2025.

The Company then analyzed each environmental and regulatory cost scenario through the Swim Lane analysis to determine its least-cost plan under the various retirement scenarios. The results of the Base Case run are shown in Figure 1 below.

[6] Minnesota Power, 2021 Integrated Resource Plan, Appendix K, p. 16.

Figure 5: Net Present Value of each Environmental and BEC Retirement Scenario[7]

	NPV ($millions)				
	PrefPlan	FastExit	Early3	Early4	StatusQuo
CLE1S	$7,814	$7,707	$7,781	$7,852	$8,061
CHE1S	$9,727	$9,290	$9,607	$9,721	$10,337
CLER1S	$7,494	$7,502	$7,486	$7,537	$7,632
CHER1S	$8,276	$8,366	$8,302	$8,281	$8,379
CREF1S	$7,891	$7,944	$7,903	$7,918	$8,010
[Trade Secret Data Begins[8]					
CCUST1S	[redacted]				
Trade Secret Data Ends]					

The Company also ran each environmental and regulatory cost scenario through 37 sensitivities to determine the optimal retirement dates for BEC 3 and 4. Below, for each environmental scenario, we summed the number of sensitivities that resulted in least-cost runs under each retirement scenario.

[7] CREF1S results: IRP Table 4 (Base Case Sensitivity)
CLE1S, CHE1S, CLER1S, CHER1S results: Appendix K, Tables 4,5,6,7
CCUST1S results: Workpaper 1-NPVCostTableTemplate (folder: IRP2021 Sup Analysis - Swimlane Results.zip)

[8] We have marked this data as trade secret as it appears to be only included in the Company's nonpublic filings.

Figure 6: Number of Least-Cost Sensitivities for each Environmental Scenario[9]

	PrefPlan	FastExit	Early3	Early4	StatusQuo
CLE1S	1	36	0	1	1
CHE1S	0	38	0	0	1
CLER1S	9	7	18	3	2
CHER1S	23	2	0	12	2
CREF1S	27	3	1	6	2
[Trade Secret Data Begins[10]					
CCUST1S	[redacted]				
Trade Secret Data Begins]					

The sensitivity results in Figure 2 support the results from the first run as shown in Figure 1. The net present value ("NPV") of the scenarios inclusive of environmental and regulatory costs,[11] is always lower in the early retirement cases compared to the status quo of not retiring BEC 3 and 4. The only situation in which it is least cost to not retire BEC3 and 4 early is in the scenario in which there are no environmental or regulatory costs in the future. Early retirement of the units is also increasingly beneficial when assigning a higher environmental cost to emissions. However, including a regulatory cost in the scenario introduces a tradeoff between capital and emission costs. Specifically, when there is a regulatory cost, the model selects to reduce the dispatch of BEC 3 and 4 to reduce the regulatory cost impact, while keeping BEC 3 and 4 online and avoiding additional capital expenses for replacement resources.

ii. Minnesota Power's inclusion of regulatory costs in its modeled dispatch decisions creates an unrealistic projection of BEC dispatch.

While the regulatory cost scenarios provide useful analysis, we do not consider runs with a regulatory cost in dispatch decisions to be credible projections of the near-term future, as there is no regulatory mechanism currently in place to account for emissions costs in actual operations. Relying on scenarios with regulatory costs for determining the Company's plans will lead to unintended and poor outcomes.

[9] CREF1S results: IRP Table 4 (Base Case Sensitivity)
CLE1S, CHE1S, CLER1S, CHER1S results: Appendix K, Tables 4,5,6,7
CCUST1S results: Workpaper 1-NPVCostTableTemplate (folder: IRP2021 Sup Analysis - Swimlane Results.zip)
[10] We have marked this data as trade secret as it appears to be only included in the Company's nonpublic filings.
[11] CLE1S, CHE1S, CLER1S, CHER1S, CREF1S

Outside of an IRP, the Company's actual operations will not consider any regulatory adder and thus will not realize the theoretical modeled savings. In fact, as we demonstrate below, the Preferred Plan will likely have higher ratepayer and environmental costs than the Fast Exit Case. Out of the six environmental futures, the Company focuses on the Reference Case (CREF1S) and concludes that the scenario in which BEC 3 retires in 2029 is the least-cost plan in the majority of sensitivities.[12] However, the Reference Case (CREF1S) includes a regulatory cost to operations and thus does not depict a realistic representation of how the utility will likely operate its fleet. For actual utility operations, there is no regulatory cost impacting the utility's merit order of dispatch. Therefore, for actual operations Minnesota Power is more likely to run the thermal units at a capacity factor similar to the scenarios in this IRP that do not have a regulatory cost, which, as we can see from the modeling, would actually result in the highest cost to society. Looking back at Figures 1 and 2, in the 2 scenarios with only an environmental cost (CLE1S and CHE1S), but not a regulation cost, the least-cost pathway in 74 of 76 sensitivities is the "expedited retirement of BEC3 and 4." Even under CREF1S, the Reference Case, prolonging the life of the coal units results in minimal savings (<0.7 percent) compared to the Fast Exit Case. More importantly, those savings will not materialize as long as the Company does not dispatch its units inclusive of a regulatory cost adder. Those savings are small, most likely not material, and highly uncertain.

The best way to understand what is happening in the model is to examine BEC 3 and 4 capacity factors under each scenario. [**TRADE SECRET INFORMATION BEGINS** [redacted].

Figure 7: BEC Capacity Factors under each Scenario[13]

	BEC3	BEC4
CLE1S	[redacted]	[redacted]
CHE1S	[redacted]	[redacted]
CLER1S	[redacted]	[redacted]
CHER1S	[redacted]	[redacted]
CREF1S	[redacted]	[redacted]
CCUST1S	[redacted]	[redacted]

TRADE SECRET INFORMATION ENDS]

Absent an explicit regulatory cost to the utility's dispatch, scenarios without a regulation cost, like CLE1S and CHE1S, are a more realistic representation of how the utility will dispatch its units. If the utility operates as if there is no regulatory cost to dispatching its thermal units, then the utility is likely to run the thermal units at a capacity factor more similar to the scenarios without regulatory costs.

[12] Minnesota Power, 2021 Integrated Resource Plan, p. 56-57.
[13] See Response to PUC IR-001

This would actually result in the highest cost, of the environmental futures examined, to society. In the two scenarios with only an environmental cost, but not a regulation cost, the least cost pathway in 74 of 76 sensitivities is the "expedited retirement of BEC 3 and 4."

Figure 8: Emissions from BEC 3 and 4 Under Two Regulatory Cost Scenarios[14]

[**TRADE SECRET INFORMATION BEGINS**

TRADE SECRET INFORMATION ENDS]

The CLER, CHER, and CREF scenarios are useful and informative. However, absent state or federal action to price carbon emissions very soon (an unlikely development), these scenarios are not indicative of costs that will be incurred from ratepayers or represent environmental costs that will accrue through utility operations. Consequently, it would be inappropriate to base a resource planning decision on those scenarios. The BEC emissions that are not captured in the CREF scenario (mid-carbon regulatory cost) but could materialize in practice translate to annual costs of up to $100 million in later years.[15] From an NPV perspective, discounting those costs using the Company's weighted average cost of capital ("WACC"),[16] the additional costs amount to almost half a billion dollars,[17] an amount that would erase any benefits from avoiding capital expenses and keeping the

[14] Workpapers: PrefPlan CHE1S 8760 - EnCompass Results Validation, PrefPlan CREF1S 8760 - EnCompass Results Validation

[15] We calculated the emissions costs to be between $68 million and $109 million annually from 2025-2035, with a NPV of $723 million. We calculated annual emissions cost by 1) finding the difference of Boswell 3 and 4 emissions from the reference scenario, CREF1S, and the emissions from BEC 3 and 4 from the scenarios without a regulatory cost and 2) multiplying the emissions by the Commission's adopted high emissions cost in each year.

[16] NPV calculation assumes the Company's WACC as defined in the confidential EnCompass input file: BASE-PowerSupplyFramework, folder: FINAL IRP2020 MODEL (April 1st Filing).

[17] The calculation is based on the reported emissions of the BEC units under the preferred plan in the no regulatory cost future (PrefPlan CHE1S 8760 - EnCompass Results Validation) and the emissions in the mid-carbon regulatory cost future (PrefPlan CREF1S 8760 - EnCompass Results Validation). The emissions that are not captured in the mid-carbon regulatory cost case but could materialize absent a regulatory mechanism

units online longer. Using a 3 percent discount rate, as recommended by the Interagency Working Group on Social Cost of Greenhouse Gases recommends, discounting carbon emission costs at 3 percent would result in an NPV of over $700 million.[18]

This is best illustrated by comparing the NPV of the Preferred Plan and the Fast Exit under the Reference Case sensitivity. According to the Company, keeping the Boswell units online saves customers approximately $53 million (0.67%) over the entirety of the IRP.[19] However, as explained earlier, that is under the assumption that the Company would reduce coal operations, which it isn't required, and is unlikely, to do.

B. Replacement Options for BEC 3 and 4

i. Minnesota Power's unnecessary limitation to the replacement options for BEC3 and 4 to thermal units and transmission upgrades are highly problematic.

An integrated resource plan is a planning tool to create a roadmap for meeting future demand and to test the robustness of the utility's portfolio under various future conditions. The utility is not bound to its IRP – the Commission expects the Company to adaptively manage its portfolio and operations based on its operational environment. Rather, the IRP is a planning tool that compares costs and risks of certain actions. Thus, it is disappointing and inappropriate that Minnesota Power limited its replacement options for BEC 3 and 4 to thermal units and transmission upgrades without considering any alternative options. This unnecessary limitation goes against the very purpose of an IRP and leads to faulty conclusions about the reality of alternative demand- and supply-side resources.

ii. Minnesota Power presupposes in the IRP that the only resources capable of providing essential reliability services are thermal resources, which ignores multiple available resources, such as hybrids and transmission upgrades.

In the IRP, Minnesota Power writes that BEC is the last remaining baseload generating station providing essential reliability services for northern Minnesota.[20] The Company contends that shutting down BEC, or even operating at economic operation, may result in both local and regional reliability concerns. The Company writes that baseload retirements require holistic replacements that provide voltage support, local power delivery, and regional power delivery.[21]

However, the assumption that Minnesota Power can only replace BEC with thermal resources is faulty. The Company offers minimal support for this assertion. In an information request, the Clean Energy Organizations (CEOs) asked for analysis that shows BEC must be replaced with combined cycle or

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enforcing the Company to dispatch units inclusive of their emissions costs (approximated with the no regulatory cost future) are then multiplied by the environmental cost and discounted to a present value.

[18] The Interagency Working Group on Social Cost of Greenhouse Gases outlines three discount rates (2.5 percent, 3 percent, and 5 percent). However, based on IWG review, new data and evidence strongly suggests that the discount rate regarded as appropriate for intergenerational analysis is lower, which would further increase the net present value of environmental damages (Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, February 2021).

[19] See Table 4, p. 47. Sensitivity "Base Case", Preferred Plan has a cost of $7,891,000,000 and the Fast Exit Scenario has a cost of $7,944,000,000.

[20] Minnesota Power 2021 Integrated Resource Plan, Appendix F, p. 40.

[21] Minnesota Power 2021 Integrated Resource Plan, Appendix P: Baseload Retirement Study, p. 17.

combustion turbine.[22] Minnesota Power responded that it determined that its transmission network cannot handle outside power delivery, and the Company needs a unit that acts like the coal units as a replacement. The Company continued, "[c]ombined cycle and combustion turbines have similar operational characteristics to BEC, making them valid replacement options in a retirement scenario to offset the need for a portion of the transmission network upgrades that would otherwise be required."[23]

The Company's insistence that BEC must be replaced with thermal units without examining alternatives in this IRP is not a holistic assessment and is based in erroneous assumptions about the capabilities of commercially available resources. Natural gas resources are not always available and can be interrupted. For instance, Laskin Energy Center was unavailable during the February 2021 Winter Event, because it was not able to procure natural gas.[24] Moreover, the Company's limitation is not aligned with the Company's own emissions goals to be carbon free by 2050 nor its own reasoning for why the Company need to continue to delay the retirement of BEC 3 and 4. Minnesota Power argues that part of the benefit of delaying the closure of BEC 3 and 4 is that it allows "for technology progression that leads to new resource a carbon free options that become cost-effective and available beyond the current natural gas technology."[25] Yet, there are carbon-free, dispatchable capacity resources that exist today and are often cheaper than new natural gas facilities. The Company did not model hybrid resources, such as solar plus storage or wind plus storage, that are dispatchable and can provide ancillary benefits, like black start capabilities, and could meet the Company's identified criteria for northern Minnesota. There are real-life demonstrations that carbon-free capacity resources are being built because they are cheaper. For example,

- PacifiCorp announced that its RFP shortlist includes 1,243 MW of solar paired with 682 MW of battery capacity in Utah, and 210 MW of solar paired with 52.5 MW of battery capacity in Oregon.[26]
- Florida Power and Light Company paired 409 MW of battery capacity next to an existing solar facility in 2021.[27]
- As of 2020, there were 14 wind-plus-storage projects representing 1.4 GW of wind and 200 MW of battery capacity across the country.[28]

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[22] See Response to CEO IR 027.
[23] See Response to CEO IR 027.
[24] See Response to DOC IR 003.
[25] See Response to CUB IR 004.
[26] *Clearing Up*, "PacifiCorp Trims RFP Bids Into Final Shortlist," June 18, 2021, https://www.newsdata.com/clearing_up/supply_and_demand/pacificorp-trims-rfp-bids-into-final-shortlist/article_51b8f9a4-d07b-11eb-90d9-7f6623e94d27.html.
[27] WSTP (Tampa Bay),"FPL unveils world's largest solar-powered battery in Manatee County," Dec. 13, 2021, https://www.wtsp.com/article/news/local/manateecounty/fpl-solar-battery-manatee-county/67-b54fa742-1829-45a7-8493-3b8a2cca1499.
[28] *Energy Storage News*, "Hybrid renewables-plus-battery power plants are growing rapidly -- are they a good idea?," Oct. 4, 2021, https://www.energy-storage.news/hybrid-renewables-plus-battery-power-plants-are-growing-rapidly-are-they-a-good-idea/.

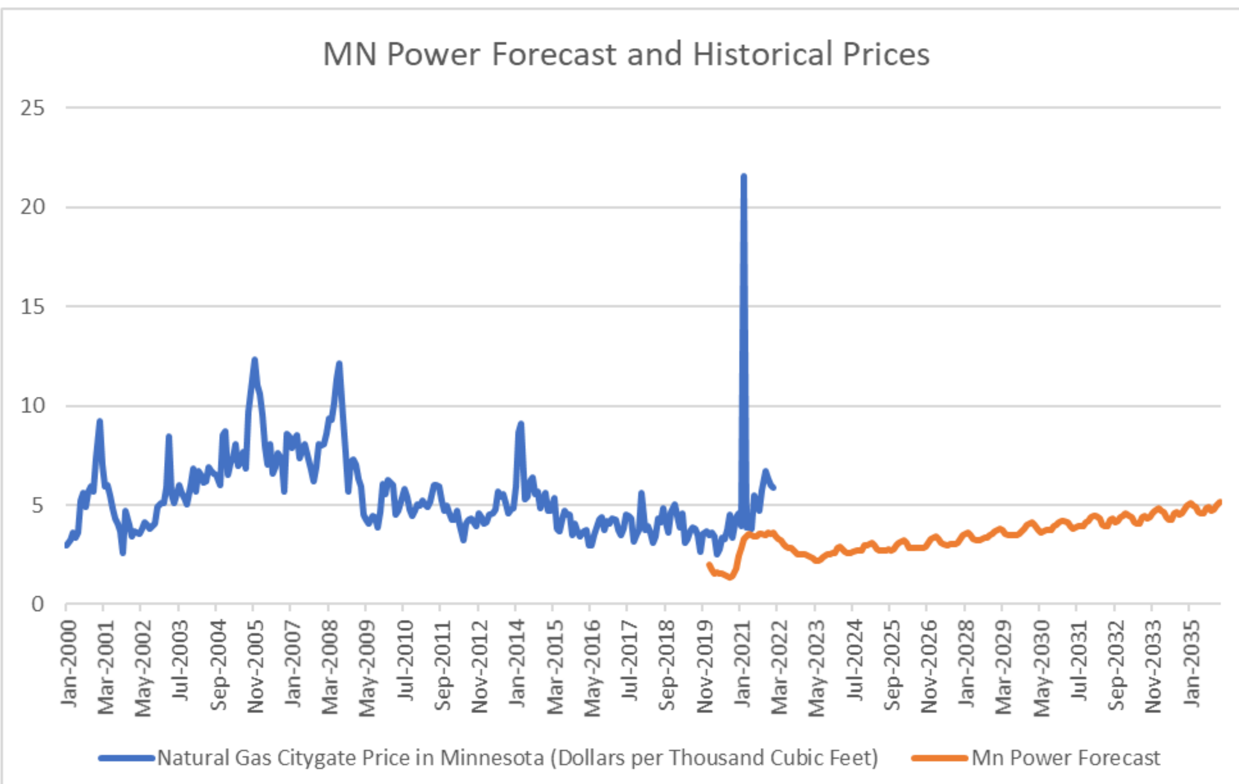
Ignoring these resources in the IRP results in an inaccurate assessment of the options available, which in turn creates the potential for misinformed decisions made for the replacement of BEC 3 and 4. The IRP is the very time for the Company to be creative and explore all feasible, commercially available demand- and supply-side resource options to adapt its portfolio in a rapidly changing energy environment.

C. Natural Gas Price Risk

i. The Company's IRP natural gas price forecast is significantly lower than actuals and exposes customers to fuel cost risk that will be borne almost exclusively by customers.

Historically, the natural gas price has been linked to crude oil prices, where both commodities' prices rose and fell together. Beginning in 2009, natural gas prices dropped, primarily due to the increase in domestic shale fracking, and became relatively stable. A low, stable gas price would become the norm for most of a decade. Minnesota Power's IRP forecast expects these low prices to continue for the entire planning horizon. As can be seen in Figure 5 below, Minnesota Power is forecasting low natural gas prices for the planning horizon. Natural gas forecasts begin at $2.85 in 2021, $3.06 by 2025, $4.09 in 2030, and do not reach $5.00 until 2035.

Figure 5: Minnesota Power Natural Gas Price Forecast Compared to Actuals[29]



[29] EIA Data is missing data for September 2021 and November 2021. To show the trend in natural gas prices in those two months, we averaged the price from the preceding month with the following month (e.g., for September 2021, we averaged the price from August 2021 and October 2021).

However, as can be seen Figure 5 above, the Company's forecast is overly optimistic, as the price of natural gas has increased dramatically in the past year. There are several factors contributing to the increase in prices including: (1) domestic and international gas market changes, (2) cost of financing new projects, (3) higher return demands from fossil fuel company shareholders, and (4) capacity limitations. First, domestic and international gas markets continue to evolve. European and Asian gas prices are higher than normal, as demand outpaces supplies.[30] The United States is not immune to this global dynamic – the U.S. has much more international exposure now due to its LNG expansion.[31] Second, the cost of financing new fossil fuel projects, such as gas wells and the distribution system for carrying that gas, is increasingly costly relative to alternative opportunities, such as renewable generation.[32] In addition, after a decade of relatively low growth of returns, fossil fuel company shareholders are demanding higher returns, which means they will want to constrict supply to maintain relatively high commodity prices.[33] Finally, it is notoriously difficult to build new natural gas pipelines, which means that there is a finite capacity to transport natural gas to load.[34] This is particularly noteworthy during peak periods, like the February 2021 Winter Event, when supply from Texas/Oklahoma was disrupted, demand was approaching design day conditions, and pipelines were issuing warnings about supply cuts.[35]

There are two consequences of Minnesota Power's gas price forecast being lower than actuals. First, the Company's IRP model is inaccurately biased towards natural gas generation in both its Capacity Expansion analysis and its production cost modeling. Thus, natural gas generation will appear to be more cost-effective than it is.

The second consequence is that the risk of an increase in natural gas prices is significant and borne almost exclusively by ratepayers, not the Company itself. The cost of natural gas and other fuels are passed to customers on a one-to-one basis through the power cost adjustment. There is no mechanism for the utility to share the costs and benefits of its natural gas price forecast. Thus, the Company is underrepresenting the risk to customers of its exposure to natural gas prices. As can be seen in Figure 5, above, and has been discussed in the Commission February 2021 Price Spike Event dockets,[36] certain conditions can cause extreme pricing events that can cost individual utilities

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30 LevelTen Energy, *Market Insights*, "A Perfect Storm: Understanding the European Energy Crisis," Oct. 28, 2021, https://www.leveltenenergy.com/post/europe-energy-crisis.

31 U.S. Energy Information Administration. "U.S. liquified natural gas exports grew to record highs in the first half of 2021." July 27, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48876.

32 *Bloomberg*, "Cost of Capital Widens for Fossil-Fuel Producers," Nov. 9, 2021, https://www.bloomberg.com/news/articles/2021-11-09/cost-of-capital-widens-for-fossil-fuel-producers-green-insight.

33 *CNN Business*, "US oil companies are in no rush to solve Biden's gas price problem," Nov. 10, 2021, https://www.cnn.com/2021/11/10/energy/oil-gas-prices-joe-biden/index.html?.

34 *Forbes,* "Oil and Gas Pipelines Increasingly Losing Legal Challenges," July 6, 2020., https://www.forbes.com/sites/scottcarpenter/2020/07/06/oil-and-gas-pipelines-increasingly-losing-legal-challenges/?sh=145797a91e88

35 See Direct Testimony of Bradley Cebulko on behalf of the Citizens Utility Board of Minnesota, Exhibit_(BC-D), p. 12, December 22, 2021, in OAH Docket No. 71-2500-37763, MPUC Docket Nos. G008/M-21-138, G004/M-21-235, G002/CI-21-610, G011/CI-21-611

36 See Direct Testimony of Bradley Cebulko on behalf of the Citizens Utility Board of Minnesota, Exhibit_(BC-D), p. 12, December 22, 2021, in OAH Docket No. 71-2500-37763, MPUC Docket Nos. G008/M-21-138, G004/M-21-235, G002/CI-21-610, G011/CI-21-611

hundreds of millions of dollars. As we discuss later in these comments, the Company plans to scale back their renewable energy procurement because it is worried about near-term rate increases associated with the projects. However, the Company's IRP does not acknowledge the fuel cost risk that is borne exclusively by customers. This poses a price risk, borne entirely by Minnesota Power's customers, that is especially important at a time when gas prices are so high and the gas market so unpredictable.

D. Load Forecast

i. Given the utility's uniquely risk profile (large, lumpy industrial load) the Company needs to exercise relatively greater caution when making investments in large generation and transmission to minimize the risk of stranded assets.

Minnesota Power has a unique customer base, as its share of industrial customers is significantly larger than it is for other utilities. Approximately 72 percent of retail energy sales were delivered to industrial customers in 2020, while for the average utility in the United States, retail energy sales to industrial customers makes up 28 percent of retail energy sales.[37] As a result of its unique customer profile, the Company is vulnerable to large and lumpy increases and decreases in demand that shift with conditions outside of its control. This condition makes any investment into large new generation or transmission projects, such as a new natural gas plant, especially risky. In the Company's 2021 General Rate Case, the Company testified that highly cyclical industries such as paper manufacturing and taconite mining and processing pose "a significant risk to the Company as changes in economic conditions could result in significant variations in the Company's sales."[38]

The Company also routinely highlights this risk in securities reports filed with the Securities and Exchange Commission and shared with the Company's shareholders and potential investors. For example, the Company includes this risk factor in its most recent 10-K Annual Report filing:

> Minnesota Power's taconite customers, which are currently owned by only two entities at the end of 2021, accounted for approximately 28 percent of consolidated operating revenue and 32 percent of Regulated Operations operating revenue in 2021. These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the marketplace. The North American paper and pulp industry also faces declining demand due to the impact of electronic substitution for print and changing customer needs. As a result, certain paper and pulp customers have reduced their existing operations or idled facilities in recent years and have pursued or are pursuing product changes in response to declining demand. Additionally, the taconite industry could be impacted by changing technology in the steel industry such as the adoption of electric arc furnaces for steelmaking, which could result in declining demand for taconite and the electricity used during its production.[39]

[37] Direct Testimony and Schedules of Frank L. Frederickson, Docket No. E015/GR-21-335, p 4, lines 8-15.
[38] Direct Testimony and Schedules of Ann Bulkley, Docket No. E015/GR-21-335, p. 7, lines 16-18.
[39] See, e.g., Allete, Inc. 2021 10-K Annual Report (filed Feb. 16, 2022) at 24.

This risk makes it especially important for the Company to ensure that its IRP is reflective of an accurate load forecast, to the degree possible, and that its investments minimize the chance of stranded assets despite the difficulty in predicting the Company's future sales.

Since the Company filed its IRP, the Company has filed a new load forecast in its 2021 General Rate Case. The 2021 IRP Reference Case is based on the 2020 Annual Forecast Report "2020 AFR"), while the 2021 General Rate Case uses the 2021 Annual Forecast Report ("2021 AFR"). The 2020 AFR forecast 103 MW of system loss by 2030, while the 2021 AFR forecasts 112 MW of system load growth by 2030. That is a 215 MW difference in system load projections between the 2020 and 2021 Annual Forecast Reports. The comparative forecasts for residential and commercial customers do not substantially shift from one forecast to the next. The change is driven almost entirely by the industrial load forecast. The 2021 AFR predicts additional load from several new and existing customers, including an industrial facility on the Iron Range by mid-2026 and a new industrial facility in Duluth in 2023.[40]

The significant change in industrial load forecasts from one forecast to the next highlights the unique risk to the utility and ratepayers attributable to the utility's load profile. By risk, we are primarily referring to the risk of stranded assets for building generation, transmission, and distribution plant to meet industrial load that does not materialize or disappears due to the conditions outside the control of the utility. This risk is most acute when the utility proposes to add large generation resources with long lives to meet this uncertain future load. One way that the utility can minimize its risk of stranded assets is to add relatively smaller increments of demand- and supply-side resources, which can be scaled up in a relatively short period of time.

ii. The Company's IRP identifies the early closure of BEC 4 as the optimal scenario with the addition of the Keetac facility's load.

In December 2020, United States Steel's Keetac facility resumed production,[41] but, due to timing of the development of the 2020 AFR load forecast, it was not included in the 2020 load forecast. However, the Company considered scenarios in its IRP that anticipated the return of the recently idled industrial customer load. Specifically, the Plan considers the following two scenarios: 2020 Load with Keetac and AFR 2020 High Scenario, both of which account for the resumed operations at the Keetac facility. The AFR 2020 High Scenario forecasts compound annual growth for both energy sales and peak demand being 0.1%, which is comparable to AFR 2021, which forecasts compound annual growth of 0.6% and 0.4% for energy sales and peak demand, respectively. These sensitivities are important for understanding the optimal BEC3 and 4 closure timeline. In Figure 6 below, lines 28 and 29, the 2020 Load with Keetac and AFR 2020 High Scenario sensitivities show that least-cost scenario is to retire BEC4 as early as feasible.

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[40] Docket No. E-999/PR-21-11, Minnesota Power AFR 2021.

[41] *Duluth News Tribune*, "US Steel will restart Keetac next month," Nov. 5, 2020, https://www.duluthnewstribune.com/business/us-steel-will-restart-keetac-next-month.

Figure 6: 2021 NPV of Cost for Reference Case Sensitivities[42]

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	**2021 Plan** ***Retire BEC3 in 2029***	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement of BEC 3 and 4**	**Base Case "Do Nothing"**
Base Case	$7,891	$7,903	$7,918	$7,944	$8,010
1 Coal +20%	$7,750	$7,783	$7,762	$7,837	$7,846
2 Coal -10%	$7,963	$7,969	$7,991	$7,993	$8,093
3 Biomass +15%	$7,888	$7,908	$7,909	$7,932	$8,001
4 Biomass -15%	$7,897	$7,917	$7,917	$7,950	$8,006
5 Lower Gas -50%	$7,780	$7,809	$7,758	$7,814	$7,871
6 Low Gas -25%	$7,874	$7,887	$7,862	$7,914	$7,976
7 High Gas +25%	$8,033	$8,045	$8,075	$8,087	$8,163
8 Higher Gas +50%	$8,133	$8,139	$8,165	$8,166	$8,304
9 Highest Gas +100%	$8,359	$8,338	$8,391	$8,368	$8,545
10 Energy Market -50%	$6,619	$6,674	$6,673	$6,820	$6,562
11 Energy Market -25%	$7,346	$7,383	$7,377	$7,499	$7,358
12 Energy Market +25%	$8,339	$8,344	$8,357	$8,316	$8,537
13 Energy Market +50%	$8,578	$8,565	$8,565	$8,493	$8,790
14 Capital Costs -30%	$7,891	$7,903	$7,889	$7,881	$8,018
15 Capital Costs +30%	$7,887	$7,907	$7,935	$8,007	$8,011
16 No Market Sales	$7,734	$7,768	$7,761	$7,822	$7,818
17 No Sales and Purchases	$9,315	$9,524	$9,162	$9,307	$9,369
18 Market Access -50%	$8,298	$8,365	$8,258	$8,312	$8,401
19 Low Interconnect Costs	$7,876	$7,890	$7,898	$7,927	$8,014
20 ITC & PTC Extension	$7,892	$7,896	$7,907	$7,937	$8,005
21 Wind Cost Curve Low	$7,895	$7,907	$7,915	$7,949	$8,012
22 Wind Cost Curve High	$7,892	$7,911	$7,924	$7,946	$8,011
23 Solar Cost Curve Low	$7,883	$7,900	$7,905	$7,932	$8,008
24 Solar Cost Curve High	$7,911	$7,920	$7,938	$7,961	$8,013
25 Storage Cost Curve Low	$7,892	$7,911	$7,916	$7,946	$8,014
26 Storage Cost Curve High	$7,891	$7,910	$7,916	$7,944	$8,010
27 AFR 2020 Low Scenario	$7,573	$7,598	$7,607	$7,657	$7,668
28 AFR 2020 Load w Keetac	$8,385	$8,399	$8,377	$8,385	$8,511
29 AFR 2020 High Scenario	$8,424	$8,443	$8,406	$8,424	$8,551
30 Residential TOU	$7,884	$7,894	$7,908	$7,935	$8,012
31 Higher DG & EV Growth	$7,896	$7,900	$7,913	$7,946	$8,011
32 Renewable ELCC -2.5%	$7,896	$7,919	$7,916	$7,945	$8,013
33 Renewable ELCC +2.5%	$7,888	$7,905	$7,915	$7,947	$8,011
34 PRM -2%	$7,892	$7,909	$7,913	$7,935	$8,010
35 PRM +2%	$7,899	$7,917	$7,918	$7,946	$8,013
36 MISO CF -2%	$7,886	$7,902	$7,915	$7,942	$8,004
37 MISO CF +2%	$7,906	$7,927	$7,912	$7,946	$8,019
Sum of Least Cost Runs	**27**	**1**	**6**	**3**	**1**

In its reply comments, the Company should address the impact of the Keetac facility on its optimal portfolio and retirement dates for BEC 3 and 4 and explain why its analysis determines that retiring BEC 4 as early as feasible is the least cost option for the sensitivities that include the return of Keetac.

42 Minnesota Power, 2021 Integrated Resource Plan, p. 57, Table 4.

The Company should also explain why it is not proposing to retire BEC 4 as early as is feasible, given that Keetac is online.

E. Resource Procurement in Action Plan

i. The Company unnecessarily restricts its wind and solar procurement to 200 MW of each resource.

Minnesota Power's preferred portfolio identifies 300 MW of solar and 300 MW wind for procurement. However, the IRP states that the Company will only procure 200 MW of solar and 200 MW of wind as part of its Action Plan.[43] Minnesota Power reasons that it must decrease its procurement to manage excess energy and reduce near-term rate impacts. The Company writes: "additional wind, above 200 MW, in the near term will result in excess energy in the portfolio with NETC coming online and BEC Unit 3 continuing to operate through end of 2029."[44] As the Company acknowledges, "[c]onstruction of NETC has not yet commenced nor is the project schedule finalized."[45] There are a number of legal proceedings that may further delay the Nemadji Trail Energy Center ("NTEC") project. The project may be delayed further nor may not come to fruition at all. Additionally, Minnesota Power could decide to sell some or all of its remaining portion of NTEC or to otherwise not move forward with the project.

In the case that NTEC is not further delayed or canceled, there are opportunities to manage potential excess energy. Storage, either paired with wind and solar or standalone, can absorb excess energy. The Company is part of MISO and can also sell excess energy into the market. Given the recent news that MISO may be experiencing capacity shortfalls,[46] there appears to be an opportunity for Minnesota Power to provide energy and capacity to the market. Consequently, the justification for restricting procurement of wind and solar to 200 MW is faulty.

Furthermore, the Company's focus on reducing near-term rate impacts from renewable additions may not be in the best interest of customers. The Company forecasts that the there is a small near-term power supply increase ($1-$2/MWh) caused by the addition of wind, which would put additional stress on customer rates. As earlier discussed, there is inherently less fuel cost risks associated with renewables than thermal resources. And as we demonstrated, the Company's natural gas price forecast is overly optimistic. Wind and solar have no fuel costs and are not subject to market fluctuations. This is a significant reduction in price risk. By waiting to procure additional resources, the Company may also be foregoing the ability to take advantage of the Solar Investment Tax Credit ("ITC"). The Company would be eligible for a 26% ITC rate should construction begin prior to the of 2022 and a facility be in service prior to January 1, 2026. Should construction begin prior to the end of 2023 and a facility be in service prior to January 1, 2026, the Company would be eligible for a 22% ITC rate.

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[43] Minnesota Power, 2021 Integrated Resource Plan, p. 43.
[44] Minnesota Power, 2021 Integrated Resource Plan, p. 43.
[45] See Response to CEO IR-084
[46] *Utility Dive*, "Capacity prices jump across MISO's central and northern regions, driven by supply shortfall," April 18, 2022, https://www.utilitydive.com/news/capacity-prices-auction-miso-midcontinent/622186/#:~:text=MISO's%20capacity%20shortfall%20could%20grow,said%20Friday%20in%20an%20email.

F. Nemadji Trail Energy Center

i. The circumstances around the Nemadji Trail Energy Center plant have significantly changed.

On July 28, 2017, Minnesota Power filed a petition for the approval of a number of supply-side generation resources, including a 48 percent capacity share of the planned NTEC, a 525 MW natural gas combined-cycle facility in Wisconsin. On January 24, 2019, the Commission issued an Order that approved a capacity dedication agreement and an affiliated interest agreement for the plant. In September 2021, during this IRP, Minnesota Power's parent company, Allete, announced the sale of 30 percent of NTEC to Basin Electric Power Cooperative.[47]

At a Planning Meeting the Commission held on September 28, 2021, the Company's representatives were asked whether and how the Company's partial sale of its interest in NTEC would be addressed in this IRP – and specifically how it would be addressed in the Company's modeling utilized in this IRP.[48] In response, the Company noted that NTEC had been built into base modeling in this IRP and suggested that, because it would file an additional IRP before NTEC becomes operational, issues related to the partial sale of NTEC would be better addressed in the Company's next IRP, not this one.[49] We disagree. We believe it is highly important to further consider the need for NTEC in this IRP before it is built and not after construction has commenced. Such consideration should take into account circumstances that have changed since the Company incorporated NTEC into the base modeling that informs its current IRP filings.

Since the Commission issued its Order approving a capacity dedication agreement and an affiliated interest agreement for the plant, Minnesota Power's circumstances have changed significantly. The Company still anticipates that NTEC will be operational in 2025; however, it acknowledges that construction has not yet commenced, and the project schedule is not finalized.[50] Since the Commission approved the capacity dedication agreement in 2019, the Company's share of the plant has decreased from approximately 50 percent to 20 percent. In addition, the Company's initial projections for natural gas prices in 2016 do not align with recent developments with the natural gas price. In its 2015 IRP, the Company wrote: "The outlook for ongoing low natural gas prices, as well as advancements in natural gas generation technology and declining costs, support the selection of natural gas as part of the Company's EnergyForward Resource Package."[51] The Company wrote that current natural gas prices were ranging between $2.50 and $3.00/MMBtu, and were likely to remain lower than historical values for the foreseeable future. However, as we discussed in the above section on natural gas prices, Henry Hub gas prices have been above $3.00/MMBtu since June 2021 and have subsequently climbed to approximately $6.80/MMBtu by the end of April 2022. We also have a better

[47] Allete Investor News, "Allete Announces Third Partner in Nemadji Trail Energy Center Project," September 28, 2021. https://investor.allete.com/news-releases/news-release-details/allete-announces-third-partner-nemadji-trail-energy-center

[48] Minnesota Public Utilities Commission, Regular Planning Meeting (Sept. 28, 2021) at 20:00.

[49] Id.

[50] See Response to CEO IR 084.

[51] Minnesota Power, 2021 Integrated Resource Plan, p.3-9.

understanding of the risks associated with extreme natural gas price spikes. In February 2021, natural gas prices in Minnesota climbed to unprecedented levels, reaching nearly $200/MMBtu.[52]

Minnesota Power has an obligation to continue to demonstrate that its actions are in the public interest, even after it received an order approving a capacity dedication agreement and an affiliated interest agreement for the plant. Minnesota Power's modeling included outdated prices of natural gas and does not test the economic impact of spikes in the price of natural gas. Despite the new uncertainty around the operability of NTEC in 2025, each of the Company's portfolios include NTEC as operational by 2025. The Company provided no modeling or analysis with a reduced share of NTEC, nor does the Company's modeling contemplate a scenario in which NTEC is delayed or never built. As such, we do not have the necessary analysis to understand if the Company's continued plan to be a part-owner NTEC is still in the public interest. It is evident that, since the Commission issued its Order approving a capacity dedication agreement and an affiliated interest agreement for the plant, the circumstances have changed. Given the changing circumstances, the Commission and Minnesota Power should take this opportunity to again consider the cost-effectiveness of NTEC.

G. Non-Wires Solutions in the Integrated Resource Plan and Integrated Distribution Plan

i. The Company should immediately incorporate an analysis of non-wires solutions into its resource planning as a tool for deferring or reducing the size of large investments, such as the replacement options for BEC 3 and 4.

The electric industry has been undergoing a massive change in the last few years, as the cost of solar, wind, and battery technology has precipitously decreased, and new technology-enabled devices and software allow the system to be more flexible. Utilities across the country are looking to non-wires solutions ("NWS") to defer or replace more expensive distribution and transmission projects. Unfortunately, Minnesota Power appears to not be keeping up with the industry. In its 2021 integrated distribution plan ("IDP"), the Company wrote, "[n]on-wires solutions cannot displace the need to modernize and replace aging equipment, even when the modernization project may result in increased reliability or load-serving capability."[53]

The Company's statements are concerning. The Company admits that it does not have sufficient experience with identifying, evaluating, and implementing non-wires solutions.[54] The lack of knowledge on how NWS is being used and the Company's outdated understanding of NWS is problematic because (1) this goes against the Company's stated intentions to dramatically increase its investments in grid modernization starting in 2023[55] and (2) NWS may be able to help alleviate the challenges identified by the Company when BEC closes.

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[52] See Direct Testimony of Bradley Cebulko on behalf of the Citizens Utility Board of Minnesota, Exhibit_(BC-D), p. 12, December 22, 2021, in OAH Docket No. 71-2500-37763, MPUC Docket Nos. G008/M-21-138, G004/M-21-235, G002/CI-21-610, G011/CI-21-611
[53] Minnesota Power, 2021 Integrated Distribution Plan, Docket No. E015/M-21-390, p. 67.
[54] See Response to CUB IR 15.
[55] Minnesota Power, 2021 Integrated Resource Plan, Appendix G, p. 36.

There are a number of high-profile examples of utilities that have used NWS to address significant transmission and distribution needs. For example, ConEd's Brooklyn-Queens demand management program was created to defer a $1.2 billion substation upgrade through a combination of energy efficiency, demand response, distributed energy resources, and other customer-side demand reduction measures.[56] In the Pacific Northwest, the Bonneville Power Administration abandoned a planned 80-mile, 500 kV transmission line to pursue NWS to address the needs of the region.[57]

Minnesota Power recognizes that it still has work to do on NWS. To address gaps in knowledge and existing the Company initiated a consultant-led non-wire alternative study.[58] The Company anticipates that it can begin implementing the consultants' recommendations as soon as 2023. The Commission should require the Company to file the study in its IRP and IDP dockets to allow for stakeholders for review. The Commission should then require the Company to begin integrating NWS into all the company's planning practices, including its IRP and distribution plan, with a focus on how NWS can help ameliorate the localized reliability needs of northern Minnesota when BEC 3 and 4 eventually retire. NWS solutions can take years to build, so it is imperative for the Company to begin its integration as soon as possible.

III. Conclusion

As stated, CUB applauds Minnesota Power's commitment to quickly reducing carbon emissions while maintaining affordable, reliable electricity for its customers. However, flaws in its modeling and analysis in this IRP result in a Preferred Plan that is severely flawed and likely not in the best interest of ratepayers nor the least-cost pathway to accomplish the Company's stated goals.

CUB intends to examine alternative modeling presented by other intervenors and consider recommendations for the Company's resource selection in reply comments. At present, we recommend:

- In reply comments, the Company should address the impact of the Keetac facility on its optimal portfolio and retirement dates for BEC 3 and 4, explain why its analysis determines that retiring BEC 4 as early as feasible is the least-cost option for the sensitivities that include the return of Keetac, and explain why it is not proposing to retire BEC 4 as early as feasible, given that Keetac is online.
- In reply comments, the Company should address the risk and potential ramifications of relying on an environmental future that contains a regulatory cost in its IRP when the Company's actual operations do not have such a constraint.
- The Commission should require the Company to file its consultant-led non-wire alternative study in its IRP and IDP dockets. The Commission should then require the Company to begin

[56] New York-New Jersey CHP Technical Assistance Partnerships, "Program Profile: ConEdison Brooklyn-Queens Demand Management Program," June 2019, https://chptap.ornl.gov/profile/49/ConEdisonBrooklyn-QueensDemandManagement%28BQDM%29Program-profile.pdf.
[57] *UtilityDive*, "BPA turns to non-wire alternatives in cancellation of transmission project", May 19, 2017, https://www.utilitydive.com/news/bpa-turns-to-non-wire-alternatives-in-cancellation-of-transmission-project/443125/.
[58] See Response to CUB IR 15.

integrating NWS into all planning processes, including its IRP and IDP, with a focus on how NWS can help ameliorate the localized reliability needs of northern Minnesota when BEC 3 and 4 eventually retire.

Thank you for your consideration of these comments.

Sincerely, April 29, 2022

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