Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: June 9, 2016 .... **Agenda Item #5

Company:	Minnesota Power (MP or the Company)
Docket No.	**Docket No. E015/RP-15-690**
	In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan
Issue:	Should the Commission approve MP's 2015 Integrated Resource Plan?
	What modifications, if any, should be made to MP's proposed plan?
	When should Minnesota Power file its next resource plan?

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Relevant Documents

Minnesota Power, Initial Filing .... September 1, 2015
Clean Energy Organizations, Comments .... January 4, 2016
Department of Commerce, Comments .... January 4, 2016
Large Power Intervenors, Comments .... January 4, 2016
Large Power Intervenors, Comments .... February 18, 2016
Clean Energy Organizations, Reply Comments .... March 4, 2016
Department of Commerce, Reply Comments .... March 4, 2016
Large Power Intervenors, Reply Comments .... March 4, 2016
Minnesota Power, Reply Comments .... March 4, 2016
Speak Up Comments .... March 7, 2016

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

Contents

Background

On September 1, 2015, Minnesota Power (MP or the Company) filed its 2015 Integrated Resource (IRP) for planning years 2015-2029.

On November 9, 2015, the Department of Commerce, Division of Energy Resources (Department) filed its completeness review, concluding MP's resource plan contained all information required by Minn. Rule. 7843.0400 (Contents of Resource Plan Filings).

On January 4, 2016, the following parties filed comments:

- The Minnesota Department of Commerce, Division of Energy Resources (the Department);

- The Clean Energy Organizations (consisting of Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires); and

- The Large Power Intervenors (consisting of ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy, Limited Partnership; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; PolyMet Mining, Inc.; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keewatin Taconite and Minntac Mine); United Taconite, LLC; and Verso Corporation)

On March 4, 2016, Minnesota Power filed reply comments in support of its preferred resource plan. The Large Power Intervenors and the Clean Energy Organizations filed reply comments reiterating their preferred modifications to the plan. The Department filed reply comments recommending approval of the plan with modifications. The Commission also received 21 comments on *Speak Up!* and 755 letters and signatures in support of community solar.

1. The Resource Planning Process

The resource planning statute, Minnesota Statutes § 216B.2422, authorizes the Commission to approve, reject, or modify a resource plan, consistent with the public interest. Under the resource planning rule, Minn. Rule. 7843, resource options and resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

A resource plan is defined as "a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs." Contents, scenarios, requirements, and goals of a resource plan are detailed in both the IRP Statute and the IRP Rule.

At a minimum, a resource plan must include: an energy and demand forecast, long-range emissions reduction planning (which refers to progress in meeting the Minnesota Greenhouse Gas Reduction Goal), and a range of environmental costs incorporated into the planning. The environmental costs include both the value set in the environmental externalities docket[1] and the carbon dioxide values set in the CO_2 values docket.[2] Also, under subdivision 4 of Minn. Stat. § 216B.2422, if the utility plans to construct or acquire a nonrenewable resource, the utility has the burden of proof to show why a renewable resource is not in the public interest.

According to Rule, "Parties and other interested persons may express support for the proposed resource plan filed by a utility. Alternatively, parties and other interested persons may file proposed resource plans different from the plan proposed by the utility."[3] The Commission may consider all proposed plans, in combination or separately, when identifying a "preferred plan." Subpart 2 of the IRP Rule states:

> Subp. 2. **Preferred plan**. If the commission concludes that a set of resource options would be optimal, considering the desirable attributes listed in subpart 3 (the Five Factors to Consider), it may identify that set of resource options as a preferred resource plan. A preferred resource plan need not have been specifically proposed or advocated by the utility, an intervening party, or other interested person.

In resource planning, attention is often focused on the question of "need," which, in a general sense, refers to the size, type, and timing of supply- and demand-side resources a utility must acquire to meet its planning reserve requirements. The term "need," as it relates to size, type, and timing, is a useful guidepost for the Commission's consideration of short-term and long-term procurement (or retirement). This said, the five factors to consider in the resource planning rule demand consideration of a whole host of factors and variables beyond a utility's projected net capacity position, and over a range of possible outcomes.

A comprehensive approach balancing rate impacts, risk, environmental considerations, utility flexibility, and so on is not always captured entirely by a strict focus on meeting a capacity

[1] Docket No. 00-, Docket No. 14-643
[2] Docket No. 09-177
[3] Minn. Rule. 7843.0300, Subpart 11.

deficit megawatt-for-megawatt, particularly in instances in which unit retirement is contemplated or local reliability issues exist. To fully address "need," the Commission's review of resource plans, guided by the five factors to consider and based on the totality of record evidence, *includes* cost and resource adequacy, but goes beyond it, into an evolving paradigm of value-driven decision-making.

2. Company background

A division of ALLETE, Inc., Minnesota Power serves about 144,000 retail electric customers and 16 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. ALLETE subsidiary Superior Water, Light and Power provides electricity to 15,000 customers, natural gas to 12,000 customers and water services to 10,000 customers in northwestern Wisconsin.

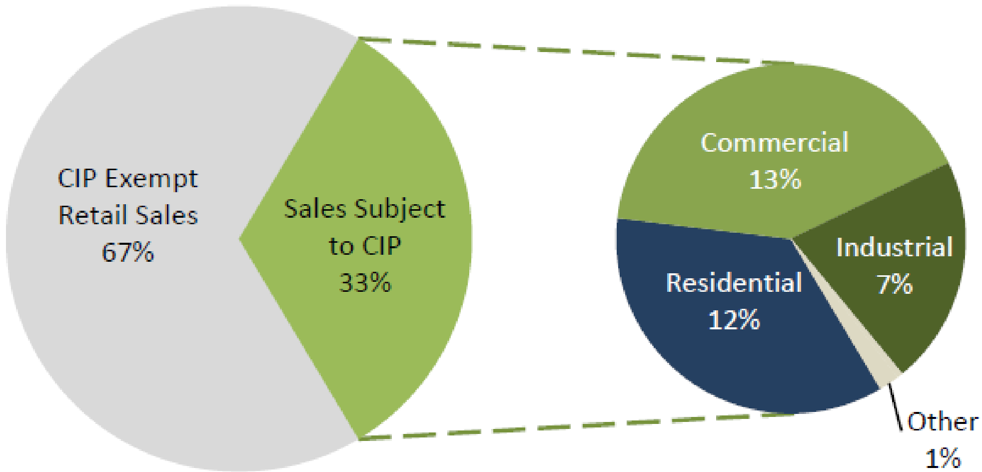
MP's peak demand is approximately 1,800 MW. For comparison, below are approximate peak demands of other utilities operating in Minnesota, including MP:

Minnesota Power	1,800 MW
Great River Energy	2,500 MW
Otter Tail Power	800 MW
Xcel Energy	9,500 MW

Minnesota Power is a winter-peaking utility, although as a member of the Midcontinent Independent System Operator (MISO), MP bases its resource need on the summer season MISO Load and Capability (L&C) calculation. The MISO L&C calculation accounts for Minnesota Power's load forecast, expected demand-side resources, firm and participation purchases and sales, accredited unforced generating capability (UCAP), and MISO's required 7.1 percent planning reserves.

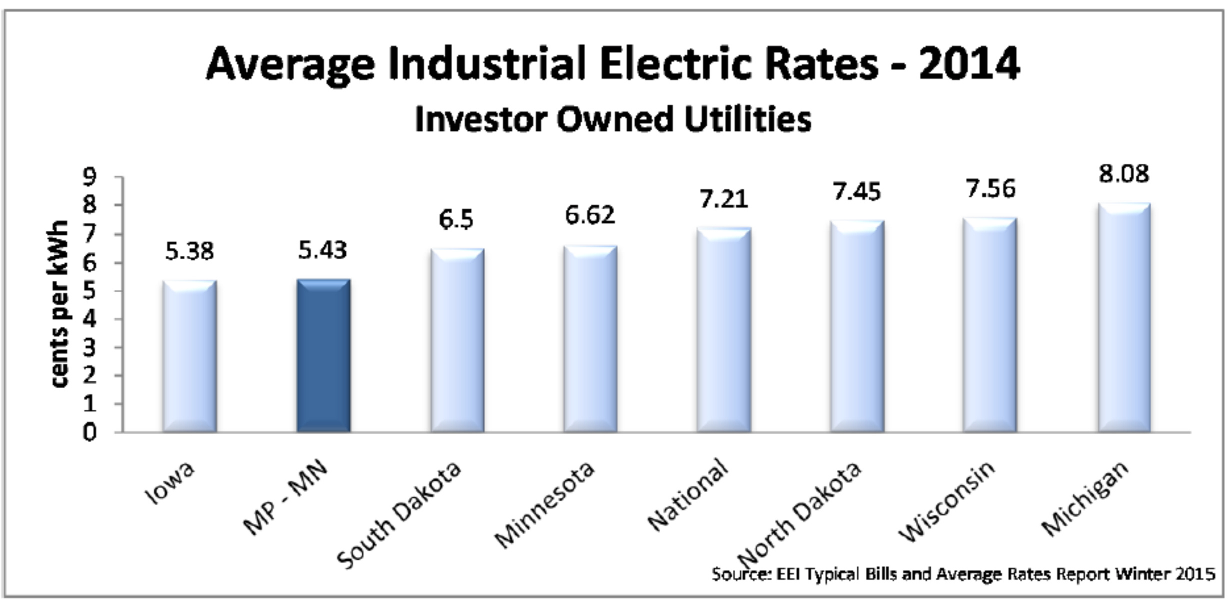
The majority of MP's energy sales serve large power customers, primarily in the taconite mining, iron concentrate, paper, pulp, refining, and pipeline industries. Many of these industrial customers operate continually, giving MP a uniquely high load factor of about 80 percent, which results in less demand variation than utilities with a lower load factor.

In total, roughly 67 percent of the Company's load comes from 15 customers who are exempt from paying for and participating in the Conservation Improvement Program (CIP). As a result, CIP goals, funding, and design focus on the Company's total retail load subject to CIP. The figure below compares CIP sales to CIP-exempt retail sales. The figure also breaks down CIP sales by class, showing that the Commercial and Industrial (C&I) customers comprise a majority of the load subject to CIP.



Figures 29-32 of MP's IRP (on pages 77-79) show comparisons of MP's electric rates by class to regional and national averages. According to the Company, MP has very competitive rates for residential, commercial, and industrial customers when compared to regional and national rates. Figure 32 of MP's IRP shows that MP's industrial electric rates are lower than other utilities operating in Minnesota as well in other states in the region.

Figure 32: Regional and National Comparison of Industrial Electric Rates in 2014



The Large Power Intervenors dispute MP's claims that the Company's industrial electric rates are "competitive." LPI focus much of its comments and recommendations on the competitiveness of MP's rates and urge the Commission to take into account the rate impacts of the action plan it approves.

Overview of Resource Plan

1. Load Forecast

The load forecast is the foundation of integrated resource planning, as capacity and energy resource commitments are based on forecasts of energy consumption and seasonal peak demand. For this resource plan, Minnesota Power used its 2014 Advance Forecast Report (the 2014 AFR)—an annual reporting requirement[4] of historical and forecast customer sales and demand values—as the basis for the 2015 IRP.

The 2014 AFR includes several scenarios that reflect the uncertainty the Company faces in its sales and demand projections. This uncertainty is in large part due to existing industrial customers' future production and new industrial load that may be added in Minnesota Power's service territory during the 15-year planning horizon. The "Expected Case," or "Moderate Growth" scenario, represented the Company's best expectations at the time of the 2014 AFR.

According to the "Expected Case," average annual energy sales and peak demand were both projected to grow at about 1.1 percent per year from 2014 through 2028.[5] Of note, though, is that MP's averaged estimate was skewed somewhat by the fact that the forecast added approximately 215 MW of load from new and existing large customers pre-2020, which created a spike in energy and demand growth in the early years.[6] Staff includes years 2014-2018 of the 2014 AFR in the table below to illustrate this fact.

Table 1: Moderate Growth Energy Sales

Year	Yr/Yr Growth
2014	0.2%
2015	4.1%
2016	6.6%
2017	-0.6%
2018	0.7%

The average growth rate during years 2017-2028 (the period *after* the large customers are added) is 0.41 percent for total energy sales and 0.45 percent for annual peak demand.

For the IRP, Minnesota Power used the "Moderate Growth Scenario with Deferred Resale," which is "identical to those in the Moderate Growth (Expected Case) scenario, except the start of a new mining customer's facility in Nashwauk is delayed by one year."[7] In other words, MP's 2015 IRP uses the same forecast as the 2014 AFR, only MP's expectation for its wholesale

[4] Under Minn. Stat. 216C.17 (Energy Forecasts and Statistics), electric utilities must submit to the Minnesota Department of Commerce an Annual Forecast Report by July 1 of each year. The AFR must contain historical and forecast customer sales and demand values, including forecast methodology and discussion.
[5] Appendix A (2014 AFR), p. 1.
[6] Table 1 in Appendix A (Advance Forecast Report).
[7] *Ibid*, p. 3.

customer in the City of Nashwauk, Essar Steel, is delayed by one year.[8] Thus, a main driver of MP's short-term need for energy—and therefore the action plan which MP proposes to meet it—is partially the result of specific load additions in MP's service territory over the next five years.

a. Clean Energy Organizations

The Clean Energy Organizations disputed the accuracy of MP's forecast, arguing it overstates future demand, for reasons including MP's new large customer load. CEO questioned when, or even if, certain proposed large projects—e.g. the PolyMet nickel-copper mine, the Essar Steel project, and the Sandpiper pipeline—will come online, as well as whether existing production may be idled or ramped down. CEO also claimed MP's forecasts for the residential and commercial sectors are overly optimistic, given recent consumption trends. Third, CEO does not believe the Company adequately accounted for customer-owned generation. Any of these factors would suggest MP overestimated its future resource needs, but taken together, CEO strongly disputes MP's claim that it needs additional supply-side resource in near-term.

b. Department of Commerce

In its reply comments, the Department disagreed with CEO on several fronts that MP has overstated its need. Overall, the Department stressed the importance of considering a range of forecasts: "for resource planning it is important to develop an expansion plan that is cost-effective over a wide range of potential futures, including a range of forecasts. If Minnesota Power planned its system around a point estimate or one particular forecast in time, it could potentially lead to MP procuring inadequate or excessive supplies of electricity."[9] The Department concluded that MP's forecasts were satisfactory, and recommended their approval.

c. Staff Discussion

The Commission does not need to specifically approve the load forecast or make a finding on its reasonableness; however, as staff will discuss throughout this briefing paper, important and significant short-term decisions might be predicated on the existence (or not) of new load additions and/or load growth from existing customers. Whether the Commission should take a "range" or "point estimate" approach could be, to some extent, an exercise in semantics for this particular case: if new load is not likely to materialize, or if MP's customers' production or global consumption has a more dire-looking outlook than previously projected, staff believes this should be taken into account on some level.

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[8] On Page 20 of MP's Resource Plan, the Company includes a section further describing "Specific Load Additions." In it, MP details, "Essar Steel Minnesota, a significant new customer for the City of Nashwauk, a valued municipal customer, remains in the Company's 15 year outlook. PolyMet, a copper-nickel mine operation located just outside Hoyt Lakes, Minn. is another significant new industrial customer for Minnesota Power, and is included in the 15 year outlook. These additions are reflected in the Base Case of the 2015 Plan."

[9] Department of Commerce, Reply Comments, at pages 2-3.

2. Existing Power Supply (Capability)

As shown in Table 2 below, MP has approximately 1,900 MW of MISO-accredited generating capability, not including its approximately 100 MW of interruptible demand response.

Table 2: MP's Generation Capability

Generation Resources[10]	Accredited Capacity (MW)
Coal	
Boswell 1 & 2	132
Boswell 3	346
Boswell 4	446 (MP's share)
Milton R. Young 2	90
Taconite Harbor 1 & 2	139
Natural Gas	
Laskin Energy Center[11]	69
Biomass	
Cloquet Energy Center	23
Hibbard Energy Center	62
Rapids Energy Center	30
Hydro	115.6
Wholesale Power Contracts[12]	450
Wind[13]	
Bison Wind Energy Center (1-4)	66
Oliver Wind	17
Taconite Ridge	3.6

Much of MP's generation is coal-fired, although diminishingly so due to the retirement of its Taconite Harbor Energy Center (THEC) Unit 3 and refueling of Laskin Energy Center (LEC). MP's largest generating facility is the Boswell Energy Center (BEC), located in Cohasset, Minnesota, which is more than 1,000 MW in size and consists of four generating units.

[10] This table does not include demand response, although MP states they have over 100 MW of interruptible load.
[11] The coal to natural gas conversion at Laskin was completed in 2015. Accredited capacity for LEC after the refuel is expected to increase over time to 100MW.
[12] Wholesale power contracts represented here include: 50 MW Manitoba Hydro, 50 MW MPC, 50 MW GRE, 50 MW Xcel, 2.5 MW Wing River, 12.5 MW LEA, 100 MW Basin.
[13] The megawatts of wind listed above are in MISO accredited capacity terms. MISO's wind capacity credit for wind is 14.6 percent. In terms of nameplate capacity, Bison Wind Energy Center, Oliver Wind, and Taconite Ridge amount to approximately 570 MW.

Minnesota Power is also engaged in several wholesale contracts to meet its planning reserve requirements. In the short- and intermediate-term, a large share of MP's emerging capacity deficit will be met by wholesale transactions, some of which will be delivered from hydroelectric facilities in Manitoba via the Great Northern Transmission Line.

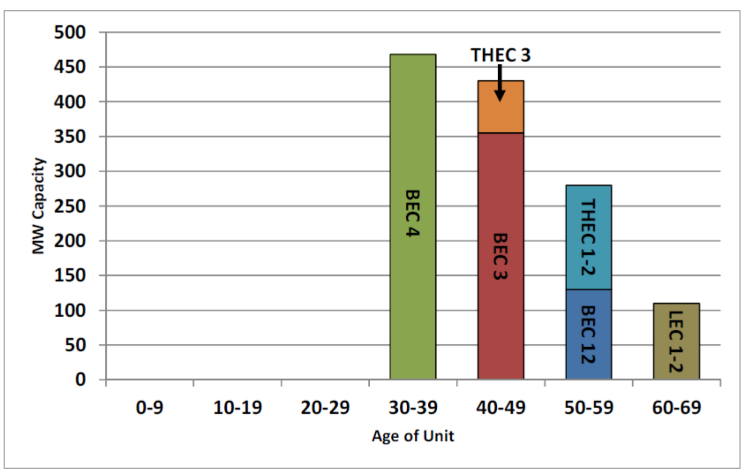
In December 2013, MP entered into an agreement with Manitoba Hydro-Electric Board (MHEB) for a 50 MW purchase beginning on June 1, 2015, and continuing through May 31, 2020.[14] In May 2011, Minnesota Power entered into an agreement with MHEB for a 250 MW purchase beginning on June 1, 2020, and continuing through May 31, 2035.[15]

In the Company's five-year action plan proposed for this IRP, MP plans to rely on "bridge capacity purchases" to meet expect short-term capacity deficits until the beginning of its 250 MW PPA with Manitoba Hydro in 2020. Since the IRP was filed, MP has executed three capacity contracts, totaling 150 MW in size, as replacement capacity for its plan to phase-out Taconite Harbor 1 & 2 by 2020 (this will be discussed in greater detail below).

a. Power Supply Changes

Since 2009, Minnesota Power has generated the majority of its electricity from its Boswell Units 1-4, Laskin Units 1-2, and Taconite Harbor Units 1-3, all located in Minnesota. Prior to MP's 2013 resource plan, the Boswell, Laskin, and Taconite Harbor Energy Centers were all coal-fired generation facilities. Due to environmental considerations and the facilities' age, among other factors, some of these units have been retired or refueled, and the unit replacement issue continues into the instant IRP. Below is a figure from Appendix J of MP's IRP, showing the age of Minnesota Power's coal fleet, a focal point of the unit retirement/replacement conversation:

Figure 1: Minnesota Power's Age of Fleet



As an outcome of the Company's 2013 resource planning proceeding, the Commission approved MP's proposal to (1) retire its coal-fired, 75 MW Taconite Harbor Unit 3 and (2) convert its coal-fired 110 MW Laskin Energy Center (LEC) to a natural gas-fired peaking facility.

[14] Docket No. 14-926
[15] Docket No. 11-938

In addition to its owned coal units, MP has also received coal-fired generation through a long-term purchase agreement from Square Butte Cooperative's Milton R. Young 2 (Young 2) lignite coal generating station in North Dakota. In MP's 2010 IRP, the Company outlined its plans to phase out the coal-fired energy delivery contract with Young 2 in conjunction with its renewable expansion plan, by purchasing the Square Butte direct-current transmission line (DC Line) to deliver wind energy.

Through its acquisition of the DC Line, MP has stepped down its position in Young 2 and developed its Bison Wind Energy Center, delivering approximately 500 MW of wind across the freed-up transmission capacity. MP will phase out its energy from Young 2 completely by 2026.

By removing Laskin Energy Center and Taconite Harbor Unit 3 from its system (as coal-fired units) and reducing its position in Young 2, in total, MP has reduced its position in coal-fired capacity by nearly 500 MW since its 2010 IRP. Over that same span, MP has developed more than 500 MW of renewable energy projects, as shown by Table 3 below.

Table 3: Minnesota Power Renewable Expansion Plan

Project	**Capacity (MW)**	**Commission Approval**
Bison 1	82	May 2009
Bison 2	105	September 2011
Bison 3	105	November 2011
Bison 4	205	January 2014
Camp Ripley Solar	10	February 2016

3. MP's Preferred Expansion Plan

For the 2015 planning process, MP proposes its "Preferred Plan," as it is referred, which further reduces its coal-fired energy position by transitioning its Taconite Harbor 1 & 2 (THEC 1 & 2) and Boswell 1 & 2 (BEC 1 &2) away from coal. However, MP's ultimate plans for the replacement energy and capacity from those units are not entirely certain. Questions still remain about MP's long-term replacement plans for THEC 1 & 2 and BEC 1 & 2, beyond temporary wholesale transactions; thus, MP's coal transition plan is the most contentious area of dispute among the parties.

In the five-year action plan, MP proposes to "idle" THEC Units 1 & 2 in October 2016, before ceasing coal-fired generation at those units by 2020. MP explores alternatives at THEC post-2020, but does not give a concrete re-purposing plan. At Boswell, MP proposes to upgrade the facility to reduce sulfur dioxide (SO_2) emissions in 2018 and cease using coal at Units 1 & 2 for electric generation in 2024; however, MP proposes to revisit the long-term viability of BEC 1 & 2 in the next resource plan.

An outline of MP's Preferred Plan is shown below, taken from pages 68-69 of the IRP. MP differentiates its plan between short-term and long-term steps the Company intends to take.

MP's Short-term Action Plan:

- "Idle" operations at THEC 1 & 2 in October 2016 and maintain availability for seasonal reliability needs;
- "Cease coal operations" at THEC 1 & 2 by the end of 2020;
- Evaluate refueling, repurposing or retiring the THEC facility in the next resource plan;
- Continue engineering and design planning for additional SO_2 reduction at BEC 1 & 2 for 2018 project implementation;
- Implement a backup generation pilot program for approval and implementation;
- Begin the competitive procurement process of efficient 200-300 MW natural gas combined cycle generation supply for implementation by 2024; and
- Add 10 MW of utility-scale solar at Camp Ripley, and implement a community solar program by end of 2016.

MP's Long-term Action Plan:

- Continue implementation of the 250 MW and 133 MW Manitoba Hydro PPA and Great Northern Transmission Line in the 2020 timeframe (383 MW);
- Optimize the timing of the remaining 22 MW of new solar projects to meet the SES;
- Reduce MP's off-take of the Young 2 resource from 100 MW to zero by 2026;
- Assess the viability of BEC 1 & 2 by 2025; and
- Secure and implement 200-300 MW natural gas combined cycle unit by 2024.

MP asserts that its Preferred Plan positions its power supply well for a potentially carbon-regulated future. According to the Company's calculations, "the Preferred Plan is consistent with EPA's Clean Power Plan goal of 30% CO_2 reduction from 2005 levels by 2030."[16]

a. Staff Comment

A core element of MP's long-term vision is to retain Boswell Energy Center as its lone coal-fired baseload generating facility for dispatchable thermal electricity. Despite the teetering results of the economic analysis in the resource plan—in which some scenarios favor retiring Boswell Units 1 & 2, some favor refueling it, and others favor continuing their operation—MP is strongly committed to keeping Boswell Energy Center a singular, coal-fired facility to deliver energy over the long-term, much longer in fact than the span of the current planning period. In doing so, MP plans to incrementally step-down the rest of its coal-fired generation and expand its position in natural gas generation by acquiring a new natural gas combined cycle unit and, possibly, repurposing Taconite Harbor Energy Center to maintain local reliability.[17]

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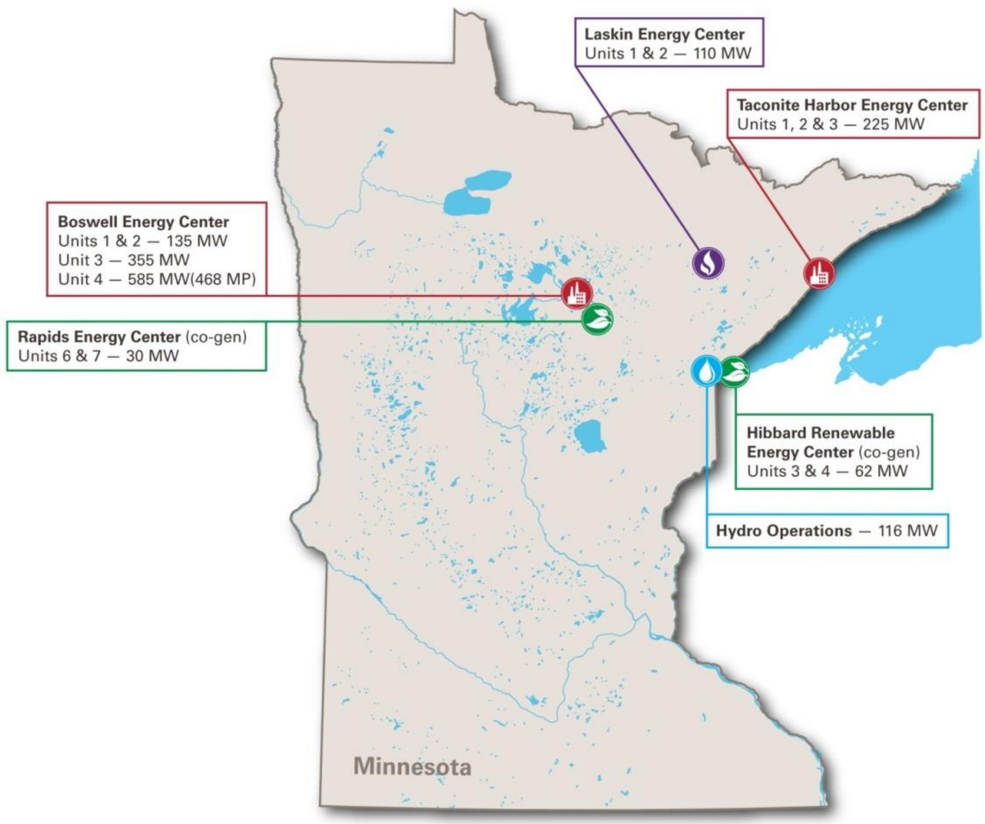
[16] MP Resource Plan, p. 82.
[17] Appendix C, pp. 27-28.

A challenge for this resource plan proceeding is to fully understand the interrelationship of all steps, as it would be incomplete to view them in silos. For instance, below is a locational map of MP's dispatchable generation. As shown, there is a generation-rich area in MP's service territory that includes several energy-intensive large industrial customers. Of utmost importance is that, as generation in this area is removed or added or its fuel source is changed, the reliability impacts are well-understood. While the location of generic resource options is typically outside the scope of resource planning, it may be uniquely critical here, given that the dominant contested issue is whether to retire or refuel multiple baseload units in a specific area.



Also important is to understand how MP's Preferred Plan (and the scenarios compared against it) could affect, be affected by, or be compatible with related Commission proceedings as well as standards and requirements relevant to other entities, such as the Midcontinent Independent System Operator (MISO) and the U.S. Environmental Protection Agency (EPA).

For example, while MP proposes to "cease coal-fired generation" at BEC 1 & 2 in 2024 (at the end of its remaining life), it is critical to know what that means in both the functional and financial sense of term; there is a separate docket currently open at the Commission in which the Company has filed a petition to extend the remaining lives of all Boswell Energy Center Units, including BEC 1 & 2, until 2050.[18] In that Petition, filed on November 17, 2015, Minnesota Power states:

[18] Docket No. 15-988, MP Petition to Modify the Boswell Energy Center Remaining Life.

> Minnesota Power believes it is appropriate to combine all of BEC, not just the Common Facilities, into one remaining life because the units share critical infrastructure making them difficult to be separated and because the entire facility has been well maintained to extend operations to 2050.

In this regard, the terms "retire" or "shut down" would be vastly different than the term "cease," even though the functional distinctions are not made apparent from a modeling perspective. In the Strategist analysis, for instance, the amount of energy delivered by BEC 1 & 2 is the same—zero—whether the units cease to operate or retire completely. Yet the Company strongly opposes retiring BEC 1 & 2 or THEC 1 & 2 because of the reliability impacts of doing so.

In addition, as listed above in the bulleted "Short-term action plan," MP proposes that, in 2018, it will retrofit BEC with an approximately $30 million emissions reduction project to reduce SO_2 at BEC 1 & 2; however, in the "Long-term action plan," MP proposes to assess the viability of BEC 1 & 2 in the next resource plan. It is difficult for the Commission to know the full value of an emissions reduction investment if the fate of BEC 1 & 2 is left unresolved.

There is typically not significant overlap between utilities' resource planning and air pollution compliance. The Department normally verifies whether utilities are in compliance with federal environmental regulations, but in general, it does not recommend the least-cost compliance measures for each environment regulation affecting its generation fleet. In this case, however, MP's air regulations uniquely merge with its least-cost, reliability-focused planning.

In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin 2. In 2014, MP entered into a consent decree (CD) with EPA, whereby MP agreed to "retire, refuel to non-fossil fuel, or re-route" the flue gas from BEC 1 & 2 through the Boswell 3 scrubber by the end of 2018.

What is complicated here is that, first, the CD was entered into in-between resource plans, and the date for compliance in 2018, leaving little time to contemplate alternative compliance measures and act accordingly. For example, retiring BEC 1 & 2 by 2018 is not only a significant reliability issue, but it is likely also a practical impossibility. And while MP evaluated a Boswell Gas Refuel scenario, this option was generally higher in cost, and it may not comply with the CD with EPA anyway because the CD allows only for a "non-fossil fuel" alternative.

In receiving approval of its resource plan as filed, presumably MP will proceed with its SO_2 reduction plan for Boswell 1 & 2, and such an investment could shape the Commission's view of how to assess the long-term viability of BEC 1 & 2, in both cost recovery dockets and subsequent IRPs, due to the ratepayer commitment in the near-term.

Similar issues also exist for Taconite Harbor Energy Center. As with Boswell 1 & 2, MP plans to "cease" coal-fired operations at Taconite Harbor 1 & 2, but MP refrains from using the word "retirement" in reference to those units. It may be the case that the "idle" is merely a temporary measure before a repurposing or re-missioning project can be further developed; nevertheless, it certainly *is* the case that any such plan is, at best, still in development. MP describes possible conversions to natural gas or torrefied wood, but goes onto argue the practical, economic, and technical challenges associated with each alternative.

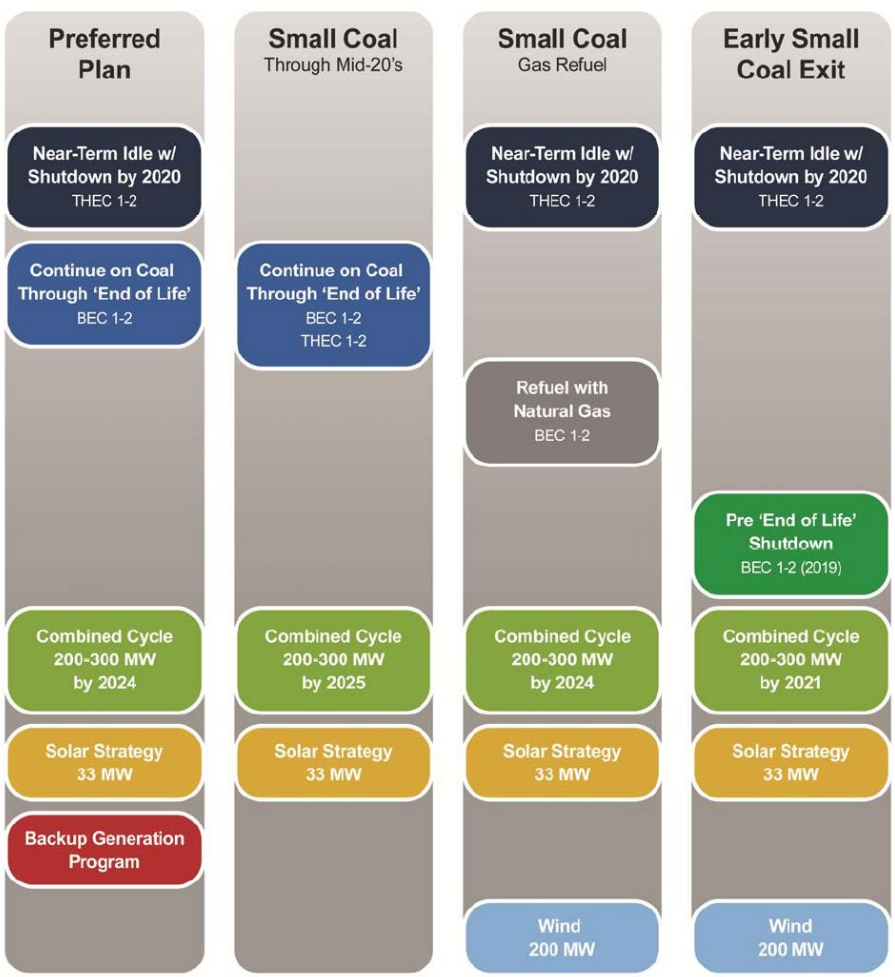
Alternative Plans and Proposed Modifications

1. MP's Comparative Scenarios

In addition to MP's "Preferred Plan," the Company evaluated three alternative scenarios, also referred to as "swim lanes." The alternative plans are: "Small Coal Through Mid-2020s" (or Continue on Coal); "Small Coal with Gas Refuel" (or Boswell Gas Refuel); and "Early Small Coal Exit" (or Early Coal Exit).

The differences among the four plans primarily involve (1) the options to retire, refuel, or continue to operate the Taconite Harbor 1 & 2 and Boswell 1 & 2 and (2) the in-service date for the Company's proposed natural gas combined cycle unit. Figure 21 below illustrates these and other differences. MP provides more detail of each scenario in Appendix K.

Figure 21: Preferred Plan and Alternative Swim Lane Resource Additions



Some features common among all or most of the alternative plans include the following:

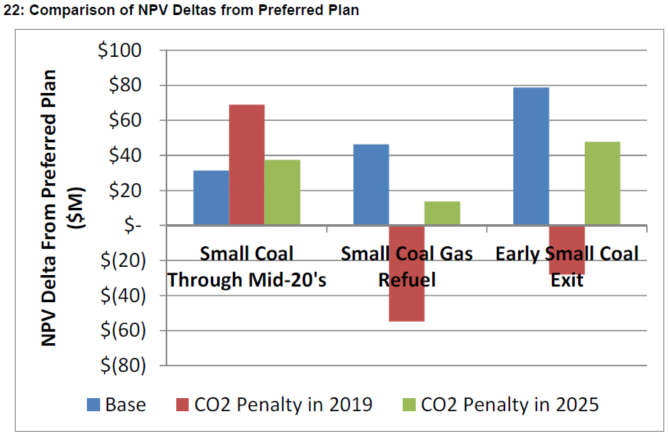
- A partial share of a natural gas combined cycle facility is added in the long-term action plan, reflecting the need for additional baseload/intermediate generation.
- Except for the Continue on Coal plan, which continues the operation of THEC 1 & 2 and BEC 1 & 2, all scenarios add 150 MW of short-term bilateral energy contracts, reflecting the need for replacement energy to idle THEC 1 & 2.[19]
- All plans add 33 MW of solar energy to comply with the SES.
- Energy efficiency programs beyond the current 1.5 percent goal show the potential to reduce overall power supply cost, although the timing and equitable distribution of benefits to all Minnesota Power customer's needs to be monitored.

Primary differences in MP's three alternative plans include the following:

- No new wind is included in the Preferred Plan. New wind is present only in the Boswell Gas Refuel and Early Coal Exist scenarios.
- In the Continue on Coal plan, THEC 1 & 2 and BEC 1 & 2 would continue to operate until 2026 and 2024, respectively (the end of their accounting life);
- In the Boswell Gas Refuel plan, BEC 1 & 2 would be converted to natural gas peaking units, and 200 MW of wind would be added for replacement energy;
- In the Early Coal Exit plan, in addition to the THEC idle, BEC 1 & 2 would be shut down in 2019; 300 MW of bilateral baseload purchases would be added in 2019; the natural gas CC unit would be added 2021 (three years earlier than the Preferred Plan); and 200 MW of wind would be added.

According to MP's analysis, the Preferred Plan yields the lowest power supply cost without a carbon price. The Preferred Plan is also least cost when CO_2 prices are introduced in 2025. When CO_2 costs are added earlier—in 2019—the Boswell Gas Refuel, which adds 200 MW of new wind to deliver the energy, is the least-cost scenario. Second-most inexpensive is the Early Coal Exit scenario, which also adds 200 MW of new wind. The trend here is how CO_2 prices sway the outcome away from coal (due to the higher variable cost) by adding wind. Figure 22 below illustrates the relative impact of CO_2 prices compared to the Preferred Plan.

Figure 22: Comparison of NPV Deltas from Preferred Plan



[19] These bilateral contracts have already been procured, per MP's May 18, 2016 filing.

2. Parties' Recommendations and Proposed Alternative Plans

The IRP rule allows parties to propose alternative resource plans for the Commission's consideration.[20] The Commission can adopt these plans outright or specific proposed modifications when identifying a plan most consistent with the public interest.

The Department created its own "DOC Preferred Plan" by replicating MP's modeling in Strategist, making changes to create a new base case, running additional scenarios under a variety of contingencies (or sensitivities), and making recommendations based on its judgment of the most reasonable plan.

The table below compares MP's Preferred Plan to the DOC Preferred Plan, excluding DSM:

Table: Comparison of MP Preferred Plan and DOC Preferred Plan

Year	Minnesota Power	Department of Commerce
2016	Idle THEC 1 & 2 10 MW Solar (Camp Ripley) 1 MW CSG	11 MW Solar
2017		Retire THEC 1 & 2
2018		300 MW Wind
2019		
2020	Cease coal at THEC 1 & 2 383 MW Manitoba Hydro 12 MW Solar	383 MW Manitoba Hydro 12 MW Solar
2021		
2022		Retire BEC 1 & 2 Add 200-400 MW NGCC; Up to 200 MW Wind; and Up to 50 MW Solar
2023		
2024	Cease coal at BEC 1 & 2 200-300 MW NGCC	
2025	10 MW Solar	10 MW Solar
2026		
2027		
2028		
2029		
2030		

Interestingly, the Department and MP agree on the forecast, but arrive at a very different place when it comes to the least-cost means to deliver energy in the upcoming years (2017-2019).

[20] Minn. Rule. 7843.0300, Subp. 11.

This is largely due to the differences in, first, modeling technique (namely the consideration of "superfluous units," which will be discussed in the "Wind Additions" section of this paper) and, second, the amount of market energy and output from THEC 1 & 2 existing in MP's plan.

The Clean Energy Organizations and Large Power Intervenors did not create alternative, year-by-year action plans, but recommended modifications of and findings on certain aspects of MP's and DOC's respective plans.

Overall, party comments largely focused on (1) the core elements of MP's proposed IRP—primarily Taconite Harbor 1 & 2, Boswell 1 & 2, MP's natural gas unit proposal, wind procurement, solar energy, and demand-side management—and (2) why their recommendations most align with the Commission's "Five Factors to Consider" established by rule.

Taconite Harbor 1 & 2

The issue of retiring all three units at the coal-fired Taconite Harbor Energy Center has been a focal point of MP's resource planning proceedings since its 2010 IRP.

In the Commission's May 6, 2011 *Order Approving (2010) Resource Plan*, the Commission required MP, as a compliance filing, to conduct a "baseload diversification study," to compare the continued operation of the Taconite Harbor Units against retiring them in the near- to intermediate-term.

In Minnesota Power's 2013 resource plan, MP proposed to retire Taconite Harbor Unit 3 in spring 2015, but to continue operation of Taconite Harbor 1 & 2. Ultimately, the Commission approved MP's proposed plan, but, in light of some economic results favoring the retirement of THEC 1 & 2, required MP "to include a full analysis of the effects of retiring or repowering the Taconite 1 and 2 plants, including transmission and distribution effects." [21]

In its 2015 Plan, MP is proposing a short-term "economic idle" at Taconite Harbor 1 & 2 in October 2016, before altogether "ceasing coal-fired operations" at THEC by the end of 2020. The benefit of economic idling would, according to MP, "take advantage of trends in lower cost replacement energy supplies from wholesale markets."[22]

Notably, MP does not propose retiring the units; rather, the Company proposes to offer them basically as emergency energy for the broader MISO region. In effect, THEC 1 & 2 becomes an energy-only resource available to regional markets for electric generation on a seasonal basis.

To explain further what "economic idling" means, staff refers the Commission to the following excerpt from Page 9 of MP's reply comments:

> Under the economic idling, Minnesota Power will offer THEC into the annual Midcontinent Independent System Operator ("MISO") Capacity Auction for the

[21] Commission ordering paragraph 14, November 12, 2013, Docket No. 13-53.
[22] Minnesota Power reply comments, p. 8.

> 2016/2017 planning year in March 2016. The Company will continue to offer THEC into each subsequent Annual Capacity Auction for planning years 2017/2018, 2018/2019 and 2019/2020. If THEC is selected as economical in the capacity auction, Minnesota Power will offer THEC into the energy and ancillary market if the units clear MISO's Annual Capacity Auction for that planning year. If THEC is not selected, the facility will be placed in long-term cold and dry lay-up status. A modest fuel supply will be preserved on site in the event that Unit 1 and/or Unit 2 are restarted to address reliability or system emergency needs. Additional fuel can be delivered to the site if necessary based on the anticipated period Unit 1 and/or Unit 2 are expected to operate. With appropriate notice from MISO, trained staff will temporarily transition from their current assignments back to THEC and prepare the unit(s) for operation.
>
> It is difficult to predict if the units will be required to restart to address reliability or emergency needs on the transmission system. Outside of a system emergency need, Minnesota Power anticipates the greatest potential for the units(s) to be called upon to support system reliability is during the summer peak demand period.

MP states in its excerpt above that THEC 1 & 2 may or may not be selected in the Annual Capacity Auction. At the same time, MP opposes retiring the units because, according to MP, "a THEC 1 & 2 shutdown scenario would create transmission reliability concerns in the area, and require two sets of transmission projects to ensure the electric service to Minnesota Power customers is maintained."[23] It is not clear what conditions would trigger MISO to select the units in its auction (or not), nor whether reliability problems will exist in the event THEC 1 & 2 are not selected in the auction. To the extent reliability problems do exist, the Commission might need more information explaining why idling is best reliability solution if the outcome of offering THEC into each Annual Capacity Auction is not known.

Furthermore, while MP characterizes its idling approach as one in which "the units will be required to restart to address reliability or emergency needs on the transmission system," there is ambiguity regarding what "needs on the transmission system" actually means. It is not clear if local reliability conditions are distinct from the "emergency needs" of the broader RTO, or if they are one and the same. It is also not clear what an "emergency need" is—i.e., whose emergency is it—and whether having THEC 1 & 2 in idle is a situation in which ratepayers are most insulated from however emergency situations are defined. A transmission upgrade, a new unit, or keeping THEC 1 & 2 in operation are all alternatives, but whether they could better protect ratepayers from system emergencies has not been made apparent. Also, the IRP analysis was conducted without knowledge of the specific replacement capacity and energy for THEC 1 & 2, so the contributions from that replacement power and energy are unknown.

The complicated nature of the idle introduces uncertainty into the IRP analysis regarding how MP's energy requirements will be met. If THEC 1 & 2 are selected in the capacity auction, it is unknown how much or when these units could be dispatched. MP's Strategist analysis assumes THEC 1 & 2 will operate with typical baseload operations in 2015-16. A step-down in

[23] MP Reply Comments, p. 11.

generation takes place in '17-18, and the output reduces to zero in 2019 and beyond. If the Commission believes this approach to modeling unit dispatch is unsatisfactory, there could likewise be a lack of confidence in MP's calculated power supply savings of the idle, which MP estimates as a "cost savings for customers ranging from $29 to $43 million."[24]

To be clear, staff does not oppose the idling concept. While vague, idling could provide MP some flexibility as it transitions away from coal-fired operations. In fact, one could ask why retirement is superior to idling, since THEC 1 & 2 are undepreciated assets, retiring them would not only present reliability issues but would also likely be impractical to do by 2017, and the units are not assumed to operate to any significant degree. And because the Strategist analysis assumes no capacity from THEC 1 & 2 after 2017 and no energy delivery in the 2020s, the ambiguity in the idling concept does not appear to meaningfully disturb the action plan overall.

The problem is that, at this point, the option to idle and cease (and perhaps repurpose) is more conceptual while the problems are real. All parties seem to agree in the sense that THEC 1 & 2 will be transitioned away from its current state, as a coal-fired facility, in the immediate term. The disputed questions remaining include whether idling provides value or imposes costs relative to retirement. Staff's main concerns include transparency and ways to monitor costs and operations moving forward, such as:

- how reliability would be maintained if the units are not selected in the Auction;
- how MP's idling plan could meet MISO planning reserve margin requirements for each planning year if the units are selected (so that MP does not overstate its need);
- whether MP has documentation provided to and/or received from MISO detailing how idling would be reflected in its resource adequacy;
- how much fuel supply (and at what cost) will be needed at the site; and
- in a proposal where uncertainty is high, how can ratepayers be insulated from the possibility that benefits might be less than the $29 to $43 million of cost savings MP has calculated by pursuing the idling approach.

a. Department of Commerce

The Department ran a retirement analysis which included six combinations of retiring Taconite Harbor 1 & 2 and Boswell 1 & 2:

Key to Abbreviations

Scenario	
TEBE	Taconite Harbor 1 & 2 shut down early, Bosell 1 & 2 shut down early
TEBG	Taconite Harbor 1 & 2 shut down early, Bosell 1 & 2 convert to natural gas
TEBL	Taconite Harbor 1 & 2 shut down early, Bosell 1 & 2 shut down late
TLBE	Taconite Harbor 1 & 2 shut down late Bosell 1 & 2 shut down early
TLBG	Taconite Harbor 1 & 2 shut down late Bosell 1 & 2 convert to natural gas
TLBL	Taconite Harbor 1 & 2 shut down late, Bosell 1 & 2 shut down late

[24] MP Resource Plan, p. 53.

In total, the Department ran each of the six scenarios 25 times—a base case plus 24 contingencies. The contingencies used for each scenario included ranges of: energy and demand forecasts; externalities costs; coal, natural gas, wind, solar, and spot market prices; and capital costs.

According to the Department, "Based upon review of the modeling results, the Department concluded that the overall best plan clearly involves shutting down Taconite Harbor units 1 and 2 early."[25] The lowest cost plan under base case/medium conditions was the Taconite Harbor 1 & 2 shut down early, Boswell 1 & 2 shut down early, or TEBE, scenario.

Attachments 1-13 of the Department's initial comments provide the Strategist outputs for the scenarios and contingencies evaluated in the THEC 1 & 2 and BEC 1 & 2 retirement analysis. Attachment 2 most closely resembles MP's Preferred Plan because this includes the Company's embedded DSM.

In the table below, staff provides the delta (in $ PVSC) of each scenario relative to the TEBE case, using base case conditions, under the "Standard Modeling Approach, Energy Efficiency +11 GWh" set of outputs listed in Attachment 2:

Scenario	**PVSC Difference ($ Million)**
TEBE	-
TEBG	+$23 million
TEBL	+$8 million
TLBE	+93 million
TLBG	+$130 million
TLBL	+$138 million

Different contingencies naturally produce different results. However, while the PVSC changes under different conditions the trend remains similar: the Department's analysis consistently found that Taconite Harbor-Early retirement scenarios (TE-) were much less costly than those which retired Taconite Harbor later (TL-).

The Department did not analyze a Taconite Harbor repurposing option. According to the Department, "because natural gas is not a viable option, the Department agrees with MP's screening analysis that determined continued coal use is more economic than gas conversion at Taconite Harbor at any capacity factor."[26] This is important because, according to MP, "A refuel of the THEC 1& 2 boilers to natural gas is a viable remission option." Also, MP recommends a Preferred Plan which "will continue to consider future refueling and remission opportunities."[27]

[25] Department comments, pp. 32-1-32.
[26] Department initial comments, p. 19.
[27] MP reply comments, p. 12.

(The Department does not even mention the possibility of MP's THEC conversion to biomass.) Essentially, the Department's approach would suggest that the only options it considers plausible for THEC 1 & 2 is continuing THEC on coal or retiring it, and the Department's findings strongly suggest retirement is least-cost.

b. Clean Energy Organizations

The Clean Energy Organizations recommend immediate retirement of Taconite Harbor 1 & 2. Like staff, the CEOs question whether the idling proposal as modeled in the resource plan is a realistic representation of its function within the overall MISO system.[28] Regardless of this, CEOs argue, the THEC units are "not economic to operate currently … and do not cover their operating costs through MISO revenue let alone their fixed costs."[29] Moreover, based on MP's response to CEO Information Request No. 3, the variable costs THEC 1 & 2 are increasing over time, further demonstrating that the early retirement option is the least-cost path forward.

Strictly on the basis of environmental compliance, CEOs argued, "Even if the continued operation of THEC Units 1 & 2 were economical (which it is not), Minnesota Power's plan to continue operating the units will likely result in violations of the EPA health-based, 1-hour National Ambient Air Quality Standard (NAAQS) for SO_2. Indeed, Minnesota Pollution Control Agency's modeling demonstrates that Minnesota Power's current permit causes significant exceedances of the 1-hour SO2 NAAQS in the communities, parks, and recreation areas surrounding the power plant."[30]

The CEOs disputed MP's claim that the Company complied with the Commission's order to analyze the transmission and distribution effects of unit retirement. Doing so, in CEOs view, would have required a demonstrated coordination with MISO through MISO's Attachment Y (unit retirement) process. Thus, CEO recommended that MP should retire THEC and begin the Attachment Y process as soon as possible. In the alternative, the Commission should require MP to request MISO to conduct an "information only" Attachment Y-2 study in order to substantiate MP's claim that the two units are needed for grid reliability.[31]

c. Large Power Intervenors

LPI recommends the Commission approve MP's plan to idle THEC 1 & 2, which LPI argues is particularly important in light of significant and ongoing regulatory uncertainty. In general, LPI advocates for a "no-regrets" approach, which includes exercising caution and preserving flexibility to make the most cost-effective decisions for ratepayers. In addition, LPI emphasizes reliability issues which may arise as a result of unit retirement and the possibly detrimental rate impacts of not addressing reliability issues fully. LPI is not convinced the Department or CEO

[28] CEO initial comments, p. 18.
[29] *Ibid*.
[30] CEO initial comments, p. 21
[31] An Attachment Y-2 is a non-binding evaluation; the same Xcel requested MISO to conduct for Sherco 1 & 2.

meaningfully analyzed the need for, or cost of, the requisite transmission upgrades as a result of the units' closure.

d. Minnesota Power Reply

In reply comments, MP warned of the "significant consequences with a near-term shutdown of THEC." In Part 4 of Appendix F of the IRP, MP provided two transmission impact scenarios, representing near-term and long-term system conditions under a THEC closure. MP reiterated the findings from those scenarios to argue that the cumulative impact of closing the two remaining units at THEC, in combination with the Taconite Harbor 3 shutdown and Laskin refueling, results in several concerns for the local transmission system.

Because Minnesota Power is a member of MISO, any unit closure on MP's system is required to utilize the MISO Attachment Y process. Section 38.2.7 of the MISO Tariff describes the process for generator retirements:

- First, MP must submit an Attachment Y to MISO stating when the generation resource is to be retired. This must be done at least 26 weeks before the targeted retirement date.

- Second, MISO will perform reliability analyses to determine if the unit may be retired without causing reliability issues on the transmission system.

- Third, if the unit closure does not impact reliability, the unit is allowed to shut down as scheduled. If the unit closure results in reliability criteria violations on the transmission system, the unit is placed on a System Support Resource ("SSR") agreement per Attachment Y-1 of the MISO Tariff. The unit will then remain operational under the SSR agreement until the transmission upgrades necessary to provide adequate transmission system reliability are constructed.

Because MP does not propose to retire THEC 1 & 2, but rather to cease its operation as a coal-fired facility, MP has not begun the MISO Attachment Y process.

e. Staff Discussion

On May 18, 2016, MP filed its reply comments in its 2015 Remaining Life Depreciation Petition docket.[32] In MP's depreciation docket, the Department recommended approving a remaining life of six years (2020) for THEC. MP disagreed with the Department's recommendation and "requests the Commission approve the current remaining useful life of twelve years (2026)."

While the depreciation petition is an open docket at present, and while decisions regarding asset depreciation are separate to resource planning, MP's reasons for disputing the Department's recommendation on depreciation are telling to the Company's actual plans for the facility, and thus relevant to the IRP. According to MP's reply comments in its depreciation docket:

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[32] Docket No. 15-711

> Minnesota Power has no plans to decommission the THEC in 2020 when it proposes to cease electric generation with coal as its primary fuel. Minnesota Power is continuing to develop multiple utility re-missioning and refueling opportunities for THEC to produce electricity that are **in the best interests of Minnesota Power customers**, and also economically benefit the communities and surrounding region.[33] (Emphasis added.)

Staff's concerns here relate to consistency, compatibility, and transparency. In the resource plan, MP presents the following graphical representation of its Preferred Plan in Figure 21 of Appendix K, noting it will "Shutdown [THEC] by 2020":

Figure 21: Preferred Plan and Alternative Swim Lane Resource Additions

MP's Preferred Plan seems to contradict the Company's position in its depreciation filing. This could be due to a lack of common language between separate dockets; however, equally confusing is MP's discussion of "re-missioning and refueling opportunities" in the IRP:[34]

> The first step in the THEC1&2 evaluation is to compare the re-missioning alternatives of compressed natural gas and torrefied wood to continuing on coal before considering a shutdown alternative for the facility. THEC has been maintaining a 60 to 75 percent capacity factor for the past eight years, providing baseload energy and capacity for Minnesota Power's customers. When the generation costs are compared one-to-one, **continuing to operate on coal is clearly the lowest cost option for customers, with and without a carbon regulation penalty**.[35] (Emphasis added.)

In this single excerpt, MP refers to three vastly different options—shut down, continue on coal, and re-missioning—and concludes that continuing on coal is the best option. And given MP's repeated claims about reliability problems and socioeconomic factors associated with retirement, staff can only conclude, simply by process of elimination, that MP's Preferred Plan does *not* propose to retire THEC by 2020; rather, the Company expects coal to be the most prudent option for THEC until 2026, although perhaps not in the same way as it has operated historically.

MP seems to want it both ways by removing THEC 1 & 2 (and BEC 1 & 2) from its IRP capacity outlook, while arguing strongly against the units' retirement *and* revealing the cost

[33] May 18, 2016 reply comments, p. 2.
[34] Resource Plan. p. 14.
[35] Resource Plan, p. 51.

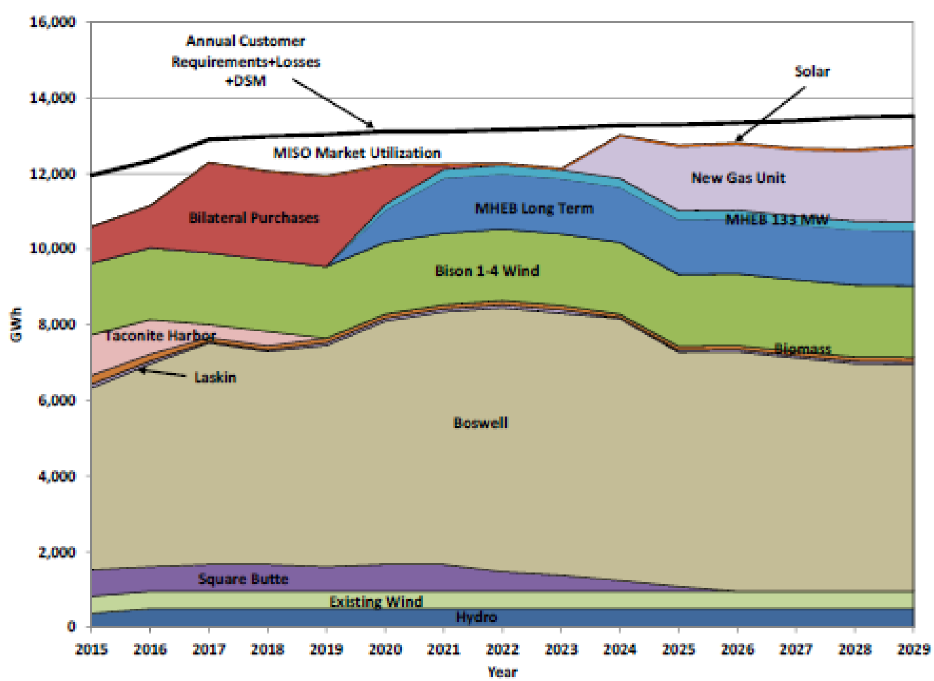
premium to re-missioning options. While MP's conclusion in the resource plan is that idling but continuing on coal is in the best interest of its customers, in the depreciation docket, MP at the very least implies that the Company is moving in the direction of "re-missioning and refueling opportunities."

Overall, staff's interpretation of MP's entire discussion, including both the IRP and depreciation dockets, is that the Company may retire THEC 1 & 2, but no sooner than 2026. Based on its most current analysis, MP believes continuing on coal is the most cost-effective option at all capacity factors and with or without CO_2 regulation.[36] When environmental regulations become more certain, when the end of accounting life draws near, or until the Commission demands an alternative, MP seems to offer no support for any option other than continuing THEC on coal through 2026, even though the Preferred Plan contemplates ceasing coal-fired operations.

Boswell 1 & 2

Minnesota Power expects its Boswell Energy Center (BEC) to be the Company's major, owned centralized thermal generation asset for long-term baseload operations. BEC is Minnesota Power's largest generation facility, with a capacity of over 1,000 MW. Substantial investments have been made at BEC since 2007, the largest being its \$350 million multi-pollutant BEC Unit 4 Environmental Retrofit Project.[37] According to Figure 22 of the IRP (Projected Energy Position), MP expects BEC to generate approximately 6,000 GWh of energy per year, nearly half of its total generation.

Figure 22: Preferred Plan Energy Position Outlook[67]



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36 Resource Plan, p. 51.
37 Docket No. 12-920

There are 4 units at the Boswell Energy Center. Units 3 & 4 are much larger and (relatively) newer than Units 1 & 2. At issue here is the possible retirement of Units 1 & 2. Boswell Units 1 & 2 account for 132 MW of accredited capacity (135 MW nameplate). BEC 1 & 2 were placed into service in 1958 and 1960, respectively. Their current economic life extends through 2024; however, as discussed previously, MP is petitioning that the entire facility have the same remaining economic life, and to be extended to 2050. MP plans to invest $30 million in an SO_2 reduction at BEC 1 & 2 in 2018; however, MP states it does not expect new or additional costs from 2024 to 2050.[38]

a. Department of Commerce

The Department focused its Strategist analysis on the potential shutdown dates for the Company's Taconite Harbor 1 and 2 and Boswell 1 and 2 units. The Department examined three possible alternatives: refueling Boswell 1 & 2 with natural gas, retiring the units in 2019 (early retirement) and retiring the units in 2024 (late retirement). The Department's analyses suggested refueling Boswell 1 & 2 with natural gas would be the most expensive of the three alternatives. The Department's analyses also showed that the other two alternatives (early or late retirement) were typically very close in cost, with early retirement slightly lower in cost under most scenarios. However, the Department argued:

The main difference was that an early shut down required MP to rely upon substantial short term base load capacity for an additional three years. The short term capacity is necessary to meet the Company's load and capability requirements. From this information the Department concluded that MP should coincide its shut down of Boswell units 1 and 2 with the addition of natural gas capacity.[39]

b. Clean Energy Organizations

CEO recommends the Commission modify MP's action plan such that Boswell 1 & 2 will be shut down as soon as replacement capacity is available. However, CEO does not agree with MP or the Department in the amount or type of that capacity. While CEO agrees with the Department's recommended shut down date of 2022, CEO argues the retirement date could occur sooner. In any path the Commission chooses, CEO urges the Commission to avoid approving any additional investments in Boswell 1 and 2.

As CEO observes, Boswell 1 & 2 are nearly 60 years old, and any expenditures in aging coal-fired infrastructure should carefully consider the units' long-term viability as well as the possibility of even more maintenance and investments moving forward, especially in light of current and future environmental regulations. As such, if the Commission does not determine the most prudent course of action is to retire Boswell 1 & 2 in near-term, CEO recommends the

[38] MP Response to PUC IR #5.
[39] Department of Commerce, Initial Comments, p. 32.

Commission require MP to provide "technical justification for continuing to operate [Boswell] Units 1 and 2 for more than five years."[40]

c. Large Power Intervenors

LPI cautioned against an early retirement of Boswell 1 & 2. LPI raised concerns that "this push to retire BEC 1 & 2 early has not fully accounted for the broader system reliability and operational implications for the larger Boswell facility identified by Minnesota Power."[41] LPI also pointed to the uncertainty surrounding the Clean Power Plan, arguing "While these regulations develop, there is significant uncertainty in determining the lowest cost strategies for compliance."[42] Overall, LPI argued MP's proposed approach to Boswell 1 & 2 "will preserve more flexibility to make the most cost-effective decisions for ratepayers."[43]

d. Staff Discussion

Staff's interpretation of MP's proposal to "operate Boswell 1 & 2 on coal to bridge to a new [natural gas combined cycle unit] in 2024" is slightly different from the parties'. The Department and LPI, for example, refer to MP's plan for BEC 1 & 2 as a retirement by the end of its economic life. In staff's understanding, MP's proposal does not suggest a shutdown or retirement date at all, and little suggests the BEC 1 & 2 be taken offline in 2024.

In fact, BEC 1 & 2 would not functionally separate from BEC, and no facility equipment is suggested to become unavailable for use. MP proposes that generation will cease, but it will still utilize existing equipment at BEC 1 & 2 to provide operational support to Units 3 & 4, such as during black start procedures, ongoing operations, and critical system restoration.

Second, MP leaves open the possibility that BEC 1 & 2 may continue to generate electricity beyond the end of its accounting life. On Page 14 of Appendix C, MP states, "Capital investments are continuously reviewed and prioritized across the generating fleet, including BEC 1 & 2, **with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period**." (Emphasis added.)

Third, in its transmission study analysis, MP concluded, "Shutting down BEC 1 & 2 results in several concerns for the local transmission system." MP is also proposing, in a separate docket, to extend the physical life of BEC 1 & 2 until 2050 to address these concerns. Both suggest that MP expects BEC 1 & 2 will continue to play a role, in some fashion, in its system operations at least until the end of its economic life, but probably longer.

MP states that its long-term action plan is to assess the economic viability of BEC 1 & 2 to determine the units' competitive position by 2025. According to MP:

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[40] Clean Energy Organizations, Reply Comments, p. 6.
[41] Large Power Intervenors, Reply Comments, pp. 3-4.
[42] *Ibid*, p. 4.
[43] *Ibid*, p. 2.

> Continuing BEC 1 & 2 provides a reasonable cost power supply resource for customers in comparison to alternatives, and allows the Company to bridge to its next significant resource addition. At the time of this analysis, that resource is identified as an efficient natural gas-fired generation unit that would be built in the mid-2020 timeframe, congruent with the BEC 1 & 2 end of useful accounting life in 2024, **at which point the future state of BEC 1 & 2 will be decided**.[44] (Emphasis added)

Staff has two main concerns with MP's statement. First, MP seems to identify the end of units' accounting life, 2024, as the point at which "the future state of BEC 1 & 2 will be decided." With the future of BEC 1 & 2 unknown at this time, and with MP's "goal of maintaining current capacity … throughout the planning period," it is difficult for the Commission to determine the appropriate size of the next resource addition. And if BEC's end of life is to be extended until 2050, with the viability of BEC 1 & 2 is to be reassessed in the next resource plan, it is difficult for the Commission determine the basis for the natural gas acquisition.

Conversely, if MP will indeed shutdown BEC 1 & 2 in 2024, staff questions the value of a $30 million investment to reduce SO_2. And if BEC 1 & 2 must retire earlier than 2024—for instance, to meet an interim (2022) Clean Power Plan compliance date—the value of such an investment is even less. Nevertheless, it appears MP's Consent Decree with EPA requires the Company to do *something* to comply with the BEC 1 & 2 Notice of Violation, and that something must not include a conversion to a fossil fuel resource. In this regard, early retirement with the transmission upgrade[45] may be cheaper and more practical than further capital investment.

The Clean Energy Organizations assert that "Minnesota Power has not established the need to keep Boswell Units 1 & 2 operational," and CEOs request that the Commission order a full analysis of ceasing operations at Boswell Units 1 and 2. The Commission has done this before, for example, in the case of the Sherco Life Cycle Management Study it ordered in Xcel Energy's 2011 Resource Plan. Staff supports CEOs' request, in part because it could illuminate how decisions made at BEC could affect reliability impacts of MP's system overall. However, staff believes further study would imply no modifying action would be taken on BEC 1 & 2 at this time, since CEOs' recommendation for the study intends to question the units' long-term viability, which is redundant if the Commission determines BEC 1 & 2 should be shut down.

Boswell Energy Center is unique in its size and long-term value as a baseload resource, particularly for a high load factor utility like MP. BEC is also unique in its role for balancing environmental compliance with avoiding stranded costs. Since MP is phasing out all of its coal-fired fleet except Boswell, this facility is directly tied to the Company's overall ability to comply with all environmental regulations affecting it, including the EPA Clean Power Plan. In the context of balancing reliability impacts with environmental regulations, the significance of the entire BEC facility cannot be understated—it is a 1,000+ MW baseload resource operating in a 1,800 MW system. This means that the BEC is critical to preserve system reliability, while also being the epicenter of environmental compliance.

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[44] Resource Plan, p. 45.

[45] The cost of the transmission upgrade is provided on page 45 of the resource plan, but MP designated this cost as Trade Secret.

For several reasons, staff views Boswell Energy Center, as an entire facility, as both a short-term and long-term issue. Many potential options for the future of BEC 1 & 2 are discussed throughout the IRP Petition, party comments, and in this briefing paper. In weighing each option, the Commission could discuss the issues underpinning it, including:

- The type and costs of (and options for) local system upgrades and grid management;[46]
- The long-term value of making an environmental retrofit investment in 2018;
- The operational value of BEC 1 & 2 as part of an integrated facility;
- The age of the units (BEC 1 & 2 are among MP's oldest units, having been placed into service in 1958 and 1960, respectively);
- How "ceasing" operations is different than retirement; and
- How resource planning decisions regarding BEC 1 & 2 could carry into other dockets (e.g. the BEC life extension docket).

MP's Proposed Natural Gas Procurement

On October 15, 2015, Minnesota Power issued a request for proposals (the "RFP") for up to 400 MW of capacity and energy beginning in the 2022 to 2024 timeframe.

a. Department of Commerce

The Department's recommended action plan includes a 200 MW natural gas combined cycle unit, to coincide with the shutdown date of Boswell 1 & 2. The Department found that the majority of contingencies resulted in adding either one gas CT unit or one CC unit; the most common addition being a single CC unit.

b. Large Power Intervenors

Among the Large Power Intervenors' chief concerns is that MP proceeded without Commission approval on beginning the competitive procurement process for natural gas generation. LPI contended that no formal press release was issued by Minnesota Power regarding this RFP, and there was only a mere mention of the RFP on its website. LPI also questions "why Minnesota Power believes the Commission should make any decision now for a need that allegedly doesn't arise until 2024."[47]

Also, LPI observed that MP appears to be "working closely with the City of Cohasset on what is referred to as the Itasca Energy Center ("IEC") project."[48] The City of Cohasset—which is the location of the Boswell Energy Center—has announced plans for a $300 million, 400 MW

[46] Resource Plan, Appendix F, p. 19.
[47] *Ibid*. p. 6.
[48] Large Power Intervenors initial comments, pp. 5-6.

natural gas facility, to be developed by Texas-based Navasota Energy.[49] Construction is expected to begin in 2018 after the permitting process is complete. According to the article that LPI cites, the Itasca Energy Center is "just one of many firms in the running for a contract to develop such a facility for Minnesota Power."

LPI concludes, "Minnesota Power's natural gas RFP should be withdrawn and revised to be commensurate with the Resource Plan (when approved) and to allow customer participation." LPI encouraged the Commission to require MP to "formalize a process for working with large power customers interested in self-generation or cogeneration and incorporating such resource options into the Company's resource planning process."[50]

c. Clean Energy Organizations

Like LPI, CEO strongly opposes MP's self-initiated competitive bidding process for up to 400 MW of natural gas combined cycle capacity for at least three reasons. First, CEO argues MP overstates its need, such that BEC 1 & 2 could be replaced earlier and with a non-fossil-fuel resource. Second, in the event a higher need could emerge, CEO believes a more reasonable path would be to explore demand response program alternatives. Third, CEO notes that Minnesota law[51] prohibits Commission approval of a new natural gas resource in the IRP unless Minnesota Power has first demonstrated that a renewable energy facility is not in the public interest.

The Clean Energy Organizations recommend the Commission "suspend [MP's] pending natural gas power plant procurement." If or when a need does emerge, MP should initiate a resource acquisition that is "fuel-neutral."

d. Minnesota Power Reply

In MP's reply comments, the Company stated, "Minnesota Power determined it was necessary to begin its natural gas investigation to ensure it could gain access to a new larger CC facility by 2024. Actual resource additions will vary based on continued updates to customer load outlooks and availability of competitive opportunities."

MP also responded to LPI's concern that the acquisition process was premature:

> To add a new natural gas resource to the power system is a lengthy process; the planning, design, contracting, environmental, transmission additions and regulatory approval quickly add up to a six to eight year process.[52]

And with regard to LPI's claim that the RFP process was not transparent, MP replied:

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[49] http://www.scenicrangenewsforum.com/minnesota-power-energy-project-developer-has-yet-to-be-selec/ (via LPI initial comments, p. 6)
[50] LPI reply comments, p. 6.
[51] Minn. Stat. § 216B.2422, subd. 4
[52] MP reply comments, p. 17.

> [Minnesota Power] employed the following best practices for communicating power supply RFP: sequential advertisement in Platts Megawatt Daily, submitted to exploders for North American Electric Marketing Association (NAEMA) and over 400 industry development entities, as well posted the RFP on Minnesota Power's company website.[53]

e. Staff Discussion

Both LPI's and CEO's recommendations would effectively terminate the Company's natural gas competitive bidding process already underway and nearing its end. In staff's view, this action might be over-reaching, even if the Commission determines the record does not support a natural gas combined cycle addition, because MP has the right to seek out projects that meet its projected demand and energy requirement (although with transparency). This does not waive MP's burden of proof, of course, to demonstrate that the natural gas project is in the public interest; it simply means the Commission could simply take no action on the bidding process.

MP's pursuit of a natural gas unit follows from the Company's 2013 resource plan, in which the Company proposed "to add 200 – 250 MW of natural gas combined cycle generation after 2020."[54] Specifically, MP's 2013 Preferred Plan included, among other actions:[55]

> Investigating, for inclusion in its next resource plan, an intermediate natural gas generation resource for Minnesota Power's customers to meet expected capacity and energy needs in the post-2020 timeframe. Minnesota Power will use bilateral market purchase contracts with secured pricing as a bridge to implementation of a natural gas unit to flexibly and economically help meet resource needs in the period between 2014 and 2020.

Certainly, to LPI's point, there is a significant gap between "investigating" a long-term resource and issuing an RFP for 400 MW of new capacity.

LPI and CEO are justifiably concerned about MP's natural gas procurement process. First, the Commission's finding of need in the 2013 resource plan only directed the Company to acquire resources in the 2015-2017 timeframe, not 2024. Second, it could be argued that MP did not comply with Minn. Rule. 7843.0400, Subp. 3(c), which states that a resource plan filing must include, among other things, "a schedule of key activities, including construction and regulatory filings." The discussion of a natural gas RFP was not included in the 2013 IRP, and the RFP itself was not included in the 2015 IRP record until LPI attached it to its February 18, 2016 comments.

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[53] *Ibid*.
[54] Minnesota Power's 2013 Integrated Resource Plan, Page 9
[55] Minnesota Power 2013 IRP reply comments (Docket No. 13-53), July 3, 2013, p. 3.

The schedule for MP's gas acquisition is shown below in the RFP schedule, filed as Exhibit B in LPI's February 18, 2016 comments. As indicated by the table, the bid selection process and the negotiation phase should be nearly complete:

Minnesota Power RFP Schedule

Event	Anticipated Date
Release of RFP	October 15, 2015
Notice of Intent to Bid Due	November 16, 2015
Proposal Submittal Deadline	**5:00 pm CST on January 5, 2016**
Selection of Bid(s)	February 15, 2016
Complete Negotiations	Second Quarter 2016

As MP proceeds with its actual resource additions, the Commission could make a size and timing finding in its IRP Order to clearly state what the record evidence supports regarding MP's capacity need. Such a finding would be very different from whether or not MP's natural gas selection could be the most prudent resource to fit that need; rather, staff suggests a finding of capacity need merely because, once MP submits for Commission approval its natural gas acquisition proposal, or any other proposal for that matter, parties may re-introduce the same disputes over need, and the Commission may be asked to revisit the same issues.

Overall, staff shares LPI's concern about making "a firm commitment to new gas generation sooner than necessary and without full exploration of alternatives." As LPI pointed out, "by 2024, there may be more cost effective options available for replacement of these units."[56] However, resource plans are a snapshot in time, and according to the economic analysis conducted by MP and the Department for this plan, a 200-300 MW natural gas unit in the 2021-2024 timeframe is a robust expansion result across multiple scenarios and sensitivities.

Certainly staff agrees with LPI that there are always numerous possible alternatives for a capacity need eight years in advance. To LPI's argument about timing, MP could wait until new or expanded industrial loads materialize before making such a large financial commitment. To CEO's argument about the renewable preference statute, since MP will be issuing an RFP for utility-scale solar pre-2020 anyway (although to comply with its SES), MP could expand the size and scope of that utility-scale solar RFP to account for at least part of a possible need. Alternatively, MP could employ the same exact strategy it has used previously and in this IRP, which is to secure one- to multi-year bilateral contracts in light of capacity need uncertainty.

One option not explored in this case is procuring bids for demand response resources. As an example of this approach, in 2012, Puget Sound Energy (PSE) issued a demand response RFP which targeted Commercial-Industrial customers. The RFP stated, "PSE has a demand response capacity need identified by PSE's IRP. PSE's IRP analysis, which guides the resource acquisition process, is based on a loss of load probability planning standard for electric resources. … PSE's loss of load probability modeling shows a favorable fit for a capacity

[56] LPI reply comments, p. 4.

resource of dispatchable demand response in the one to four hour event duration range."[57] Because this is an unexplored option, the Commission could direct MP to work with parties and staff to establish the parameters of such a process to consider in the next resource plan.

As mentioned previously, a focal point of staff's analysis of MP's IRP is the interrelationship of ceasing operations at Taconite Harbor and BEC 1 & 2, new hydro, new wind, and SES compliance (among other things) in the context of grid reliability, rate impacts, and value-driven planning. A large combined cycle unit provides benefits including dispatchable electricity, economies of scale, currently low natural gas prices, and it concurrently satisfies both the Company's capacity and energy requirements. Furthermore, it is relatively straightforward to incorporate into economic modeling. A "mix-and-match" type approach, on the other hand—which could include combinations of demand response and distributed energy resources for capacity, and conservation, self-generation, and cogeneration for energy—is more difficult to rely upon for long-term resource adequacy. However, the benefit of such an approach could be to incrementally build toward an eventual, targeted need, like stairs on a 300 MW staircase, in a way that is low-risk and insulates against forecast uncertainty, because it can adapt to changes in capacity outlooks over time without significant financial commitments occurring at once. A limitation of resource planning is that a portfolio of incremental options is difficult to compare or sum up as an "alternative" to a large-scale gas unit which Strategist selects once a capacity deficit occurs.

Ultimately, the matter at hand is whether MP's natural gas procurement (and its process for procuring it) is reflective of the record evidence, and staff believes a strong case is made that it is. Moreover, the means by which MP is pursuing its acquisition is nearing its end, and restarting it changes the nature of the resource acquisition process from one which is MP-led to one which is effectively Commission-led. Thus, the options the Commission has is to either let that MP-led process run its course and later review the reasonableness of the project it selects—compared to an appropriate set of alternatives—or to terminate the process and direct the Company to take a different approach.

Wind Additions

In MP's Initial Petition, the Company did not propose any new wind additions to its system. In the Department's analysis, the Department observed that MP has an energy need early in the planning period and concluded that MP's five-year action should be modified to include 300 MW of wind by 2018. The Clean Energy Organizations support the Department's recommendation. The Large Power Intervenors do not take a specific position on the wind additions, but recommend the Commission approves MP's five-year action plan as initially proposed.

MP believes the recommendation to 300 MW of new wind is excessive; however, MP agrees that 100 MW of new wind could be beneficial to customers over the long-run given the currently low price for wind and recent extension of the federal Production Tax Credit (PTC).

[57] Puget Sound Energy, Request for Proposals, http://pse.com/aboutpse/EnergySupply/Documents/DemandRFP.pdf

1. MP's Wind Assumptions and Modeling Approach

a. Clean Energy Organizations

The Clean Energy Organizations raise two important points about how Minnesota Power considered economic wind: the price assumptions and how Strategist was allowed to add wind.

CEO claims that renewables, both wind and solar, were modeled at higher than realistic prices. Regarding the price of wind, CEO argues that the wind price should consider the benefit of the wind Production Tax Credit (PTC), which Congress extended for five years (on a step-down basis) on December 18, 2015. MP acknowledges this in its reply comments and notes that the PTC was extended after the Company filed its resource plan. In part because of the PTC extension, the Company is willing to explore adding new wind during the five-year extension period.

The second part of CEO's objections refers to the price assumptions' distance from actual market prices. CEO cites a UBS Global Research report in which Xcel Energy reported its wind PPAs were priced in the $20/MWh range.

The Clean Energy Organizations also object to MP's modeling approach, specifically with regard to how Strategist was allowed to add wind units. CEO argues that the number of wind units available for consideration was inappropriately constrained. The Department had a similar criticism, and modeled wind differently in its analysis. Both CEOs' concerns with MP's modeling and the Department's changes to MP's base model led to the result of significant wind additions in the five-year action plan.

b. Department of Commerce

The Department's modeling technique differed from MP's modeling approach by allowing the selection of "superfluous" wind units. A "superfluous unit" is a unit which Strategist can choose if it provides cost-effective energy even when there is no capacity need. Generally, since Strategist is a capacity expansion model, it adds resources only when there is a capacity need. And because wind units have relatively little capacity value, the Strategist model is not likely to select wind resources to fill a capacity deficit. Thus, the Department's modeling technique allowed Strategist to consider whether wind could be cost-effective additions on an energy basis.

The Department summarized its choice of size and price as follows:

> The Department allowed Strategist to choose generic wind units in even numbered years for 2018 to 2030; the size of the units was 300 MW for 2018 and 100 MW in the subsequent years. The units were labeled superfluous in years 2018 to 2022. The Department included estimates of integration and cycling costs in the generic wind costs. The 2018 wind unit was modeled with a flat cost of $50 per MWh for 20 years. The cost of subsequent wind units was escalated at two percent per year to determine the flat cost.

In Attachment 2 of the Department's initial comments, which shows the number of units added under each scenario, the Department's modeling results suggest that unit retirement scenarios only minimally impact the number of wind units selected. Staff shows an excerpt of the Department's retirement scenarios below to reflect the fact that all unit retirement combinations selected between three and five wind units (of 100 MW each).

Taconite Harbor & Boswell Retirement Scenarios	
Scenario (Mid-Forecast)	**Wind Units**
TEBE (TH-early/Bos1&2-early)	4
TEBG (TH-early/ Bos1&2-gas)	5
TEBL (TH-early/ Bos1&2-late)	4
TLBE (TH-late/ Bos1&2-early)	4
TLBG (TH-late/ Bos1&2-gas)	4
TLBL (TH-late/ Bos1&2-late)	3

In the Department's analysis, the size of the superfluous wind in 2018 is due to the energy need in the early years of MP's planning period. According to the Department, "once that initial need is filled smaller units provide a better match for MP's forecasted energy growth rate."[58]

c. Minnesota Power Reply

The Department and MP disagree over the optimal amount of wind because, according to MP, the additions the Department recommends could create excess energy on its system.

However, MP's IRP was filed before the PTC extension, and in reply comments, MP acknowledged that a small amount of new wind—MP suggests 100 MW—while the PTC is available is a reasonable compromise and could have long-term value for its customers.

d. Staff Discussion

MP used a range of \$35/MWh to \$75/MWh for its wind price sensitivities. This range, to CEOs' point, includes wind price estimates well in excess of any wind PPA recently approved by the Commission. Even if the amount of the PTC benefit was simply added back to the levelized cost, without any market recalibration—an overly simplistic assumption, in staff's view—the upper bound would still be much higher than recently approved wind PPAs.

[58] DOC Initial Comments, p. 17.

As one source for comparison, the levelized cost for each of MP's Bison Wind Energy Center Units (1-4) was far below the upper bound used for MP's assumptions. While the price for each Bison project is Trade Secret, the average levelized cost of the four Bison projects[59] is less than MP's assumed $35/MWh lower bound.

As another source for comparison, in 2013, Xcel Energy issued a request for proposals for approximately 200 MW of wind generation. In response, Xcel received proposals for 57 projects comprising approximately 6,300 MW of wind resources. Of these 57 projects, 14 fell below the $29/MWh threshold Xcel used to screen candidate proposals.

Staff acknowledges that grouping together MP's Bison Wind projects and Xcel's 2013 wind RFP results may not be the best benchmark to gauge the reasonableness of a wind price forecast; however, staff believes that comparing MP's wind price assumptions to historic, but recent, wind prices for Minnesota utilities justifies giving more weight to MP's and the Department's "low cost" sensitivities.

Tables 8 and 9 on Pages 83-84 of MP's Petition show the Net Present Value of a series of 50 sensitivities MP ran in its model, each with and without the Commission's $21.50/ton CO_2 value. When wind was priced at the lowest bound, $35/MWh, both the Boswell Gas Refuel and Early Coal Exit scenarios were lower in cost than the Preferred Plan, with or without a CO_2 price.

There is a distinction, though, between rate impacts and levelized costs. A stream of expected total revenue requirements over time is fairly easy to project, whether under a PPA or ownership structure, as certain assumptions can be made about capital costs, capacity factors, and so on. There is less certainty in monetizing offset costs, particularly if the load forecast is overstated or there is indeed excess energy on the system, to calculate immediate rate impacts.

An additional 300 MW of new wind in 2018 would be a major investment for the Company. By comparison, the total size of MP's Bison Wind Energy Center (Bison 1-4) is about 500 MW, and MP developed this wind over the course of several years and in conjunction with the acquisition of a transmission line. This is not to say in absolute terms that 300 MW of new wind is excessive, especially given the robustness of the result in the Department's analysis. But if the Commission adopts the Department's recommendation to add "up to 300 MW" of new wind, staff suggests possibly modifying the language to include a broader range, such as "100-300 MW." While there could be no meaningful difference in the literal interpretation of the modified language, a range reflective of both MP's and the Department's positions, at least aesthetically, gives both positions equal weight. The exact amount could be resolved at a later date and in an actual wind acquisition proceeding, so for the IRP's purposes, staff is concerned 300 MW might be too high, and an additional target (or range) could balance that out.

Future Proceedings

As a next step, the Commission could modify MP's action plan, initiate a competitive bidding process, or both. Opening a bidding process for new wind, leaving the range of MW sought

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[59] Levelized cost calculations were derived from the Trade Secret Comments of the Department of Commerce for each of the four Bison Wind dockets.

broad enough reflect the Company's and Department's positions, could both resolve the dispute over price and allow for a refreshed look into the uncertainty of the energy need. The timing of the proceeding, however, should focus more so on the forecasted energy need, since that is the basis for the Department's recommendation.

Of course, the Commission could also determine that it is premature to add any resources at this time, if load growth appears so dismal to justify delaying resource acquisition altogether. Moreover, as stated above, there is glaring uncertainty regarding the Company's plans for THEC 1 & 2 and its acquisition of a natural gas plant. Both decisions affect the equation in determining the offset costs, which in turn affects the total rate impact.

Demand Side Management (DSM)

In Minnesota Power's previous (2013) resource plan, the Commission approved "an energy savings goal of 1.87 percent of Minnesota Power's retail sales by its next resource plan filing,"[60] which was a modification to the IRP raising the DSM level. In its order, the Commission stated:

> The Commission agrees with the Department that 1.87 percent of Minnesota Power's retail sales is an appropriate energy conservation benchmark, which the Commission will establish until the Company's next resource plan. Based on the Department's calculations, this savings goal reflects a 0.2 percent increase over current savings that could be cost-effectively achieved.
>
> However, the Commission concludes that, going forward, more detailed information on conservation on Minnesota Power's system is needed to perform a detailed cost-benefit analysis of energy savings.

This additional information became what is referred to in the IRP as Order Point 12, which sought to, essentially, distinguish between CIP savings non-CIP-exempt savings and consider additional scenarios to test DSM similar to supply-side scenarios which are stressed at various fuel prices. Specifically, the Commission ordered the followed analysis:[61]

> 12. For its next resource plan, Minnesota Power shall:
>   a. Identify the amount of energy savings embedded in each year of its load forecast, in terms of total savings (kWh) and as a percentage of non-CIP-exempt retail sales;
>   b. Identify the amount of system-wide energy savings, including aggregate data for CIP-exempt customers, embedded in each year of its load forecast;
>   c. Evaluate additional conservation scenarios for its CIP-exempt and non-CIP-exempt customers, that would achieve greater energy savings beyond those in the base case; and

[60] Commission ordering paragraph 11, Docket 13-53, November 12, 2013.
[61] Commission ordering paragraph 12.

d. Provide cost assumptions for achieving every 0.1 percent of savings above 1.5 percent of non-CIP-exempt retail sales.

Appendix B of MP's 2015 Plan contains the most granular information regarding Minnesota Power's DSM planning efforts. Appendix B includes MP's energy savings scenario analysis, a demand response study, and an in-depth discussion of Order Point 12 of the 2013 Plan.

Regarding terminology, the Commission modified MP's 2013 resource plan to include an additional +0.2% of energy savings, or 1.87%, for its 2015 IRP. Since that time, resource planning has shifted from evaluating and discussing DSM portfolios solely by percentages of retail sales into scenarios which test incremental levels of units of total energy saved, or gigawatt-hours (GWh). (This shift has largely been a result of the Department's efforts to evaluate energy savings a resource to be compared against supply-side alternatives.)

1. MP's Non-CIP-Exempt Level of DSM

In MP's 2015 Plan, the scenario analysis was limited to DSM levels applicable to customers participating in and paying for CIP. In this analysis, the Company evaluated four energy savings levels, listed both in percentages and units of energy saved. Table 1 on page 17 of Appendix B shows the energy savings scenarios used for the IRP.

Table 1: Summary of Alternative CIP Scenarios

Scenarios		Annual Program Costs (million $)					*Annual Savings at the Generator	
*% of Sales** (rounded)*	*Plan*	*Incentives*	*Admin*	*Nonimpact*	*Total*	*Total Incremental Costs*	*Energy (GWh)*	*Summer Peak (GW)*
1.5%	Existing	$3.4	$1.2	$2.4	$7.1	$0.0	46.5	0.0071
1.87 %	+ 11 GWh	$4.8	$1.7	$3.2	$9.7	$2.7	57.3	0.0087
2.0%	+ 15 GWh	$5.6	$1.9	$3.6	$11.1	$4.1	61.2	0.0093
2.5%	+ 30 GWh	$9.4	$2.9	$5.3	$17.6	$10.5	76.5	0.0116

Of note, while Order Point 11 of the Commission's November 12, 2013 Resource Plan order set an energy savings goal of 1.87 percent of retail sales, MP's "Existing Plan" above included 1.5% of retail sales, or 46.5 GWh of energy savings. The Department observed the disparity between the Commission's order and MP's characterization of its energy savings and noted, "The Department's review of MP's Strategist inputs indicates that MP included the +11 GWh incremental savings in its Preferred Plan. However, statements from MP regarding the amount of energy savings in its Preferred Plan are ambiguous, and are not clear from reading the

Company's narrative … Based on the Department's review of MP's Strategist inputs, the Department concludes that the Company complied with Commission Order Point 11."[62]

For future filings, the Department requested that the Company provide a more clear energy savings proposal. Staff agrees and suggests that, due to the ambiguous nature of MP's description of its energy savings in its Preferred Plan, the Commission approve a specific level of energy savings in its order; however, modifying MP's proposed energy savings level should achieve the same result.

Anticipating that parties might recommend higher DSM goals than what the Company proposed, MP provided a lengthy discussion of the obstacles it faces to achieve savings levels above the +11 GWh scenario. Specifically addressing the scenario analysis required by Commission order in the last IRP, MP stated:

> Minnesota Power's approach to developing scenarios for energy efficiency achieved through CIP included analysis and research providing insight into historical performance, future opportunities, and the changing energy-efficiency environment. One of the key findings from the analysis was that a significant portion of the most cost-effective savings in the past has been achieved through a small number of very large, strategically planned customer projects. Given the circumstantial nature of these large-scale projects, predicting the opportunity for projects of similar magnitude in the future cannot be done with any degree of certainty. Due to the extent that recent CIP achievements have been driven by these large-scale projects, there is a high degree of risk associated with assuming historical performance is sustainable for the 2015 planning period or that savings levels can be increased from one year to the next.[63]

MP later emphasizes the distinction between system costs and rate impacts:

> While the current estimation methodologies are acceptable means of measuring program performance and gauging savings impacts, long-term resource planning necessitates reducing risk and uncertainty. As such, a conservative approach to determining the best level of energy efficiency to incorporate in the resource plan is imperative.
>
> Key factors of the costs and benefits associated with various levels of energy efficiency are not only the environmental benefits and potential overall cost savings associated with conservation, but also the actual rate impact on each individual customer class. Given the current rate structure and cost recovery mechanisms, high energy-efficiency commitments could lead to some reductions in total cost, but would likely be accompanied by rate increases for certain customer subsets. Balancing these impacts was an important consideration during the planning process.[64]

[62] Department of Commerce, initial comments, p. 41.
[63] Resource Plan, Appendix B, p. 1.
[64] *Ibid*, p. 2.

According to MP, residential programs tend to be more expensive on average and make up just under 20 percent of annual CIP savings. The residential cost per kWh (in terms of first-year savings) has increased from about $90/MWh in 2010 to almost $130/MWh in 2014.

The commercial/industrial (C/I) program, or Business program, accounts for the majority of CIP savings, or roughly 80 percent. The C/I cost per kWh has slightly decreased between 2010-2014, from just under $60/MWh to about $45/MWh, or $50/MWh on average. C/I savings have increased over the same period from roughly 44,900 MWh in 2010 to about 65,000 MWh in 2013 and 2014. As noted above, high levels of savings in the C/I program have come from very large projects with proportionally lower costs.

a. Department of Commerce

The Department concluded that MP's cost assumptions for incremental levels of energy efficiency were too high, and did not align with historical costs per kWh for its energy savings programs. However, the Department did not conduct scenario analyses with lower cost assumptions because all of MP's energy savings scenarios, even at MP's estimated costs, were cost-effective. Thus, the Department recommends the Commission modify MP's resource plan to adopt the highest level of energy savings, 76.5 GWh (or 2.5%).

The Department also refers the Commission to Minn. Stat. §216B.2401, which identifies energy savings as the State's preferred energy resource:

> The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. The legislature further finds that cost-effective energy savings should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change. Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas through cost-effective energy conservation improvement programs and rate design, energy efficiency achieved by energy consumers without direct utility involvement, energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

According to the Department, "When analyzing the appropriateness of a utility's energy savings plan within an IRP, the Department considers, along with other factors, Minnesota's clear preference for energy savings as a resource."

b. Clean Energy Organizations

The Clean Energy Organizations also assert that MP's cost estimates for incremental energy efficiency are well above what the Company has historically experienced. Table 3 from CEOs initial comments show MP's CIP achievements and first year unit costs for 2007 through 2014.

Table 3. Minnesota Power's 2007 – 2014 CIP Achievements and their First Year Cost[46]

Year	Achieved CIP Energy Savings (GWh)	Average First Year Cost per kWh Saved
2007	44.2	$ 0.09
2008	48.9	$ 0.10
2009	52.9	$ 0.10
2010	60.5	$ 0.09
2011	69.1	$ 0.09
2012	63.2	$ 0.11
2013	77.6	$ 0.08
2014	76.3	$ 0.09

Then, in Table 4 (below), CEOs show the minimum incremental energy savings costs for additional savings used in the IRP. (The incremental level is compared to MP's "Existing Plan," or 46.5 GWh in 2016.)

Table 4. IRP Incremental Energy Savings Costs[47]

Incremental Savings Per Year (GWh)	First Year Incremental Program Cost ($000) (Table 14 of Appendix K)	Average Cost of Incremental Savings ($/kWh)
3	$ 511	$ 0.17
6	$ 1,199	$ 0.20
9	$ 2,034	$ 0.23
11	$ 2,665	$ 0.24
12	$ 2,988	$ 0.25
15	$ 4,064	$ 0.27
18	$ 5,206	$ 0.29
21	$ 6,438	$ 0.31
24	$ 7,725	$ 0.32
27	$ 9,057	$ 0.34
30	$ 10,525	$ 0.35

As CEOs observe, the assumed energy savings levels in the IRP are in some cases two to three times higher than the average cost to achieve the incremental 30 GWhs above the Company's CIP minimum goal.[65]

c. Minnesota Power reply

According to MP, measure lives and lifetime savings estimates are two factors which can contribute to volatility and unpredictability during a resource planning period. A forecasting error risk can occur if, for instance, the level of savings from a particular program decreases over time, or if the actual savings realized from that program differ from the assumptions used.

d. Staff Discussion

MP strongly challenges the Department's recommendation, calling a 76.5 GWh achievement "aggressive and significantly beyond the energy-savings goal established for utility CIPs."[66] While such a characterization could be true, that does not necessarily mean the savings level is unrealistic, unattainable, or cost prohibitive. In fact, the legislature uses the term "aggressively" in Minn. Stat. § 216B.2401, which states, "The legislature further finds that cost-effective energy savings should be procured systematically and aggressively."

According to the last decade of MP's CIP Achievements, as shown by Figure 15 of CEOs initial comments, [67] the Department's recommendation is in line with MP's savings levels in recent years.

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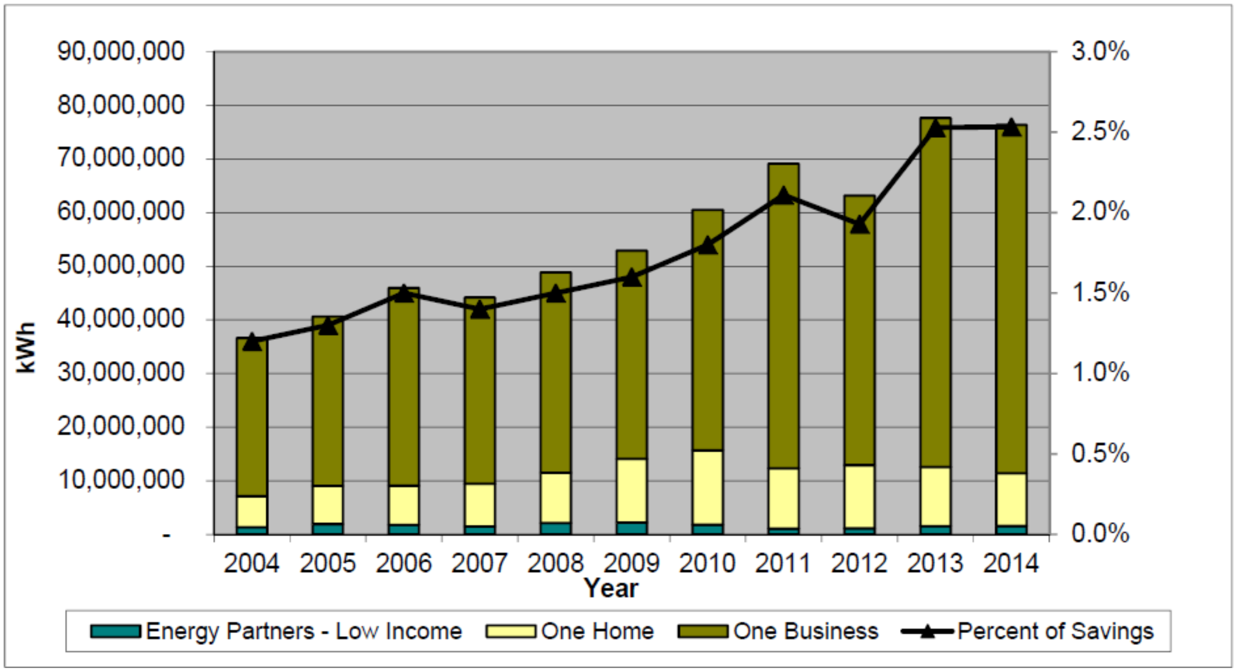
[65] CEOs initial comments, pp. 38-40.
[66] MP reply comments. p. 26.
[67] CEOs initial comments, p. 34.

Figure 1: Minnesota Power's 2004–2014 CIP Achievements



Appendix B, Part 2 of MP's resource plan includes a DSM study conducted for MP by LADCO Services, LLC. The study was prepared to assess the conservation plan scenarios under the standard Societal, Utility and Rate Impact tests. In short, the LADCO study found:

- All plans were cost-effective by the Societal and Utility tests, which is consistent with the Department's findings (although the Department did not use the LADCO study in its analysis); and
- All plans were not cost-effective by the Ratepayer Impact Measure (RIM) test.

Assumptions used in the LADCO study were developed by Minnesota Power's CIP group, based on implementation through the study period—2016 through 2030. The rate impact of each plan, relative to the "Existing Plan," was calculated for the year 2021. The Plan Savings in 2021, and its cost-effectiveness by the three tests, are shown below.

TABLE ES-2
Plan Savings in 2021 and Cost-effectiveness by Plan

	Annual—Year 2021			Present Value over Life		
	Savings at Generator			B/C Ratio		
Plan	Energy (kWh)	Summer Peak (kW)	Financial Savings ($)	Societal Test	Utility Test	RIM Test
-16 GWh Plan	18,011,346	29,850	7,052,841	1.90	3.26	0.49
Existing Plan	277,608,373	41,922	10,039,783	2.01	3.58	0.50
+11 GWh Plan	331,165,798	50,045	10,576,048	1.97	3.24	0.49
+15 GWh Plan	351,065,046	53,063	10,332,800	1.95	3.05	0.49
+30 GWh Plan	427,478,185	64,652	8,220,065	1.89	2.44	0.49

According to the LADCO study, all plans produce approximately the same benefit-cost (B/C) ratio for the Rate Impact Measure test. For the Utility Cost test, the B/C is greatest under the Existing Plan. The financial savings are greatest under the +11 GWh (1.87% savings) plan.

Appendix B—Part 2-A: "Plan Parameters and Year 2017 Impacts" includes incentives, administrative costs, total energy savings, and other factors assumed for each scenario. To highlight a few values in order to give context to the possible rate impacts or incentives required, staff created the following table below. (If staff understands MP correctly,[68] the following plan parameters were prepared by MP's CIP group.)

Year 2017	**Existing Plan**	**+11 GWh**	**+15 GWh**	**+30 GWh**
Incentives ($)	3,571,012	5,008,680	5,800,268	9,769,008
Admin Costs ($)	3,508,443	4,735,943	5,343,401	7,835,883
Total Costs ($)	7,079,455	9,744,623	11,143,669	17,604,891

To achieve the +30 GWh level by 2017, MP assumes total costs nearly double relative to the +11 GWh plan. Incentives must increase by 95%, while Administrative Costs increase 65%.

MP qualifies the results of the LADCO study with a statement that "Although Minnesota Power commissioned this study, the views expressed are those of the author and not necessarily those of Minnesota Power."[69] Staff agrees that the study should probably not be considered as superior to the DSM analysis performed by MP, the Department, or CEOs; however, it is one piece contributing to staff's overall view of MP's DSM potential. After all, if the study has zero value, MP should not have incorporated it into its resource plan or commissioned it in the first place.

As stated previously, one of the Commission's five factors to consider in resource planning is to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints."[70] Common arguments which support various levels of DSM in IRP include: the Commission should approve expansion plans that are least-cost, suggesting the Commission give more weight to the utility cost test; the Commission should approve expansion plans that keep rates low, suggesting the Commission give more weight to the Rate Impact test; or, utility rates could go up while bills go down, so the customer impact is most important.

Of its roughly 33% of load subject to CIP, MP reported that its "large project contributions over the last five years" have accounted for "between 9% and 40% of total portfolio savings."[71] To staff, MP makes a persuasive argument regarding the limitations of modifying MP's total CIP portfolio to its maximum level because, it seems, there may be great disparity between who benefits and who doesn't. Targeted large project conservation seems to have worked well to advance MP's total conservation achievements, but MP raises a good point about the predictability of similar programs moving forward.

[68] Appendix B—Part 2, p. ES-1.
[69] *Ibid*.
[70] Minn. Rule. 7843.0500, Subpart 3.
[71] Appendix B, p. 4.

This said, even assuming that targeted large energy savings projects may be less fruitful during the planning period, in staff's view, there is a robust amount of evidence in the record supporting a Commission finding that MP should procure *at least* 57.3 GWh of energy savings (alternatively called the +11 GWh or 1.87% scenario). There is also a substantial amount of record evidence to support a 61.2 GWh (+15 GWh or 2.0% scenario), should the Commission choose to modify MP's plan.

Justifications include:

- As part of its Preferred Plan, MP included an energy-savings assumption well above the energy-savings goal of 1.5% established in CIP statute.
- The Department's and CEOs' analyses support an energy savings level of 76.5 GWh, or 2.5%;
- The LADCO study commissioned by the Company found that all conservation scenarios passed the utility and societal cost tests; furthermore, financial savings to the Company were greatest at the +11 GWh and, next, +15 GWh scenario levels;
- Over the last five years, MP has consistently achieved more than 2% of energy savings; and,
- Minn. Stat. § 216B.2401 identifies energy savings as the State's preferred energy resource and that cost-effective energy savings should be procured systematically and aggressively.

2. CIP-exempt savings

In Order Point 12 of MP's 2013 resource plan, the Commission required the Company to:

> Identify the amount of system-wide energy savings, including aggregate data for CIP-exempt customers, embedded in each year of its load forecast.

The basis for the Commission inquiry was largely due to the fact that roughly 67 percent of the MP's load comes from 15 customers who are exempt from participating in and paying for CIP.

The Commission's Order in MP's 2013 Resource Plan stated that "resource planning should reflect the possibility of energy conservation among all of Minnesota Power's customers … The Commission will therefore require Minnesota Power's next resource plan filing to include more detailed information concerning system-wide energy conservation. Specifically, analysis and aggregated energy savings data for CIP-exempt customers will be required. This information will help paint a more complete picture of the possibilities for energy conservation on Minnesota Power's system."[72]

MP includes an econometric forecast which has a determined amount of energy and demand savings embedded within it. To comply with the language of ordering paragraph 12.b., MP organized its retail customers into CIP customers and CIP-exempt customers. The forecast assumes that the future is a function of past achievements, and for its CIP-exempt customers, MP

[72] Commission order in Docket 13-53, Minnesota Power 2013 Resource Plan, November 12, 2013, p. 6.

used a five-year historical energy savings average to inform the amount of savings to be embedded annually. Historical data for CIP-exempt customers was used from Trade Secret energy savings information provided by its large industrial customers. This approach resulted in an embedded energy savings estimate of the sum of the five-year average from CIP-exempt customers. When both customer sets are combined, MP estimates it will achieve 450 GWh of energy savings by 2029.

With regard to capturing more savings from all customers, MP did not assume additional energy savings from its CIP-exempt customers. MP cautions the Commission against using any sort of scenario analysis or achievement potential when discussing CIP-exempt customers. (In MP's 2013 Resource Plan, the Large Power Intervenors filed a request for reconsideration of ordering paragraph 12.b., arguing the Commission has no jurisdiction over energy savings of CIP-exempt customers. MP filed a letter supporting LPI's request.) MP explains this approach in its IRP Petition:

> Embedded conservation is not something that can be estimated with a high degree of certainty, regardless of the method used. While this study represents a good faith effort to meet the requested calculations, the results should only be considered estimates … When developing its customer load forecasts each year, Minnesota Power makes no explicit assumptions for demand-side management/conservation, and does not in practice adjust its econometric load forecast for projected amounts of these items.

MP further details the difficulties in running a DSM analysis from CIP-exempt customers in a similar way as its CIP customers, perhaps most pointedly here:

> Minnesota Power conducts cost/benefit analysis for non-CIP-exempt customers using measure-specific cost estimates, assumptions of consumer behavior, and general assumptions of potential savings. In contrast, CIP-exempt customers' conservation is characterized by large and irregular energy saving projects, often requiring significant capital investment. There are also very few CIP-exempt customers; application of general assumptions for consumer behavior or potential savings is appropriate when applied to a large group of residential or commercial customers, but is not a viable approach to CIP-exempt conservation planning. Without gaining access to forward looking and proprietary business specific plans for each CIP-exempt customer, or making considerable assumptions that may not be well-founded, Minnesota Power cannot evaluate conservation scenarios on behalf of its CIP-exempt customers in the same way it may evaluate conservation measures for non-CIP-exempt customers.

MP later provides a Trade Secret, qualitative discussion of energy efficiency investments made by four of its large industrial customers. But regarding the scenario analysis of higher energy savings levels, savings from CIP-exempt customers are held fixed, for reasons explained above.

a. Clean Energy Organizations

CEO argued MP did not comply with the Commission's Order from its 2013 IRP, and that MP's plan does not meet the state's 1.5% energy savings policy goal. CEO cited Order Point 12.c, which required MP to "Evaluate additional conservation scenarios for its CIP-exempt and non-CIP-exempt customers, that would achieve greater energy savings beyond those in the base case." In spite of this requirement, CEO argued "Minnesota Power did not analyze any additional conservation scenarios for CIP-exempt customers. As it did with CIP customer savings, the Company simply assumed that the savings its CIP-exempt customers say were realized in recent years would continue to occur at the same levels and be embedded in the load forecast similar to the approach taken with CIP savings."[73]

As a result of this omission, CEO argued MP's plan would not meet Minnesota's 1.5% energy savings policy goal. CEO cited Minn. Stat. §§ 216B.2401 and 216C.05, which sets an annual energy savings goal of at least 1.5 percent of annual retail energy sales. The 2013 MP IRP Order states:

> The Commission agrees with the Environmental Intervenors that the energy savings goals described in Minn. Stat. §§ 216B.2401 and 216C.05 do not exclude consideration of savings that may be achieved by Minnesota Power's CIP-exempt customers. A significant amount of demand on Minnesota Power's system comes from CIP-exempt customers, but Minnesota Power's resource plans—which must consider energy conservation as an energy resource—serve CIP and CIP-exempt customers alike. Accordingly, resource planning should reflect the possibility of energy conservation among all of Minnesota Power's customers.[74]

While the Department's recommended level of energy efficiency would result in savings of 2.5% of *CIP-exempt* sales, their recommendation would only constitute 0.82% of the Company's *total* retail sales. Thus, CEO concluded, even at the Department's recommended level, MP would not meet the state conservation goal.

b. Large Power Intervenors

LPI took issue with the CEOs' position on conservation opportunities from CIP-exempt customers. As LPI argued:

> CIP-exempt customers […] have their own strong incentives to reduce their production costs. The CIP statute recognizes this built-in incentive and makes it the basis for obtaining a CIP exemption. By statute, CIP-exempt customers are responsible for planning, financing, and implementing their own energy conservation and energy efficiency efforts. […] [T]he utility is not required to verify the energy savings reported by customers who do not participate in CIP. Further, CIP-exempt customers are not required to report the highly confidential and proprietary information Minnesota Power would need to perform such verification. Efficiency is of the utmost importance to the energy-intensive, trade-

[73] Clean Energy Organizations, Initial Comments, p. 41.
[74] At page 6.

> exposed customers that compose the CIP-exempt customer group, but it is not legally or practically possible to impose CEO's suggestion that Minnesota Power should use the same evaluation, measurement, and verification techniques on CIP-exempt customer savings as it used on CIP customer savings.[75]

c. *Department of Commerce*

While the Department agreed that MP should encourage its CIP-exempt customers to be as efficient as possible, it argued Minn. Stat. §216B.16 Subd. 6b "does not allow MP to charge ratepayers for providing CIP services to the exempt customers" and so "it is not clear how MP would engage with the customers and document the energy savings."[76] The Department encouraged CEO to develop concrete proposals for how this could be done.

Solar Energy

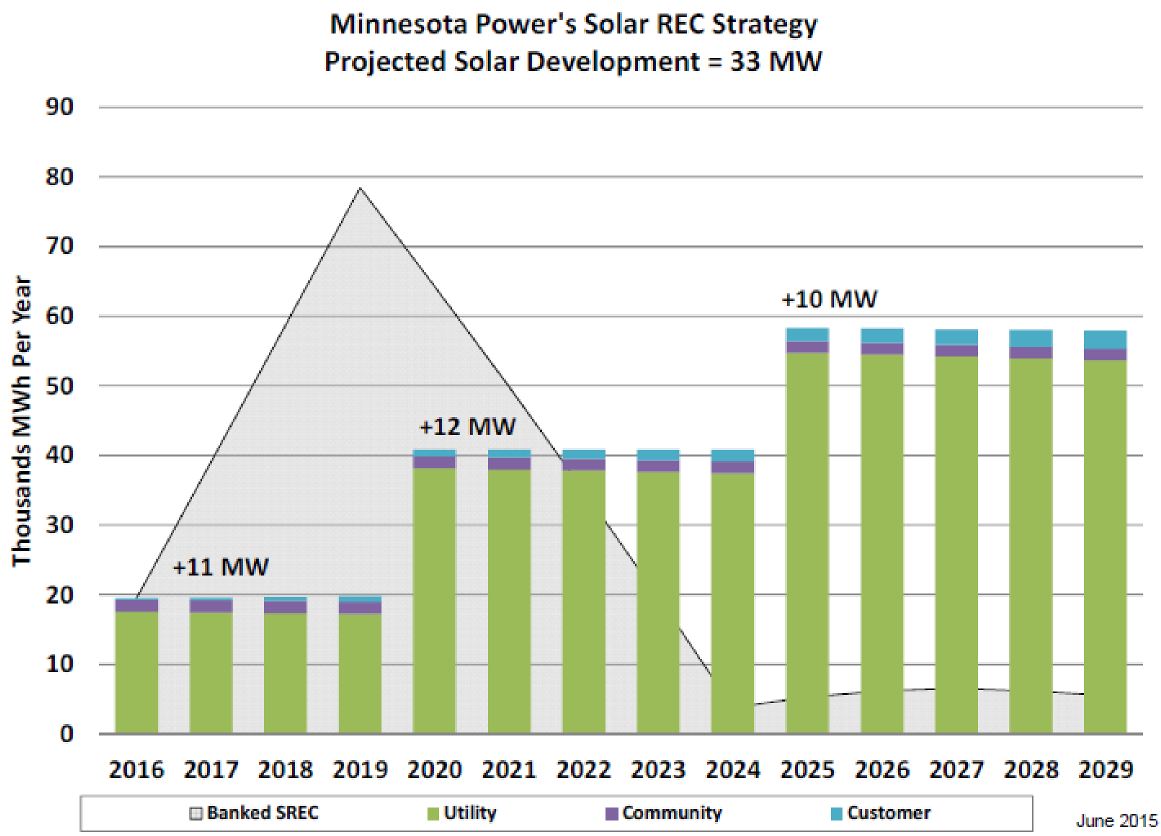
Below, staff presents the issue of solar energy in two parts, Solar Energy Standard compliance and solar energy as an economic resource for MP's system.

1. Solar Energy Standard compliance

Minnesota's Solar Energy Standard (SES)[77] requires investor-owned utilities to procure at least 1.5 percent of their Minnesota retail sales from solar energy, beginning in 2020. The SES Statute exempts retail electric sales to iron mining and processing facilities or a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer; these types of customers make up a majority of MP's retail electric sales. Thus, MP's SES compliance obligation is relatively small: the Company estimates it will need 33 MW of capacity to meet its obligations. The SES also requires 10% of the mandate be generated by small solar (≤ 20 kW).

MP plans to meet its general SES obligation through three utility-scale projects: the first is the 10 MW installation at the National Guard's Camp Ripley, which was approved by the Commission in Docket 15-773; the second installment would be (approximately) 12 MW in 2020, and the third installment would be 10 MW in 2025.

[75] Large Power Intervenors, Reply Comments, p. 8.
[76] Department of Commerce, Reply Comments, pp. 12-13.
[77] Minn. Stat. §216B.1691 Subd.2f.



MP has also filed a petition for a community solar garden pilot program,[78] which it hopes to use to satisfy a portion of its small solar obligations.

a. Department of Commerce

The Department concluded MP's plan, if carried out, would satisfy the Company's general SES obligation. However, the Department raised concern about MP's ability to meet its small-solar mandate:

> In its most recent SES compliance report, MP reported that it had approximately 132 solar net metered customers on its system; however, the contract for those customers does not require transfer of the SRECs associated with the net metered solar generation to the Company. MP has requested the ability to count the solar generation from its community solar subscriptions towards its Small Solar Carve-out; however, the Commission has not yet ruled on the Company's request and concerns have been raised in that proceeding.[79]

[78] Docket 15-825
[79] Department of Commerce, Initial Comments, at page 58.

b. Staff Discussion

In response to Staff Information Request #8, MP provided a table displaying its projected SES obligation and its projected solar generation. The filing largely supports the Department's conclusion: the Company's preferred plan appears to satisfy its projected general SES obligation,[80] but additional generation will be needed for the Company to meet its small-solar obligation. Staff notes that the Company—like all IOUs—is required to file a report on its progress toward meeting the SES by June 1st (in Docket 16-342); thus, the Commission will soon have an opportunity to take a closer look at these issues.

2. Solar Additions above SES Requirements

MP's Strategist modeling generally did not find solar PV to be a cost-effective resource. Accordingly, MP's plan would add minimal amounts of solar, spread out over time in order to comply with its SES mandates. However, the Company did find some potential for solar at lower price points in the mid-2020s.[81]

a. Department of Commerce

The Department's base cost of solar was $100/MWh for all years—meaning, the cost did not include an escalation rate like other resource options—and included four contingencies, higher and lower in $10/MWh and $20/MWh increments.

The Department's Preferred Case[82] includes MP's staggered solar additions in 2016, 2020, and 2025, which will meet MP's SES requirements. However, the Department's plan modifies MP's plan to include up to 50 MW of additional solar by 2022.

Like the Department's approach to selecting new wind, the Department allowed the model to select optional—or superfluous—solar units without a capacity deficit, if doing so would reduce system costs. [83]

Staff refers the Commission to Attachment 2 of the Department's initial comments, which includes the Strategist outputs under various scenarios and contingencies. Staff identified two factors driving the modeling results, the impact of the load forecast on solar unit additions and the impact of solar prices on solar unit additions.

Page 3 of 122 of Attachment 2 includes the following forecast contingencies:

[80] Though Staff notes the Company's IR response suggests the final 10MW solar installation should be added in 2024 rather than 2025.
[81] For a more detailed discussion, s*ee*: Minnesota Power's IRP, at pages 65-66.
[82] Department initial comments, p. 34.
[83] *Ibid*, p. 18.

Forecast	
FCSLL	Low Forecast
FCSL	Mid-low forecast
FCSM	median forecast
FCSH	mid-high forecast
FCSHH	high forecast

In reviewing Page 3 of Attachment 2, staff observed the following:

- Under median forecast conditions (FCSM), the model selected two 50 MW generic solar units (at the base case solar price, or $100/MWh).
- Under the mid-high forecast contingency (FCSH), the model generally selected only one 50 MW generic solar unit, because an additional combined cycle unit was preferred under conditions of higher energy and demand.
- Under the highest forecast contingency, the number of solar units varied greatly, ranging from 0-2 units, depending on other factors which dictated whether more capacity purchases were required or whether the coal units were needed.
- Under the mid-low and low forecast (FCSL and FCSLL), no additional solar units were selected.

Based on staff's understanding of the Department's results, all else constant, the amount of solar energy added was very sensitive to the forecast contingency.

The model was also price-sensitive. Page 7 of Attachment 2 includes the following solar prices contingencies ($80/MWh to $120/MWh):[84]

Solar Price	
SLRLL	Low Solar Cost
SLRL	Mid-low Solar Cost
SLRM	Median Solar Cost
SLRH	Mid-high Solar Cost
SLRHH	High Solar Cost

Staff observed the following regarding the sensitivity of solar additions and solar prices:

- Under high solar cost (SLRHH), $120/MWh, the model selected zero or one solar unit(s).
- Under the median (SLRM), $100/MWh, and the mid-low solar cost (SLRL), $90/MWh, the model always selected two 50 MW solar units.
- Under the low solar cost (SLRLL), $80/MWh, the model selected from two to up to six solar units, or 300 MW of solar.

Importantly, the Department found that the amount of solar depends on the level of DSM, probably because solar would be the marginal fuel. According to the Department, the "Strategist modeling resulted in an additional 50 MW of solar generation in scenarios with high (76.5 GWh) DSM, and an additional 100 MW at lower DSM levels (e.g., 57.3 GWh)."[85]

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[84] Staff references Page 7 of 122 of Attachment 2 because this set of outputs used median forecast conditions.
[85] Department initial comments, p. 58.

b. Clean Energy Organizations

CEOs argued MP's solar price assumptions were "higher than realistic."[86] As CEOs note, after MP filed its plan, Congress passed an extension of the solar Investment Tax Credit (ITC), which will have a major impact on potential solar PPA prices. CEOs also noted that MP's base price for solar is considerably higher than recently approved—both in Minnesota and nationally—solar PPAs.

c. Minnesota Power Reply

Neither MP nor the Department directly addressed CEO's arguments about its price estimates for solar. However, MP did state it will "continue to evaluate new solar technology trends in future resource plans" and sometime around 2020, it plans to "initiate an open, non-site specific competitive acquisition process for additional utility scale solar to serve its customers."[87] Staff notes that the Commission made a finding to this effect at the time it approved the Company's Camp Ripley solar project.[88]

d. Staff Discussion

A review of recent cost declines for solar PV suggests the base cost of solar assumptions MP and the Department used for their analysis may have overstated solar PPA prices. The installed price of utility-scale solar PV has fallen rapidly. According to the Lawrence Berkeley National Laboratory (LBNL), installed costs were cut in half between the 2007-2009 period and 2014.[89] This trend has continued: GTM Research has found that the installed price for utility-scale solar systems dropped by 12% in 2014[90] and by another 17% in 2015.[91] Staff notes that these are not estimates, but the actual installed costs of completed projects across the U.S.

These installation cost reductions translate into cheaper PPAs. According to LBNL, "levelized real PPA prices for utility-scale PV projects consistently fell by almost $25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples."[92] Minnesota has seen evidence of this trend. Xcel Energy's 2014 open RFP for utility-scale solar PPAs received a robust response: 15 bids comprising over 630 MW came in at or below the initial screening threshold of $85/MWh. Ultimately, the Commission approved 3 projects, totaling 187 MW, with an average levelized price of $73.20/MWh.[93] Notably, one of these projects would be located in North Branch, Minnesota, which is very close

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[86] Clean Energy Interveners, Initial Comments, page 25.
[87] Minnesota Power, Reply Comments, page 18.
[88] Minnesota Public Utilities Commission, February 24, 2016 Order in Docket 15-773, at Order Point 10, page 8.
[89] Bolinger and Seel, "Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States," *Lawrence Berkeley National Laboratory*, September 2015, page 13.
[90] Munsell, Mike, "Solar PV Pricing Continues to Fall During a Record-Breaking 2014," *GreenTech Media*, March 13, 2015 (link).
[91] Gallagher, Ben, "Pricing for Solar Systems in the US Dropped 17% in 2015," *GreenTech Media*, March 15, 2016 (link).
[92] Bolinger and Seel, "Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States," *Lawrence Berkeley National Laboratory*, September 2015, page 36.
[93] *See*: Xcel Energy's October 24, 2014 Petition in Docket 14-162.

to MP's service territory and receives the same amount of sunlight as much of MP's service territory.[94]

The solar cost input MP used in developing its Preferred Plan is dramatically higher than the PPAs approved for Xcel Energy. For MP's base case input, it appears to have used a levelized price of over $100/MWh (with the full ITC) and over $150/MWh (with a 10% ITC).[95] The Department's base case estimated solar PPA prices at $100/MWh. Even the "low solar" contingencies used by MP ($75/MWh) and the Department ($80/MWh) were higher than the average price of the PPAs approved for Xcel. Said another way, although Xcel's RFP produced bids in the low $70s/MWh, and the national data show installed costs—and, thus, PPA prices—have fallen considerably since then, the range used for MP's economic analysis would imply a significant increase from 2014 to today, even under the *most optimistic* scenarios.

The reasonableness of the range is not a decision item itself, but more so a conversation for future planning iterations; however, the Commission could apply its judgment on the range by giving more weight to contingencies at the lower bound. Staff agrees with the CEOs that MP's base case solar price input likely inflates the cost of an expansion plan which includes more solar resources. A separate question, though, is determining how to incorporate the low bound into decisions pertaining to MP's system overall. One option is to modify MP's expansion plan consistent with the Department's results. A second is to adopt CEOs recommendation that, in the event of an emerging need, any acquisition process should be fuel-neutral.

Another option, which may not fit neatly into a procedural bucket, is to direct that any further planning or acquisition phase consider not just the cost of solar, but its value to the grid. MP is in a unique situation of phasing out its coal fleet amid significant local reliability concerns, and resource planning only considers future resource options generically and without regard to location. In the Department's analysis, even the lower cost generic solar resources are competitive, in the model, with bridge capacity purchases. Perhaps there is an opportunity to dive deeper into the value solar resources can provide to the very real reliability problems MP faces in its *Energy**Forward*** transition plan.

EPA Clean Power Plan

Minnesota Power's "Affected Facilities" under the Clean Power Plan include:

- Boswell Energy Center (1-4),
- Hibbard Renewable Energy Center,
- Laskin Energy Center (1-2), and
- Taconite Harbor Energy Center (1-3).

In PUC Information Requests No. 4 and 5, staff requested MP report its 2012 Actual CO_2 Emissions from Affected Facilities, which is the baseline year for emissions compliance. Staff sought 2012 Actuals to compare them to the Strategist outputs of projected facility-by-facility

[94] *See, e.g.*: NREL's solar resource maps: http://www.nrel.gov/gis/solar.html
[95] Minnesota Power IRP, Appendix K, Figure 6 at page 9.

CO_2 emissions for Affected EGUs, then reviewed the amount of CO_2 reduction for the facility, as well as MP's broader CO_2 emissions position.

To the merits of this approach, the Strategist outputs are a service territory-wide projection based on a number of factors and variables, including the fact that the Commission's CO_2 values imputed into the model affect the dispatch. Still, the 2012 Actuals are federally reported[96] emissions, so they could provide some (even if limited) insight into MP's CPP compliance baseline. And, if the output for projected emissions used in resource planning provides a useful projection for a utility's forward-looking CO_2 position, comparing the Actuals to the Projections could facilitate some understanding MP's Clean Power Plan compliance.

MP designated all projected CO_2 emissions as Trade Secret, even the totals. However, staff refers the Commission to MP's Responses to PUC IRs Nos. 4 & 5. Qualitatively, and in the aggregate, comparing the Actual emissions to Projected emissions suggests that, assuming MP follows through with its Preferred Plan to cease coal at BEC 1 & 2 and THEC 1 & 2, the Company is reasonably positioned to meet a 2030 compliance target.[97] The Company may encounter compliance challenges at the interim target, which can be expected given the size of Boswell Energy Center relative to MP's total system capability. However, any challenges which could potentially exist at the interim target date appear manageable enough to justify waiting for other policy and judicial issues surrounding the CPP to unfold before taking more aggressive measures. Overall, MP's calculations are consistent with its claim that the Preferred Plan positions the Company reasonably well for CPP compliance in 2030.

Discussion of Decision Options

The Commission could address MP's resource plan a number of different ways. First, it could address the resource plan issue-by-issue, as structured in the briefing paper, and deliberate on each particular one before moving on to the next. Alternatively, staff presents a step-by-step approach below which attempts to capture the underpinnings of the dispute issues.

Step One: Identify MP's short-term energy need.

The uncertainty regarding the short-term energy need is in part due to the existence (or not) of several large customers in MP's service territory, which could in turn affect the choice of resources to be procured.

[96] Actual emissions are the annual CO_2 emissions data measured by CO_2 Continuous Emission Modeling Systems ("CEMS") and reported to the EPA as required by 40 CFR Part 75. This regulation establishes CEMS and reporting requirements in support of EPA's Acid Rain Program (ARP), which was instituted in 1990 under Title IV of the Clean Air Act. Projected unit-level CO_2 emissions results are an output from the Strategist model. For each fossil fuel generating unit modeled in Strategist, a CO_2 emission rate is entered into the model and is used to calculate the annual emissions. For Minnesota Power's existing resources, the CO_2 emission rate is based on historical rates. (*See MP's Response to MPUC IR #3*.)

[97] (and assuming a 30% reduction target from 2012 levels at Affected Facilities).Minnesota's assigned rate-based target is actually closer to 40%)

In MP's 2014 Advance Forecast Report (AFR 2014), the Company developed six forecast scenarios, with the "Expected Case" (or "Moderate Growth") scenario adding more than 200 MW of load from large industrial customers These additions are followed by very low year-over-year growth rates for both energy and peak demand.

For its IRP, MP deviated from its "Expected Case" by using its Expected Case with Deferral of these large customers. The Clean Energy Organizations argue the Expected Case with Deferral is still an overstatement, given the uncertainty in the mining, pipeline, and resale sectors. The Department disagrees, contending that "for resource planning it is important to develop an expansion plan that is cost-effective over a wide range of potential futures, including a range of forecasts."[98] The Department believes its four contingencies around the energy and demand forecast—higher and lower in 2.5% increments (i.e., +5%, +2.5%, -2.5%, and -5%)—captures the forecast uncertainty. Additionally, DOC concludes, "while it is true that capacity additions and retirements can be dependent on the load forecast, in this case the differences in the expansion plans are relatively minor and low forecast contingencies would result in fewer renewable units being selected."[99]

MP filed its resource plan in September 2015, but its 2014 forecast was developed well before then. So if a threshold forecasting issue is not only the appropriate growth rate but whether or not customers could even be on the system, MP could provide an update to the Commission on the most up-to-date status of these large customer additions. Put another way, MP could provide context and insight into whether, in a general sense, its Moderate Growth with Deferral scenarios are still reasonable at present.

Step Two: Establish Common Language

Idle, cease, retire, shut down, remission, repurpose, replace, and refuel are all terms used to discuss options at a single existing facility. While at first blush the differences may seem subtle (since the economic analysis may not differentiate between "cease" and "retire"), functionally these are very different options. For instance, in the Preferred Plan, MP proposes to "cease" coal-fired operations at Boswell 1 & 2, yet MP concurrently argues its goal of "maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period." This raises questions regarding what both "cease" means and what "available" means. At Taconite Harbor, MP is proposing to idle THEC 1 & 2 in 2016, while remissioning and repurposing alternatives are being explored; CEO and the Department recommend retirement, an alternative MP strongly opposes.

As the Commission contemplates its task to "approve, reject, or modify" MP's plan, staff suggests MP and the parties define its terminology to the Commission and use common language when making arguments, to avoid any confusion regarding what the Commission is actually being asked to approve.

Step Three: Short-term versus Long-term Concerns

[98] DOC reply comments, p. 2.
[99] *Ibid*, p. 10.

Once the Commission determines its approach to MP's forecast uncertainty, and there is more clarity to the issue of what exactly MP's plans are for its existing facilities, it could next contemplate how MP could best balance its short-term and long-term goals.

For example, taking into the account the recent extension of the federal tax incentives provides a new, but short, window of opportunity to procure renewable resources. As MP notes, "[new] wind resources could provide an energy hedge for customers in the future when the resource may be needed for customer requirements due to [Clean Power Plan] compliance, continued transformation of power supply, over forecasted energy conservation program performance, and potential for new load growth on the system."[100]

However, this hedge obviously comes at a cost, and if the Commission is persuaded that new wind creates excess energy on the system, or if the Commission determines it needs more information to be able to justify projections of offset costs, the Commission could delay any new acquisition.

Short-term versus long-term rate impacts also incorporate the issue of risk. Part of the reason MP and the Department arrive at different places when it comes to the near-term action plan is due to the fact that MP believes currently suppressed market energy prices are worth delaying significant wind acquisition. The Department concludes that significant ratepayer exposure to the spot market is overly risky and should be avoided.[101] If the Commission agrees the ratepayer risk of low market prices—assuming prices are and will remain low—is minimal, it could also have reason to delay wind procurement.

On the capacity side, LPI argues that MP's natural gas RFP was issued too early—roughly 7-8 years prior to MP's demonstrated capacity need. MP contends that adding new natural gas to its portfolio give the Company fuel diversity and minimize its carbon footprint. New, large-scale natural gas generation provides the Company with a non-coal alternative for thermal, dispatchable generation, and the Department's analysis overwhelmingly shows a gas CC is the least-cost alternative to replace MP's aging coal-fleet. The Commission could determine it is premature to acquire it, but could alternatively determine that MP can bring a Petition for Approval of a project it selects and assume the risk of the Commission rejecting it.

The discussion regarding the short-term versus the long-term largely involves uncertainty and risk. LPI's "No Regrets Approach" means avoiding major financial commitments during the unknown. The Clean Power Plan, for example, exists, but the lowest cost strategies for compliance are not even able to be known at this time. By 2024, MP may have a need, but there has not been a full exploration of alternatives. LPI acknowledges investments may be required eventually, but making investments now, which will result in immediate rate impact, is premature and may have deleterious consequence for ratepayers.

Step Four: Competitive Bidding

[100] MP reply comments, p. 16.
[101] *Ibid*, p. 15.

With a more developed understanding of both MP's short-term and long-term net capacity position and energy needs, including the current status of new large customer load, the Commission could then proceed to discuss the most appropriate procedural means by which MP should acquire future resources. (Of course, the Commission could determine that no acquisition proceeding is necessary at this time.)

If the Commission finds there is a capacity need which should be met in the near-term—and there is debate about what "near-term" means—LPI's recommendation to size the project to the need, and CEOs recommendation for it to be procured via fuel-neutral process could be a pragmatic solution.[102] However, doing so would effectively dismiss MP's own, voluntary resource acquisition process it began in October 2015—with actual bids already received—and restart it with a new, likely time-consuming contested case.

An argument for a wide open, fuel-neutral process is that there might be more options from several types of resources which can resolve the disputes over generic resource assumptions. CEO and staff raised concerns over the price inputs for wind and solar projects. Receiving actual bids as Strategist inputs, in part, could resolve these disputes. LPI and staff raised concerns about reliability. Actual bids could also inform the effect of replacement capacity by including the locational benefits of each project. The same could also be said, however, about MP's existing natural gas acquisition process.

Rather than one all-source bidding process, multiple, targeted competitive bidding processes over several years could also have its advantages. For example, the Department identified a need for energy in the short-term, and MP agreed to procure 100 MW of wind in the near-term while the PTC is in effect. MP also has a requirement to procure solar resources through a competitive bidding process to meet its next SES obligation. A piecemeal approach could help navigate the uncertainty, and in some instances the unknowns, of MP's forecast and coal transition plan.

<u>Step Five: MP's Next Resource Plan</u>

Minnesota Power recommends the Commission require MP to file its next IRP on December 1, 2018, or 39 months from its 2015 IRP filing date. This is obviously a significant variance from the biennial schedule set forth by the Commission's resource planning rules. MP does not include a discussion of why such a long variance is appropriate, but to speculate, staff believes MP could be budgeting time to accommodate for a yet-to-be-filed rate case. Alternatively, as many utilities have done, MP could be requesting an IRP extension based on the uncertainty surrounding the EPA Clean Power Plan.

If the reason for requesting delay is the Clean Power Plan, staff would not agree that resource planning should be delayed until all sources of uncertainty, including both legal and policy, are resolved. Besides, MP insists that "Minnesota Power's *Energy**Forward*** resource strategy

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[102] Of note, a wind acquisition proceeding would typically be separate from a capacity docket, because wind acquisition proceedings have a more targeted purpose of acquiring energy from a specific type of renewable resource.

positions the Company well for whatever ultimate regulations are promulgated at the federal level and implemented in Minnesota."[103]

Timing the IRP to accommodate for a rate case, on the other hand, could be reasonable and helpful to avoid some overlap and manage workload constraints. For example, in 2009, Minnesota Power filed its IRP on October 5, 2009 and its rate case on November 2, 2009. As a result, several extension requests were filed in the IRP, and the resource plan was not brought before the Commission until April 17, 2011.

Even under a workload-constrained environment, however, 39 months in-between IRP filings seems excessive. As a rule of thumb, the Commission can expect approximately nine months' time from filing-to-hearing. If MP's recommendation is adopted, the Commission can approximate that it may not hear MP's next resource plan until August 2019, assuming no extension requests.

The Commission's past practice when setting deadlines for the next IRP has been to take the following factors into account: the every-other-year schedule defined in the IRP Rule; party recommendations; issues the Commission would like to see more fully developed in the next plan (and the urgency of each); and the flexibility of the ordering requirements.

The flexibility granted to the utility in the order has influenced the Commission's preferences for when to consider a subsequent plan. In Otter Tail's 2014 IRP, for example, the Commission required Otter Tail to stay on the two-year schedule, but in doing so, purposefully allowed certain issues open to be revisited in the next plan. In MP's 2013 IRP, the Commission granted MP slightly more than two years because the Commission asked for a specific proposal to meet a 200 MW need for intermediate capacity in 2015-2017.

If, hypothetically, the Commission selected a plan which included a THEC 1 & 2 and BEC 1 & 2 retirement, to be followed by an all-source resource acquisition process thereafter, then perhaps the best allocation of resources would not be in planning, but in resource acquisition. Thus, if in the next 24 months the parties could be involved in the retirement and replacement of resources, a delay could be reasonable. Conversely, if retirement and acquisition is to be an issue for the next plan, then the Commission may decide the next IRP should be filed sooner.

With what is known at this time, staff does not believe there is sufficient justification for significantly deviating from the biennial nature of resource planning, which would set the date for MP's next IRP at September 1, 2017. If a rate case could justify an extension, MP can petition the Commission for an extension if or when it files it.

Update (as of May 31, 2016)

On May 24, 2016, Cliffs Natural Resources Inc. announced that it entered into multiple agreements with Minnesota Power, in which Cliffs will receive $31 million in cash as part of a

[103] MP reply comments, p. 19.

long-term purchased power arrangement. Under the deal, MP would add Northshore Mining to its customer base and supply electricity for the coal-fired Silver Bay plant through 2031.

On May 25, 2016, CEO issued Information Request No. 61, requesting the following:

61. Please indicate how the addition of Northshore Mining to your customer base affects your 2015 IRP. In particular,

> a. How does the addition of this customer change the demand and energy outlooks?
>
> b. Does the addition of this customer alter Minnesota Power's preferred plan and/or its small coal analysis? If so, how?
>
> c. Does the ownership of the two coal units at the Silver Bay Power plant alter Minnesota Power's plans with respect to Taconite Harbor Energy Center or Boswell Energy Center? Why or why not?
>
> d. Does Minnesota Power intend on operating the coal units at the Silver Bay Power plant?
>
> e. If the answer to (d) is yes, what pollution control technology is required to operate those coal units and what is the estimated cost to install that technology?
>
> f. If the answer to (d) is no, how will Minnesota Power meet the demand from this new customer?

Staff cannot provide analysis of MP's deal with Cliffs, and therefore takes no position on the merits of it, because staff was not made aware of the deal until the finalization of this briefing paper. However, staff requested MP provide its response to CEO in advance of the Commission hearing, and the Commission will need to rely on MP's IR response and explanation at the hearing to determine the resource planning impact.

With no analysis of this development with Cliffs' Northshore Mining, the Commission can merely make a decision on the merits of the record as is; it can decide *not* to address the merits now, ask that the record be expanded, or reserve the issue for the next IRP. Because this is a PPA not mentioned in the IRP, and because the only record evidence of it will exist as a result of CEO's inquiry, the Commission might wish to disregard the deal in any decision it makes, to make it clear that approval of the IRP does not pre-judge the merits of the PPA, or that the deal is in the baseline case of the IRP.

It could be the case that, because MP and DOC considered a range of forecast in its analyses, the possibility of a new mining customer has already been addressed at the highest level, and thus would have no influence on the overall expansion plan. Perhaps, if looking at it strictly in terms of energy and demand requirements, the deal between MP and Cliffs may not require a modified view of MP's resource needs. On the other hand, it could have a material effect, and as a result, staff has concerns with the timing, the lack of transparency, and the manner in which the Commission was notified of this development.

Staff notes that this is not the first instance in which this IRP process has had to confront a lack of transparency:

- Regarding MP's natural gas acquisition, in LPI's initial comments, it noted, "To LPI's knowledge, no formal press release was issued by Minnesota Power regarding this RFP. Instead, there is only mention of the RFP in very small font at the very bottom of its website. Yet Minnesota Power appears to be working closely with the City of Cohasset on what is referred to as the Itasca Energy Center ("IEC") project." Staff notes that MP's RFP was not filed in the IRP until LPI attached it to its February 18, 2016 comments.

- With regard to its bilateral contracts, on Page 34 of Appendix C, MP listed its "Planned Transactions" as a heading, but designated its entire discussion of procurement as Trade Secret information. Then, in a May 11, 2016 response to PUC IR No. 9, MP stated, "in fall of 2015 Minnesota Power procured THEC1&2 replacement energy and capacity through a request for proposal process." MP did not file the details of the contracts until May 18, 2016, three weeks before the hearing and seven months after the transactions. MP never did explain why the existence an RFP for firm purchases was Trade Secret.

IRP is a public process, and the intent of resource planning is to make generation-related decisions which are in the public interest. When staff issues its Notice Setting Comment Deadlines, it encourages public comment and refers the public to the Commission's e-dockets website to follow the development of the proceeding. Thus, a primary goal of resource planning is to facilitate public participation and to make the process as transparent as possible. While staff certainly respects utilities' proprietary information, utility plans should not be excessively masked by confidential information to which the public has no access.

Furthermore, the Commission's decision relies on evidence submitted as part of the record, and it should not be incumbent upon the parties to canvass through press releases, trade publications, and news articles to formulate its comments concerning certain financial commitments that affect a utility's generation planning. A news release announcing a deal made between Cliffs Natural Resources Inc. and Minnesota Power—publicized for the first time only two weeks before the Commission hearing and without identified effects to its system operations—does not reflect the public, transparent nature of IRP.

Decision Options

Approval (Minn. Stat. 216B.2422)

1. Approve Minnesota Power's 2015-2029 Integrated Resource Plan; OR
2. Approve Minnesota Power's Integrated Resource Plan with Modifications; OR
3. Reject Minnesota Power's 2015-2029 Integrated Resource Plan.

Commission Findings/Conclusions (Minn. Rule. 7843.0500, Minn. Stat. 216B.2422, Subd. 2.)

(Staff note: The Commission can choose not to make findings and conclusions and instead skip to modifications of the plan.)

Load Forecasting

4. Minnesota Power's load forecast scenarios used in its 2015 resource plan fails to account for the possibility that sales growth will approximate recent trends, thus leading to a potential overstatement of future needs. (CEO)
5. Minnesota Power's range of load forecasting used for its 2015 resource plan is reasonable for planning purposes (Department)

Capacity Need

6. The current resource plan demonstrates Minnesota Power's need for an additional 300 MW of capacity by 2023. (Minnesota Power)

Modifications / Proposed alternative resource plans *(Minn. Stat. 216B.2422, Minn. Rule. 7843.0300, Subpart 11)*

Taconite Harbor Energy Center

7. Minnesota Power shall shut down the Taconite Harbor 1 and 2 units in 2017 (Department); **OR**
8. Minnesota Power shall shut down the Taconite Harbor 1 and 2 units as early as practicable. (CEO)
9. Taconite Harbor Energy Center Units 1 and 2 will be idled in 2016, but retain the ability to restart to address reliability or emergency needs on the transmission system, and cease coal-fired operation by the end of 2020. Future refueling and remission opportunities will be considered in planning and optimization of the facility for the next Resource Plan. (Minnesota Power)

Taconite Harbor Energy Center, MISO filings

(Staff note: if the Commission selects Decision Option 7 or 8, it may also want to require MP to submit an Attachment Y or Attachment Y-2 with MISO.)

10. Minnesota Power shall submit an Attachment Y Notice to the Midcontinent Independent System Operator (MISO) of MP's intent to retire or suspend operation of Taconite Harbor 1 & 2. (CEO); **OR**
11. Minnesota Power shall submit an Attachment Y-2 with the Midcontinent Independent System Operator (MISO) as a request for a non-binding study of the transmission reliability impacts of a potential future status change at Taconite Harbor 1 & 2 (CEO).

Boswell Energy Center

(*Staff note*: The Commission might wish to address the Boswell Energy Center and natural gas acquisition concurrently, since the Department's recommendations depend on one another.)

12. Minnesota Power shall shut down Boswell units 1 and 2 once natural gas combined cycle generation is online (Department); OR
13. Minnesota Power shall shut down Boswell units 1 and 2 when sufficient energy and capacity is available (CEO).
14. If Boswell 1 and 2 are not shut down in this resource plan, Minnesota Power shall conduct a full analysis of ceasing operations at Boswell 1 and 2 for the next resource plan. (CEO)
15. Minnesota Power has not demonstrated at this time that its proposed investment in SO_2 reduction at Boswell units 1 & 2 is reasonable. (Staff)

Natural Gas

16. Procure approximately 200 MW of natural gas combined cycle generation, partly to replace Boswell Energy Center Units 1 and 2 and Taconite Harbor 1 and 2, and (Department)
17. Secure and implement 200 to 300 MW of efficient natural gas combined cycle generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs by 2024. (Minnesota Power) (Staff note: Staff does not see Options 16 & 17 as materially different.) **OR**
18. Minnesota Power shall suspend its pending natural gas power plant procurement. Any future acquisition process shall be fuel-neutral and timed consistent with the need the Commission finds in this resource plan (CEO).
19. Minnesota Power's request for proposals (RFP) for up to 400 MW of natural gas capacity was issued prematurely. The RFP should be suspended or reissued with a revised size and scope commensurate with the approved Resource Plan and to allow responses that incorporate customer self-generation or cogeneration. In any future resource procurement process, Minnesota Power must consider customer self-generation and cogeneration and give notice to existing customers to ensure that customers are able to participate (Large Power Intervenors); **OR**
    a. The Commission's approval of Minnesota Power's Resource Plan does not extend to the outstanding request for proposals for up to 400 MW of natural gas generation in the 2022-2024 timeframe. While a need could possibly arise in the 2022-2024 timeframe, it has not been established at this time that an

approximately 400 MW natural gas unit is the most prudent resource to meet this possibly emerging need. (Staff variation of LPI's recommendation.) (*Staff introduces this alternative language because it makes no determination that MP's issuance of a natural gas RFP was unreasonable; however, it does emphasize that "approving" the resource plan does not pre-judge the reasonableness of MP's natural gas acquisition.)*

20. Order Minnesota Power to formalize a process for working with large power customers interested in self-generation and incorporate that process into the resource planning process, starting with Minnesota Power's next resource plan. (Large Power Intervenors)

Wind additions

21. Minnesota Power shall acquire up to 300 MW of wind capacity in about 2018 (Department); **OR**

22. Minnesota Power shall evaluate whether adding 100 MW of new wind by 2018 with the extension of the Production Tax Credit would provide benefit to its customers. A competitive non-site specific RFP (request for proposal) shall be issued as part of the investigation. (Minnesota Power)

23. By the end of 2017, Minnesota Power shall initiate a competitive bidding process for procurement of 100-300 MW of installed wind capacity. (Staff)

Solar additions

24. Minnesota Power shall acquire solar units of 11 MW in 2016, 12 MW in 2020 and 10 MW in 2025; (Department);
25. In addition to its obligations under the Solar Energy Standard, Minnesota Power shall acquire up 50 MW of solar by 2022 as part of its least-cost expansion plan. (Department)
26. Minnesota Power will continue to monitor solar technology trends and evaluate further additions in the next Resource Plan and maintain compliance with the Solar Energy Standard. (Minnesota Power)

Conservation

27. Minnesota Power shall procure average annual average energy savings of 76.5 GWh. (Department)
28. Minnesota Power will continue to work to identify reasonable additions to its conservation and demand-side management programs where it is most beneficial for customers, while continuing to meet existing energy savings goals. (Minnesota Power)

Demand Response (Staff)

29. Minnesota Power shall initiate a demand response competitive bidding process to supplement or supplant its existing/expiring supply-side, bilateral contracts. (Staff)

Additional Commission Actions

Conservation

30. Minnesota Power shall proactively seek ways to increase conservation by its CIP-exempt customers and consider additional DSM scenarios for CIP opt-outs. *(CEO)*

31. Direct parties to convene a technical workgroup to establish a set of best practices which could include how to treat embedded energy savings, energy efficiency modeling practices, as well as load forecasting techniques. If the Commission chose, it could open an investigation docket to accomplish these goals. *(CEO)*

Distribution/Distributed Energy Resources

32. Order Minnesota Power to conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources. (Department)

Staff's Proposed Compliance Filings

Taconite Harbor Energy Center

33. If the Commission permits idling Taconite Harbor 1 & 2 (THEC 1 & 2), Minnesota Power shall submit an annual report, by August 1 of each year, to include:
    a. Whether THEC 1 & 2 were selected in MISO's Annual Capacity Auction;
    b. If THEC 1 & 2 will receive capacity accreditation in each MISO Planning Year;
    c. How often the units were dispatched in the previous planning year; and
    d. For the previous and upcoming planning year, how much fuel was and will be delivered to the THEC site.

34. Within 30 days of the Commission's order in the resource plan, MP shall file any documentation provided to and/or received from MISO regarding its plans to idle Taconite Harbor 1 & 2, including the MISO/OMS resource adequacy survey and MISO Attachment Y or Y-2 filings.

Bilateral Contracts

35. When Minnesota Power commits to a specific bilateral contract, the Company shall file pertinent details of the contract, such as the duration, price, and amount of capacity and associated energy to be procured. The filings shall be made within 10 business days after the contract is signed.

Deadline for Minnesota Power's Next Resource Plan

36. Require Minnesota Power to file its next resource plan on December 1, 2018. (MP); <u>OR</u>

37. Require Minnesota Power to file its next resource plan on September 1, 2017. (Staff)