MINNESOTA PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	October 18, 2018		Agenda Item **1
Company	Minnesota Power (MP or the Company)		
Docket No.	**E015/AI-17-568**		
	In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package		
Issues	Should the Commission adopt the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations? Should the Commission approve the affiliated Assignment of Rights Agreements authorizing MP to act as Construction Agent and Operating Agent under the NTEC Agreements? Should the Commission approve the affiliated CDA, dedicating 48 percent of the NTEC to MP and energy cost recovery through the FPE Rider? Should the Commission grant a variance to and approve the associated tariff amendments to the FPE Rider to ensure that fuel costs related to MP's share of NTEC are recovered and that MISO revenues realized under the CDA flow back to customers?		
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Relevant Documents	**Date**
Commission Orders, ALJ Orders and Report	
Order Approving 2015 IRP with Modifications (Docket No. 15-690)	July 18, 2016
Order Referring Gas Plant for Contested Case Proceedings	September 19, 2017
Office of Administrative Hearings First Prehearing Order	November 1, 2017
Relevant Documents	
Issues List, Minnesota Power	November 21, 2017
Master Exhibit List	May 9, 2018
Briefs	
Minnesota Power, *Post-Hearing Brief*	May 1, 2018
Department of Commerce, *Post-Hearing Brief*	May 1, 2018
Clean Energy Organizations, *Post-Hearing Brief*	May 1, 2018
Large Power Intervenors, *Post-Hearing Brief*	May 1, 2018
Minnesota Power, *Reply Brief*	May 22, 2018
Department of Commerce, *Reply Brief*	May 22, 2018
Clean Energy Organizations, *Reply Brief*	May 22, 2018
Large Power Intervenors, *Reply Brief*	May 22, 2018
ALJ Report	
ALJ Report – *Findings of Fact, Conclusions, and Recommendations*	July 2, 2018
Exceptions	
Minnesota Power, *Exceptions*	July 23, 2018
Department of Commerce, *Exceptions*	July 23, 2018
Clean Energy Organizations, *Exceptions*	July 23, 2018
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I. Statement of the Issues

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Should the Commission approve the affiliated Assignment of Rights Agreements authorizing MP to act as Construction Agent and Operating Agent under the NTEC Agreements?

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Should the Commission grant a variance to and approve the associated tariff amendments to the FPE Rider to ensure that fuel costs related to MP's share of NTEC are recovered and that MISO revenues realized under the CDA flow back to customers?

II. Background and Commission Orders

i. MP's 2015 IRP

On July 18, 2016, the Commission issued its *Order Approving Resource Plan with Modifications* in Minnesota Power's (MP) 2016-2030 Integrated Resource Plan (IRP).[1] Throughout these briefing papers, staff will refer to the Commission's July 18, 2016 Order as "the 2016 IRP Order" and the resource plan as "the 2015 IRP." Both refer to the same docket.

Among other things, the 2016 IRP Order directed MP to procure 100-300 megawatts (MW) of new wind, explore adding up to 100 MW of solar by 2022 (as an economic system resource), and achieve an average annual energy savings of 76.5 gigawatt-hours (GWh). In addition, the Commission approved MP's proposal to idle the coal-fired Taconite Harbor Units 1 and 2 and cease coal operations by 2020. The Commission also required MP to retire Boswell Energy Center Units 1 and 2 when sufficient energy and capacity are available, but no later than 2022.

As additional background, the Company began a competitive bidding process to procure natural gas generation shortly after filing its IRP. Parties questioned the need for and timing of MP's request for proposals (RFP) for natural gas generation, as well as why the Company was already soliciting bids during the IRP proceeding despite the claimed need being nearly eight years in the future. The Commission agreed that replacement generation should not be limited to one resource, and therefore MP was required to initiate competitive bidding processes for solar, wind, and demand response. These resource options were required to be considered as alternatives to the gas plant in the next resource plan, to be filed on February 1, 2018.

ii. Referral of Gas Plant to Contested Case

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[1] *In the Matter of Minnesota Power's Application for Approval of its 2016-2030 Resource Plan*, Docket No. E015/RP-15-690.

On June 8, 2017, MP announced its plan to file a petition for approval of a package of three resources—natural gas, wind, and solar generation—which MP referred to as the "Energy*Forward* Resource Package" (or EFRP). The June 8 letter included a request for an extension to file the Company's next resource plan, which would allow time for the Commission to review MP's Energy*Forward* Resource Package. MP further requested the Commission refer the EFRP to the Office of Administrative Hearings (OAH) for a contested case.

In its September 19, 2017 *Order Referring Gas Plant for Contested Case Proceedings, and Notice and Order for Hearing* (referral order), the Commission referred only the proposed gas plant (NTEC) for contested case proceedings, finding it was unnecessary to refer the wind and solar proposals to OAH, since those resources had already been approved in the resource plan. The Commission extended the deadline for MP to file its next IRP to October 1, 2019.

The Commission's referral order requires that MP bears the burden of proving that the proposed gas plant or any portion thereof is needed and reasonable based on all relevant factors, including the consideration of:

A. An updated forecast of demand;

B. Costs, including socioeconomic and environmental costs, which would include consideration of the most recent environmental externality values established by the Commission in Docket 14-643; and

C. Alternatives to some or all of the gas plant energy and capacity proposed by the Company, including but not limited to alternatives such as additional wind and solar resources (with updated costs), storage, demand response, and additional energy efficiency.

The Commission's referral order further stated:

> The ultimate issue in this case is whether Minnesota Power's proposed gas plant is necessary and reasonable. This turns on numerous factors that are best developed in formal evidentiary proceedings, including but not limited to consideration of the certificate of need factors and the resource planning factors.[2]

A public hearing was held in Duluth, Minnesota on February 28, 2018 and written public comments were received until March 23, 2018. Post-hearing briefs were filed on May 1, 2018, and responsive briefs were filed on May 22, 2018. The hearing record closed on May 22, 2018, following the receipt of the last responsive brief.

The parties to the proceeding include:

- Minnesota Power (MP);

[2] Commission Order for Hearing, at 5 (September 19, 2017).

- Department of Commerce, Division of Energy Resources (Department);
- The Clean Energy Organizations (CEO), consisting of the Minnesota Center for Environmental Advocacy, Sierra Club, Fresh Energy, and Clean Grid Alliance (previously Wind on the Wires);
- The Large Power Intervenors (LPI), consisting of ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and Verso Corporation; and
- The Office of the Attorney General, Residential Utilities and Antitrust Division (OAG). The OAG did not retain any witnesses or submit briefs or testimony.

Below is a list of the parties' witnesses, with the primary focus area(s) of their testimony in parentheses (there is no order of importance to the list below; staff listed the witnesses in the sequence they appear in the Master Exhibit List):

<u>Minnesota Power</u>

- Ms. Julie Pierce (Forecasting and Policy Issues)
- Mr. Eric Palmer (Resource Planning)
- Mr. Stephen Brick (Resource Selection and System Testimony)
- Mr. Alan Taylor (Independent Evaluation of RFP Process)
- Mr. Frank Frederickson (Dispatchable Capacity Requests for Project Proposals)
- Ms. Lyssa Supinski (Project and Project Agreements)

<u>CEOs</u>

- Mr. Dan Mellinger (Energy Efficiency)
- Mr. Michael Jacobs (Variable Generation, Flexibility, and Energy Storage)
- Ms. Anna Sommer (Resource Planning and Strategist Analysis)
- Dr. Elizabeth Stanton (Forecasting)
- Ms. J. Drake Hamilton (Greenhouse Gas Emissions)

LPI

- Mr. Robert Stephens (Interruptible Load)
- Mr. Michael Gorman (Affiliated Agreements)
- Mr. Brian Andrews (Forecasting and Resource Planning)

Department of Commerce

- Dr. Eilon Amit (Financial and Operational Risks)
- Ms. Nancy Campbell (Accounting and Rate Recovery Mechanisms)
- Dr. Steve Rakow (Resource Planning, RFP Process, and Risk Analysis)

III. MP's Petition for Approval of the Nemadji Trail Energy Center (NTEC)

A. Project Description

MP is requesting Commission approval of affiliated interest (AI) agreements for an approximately 250 MW share of the Nemadji Trail Energy Center (NTEC), a 1x1 natural gas combined-cycle (NGCC) generating facility.

Specifically, NTEC will consist of one H-class (290–330 MW) gas turbine generator (GTG), one heat recovery steam generator (HRSG) with duct firing, and one steam turbine generator (STG). The majority of the system, including the GTG, HRSG, and STG, will be located within enclosed structures to be insulated and heated. The GTG will burn pipeline-quality natural gas.[3]

The NTEC project will be jointly owned by MP's affiliate, South Shore, LLC and Dairyland Power Cooperative (Dairyland), the "NTEC Owners." Each of the NTEC Owners will have the rights to 50% of the capacity from NTEC (approximately 262.5 MW of an assumed 525 MW plant), and, if the assignment of rights are approved by the Commission, MP would construct and operate the facility. As part of the affiliated interest transaction that is the subject of this proceeding, South Shore has agreed to dedicate 48% of the capacity of NTEC (approximately 250 MW) to MP.

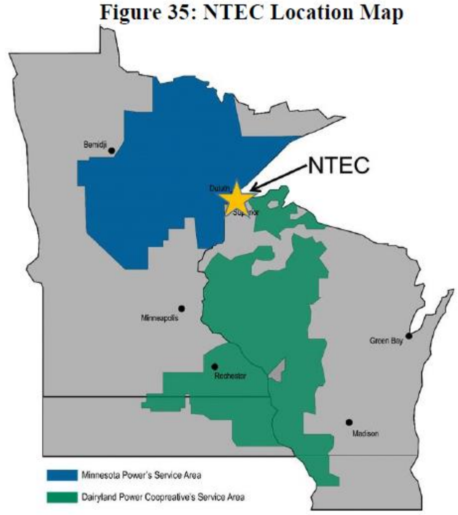
i. Site Description

NTEC will be located in Superior, Wisconsin, which MP views as a strategically beneficial location; as depicted by the figure below, it will be in close proximity to both MP's (blue) and Dairyland's (green) respective service territories:[4]

[3] Petition, Page 4-19.

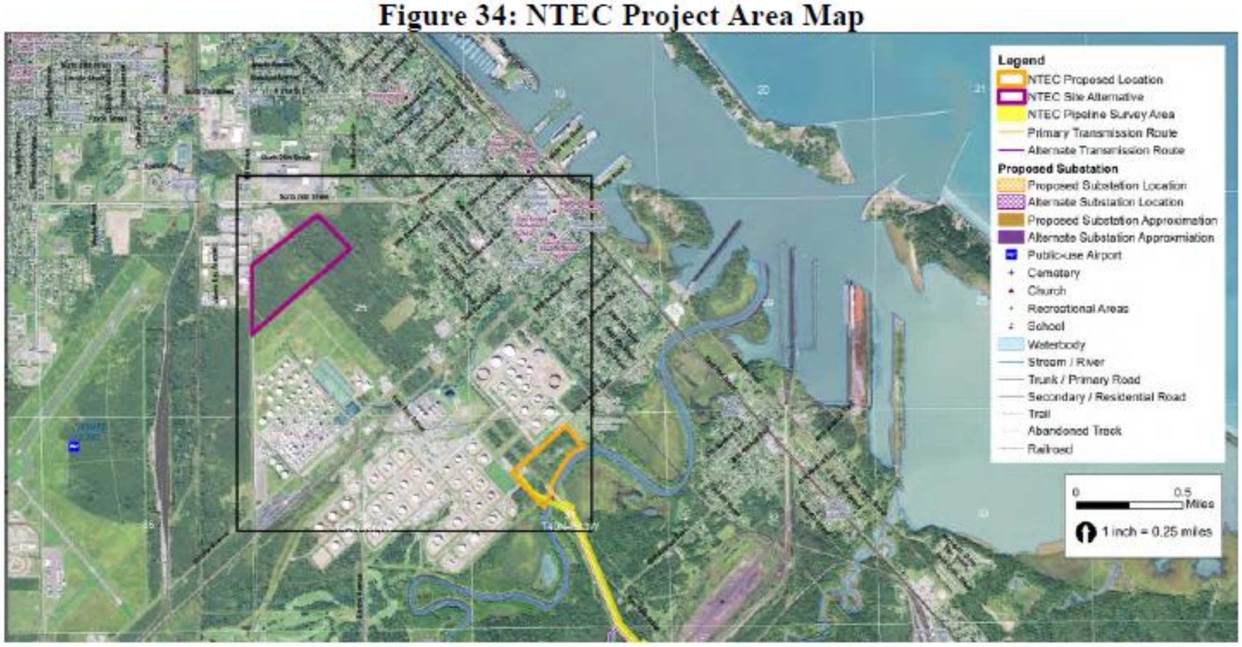
[4] Ex. MP-25, at 5 (Supinski Direct).

Figure 35: NTEC Location Map



Although a greenfield site, the NTEC site is surrounded by industrial property, with most neighboring property owned by Enbridge for use as a crude oil terminal. The location of the proposed site is depicted on Figure 34 of the Petition, shown below:[5]

Figure 34: NTEC Project Area Map



As discussed in MP witness Ms. Pierce's Direct Testimony, "the NTEC project [has] especially good access to multiple natural interstate gas pipelines, access to robust electric transmission infrastructure, and a shovel-ready industrial site."[6] The NTEC site is located less than ten miles from two interstate pipelines that go through Superior, Wisconsin: (1) the main line of Great Lakes Gas Transmission and (2) the spur line of Northern Natural Gas Company that goes from Carlton, Minnesota to Marquette, Michigan.[7] NTEC will interconnect to American Transmission

[5] Petition, Page 4-28.

[6] Ex. MP-13, at 27-28 (Pierce Direct).

[7] Ex. MP-25, at 9 (Supinski Direct).

Company's (ATC) Arrowhead-Weston 345 kV transmission line; the project will require the installation of a new 345 kV collector bus to interconnect to a new offsite 345 kV substation.[8]

For additional background on why the NTEC site was chosen, as well as for more detail of the site's unique benefits and characteristics, staff refers the Commission to "Appendix T: Combined Cycle Site Selection Study" of the Petition. In 2013, Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) was retained by a group of utilities, MP included, to evaluate joint development of a combined cycle power plant. Candidate sites were to be capable of accommodating a natural gas-fueled combined cycle generation facility with a nominal capacity of up to 900 MW. Burns & McDonnell identified preliminary site areas by overlaying maps of infrastructure critical to economic combined cycle generation power plant development.[9] The site selection study was completed in February 2014.

In the Burns & McDonnell study, NTEC—which was initially referred to as the "SupGen" site—ranked second overall. A total of 24 criteria were used to rank sites, and the NTEC site received, for instance, "the highest possible scores for distance to interconnection, pipeline delivery pressure, and system upgrade costs" as well as "the highest score for probability of surface water availability as it is located within two miles of Lake Michigan."[10]

ii. Milestones and Commercial Operation

NTEC is planned to be in service in 2024. There are four phases of the NTEC project: (1) development; (2) detailed design; (3) construction; and (4) testing and commissioning.

NTEC is currently in the development phase. Once the necessary approvals and agreements are in place, NTEC will enter into the design phase, which is expected to begin by December 2020 and continue through November 2021. The majority of construction activities are between April 2022 and December 2023, in the following sequence: the GTG will be delivered by October 2022; the HRSG in late 2022/early 2023; and the STG in early 2023. NTEC will then go through start-up and commissioning to reach a point of substantial completion by June 2024.[11]

South Shore applied for interconnection with the Midcontinent Independent System Operator, Inc. (MISO) for NTEC on June 7, 2017. The project is part of MISO's August 2017 DPP (Definitive Planning Phase) study group, which will assess the requisite transmission network upgrades.[12] Final cost estimates for interconnection are scheduled to become available in May 2019.[13]

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[8] Ex. MP-25, at 6 (Supinski Direct).

[9] Ex. MP-25, Schedule 1 of Supinski Direct (Burns & McDonnell Memo), Page 1 of 2.

[10] Petition, Appendix T, Page T-47 and T-48.

[11] Petition, Pages 4-33-35.

[12] Ex. MP-25, at 20 (Supinski Direct).

[13] Ex. MP-25, at 20-21 (Supinski Direct).

B. Ownership Share

In addition to the benefits of joint *development*, MP also lists several financial benefits of joint *ownership* by South Shore and Dairyland. According to MP witness Ms. Supinski, for instance:

> Joint ownership by South Shore and Dairyland allows each party to participate in a larger facility, achieving economies of scale and more efficient operations … These savings include construction, operating and maintenance ("O&M"), and fuel cost savings. Larger plants are also generally able to offer lower capacity prices and have lower heat rates than otherwise analogous smaller facilities.[14]

MP's request for a 250 MW share reflects 48% of NTEC's current proposed configuration as a 525 MW plant; however, NTEC could be slightly larger depending upon final turbine selection. MP also stated it could support a Commission determination that MP take South Shore's entire 50% interest in NTEC, which the Department recommends.

Ms. Supinski explained that, under Wisconsin Statutes § 196.53, MP is a "foreign corporation," and as such, MP cannot own a generation facility in Wisconsin unless one of the statute's exceptions to this requirement apply. Ms. Pierce elaborated on this, explaining why MP's subsidiary, South Shore, was a logical choice to own NTEC upon completion:

> Wisconsin Statutes only permit Wisconsin entities to obtain a Wisconsin license, permit, or franchise to own or operate a generation facility. Minnesota Power is not a Wisconsin corporation. Minnesota Power's subsidiary, South Shore, submitted the proposals for what is currently named NTEC into Minnesota Power's Gas RFP for consideration as a resource option. Since South Shore is a Wisconsin entity, it is logical for South Shore to continue to own NTEC upon completion of the generation facility, subject to affiliated agreements with Minnesota Power. This approach resolves the Wisconsin utility ownership requirements.[15]

Ms. Pierce further explained Wisconsin's regulatory requirements and how MP has addressed these risks:

> NTEC requires various federal and state permits, including a number of construction-related permitting approvals from the Wisconsin Department of Natural Resources ("WDNR"), the Wisconsin Department of Safety and Professional Services, and Wisconsin Department of Transportation. There are three permits that may take over a year or more to obtain agency approval: (1) CPCN [Certificate of Public Convenience and Necessity] approval from the Public Service Commission of Wisconsin ("PSCW") for construction of a large electric generating facility; (2) certificate of authority from the PSCW for construction of

[14] Ex. MP-25, at 17-18 (Supinski Direct).

[15] Ex. MP-13, at 31-32 (Pierce Direct).

> the SWL&P[16] lateral pipeline; and (3) the WDNR permit for construction and operation of a new source of air emissions.
>
> Minnesota Power has addressed these risks in the NTEC project schedule: it contemplates filing for the CPCN and air permit in 2018 to allow for construction to begin in 2020. SWL&P also plans to file for the certificate of authority in 2018 for the connection to the interstate natural gas pipeline, which will allow ample time for approval prior to construction and provide the PSCW with the benefit of having both approvals simultaneously.[17]

Pages 14-16 of Ms. Supinksi's Direct Testimony provides additional detail on Wisconsin-specific regulatory requirements.

C. Requests for Approval (Affiliate Transactions and Variance Request)

The agreements governing NTEC include two Project Agreements and the three affiliated interest agreements that are the subject of the Company's request for approval in this Petition.

First, the two NTEC Project Agreements entered into between South Shore and Dairyland are (1) the O&O Agreement between the NTEC Owners, with South Shore as the Operating Agent; and (2) the D&C Agreement between the NTEC Owners, with South Shore also as the Construction Agent.

The O&O and D&C Agreements that designate South Shore as the responsible agent require South Shore to complete development and construction of NTEC, as well as to operate and maintain the plant. Both agreements contemplate that South Shore's obligations will be assigned to MP upon Commission approval, hence the request for approval of the assignment of rights. Upon Commission approval, MP will undertake the development, construction, operation, and maintenance of the plant.

MP is seeking Commission approval of three AI agreements pursuant to Minn. Stat. § 216B.48, which imposes a "public interest" standard. The AI agreements, dated July 28, 2017, are discussed in Section 4.5 of the Petition and pages 23-38 of Ms. Supinski's Direct Testimony. They include:

- Assignment of Rights Agreement, Construction Agent;
- Assignment of Rights Agreement, Operating Agent; and
- Nemadji Trail Energy Center Unit Contingent Capacity Dedication Agreement (the CDA).

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[16] SWL&P is ALLETE subsidiary Superior Water, Light & Power.

[17] Ex. MP-13, at 32 (Pierce Direct).

As mentioned, under both the D&C (Construction Agent) and O&O (Operating Agent) Agreements, South Shore is designated as the responsible agent. If the Commission approves the assignment of rights agreements, MP will absorb the following responsibilities, as described by Ms. Supinski:

> As Construction Agent and Operating Agent, Minnesota Power will have primary responsibility for the management of the planning, permitting, design, construction, acquisition and procurement, completion, startup and commissioning of NTEC; the planning, permitting, design, construction, acquisition and procurement and completion of any capital improvements, renewals, additions, replacements, modifications, or repairs to NTEC; and the scheduling, dispatch, sale, or other disposition of energy and ancillary services. These responsibilities are subject to the terms of the O&O and D&C Agreements, oversight by the Management Committee, and reimbursement of actual costs.[18]

The next section will discuss the third bullet from the list above, the Capacity Dedication Agreement, or CDA, which is the mechanism by which South Shore conveys the rights to a portion of NTEC to MP, effective through the useful life of NTEC and decommissioning.

D. Cost Recovery

MP has assumed that the entire NTEC project, including network upgrades, will cost approximately $700 million, of which MP will be responsible for 48% (or 50%, depending on the Commission's decision). By dedicating the capacity and associated energy to MP on the same basis as if MP owned the dedicated capacity directly, the CDA gives MP rights to the plant as if the asset would be held in rate base.

The CDA's capacity pricing formula is based on the $700 million.[19] Also, since the pricing stream replicates a revenue requirement on a rate-based asset, it includes MP's authorized rate of return, capital structure, depreciation schedule, and so forth. This also means the per-unit cost decreases (de-escalates) over time as the asset depreciates.[20] The CDA has a 40-year term.

MP's total capital investment in the plant, which includes financing costs and capitalized interest, and MP's expected total investment in network upgrades, which also includes capitalized interest, is provided in Appendix H of the Petition, on page H-46. All calculations and support for the total capital investment as provided on page H-46 is further discussed in MP's response to Department Information Request No. 21, attached as part of Department witness Ms. Campbell's Direct Testimony.[21]

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[18] Ex. MP-25, at 29 (Supinski Direct).

[19] Ex. MP-25, at 34 (Supinski Direct).

[20] Ex. MP-25, at 32 (Supinski Direct).

[21] Ex. DER-5, at NAC-3 (Campbell Direct).

MP's proposed capacity pricing method essentially converts the installed cost of NTEC into a revenue requirement based on the assumed construction costs and cost of capital, among other inputs. Furthermore, the pricing formula assumes a "soft cap," which means if the actual cost of the plant and associated network upgrades is *less* than the target aggregate amount, MP's proportional share of net savings flows directly through to customers. If the aggregated cost of the plant and network upgrades *exceeds* the target aggregate amount, MP agreed to obtain Commission approval for recovery to ensure those costs were prudently incurred.[22]

Notably, approval of the agreements will not, in and of itself, have any immediate effect on MP's base rates. Rather, when the NTEC project goes into service in 2024, capacity costs incurred by MP will be included in base rates through a general rate case filed at or after the time the NTEC project goes into service.[23]

In summary, Ms. Supinski explained in her Rebuttal Testimony that the CDA allows Commission authority over the contract and includes a mechanism to prevent over-recovery:

> The CDA provides that Minnesota Power is giving the Commission authority over the contract and relationship on the same basis as if Minnesota Power owned the NTEC plant in its own name as a rate-based asset. Additionally, payments under the CDA are intended to mimic payments associated with any rate-based utility asset.
>
> Changes to Minnesota Power's Commission-approved capital structure, cost of capital, and depreciation will all be reflected in the payments under the CDA. Further, changes in tax rates will roll through the calculations and will be trued up to actuals as described in the CDA. This true-up feature ensures that Minnesota Power does not "over-recover" for things like the cost of capital, taxes, or depreciation.[24]

Ms. Pierce echoed these ratepayer protections, explaining that the soft cap is designed to serve the interests of its customers:

> In the event actual costs exceed [approximately $700 million], Minnesota Power would retain the burden of proving that its pro rata share of the excess costs are reasonable and prudent. Under such circumstances, the Company would be responsible to prove that changed circumstances resulted in costs above estimated costs, and that those changes were reasonable. This ensures Minnesota Power's customers are fully protected from the risk that costs exceed the estimated overall total and will incur those costs only if they are established to be prudent.

[22] Ex. MP-25, at 33 (Supinski Direct).

[23] Petition, Appendix A, Page A-3.

[24] Ex. MP-27, at 24 (Supinski Rebuttal).

In contrast, if the project costs come in lower than expected, Minnesota Power would pass the project savings (associated with the NTEC 250 MW purchase) to customers upon commercial operations of the facility through a lower capacity payment, providing a benefit that power purchase arrangements do not include.[25]

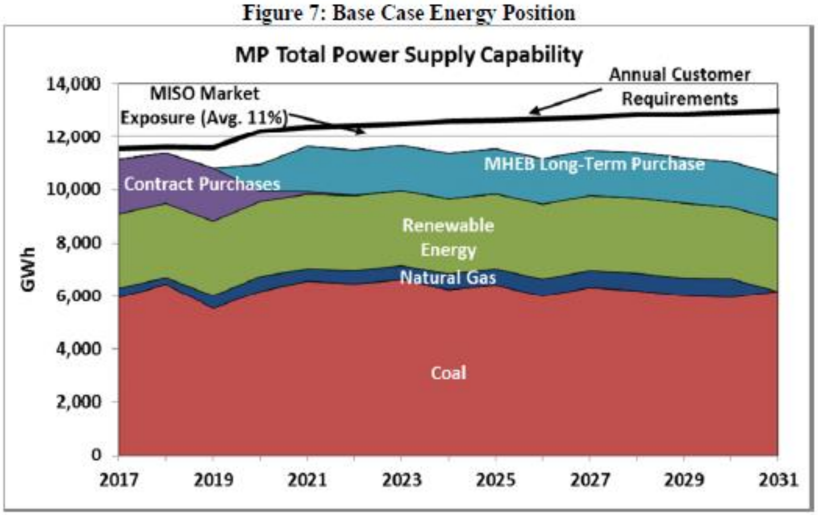
Finally, MP requests a variance and associated tariff amendments to the Company's Fuel and Purchased Energy (FPE) Rider. This is to ensure that fuel costs related to MP's share of NTEC are recovered and that all of the revenues MP receives from its share of MISO market sales of energy from NTEC flow back to customers. With this variance, customers will be treated the same as if the generating asset was owned directly by the utility.

E. System Characteristics and Operational Needs

i. Power Supply Mix

Figure 7 of the Petition shows MP's base case (i.e. without NTEC) energy position. MP's current customer energy requirement is roughly 11,000 GWh, a little over half of which is served by MP's remaining coal units, Boswell Energy Center Units 3 and 4:

Figure 7: Base Case Energy Position



However, MP noted that Figure 7 does not capture daily operational system needs, and MP's current energy position can vary by 600 MW in an hour due to wind intermittency. With the addition of another 250 MW of wind (Nobles 2 Wind), MP's energy position could vary up to 850 MW in an hour, thus creating a need for dispatchable capacity and flexible energy.[26]

ii. Need for Dispatchable Capacity

One of the primary operational benefits of NTEC will be its dispatchability; MP argued that dispatchability is particularly important given its highly-industrial customer mix, in which 13 customers represent over 70% of the Company's total demand, with around-the-clock

[25] Ex. MP-13, at 30-31 (Pierce Direct).

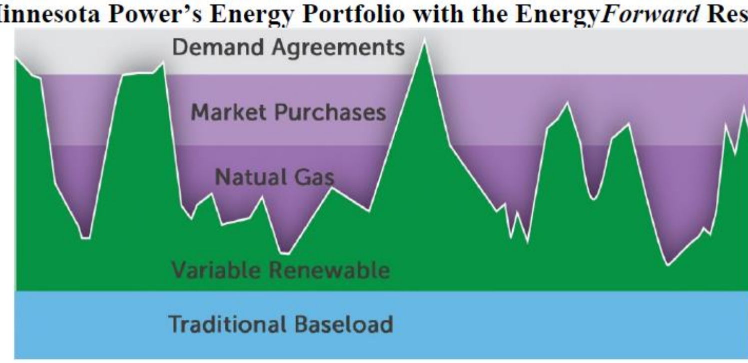
[26] Petition, Page 2-14.

operations. Additionally, MP's load factor is in the 80% range,[27] which is uniquely high and "requires the ability to smooth its deliveries to minimize swings in generation."[28]

Having more than 850 MW of renewable capacity on MP's system would amount to nearly 50% of MP's total peak demand. MP explained, "the changing shape of hourly and five-minute energy requirements caused by the existing and additional variable renewable generation in 2020 creates additional need for dispatchable capacity and flexible energy to mitigate and balance exposure to energy markets."[29] MP is concerned that, in being a high load factor utility with a significant amount of wind generation on its system, customers are vulnerable to excessive spot market risk, especially during periods where high demand corresponds with low or no wind availability.

Figure 24 of MP's Petition shows how NTEC and renewable energy could balance the MP's energy mix and, together, mitigate its exposure to potentially volatile energy markets:[30]

Figure 24: Minnesota Power's Energy Portfolio with the Energy*Forward* Resource Package



MP also discussed the interaction between wind and a natural gas resource by showing how NTEC would be dispatched. Figure 29 of the Petition, below, illustrates MP's total wind portfolio and how NTEC would meet customer demand during periods of low wind generation. As shown by the blue area—a duration curve of MP's wind portfolio—as wind generation decreases, combined-cycle natural gas generation, in red, is dispatched more frequently. Thus, the decrease in wind generation coupled with the increased dispatch of natural gas generation demonstrates the synergy between the two resources:[31]

[27] Ex. MP-13, at 7, 9 (Pierce Direct).

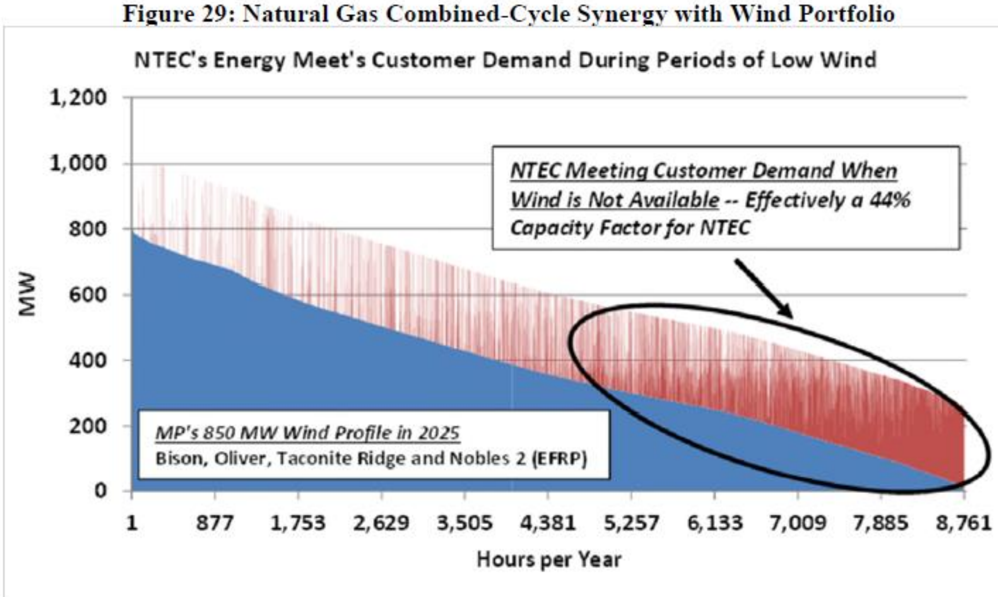
[28] Ex. MP-13, at 21 (Pierce Direct).

[29] Ex. MP-13, at 58 (Pierce Direct).

[30] Petition, Page 3-47.

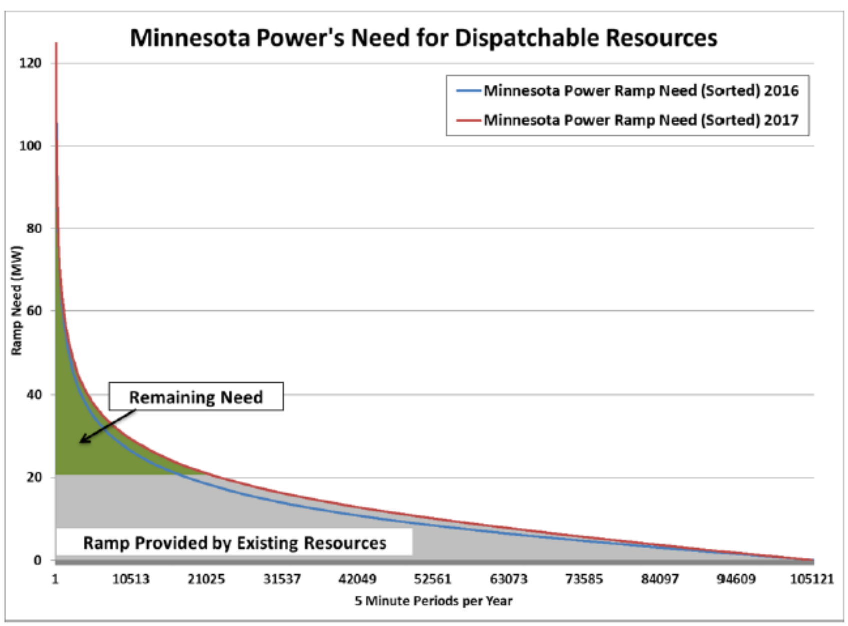
[31] Petition, Page 4-7.

Figure 29: Natural Gas Combined-Cycle Synergy with Wind Portfolio



MP estimated that its existing resources can only provide about 20 MW of "ramp," which refers to "the amount of generation that can be increased or decreased in a five-minute period."[32] According to MP witness Mr. Palmer, "its dispatchable resources expected to be in operation in 2025 fall short of the ramp need in approximately 18.5% of the five-minute periods in 2016 and 2017 combined, which is approximately two months per year."[33] Figure 5 of Mr. Palmer's Rebuttal Testimony, below, graphically depicts MP's estimate of the ramp need:

Figure 5: Need for Ramp on Minnesota Power's System



[32] Ex. MP-18, at 69 (Palmer Rebuttal).

[33] Ex. MP-18, at 69 (Palmer Rebuttal).

MP's share of the NTEC facility has the capability to ramp over 110 MW in a five-minute period.[34] Mr. Palmer's modeling showed that, with NTEC, MP would be able to meet the ramp needs of its own load in over 99% of five-minute periods.

iii. Challenges with Adding More Renewable Energy

MP emphasized that the NTEC purchase should be considered in conjunction with the Company's recent and ongoing "fleet transformation," which includes the retirement, idling, or refueling of almost 700 MW of coal generation from MP's system. This amounts to more than one-third of the Company's legacy power supply. These actions include:

- Retiring Boswell Energy Center Units 1 and 2 in 2018, eliminating approximately 135 MW of capacity from MP's system;

- Idling Taconite Harbor Energy Center Units 1 and 2 in 2016 and termination of coal-fired operations at THEC 1 & 2 by the end of 2020, eliminating 150 MW of capacity;

- Retiring Taconite Harbor Energy Center Unit 3 in 2015, eliminating 75 MW of coal-fired capacity;

- Reducing its stake in the Young Unit 2 generating station in North Dakota from 227.5 MW to 100 MW in August 2014 to zero by 2026; and

- Repowering coal-fired Laskin Energy Center (110 MW) in 2015 to run on natural gas.

Altogether, this means that, for both reliability and economic reasons, MP's current system requires the kind of flexible, dispatchable generation NTEC provides. MP goes on to explain why future capacity and energy needs cannot be met solely with renewable energy:

First, wind and solar are variable resources that cannot be relied upon 24 hours per day or throughout the year.

Second, as the installed percentage of variable generation rises, so does the production of surplus power generated during those hours when the wind is blowing or the sun is shining. This surplus power either needs to be resold in the market or is wasted.

Third, due to its intermittency, wind generation contributes only a small amount toward utility capacity requirements. And, as more wind is added in the MISO footprint, the capacity value it receives will continue to decrease due to the high penetration of intermittent generation.

[34] ALJ Report, Finding of Fact 369, at 75. (*See also* Palmer Rebuttal at 71.)

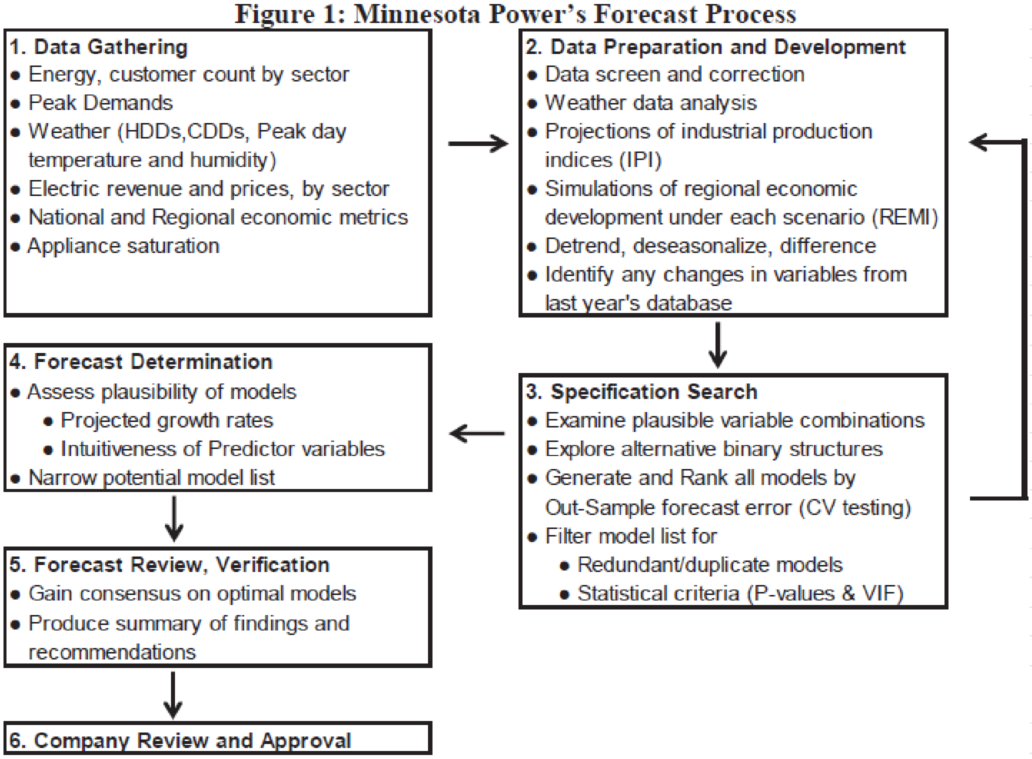
Fourth, obtaining the same amount of accredited capacity from wind and solar as that from a combined cycle unit would lead to an overbuilt system (due to the lower percent capacity credit wind and solar receives).

Fifth, according to the Company, "strategically deployed combined-cycle generation promotes overall greater CO_2 reductions, rather than focusing exclusively on variable renewable generation." A "strategic mix of variable plus dispatchable generation maximizes the use of the variable generation and therefore maximizes the potential to reduce carbon emissions in a cost-effective manner."[35]

F. Resource Needs

MP's sales and demand forecast is based on the Company's 2017 Annual Forecast Report (2017 AFR), which was filed in Docket No. E999/PR-17-11 on June 29, 2017.[36] The forecasting process involves several steps, which is illustrated in Figure 1 from the Petition below. This process includes: (1) data gathering; (2) data preparation and development; (3) specification search; (4) forecast determination; (5) initial review and verification; and (6) internal company review and approval:[37]

Figure 1: Minnesota Power's Forecast Process



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[35] Ex. MP-20, at 6 (Brick Rebuttal).

[36] *Staff note*: Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service area submit to the Minnesota Department of Commerce an annual report containing historical and forecast customer sales and demand values, including forecast methodology and discussion. This report is submitted annually by July 1 of each year.

[37] Petition, at Page 2-4.

In developing the 2017 AFR, MP made a number of changes from the forecast it used for the 2015 IRP, in part because MP attempted to incorporate the Commission's concerns that led it to decide in the 2016 IRP Order that MP overstated its resource needs. For example, the 2017 AFR assumed more conservative large industrial customer outlooks. It also "accounted for the secondary economic impacts of large industrial customers," which means, for instance, updating the regional economic outlooks and utilizing different employment scenarios.[38] The 2017 AFR also factored in new information regarding MP's industrial customers; for example, since the forecast was developed for the 2015 IRP, "eight of Minnesota Power's ten large mining and metals customers experienced some idling of production" and some remain indefinitely idled.[39]

To capture the plausible ranges of uncertainty in MP's customer outlooks, two additional demand and energy sensitivities were developed in addition to the baseline forecast: the "2017 AFR High" and "2017 AFR Low" scenarios. The 2017 AFR High outlook assumes the resumption of operations by two recently-idled iron concentrate facilities and further assumes the startup of Mesabi Metallics, resulting in nearly 100 MW of additional growth. The 2017 AFR Low outlook assumes the mining sector remains in the "status quo,"–i.e. currently-idled facilities remain idled—and PolyMet does not commence mining operations in the forecast timeframe. As a result, the low load sensitivity lowered peak demand by 43 MW and annual energy sales by 370,000 MWh.[40]

Overall, MP's 2017 AFR Expected Case (base case) forecasts a 0.9% compound annual growth in energy sales from 2017 to 2030 (versus the 1.1% growth rate from the 2015 IRP). In other words, MP projects a slower, but still positive, energy sales growth rate. Likewise, the 2017 AFR projects that peak demand will continue at a positive albeit slower annual growth rate.

i. Capacity Need

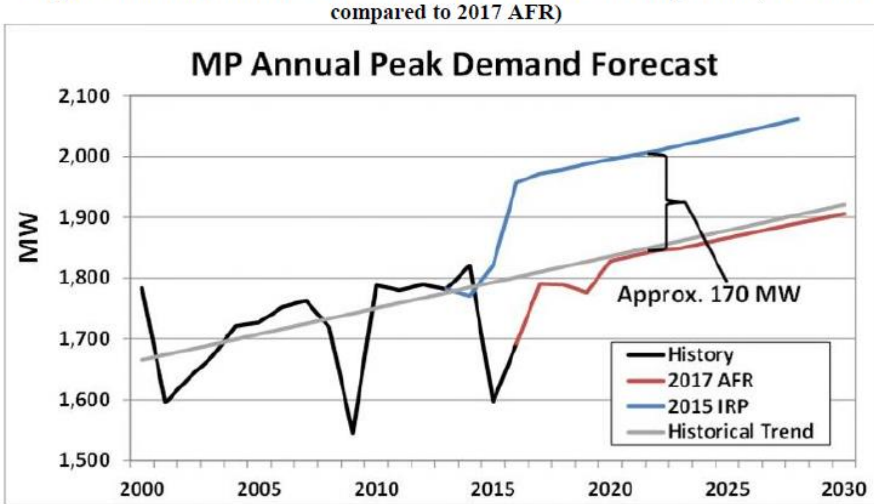
As noted above, MP's 2017 AFR expects a more modest annual peak demand forecast than the outlook used in the 2015 IRP. Figure 3 of the Petition shows that, in the post-2020 timeframe, the 2017 AFR forecast (the red line) is about 170 MW lower than the 2015 IRP forecast (the blue line). The solid black line shows historical actuals.

[38] Ex. MP-13, at 48 (Pierce Direct).

[39] Ex. MP-13, at 47 (Pierce Direct).

[40] Ex. MP-MP-15, at 46 (Pierce Rebuttal).

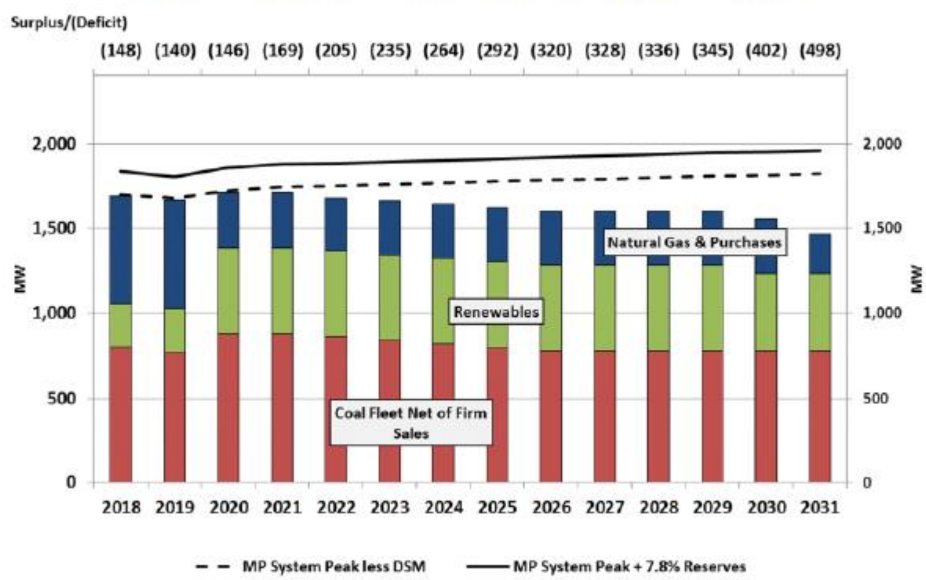
Figure 3: Minnesota Power's Annual Peak Demand Forecast Comparison (2015 Plan compared to 2017 AFR)



In accordance with MISO and the North American Electric Reliability Corporation (NERC) reliability standards, MP is required to, respectively, maintain a planning reserve margin (PRM) requirement in compliance with MISO's Resource Adequacy tariff and to maintain adequate resources to serve its system load.

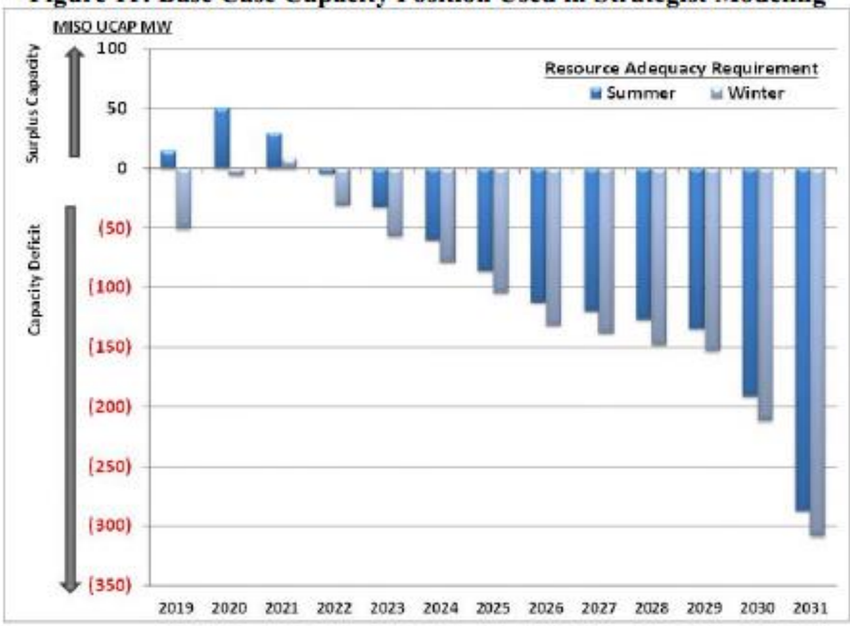
Figure 5 of MP's Petition illustrates its projected summer season capacity deficit. It assumes a 7.8% PRM, which was MISO's reserve margin at the time the Petition was filed. Of note, the solid line, which is aligned with the capacity deficit values on the top of the horizontal axis, does *not* take into account demand response or the effect of conservation on the system peak:

Figure 5: Base Case Summer Season Capacity Outlook



Because MP's capacity outlook shown in Figure 5 does not take into account DSM, it is not reflective of the capacity need modeled in Strategist. In Strategist, MP incorporated 150 MW of large industrial interruptible demand and 11 GWh of incremental energy efficiency (which effects peak demand to some extent). Additionally, MP assumed 250 MW from Nobles 2 Wind and 10 MW from Blanchard Solar. Altogether, the net capacity position used for the Strategist modeling analysis (below) shows a capacity need of about 100 MW in 2025, growing to about 300 MW in 2031. From 2026 through 2029, MP projects the need growing slowly, reaching about 150 MW by 2029 (which makes sense because the 2017 AFR assumes a moderate peak demand growth rate, and there are no unit retirements in years 2026-2029).[41,42] Also, note that MP assumes different capacity deficits for the summer and winter seasons and models those as separate futures.

Figure 11: Base Case Capacity Position Used in Strategist Modeling



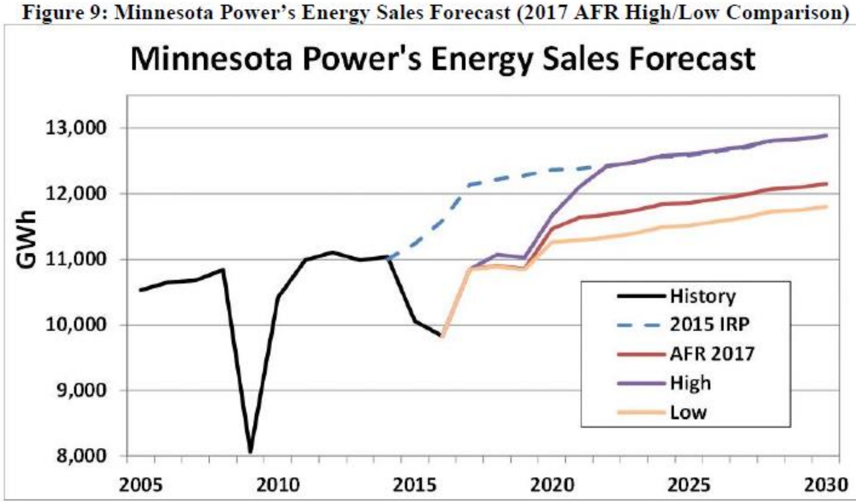
ii. Energy Requirements

As noted previously, MP's Expected Case projects an approximately 0.9% compound annual growth rate for energy sales. In the pre-2020 timeframe, though, the energy sales outlook in the 2017 AFR is much lower, by about 1,350,000 MWh per year, than the forecast used in the 2015 IRP. This gap reduces somewhat in the later years; for instance, by 2025, the 2017 AFR is about 720,000 MWh lower per year compared to the 2015 IRP forecast. This is shown in Figure 9 of MP's Petition, which also includes the High and Low forecast sensitivities MP developed, as well as historical actuals:

[41] ALJ Report, Finding of Fact 176.

[42] Petition, at Page 3-12 (Figure 11).

Figure 9: Minnesota Power's Energy Sales Forecast (2017 AFR High/Low Comparison)



According to MP, the majority of the decrease in forecasted sales is due to its downward adjustment in large customers. (There are also some differences attributable to secondary economic impacts and methodological changes implemented for the 2017 AFR.[43]) In fact, as Ms. Pierce explained, about 70% of the decrease in the outlook from the 2015 Plan is due to updated assumptions for large industrial customers.[44]

As noted, the difference in projected sales between the 2017 AFR and the 2015 IRP forecast is greatest pre-2020. Specifically, this is due to the updated assumptions which primarily involve Mesabi Metallics; Keewatin Taconite ("Keetac"); PolyMet; Magnetation Plants 2 and 4; and Silver 1 Bay Power Company.[45]

In the long-term, the 2017 AFR sales forecast still remains lower than the 2015 IRP forecast, which is mostly attributable to Mesabi Metallics and Magnetation Plants 2 and 4 being removed from the long-term forecast.

G. Resource Planning Analysis

MP's resource planning period covers the fifteen years from 2017 through 2031, and power supply costs are evaluated in Strategist through 2034. (However, as will be discussed later, the net present value computation also incorporates "end effects," which is a mathematical extrapolation of the last year of the planning period[46] intended to better reflect the overall costs of an investment with a 40-year life.[47])

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[43] Ex. MP-13, at 47 (Pierce Direct).

[44] Ex. MP-13, at 47 (Pierce Direct).

[45] Ex. MP-13, at 51-52 (Pierce Direct).

[46] Ex. CEO-10, at 21 (Sommer Surrebuttal).

[47] MP Reply Brief, at 22-23.

As mentioned, the Company used Strategist to compare various resource alternatives to meet its projected capacity and energy needs. Appendix I (Assumptions and Outlooks) provides a summary of the key economic modeling assumptions MP utilized in the Strategist analysis. Appendix J (Detailed Resource Planning Analysis) discusses resource alternatives considered in the Strategist analysis, the resource expansion plan results, and provides a comparison of the NTEC Combined Cycle proposal to three alternative generation paths called "swim lanes."

In addition to incorporating a new load forecast, MP updated and refined several inputs from the Company's 2015 IRP. In particular, MP:

- updated its existing power supply to reflect recent changes in its generation portfolio;
- updated its capacity resources to include near-term bilateral contract and accredited capacity values;
- updated costs for generation alternatives based on the latest industry data and the recent RFPs;
- updated the retirement assumptions for the existing thermal generation fleet;
- included 33 MW of SES-compliant solar generation in the base case;
- updated the environmental externality values established by the Commission; and
- assessed its incremental energy efficiency and industrial demand response assumptions.

One of MP's major points of emphasis throughout the proceeding was that it is imperative to take into account the Company's energy need as well as its capacity deficit. Due in large part to the energy loss resulting from removing nearly 700 MW of coal-fired generation in the 2015-2025 timeframe, MP claims that its system requires intermediate, dispatchable, and flexible capacity to deliver cost-effective energy on a 24 x 7 basis. MP explains at length—particular in response to the intervenors' comments and Exceptions to the ALJ Report—why it is incomplete to view this case strictly in terms of the capacity need.

A second point of emphasis was the frequency with which NTEC was selected by Strategist. This result, importantly, is directly tied to the Company's expected energy need. Overall, MP's analysis found that "[t]he 250 MW NTEC purchase was selected in nearly 90 percent of the cases … [and] is being selected because of an immediate energy need in 2025 and the longer-term capacity need."[48]

[48] MP Reply Brief, at 20.

With regard to the consideration of alternatives, according to MP, "there is no predictable hourly generation pattern for wind,"[49] and renewable energy in general is "largely intermittent and cannot be called upon when needed."[50] Energy storage could be a mitigating factor to the challenges associated with additional intermittent generation, but MP believes "battery storage is not available at an appropriate scale and is not cost-effective."[51] Compared to peaking generation (e.g. a combustion turbine), MP found that "the model consistently selected the intermediate combined-cycle resource over smaller or staged-in combustion turbine generators, as the energy-production profile of the combined-cycle resource was much more cost-effective than a peaking resource."[52]

i. Overview of Modeling Approach

MP's analytical process was a two-step planning evaluation in Strategist. "Step 1," as it is called, reflects the typical resource planning analysis whereby the model optimizes all resource alternatives allowed into the model across a broad range of sensitivities. "Step 2" involved comparing the NTEC expansion plan to three alternative expansion plans, referred to as "swim lanes."[53] In essence, the four swim lanes (the NTEC expansion plan plus three alternative paths) attempted to model the same amount of accredited capacity with different mixes of resources.

Due to the esoteric nature of the terms, it might be worth first discussing what MP means by "futures," "swim lanes," and "sensitivities," as these terms are not interchangeable, but actually represent very different things. (Figure 12 of Mr. Palmer's Direct Testimony illustrates the difference between the analysis of Futures and swim lanes.[54])

The term "Futures" refers to MP's Step 1 analysis, in which MP defines basic model parameters. For instance, as shown in Table 1 below,[55] key parameters in each Future include a summer versus winter resource adequacy construct; the inclusion or exclusion of CO_2 regulatory costs[56]; and whether the model is allowed to sell excess energy into the MISO market. For its Petition, MP developed eight "Futures" in total:

[49] Petition, Appendix J, Page J-1.

[50] Petition, Appendix J, Page J-2.

[51] Ex. MP-20, at 8 (Brick Rebuttal).

[52] MP Reply Brief, at 21.

[53] Ex. MP-16, at 15-16 (Palmer Direct).

[54] Ex. MP-16, at 17 (Palmer Direct).

[55] Petition Page 3-21.

[56] In these Futures, environmental externalities were modeled as sensitivities.

Table 1: Eight Futures Considered in the NTEC Combined-Cycle Analysis

Futures	Strategist Case Name	Resource Adequacy Season	CO_2 Regulation Penalty	Excess Energy Sold Into Wholesale Market
Future 1	C1S	Summer	No	Yes
Future 2	C2S	Summer	No	No
Future 3	C3S	Summer	Yes	Yes
Future 4	C4S	Summer	Yes	No
Future 5	C1W	Winter	No	Yes
Future 6	C2W	Winter	No	No
Future 7	C3W	Winter	Yes	Yes
Future 8	C4W	Winter	Yes	No

"Sensitivities" stress various drivers of power supply costs, such as fuel, environmental costs, capital costs, and customer load outlooks. Each Future listed in Table 1 is tested across over 34 sensitivities in the Strategist analysis. As a result, MP evaluated nearly 300 unique combinations and sensitivities.[57]

In the Company's Step 1 analysis, NTEC was selected in 96% of 292 expansion plans evaluated.[58,59] Large scale solar (of 100 MW each) was selected approximately 90% of the time across these same scenarios, most often post-2030.[60]

The term "swim lanes" is specific to MP's Step 2 analysis. These swim lanes were developed to "vary the quantity of renewable generation and the type of natural gas-fired generation."[61] In other words, swim lanes refer to predetermined generation portfolios, and the optimal portfolio (swim lane) can be revealed by which is least-cost under the greatest number of sensitivities.

The four swim lanes include the following expansion plans:[62]

- NTEC combined-cycle portfolio (also known as the Energy*Forward* Resource Package) – Consisting of the NTEC 250 MW purchase beginning in 2025, 250 MW of wind in 2020, and 10 MW of solar in 2020. The analysis also assumes 12 MW of solar in 2025 (added to comply with SES) and a 100 MW combustion turbine in 2031 (to meet capacity needs post-2030).

- 75% renewable capacity portfolio – 1,950 MW of wind added from 2020 through 2031 in 250 MW to 550 MW blocks depending on capacity need and 108 MW of gas peakers to meet capacity needs.

[57] Petition, Page 1-7.

[58] ALJ Report, Finding of Fact 200, at 44-45.

[59] Petition, Page 4-11.

[60] ALJ Report, Finding of Fact 200, at 44-45.

[61] Petition, Appendix J, Page J-16.

[62] Ex. MP-16, at 16 (Palmer Direct).

- 50% renewable capacity portfolio – 1,350 MW of wind added from 2020 through 2031 in 250 MW to 450 MW blocks and 198 MW of gas peakers to meet capacity needs.

- Large combustion turbine portfolio – 456 MW of gas peakers with the first 223 MW added in 2025 and the second in 2031, and 250 MW of wind in 2020.

Of note, swim lanes 2 and 3 were developed to comply with Minn. Stat. § 216B.2422, subdivision 2, which refers to the portion of the IRP statute that requires modeling a plan to meet 50% and 75% of resource needs with renewables. These swim lanes were modeled according to how much accredited capacity renewable resources—namely wind—could provide. However, since the time MP developed its swim lanes, the statute was changed from new and refurbished *capacity* to new and refurbished *energy*.

ii. Revised Futures and Swim Lanes

During the proceeding, MP conducted a revised Strategist analysis, in part to respond to criticisms raised by intervening parties. In short, MP added two Futures (for a total of 10) and two swim lanes (for a total of 6), which staff will discuss separately in the next section.

a. Futures

Two futures—Futures 9 and 10—were added to incorporate the Commission's updated environmental externality values, and they were included in the base case. This was done because the CEOs contended that the Commission's referral order suggested MP include its environmental externalities in the base case analysis.[63] In addition, Dr. Rakow observed in his Direct Testimony that MP "did not meet the requirements of Minnesota Statutes § 216B.2422 subd. 3 (a) during the resource acquisition analysis."[64] Subsequently, MP ran these two new Futures, and under these futures, NTEC was selected 100% of the time.

In addition, MP's made the following adjustments to its revised Strategist analysis:

- MP updated its base case load forecast to account for the approximately 20 MW decrease in demand resulting from the closure of Blandin paper machine 5;

- The ten Futures in the revised analysis were run with incremental efficiency values of both 11 GWh *and* 30 GWh (per the Commission's July 2016 IRP Order), which resulted in a total of 20 unique futures; and

- MP removed 150 MW of industrial demand response from the base case and ran the 20 revised Futures with two 150 MW blocks of demand response with 400

[63] Ex. CEO-3, at 17-18 (Sommer Direct).

[64] Ex. DER-8, at 18 (Rakow Direct).

curtailable hours at $9.50/kW-month. Demand response was made available starting in 2025 and throughout the rest of the study period.

According to MP, in terms of the frequency with which NTEC was selected, there was no material change in the Step 1 results with the revised analysis.

b. Swim Lanes

MP also added two new swim lanes at the request of LPI:

Swim Lane 5 included a 100 MW share of a CC resource like NTEC placed in service in 2025; a 50 MW CT installed in 2031; and 300 MW of industrial demand response with limitations and pricing based on LPI's demand response proposal raised in the Company's recent rate case.

Swim Lane 6 reduced the size of the proposed NTEC purchase from 250 MW to 200 MW and increased the size of the CT added in 2031 to 150 MW. Like with adding two additional Futures, MP found no material changes to the results by adding two additional swim lanes.[65]

However, under Swim Lane 6 (reduced size of NTEC), the 200 MW option was selected in 56% of the cases evaluated. This result, according to the ALJ, "[calls] into question whether the 250 MW NTEC purchase is actually the least cost option even with the biases built into the Company's Strategist analysis."[66] MP disputed this notion, stating in Exceptions that, while the results were indeed more mixed in Swim Lane 6, the 200 MW share "represents only a miniscule difference in power supply costs compared to the 250 MW proposal over the study timeframe."[67] Moreover, MP noted "a 200 MW share of NTEC capacity is not available to Minnesota Power under the RFP and contracting process and thus cannot be considered a viable alternative."[68]

According to CEO witness Ms. Sommer, the swim lanes are not important anyway because they do not represent optimized plans. As Ms. Sommer stated, Step 2 "adds no value to the analysis. When it can choose among alternatives, as opposed to a specific set of resources being forced in, Strategist creates what are called 'suboptimal plans.' Those plans meet the same constraints as the optimal plan, including reserve margin and energy requirements constraints, but have a higher cost, thus the term 'suboptimal.'"[69]

iii. Additional Discussion of Strategist Inputs

a. MP's Winter Peak

[65] Ex. MP-18, at 92 (Palmer Rebuttal).

[66] ALJ Report, Finding of Fact 238, at 52.

[67] MP Exceptions at 33.

[68] MP Exceptions, at 33.

[69] Ex. CEO-3, at 29 (Sommer Direct).

MP's system typically peaks in the evening hours during the coldest days of the year. However, in terms of peak demand, the difference between the two seasonal peaks is minimal; MP's winter peak is typically only between 15 and 20 MW higher than its summer season peak.[70] Nevertheless, according to the Company, "this unique characteristic limits the capacity resources available to meet that demand. In contrast to a summer peaking system, there is no solar capacity available during winter-season evening-hour system peaks, yet natural gas fired generation is available during these time periods on a consistent basis."[71]

That MP assumed a winter season construct is a disputed issue in this proceeding, for several reasons that will be explained in more detail in later sections. In short, the fact that MISO does not have a winter season resource adequacy construct at present questions the reasonableness for relying on this assumption. Furthermore, what MP assumes about that seasonal construct is disputed, for example, the solar capacity credit and the market price for capacity.

The Company's primary rationale for performing the modeling analysis by season was largely due to increasing penetration of renewable energy into the MISO region:

> It is critical for Minnesota Power to study its capacity need under a winter resource adequacy requirement along with the traditional summer resource adequacy requirement. Minnesota Power has a slightly winter peaking system located within the greater MISO system that is summer peaking. As the regional power supply shifts away from traditional baseload and dispatchable resources, including Minnesota Power's own power supply, it is important to understand how newer technologies perform throughout the seasons. There are technologies, such as solar, that can meet peaking needs only during summer months. When replacing traditional dispatchable resources available all year with solar, the new technologies' seasonal availability needs to be taken into consideration.[72]

MP also refers to ongoing discussions between MISO and stakeholder regarding ways to address the evolving energy landscape, and in these discussions, MISO has raised the issue of winter season resource adequacy:

> MISO has formally commenced a process with stakeholders to identify and find solutions to the issues posed by the changing energy landscape. With resource decisions and resource planning in general being a forward-looking analysis, trying to anticipate change is part of the due diligence required to plan an efficient and robust power supply for customers. It would be careless of Minnesota Power to not take into consideration its winter resource adequacy requirements in a long-term resource decision process such as this.[73]

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[70] Petition, Page 2-12.

[71] Petition, Page 1-9.

[72] Ex. MP-18, at 41 (Palmer Rebuttal).

[73] Ex. MP-18, at 41 (Palmer Rebuttal).

Overall, MP concluded "[t]he difference in results was immaterial in regards to how often the 250 MW NTEC purchase was selected between the summer and winter resource adequacy seasons."[74] However, under some conditions—the low load sensitivity, for instance—NTEC is selected less in the summer than in the winter.[75]

b. Renewable Energy Capacity Credits

Another disputed issue in this proceeding is the capacity credit MP assumed for wind and solar resources. For example, MP assumed zero capacity credit for new wind, which MP explained was a reasonable assumption due to the potential transmission constraints in wind-rich areas.[76] MP noted that high wind regions with high capacity factor wind farms "lack transmission capacity to move the energy out of these remote areas," and "[a]dditional transmission lines would need to be built to avoid curtailment."[77] Broadly speaking, MP believes "[t]he capacity credit for wind should not be based on today's system, but rather should be forward-looking, especially given the expected build out of wind in MISO."[78]

Also, MP assumed that new solar resources would have a capacity credit of approximately 27%.[79] While MP acknowledged the fact that MISO assigns solar a 50% of nameplate capacity credit, MP argued that solar capacity values will vary in a multi-season resource adequacy construct.[80] In the CEOs' alternative modeling, Ms. Sommer assigned new solar resources a 50% capacity credit; in response, MP claimed this value was "a high capacity credit for new solar" which did not take into consideration "how the solar capacity value will vary in a multi-season resource adequacy construct."[81]

H. Risk Assessment and Renewable Integration

MP witness Mr. Brick created a diagnostic model to study the point at which a renewable energy portfolio requires a dispatchable natural gas resource to smooth out the peaks and valleys associated with wind and solar intermittency. Mr. Brick explained why "a rapid-response resource, such as NGCC,"[82] is needed to balance MP's current renewable portfolio and why the NTEC 250 MW purchase cannot be replaced by variable, non-dispatchable resources.

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[74] Ex. MP-18, Schedule 13 of Palmer Rebuttal, Page 15 of 50.

[75] Petition, Page 3-40.

[76] MP Initial Brief, at 53.

[77] Ex. MP-18, at 55 (Palmer Rebuttal).

[78] Ex. MP-18, at 54 (Palmer Rebuttal).

[79] MP Initial Brief, at 52.

[80] MP Initial Brief, at 56.

[81] Ex. MP-18, at 66 (Palmer Rebuttal).

[82] Ex. MP-19, at 9 (Brick Direct).

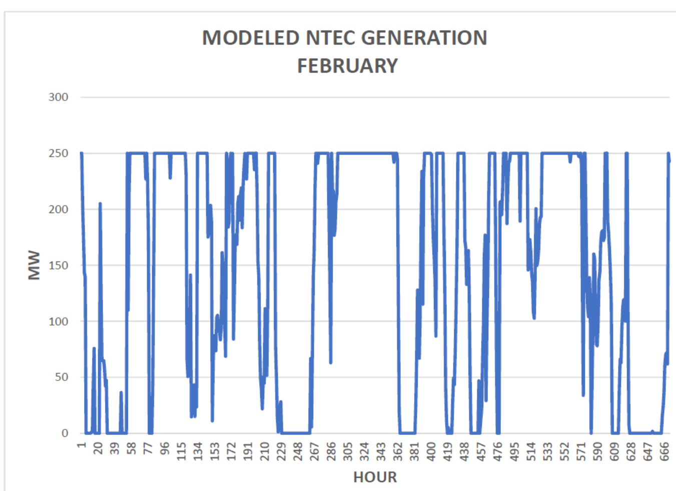
In short, Mr. Brick noted two significant conclusions from his analysis: (1) as wind penetration increases, it creates significant surplus wind generation that cannot be used efficiently[83] and (2) without NTEC, MP will have excessive market exposure that will only worsen as the amount of surplus generation increases:

> It is worth noting that if wind penetration continues to increase in the region, the likelihood diminishes that there will be customers for surplus wind, leading to wasted power. To the extent that this occurs, the underlying economics of the wind are eroded, as fixed costs are spread over fewer kWh. … [C]reating persistent and regularly occurring surplus is in nobody's best interest. As was pointed out above, this is already occurring in California, Texas and Germany, and in none of these places is it regarded as a good thing.[84]

Mr. Brick further concluded from his modeling that natural gas generation balances its renewable energy portfolio and actually enhances deliverability of carbon-free resources:

> Given the current make-up of the Minnesota Power system, adding more wind is not a reasonable replacement for the 250 MW NTEC purchase. As more wind is brought on line, surplus production grows much faster than incremental wind meeting Minnesota Power's real-time need. Such a strategy would expose Minnesota Power's ratepayers to additional market risk: the sales risk of marketing the surplus electricity and the purchase risk of filling a larger open position from the wholesale market.[85]

Mr. Brick produced the following figure to illustrate generation from NTEC in the month of February. As the figure shows, there are extended periods during this month when the NTEC is heavily utilized, which is a pattern that repeats itself throughout the year.[86]



[83] Ex. MP-19, at 14 (Brick Direct).

[84] Ex. MP-19, at 15 (Brick Direct).

[85] Ex. MP-19, at 21 (Brick Direct).

[86] Ex. MP-21, at 2 (Brick Surrebuttal).

On average, according to MP, NTEC is projected to operate at about a 40% annual capacity factor.[87] As Mr. Brick goes on to argue, "[t]here are extended periods of time when NTEC is fully dispatched to meet Minnesota Power's load,"[88] and NTEC will be able to provide MP capacity, energy, ancillary services, overall emissions improvement, and flexibility.

I. Pace Global 2017 Independent Resource Analysis

MP engaged Pace Global as a third-party evaluator to conduct an independent risk-based resource analysis of the Energy*Forward* Resource Package as a whole relative to other resource alternatives. Based on 200 simulations, on average, Pace Global concluded that the EFRP is the preferred resource portfolio for MP.[89]

Pace Global considered four alternatives to the Energy*Forward* resource package: Portfolio 1 included 75% wind; Portfolio 2 included 50% wind; Portfolio 3 included new wind as well as 210 MW of new battery resources; and Portfolio 4 included 440 MW of new natural gas peaking capacity.

As noted in the ALJ Report, the Pace Global analysis assumed MP will add a total of 22 MW of solar by 2034 to comply with the Minnesota SES, but no additional levels of solar or alternatives with large amounts of solar.[90] The Pace Global analysis also did not include demand response or additional energy efficiency as alternatives.[91] Additionally, the Pace Global analysis was completed on July 25, 2017, which means it was included with the initial Energy*Forward* resource package petition filed by MP on July 28, 2018; MP did not submit an updated version of the Pace Global analysis with its updated Petition filed on October 24, 2017.[92] Furthermore, the Pace Global analysis did not include the updated environmental externality values established by the Commission in Docket 14-643.[93] For these and other reasons, the ALJ concluded that the Pace Global analysis failed to demonstrate the NTEC purchase is the best resource option for MP.

IV. Parties' Comments

A. Clean Energy Organizations

The CEOs referenced several statutes that the Commission must consider when making its public interest determination on the 250 MW NTEC purchase:

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[87] Ex. MP-21, at 2 (Brick Surrebuttal).

[88] Ex. MP-21, at 2 (Brick Surrebuttal).

[89] Petition, Appendix N, Page N-1.

[90] ALJ Report, Finding of Fact 348, at 71-72.

[91] ALJ Report, Finding of Fact 349, at 72.

[92] ALJ Report, Findings of Fact 351 and 355, at 72.

[93] ALJ Report, Finding of Fact 358, at 73.

- According to Minn. Stat. § 216B.2401 (Energy Savings Policy Goal), "[t]he legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources."

- According to Minn. Stat. § 216B.2422, subd. 4 (Resource Planning), "[t]he commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need … unless the utility has demonstrated that a renewable energy facility is not in the public interest."

- According to Minn. Stat. § 216B.243, subd. 3 (the Certification of Need (CN) statute), "[n]o proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need."

- Also according to the CN statute, the Commission's decision must include analysis of "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation" and "any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically."

- Furthermore, the CN statute states, ""The commission may not issue a certificate of need … for a large energy facility that generates electric power by means of a nonrenewable energy source … unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source."

- According to Minn. Stat. § 216H.02, subd. 1, "[i]t is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050."

In short, the CEOs argued that:

- NTEC is not needed or reasonable to fill a capacity deficit, as there is likely no significant capacity deficit to fill because the load forecast is overstated.

- MP has not met its burden of proof that NTEC is a reasonable, least-cost option for meeting its energy needs.

- MP did not meet its burden of proof to show that alternatives such as additional renewable energy and energy efficiency are not in the public interest.

- MP has not done the analysis to show that NTEC is needed for flexibility or balancing existing or additional renewable energy on its system.

- Approval of NTEC would be inconsistent with Minnesota's statutory greenhouse gas goals.

For these reasons, CEOs recommend the Commission deny MP's Petition.

i. Load Forecast and Need Assessment

According to the CEOs, MP's load forecast overstates its needs, and it is flawed in part because it did not consider several important aspects of need. For example, MP's load forecast did not include a variation in residential and commercial usage. In particular, MP forecasts unimpeded customer energy usage, which is inconsistent with recent trends. In addition, the forecast neglects any possible economic downturns within the planning period. Moreover, it contains unrealistic assumptions surrounding the timing of the PolyMet mine (namely, that it will be running at full capacity by 2020).[94] Finally, MP underestimated energy efficiency and did not assess its potential, instead assuming the Commission-required level is the maximum possible achievement.

CEO witness Dr. Stanton observed that MP "only modeled one forecast of load and energy requirements for the residential and commercial sectors," which she argues is unreasonable because "residential and commercial load has fluctuated substantially in the past."[95] In fact, MP's low load sensitivity is exactly the same as the base case scenario, except for the exclusion of the PolyMet mine in the low case.[96] Thus, MP failed to properly acknowledge the uncertainty in future load growth by evaluation a range of outcomes.

Thus, Dr. Stanton recommended an alternative forecast, with the following adjustments:

- Removing the 250 MW NTEC purchase;

- Removing Blandin paper mill 5;

- Including the high energy efficiency sensitivity ("Embedded EE + 30 GWh"); and

- Using a 10-year historical trend in the econometric model.

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[94] ALJ Findings of Fact Nos. 115-121; Tr. at 64-65; CEOs Initial Brief at 7-10; Tr. at 32-34; see *generally* Ex. CEO-4 (Stanton Direct).

[95] Ex. CEO-4, at 19 (Stanton Direct).

[96] Ex. CEO-4, at 19 (Stanton Direct).

According to Dr. Stanton, under these assumptions, the Company would have a deficit of 23 MW in 2025—increasing to 103 MW by 2030—without the NTEC purchase.[97] Although, she explained, if (1) load grows at a slower rate than assumed; (2) the Company fulfills small capacity deficits with capacity market purchases; or (3) the Company pursues more demand response, the Company would have a capacity surplus in 2025 without the NTEC purchase.[98]

Later sections will discuss Dr. Stanton's 10-year dataset and MP's response. However, it is important to recognize Dr. Stanton's purpose for using a 10-year trend was "less to advocate for a specific methodology as a best practice and more to shed light on the weakness of the methodology itself."[99] In other words, Dr. Stanton intended to show that a longer historical dataset—MP's forecast includes data since 1990—does not necessarily provide greater statistical certainty in a regression model, especially when such data produces skewed results in favor of growth.

MP used a 26-year historical trend, which showed strong *positive* projection of growth in per customer use. A 10-year trend, however, showed a strong *negative* projection of growth in the same variable. Therefore, Dr. Stanton's point was to show that the "sensitivity to a change in the years examined suggests that this regression analysis is not robust and that caution should be used when applying it to decisions involving the public welfare."[100]

The CEOs believe the change from the 2015 IRP to the 2017 AFR reinforces this trend: what is notable about the 2017 AFR is not only that it shows a decreasing need, but MP continually exhibits a trend of overstating its needs. As shown in Figure 1 of the CEOs' Initial Brief, in all but one case, MP's forecast (dark green shade) was higher than the actual energy and demand (light green shade):[101]

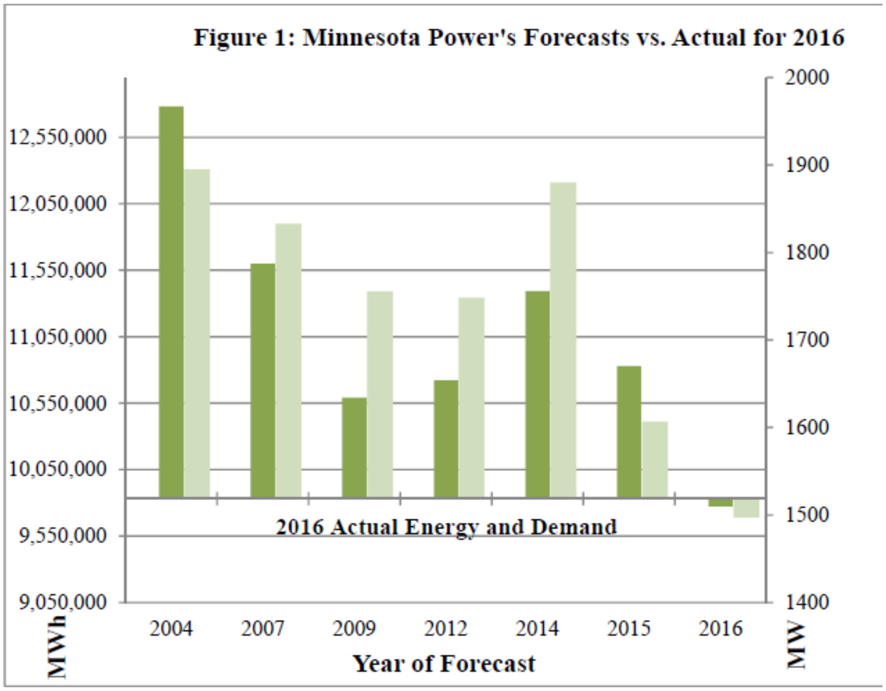
[97] Ex. CEO-4, at 23 (Stanton Direct).

[98] Ex. CEO-4, at 23 (Stanton Direct).

[99] Ex. CEO-11, at 6 (Stanton Surrebuttal).

[100] Ex. CEO-11, at 6 (Stanton Surrebuttal).

[101] CEO Initial Brief, at 13.



The CEOs emphasized that "the burden is not on the CEOs to prove that the forecast submitted is superior to the forecast submitted by Minnesota Power."[102] Nevertheless, the record demonstrates that, by including more realistic growth patterns over a more historically accurate timeframe, MP does not have a meaningful capacity need until approximately 2030.[103]

ii. Resource Planning Analysis

The CEOs argued that MP failed in several regards to perform a reasonable resource planning analysis in this proceeding. First, since the CEOs believe MP overstated its need, and given the absence of a reasonable low forecast sensitivity, MP did not envision reasonable futures.

Furthermore, the CEOs contended that "Minnesota Power only looked at alternatives to NTEC under the assumption that a resource of this exact size, type and timing was needed. Minnesota Power's only consideration of renewable alternatives to NTEC was through its fatally flawed 'swim lane' analysis."[104]

For example, MP claimed in its Initial Brief that "[t]he level of wind generation needed to provide the same amount of reliable capacity as the 250 MW NTEC purchase would be well over 1,000 MW, which is cost-prohibitive and would raise significant reliability concerns."[105] The CEOs did not find MP's conclusion surprising, mostly because MP does not need to add this much wind capacity to begin with. Similarly, with regard to energy storage, MP argued it would

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[102] CEO Exceptions, at 7.

[103] CEO Exceptions, at 7.

[104] CEOs Reply Brief, at 4.

[105] MP Initial Brief, at 60.

need to initiate the world's largest battery project to be comparable to NTEC,[106] but the CEOs responded that MP misses the point completely: a combination of battery storage with other resource alternatives such as energy efficiency could accommodate MP's minimal resource needs in the near-term.[107]

The CEOs developed an alternative resource planning analysis in Strategist. Importantly, the CEOs modeling was not intended to substitute for the full analysis to inform a size, type, and timing decision typical in IRP, but rather to "show that a reasonable set of alternatives can provide a very different picture than that painted by the Company."[108]

In the CEOs' resource planning analysis, CEO witness Ms. Sommer made the following adjustments in her Strategist analysis:[109]

- Assumed Minnesota Power could secure 194 MW of accredited demand response throughout the planning period, similar to recent average levels of MP's accredited demand response;

- Assumed Minnesota Power could achieve 30 GWh in incremental energy efficiency savings, which was the goal set by the Commission in the Company's 2015 IRP;

- Assigned a 50% capacity credit to new solar projects, which is in line with MISO guidance for new solar resources;

- Allowed Strategist to add solar in 25 MW blocks rather than 100 MW blocks;

- Assumed that half of a combustion turbine could be selected after 2025;

- Included a wind price without the production tax credit and using the National Renewable Energy Laboratory's Annual Technology Baseline price forecast;

- Assigned 18.3% capacity credit to new wind projects, which is the average wind capacity credit for Zone 1 of MISO;

- Removed UPM Blandin paper mill 5 load from the load forecast, due to its closure;

- Modified the Planning Reserve Margin from 7.8% to 8.4%, per MISO's updated Loss of Load Expectation study;

[106] MP Initial Brief, at 61-62.

[107] CEO Reply Brief, at 4.

[108] ALJ Report, Finding of Fact 339, at 70; Ex. CEO-18 at 23 (Sommer Surrebuttal).

[109] CEO Initial Brief, at 23-24.

- Included the mid-point of the Commission's environmental externality values, per the Commission's September 19, 2017 Order; and

- Turned off wholesale market sales but allowed for market purchases.

These changes in the CEOs' Strategist modeling revealed that NTEC is not the most economic choice to meet MP's potential need for capacity. Rather, in CEOs' analysis, "an expansion plan that added wind and solar to Minnesota Power's system … was lower cost."[110]

As shown in Table 1 of Ms. Sommer's Direct Testimony—this is the Corrected version filed on March 23, 2018— the "optimized result" (meaning the result "chosen" by Strategist to be least-cost) did not include NTEC, but instead added 300 MW of wind and 100 MW of solar between 2025 and 2030.[111] The differentials between the "Optimized Result" and "NTEC Forced" show that forcing NTEC into the model increases the Present Value of Societal Costs (PVSC) under all of the CEOs' Futures.

Table 3. Results of CEO Strategist Modeling

		PVSC	Resources Added 2025-2030
CEO Future - Base	Optimized Result	$10.26 billion	300 MW of wind, 100 MW of solar
	NTEC Forced	$10.41 billion	250 MW NTEC, 300 MW of wind, 25 MW of solar
CEO Future - EFG EE Savings	Optimized Result	$10.11 billion	300 MW of wind
	NTEC Forced	$10.32 billion	250 MW NTEC, 300 MW of wind
CEO Future - No Market Tiers	Optimized Result	$10.22 billion	300 MW of wind, 100 MW of solar
	NTEC Forced	$10.40 billion	300 MW of wind, 250 MW of NTEC
CEO Future - New Market Capacity Prices	Optimized Result	$10.24 billion	300 MW of wind, 100 MW of solar
	NTEC Forced	$10.41 billion	300 MW of wind, 25 MW of solar, 250 MW of NTEC

Ms. Sommer further noted that, since there were other inputs MP used that she would like to have changed but could not due to time constraints, the CEOs' Futures shown above are not necessarily ideally optimized. To address these flaws qualitatively, however, Ms. Sommer identified three main ways in which the model was unreasonably constrained: first, it was constrained in the amount of wind units it could take; second, Strategist was not allowed to optimize resource choices prior to 2025; and third, the model did not consider potential unit retirements.[112]

[110] CEO Initial Brief, at 8.

[111] Ex. CEO-3 at 28 (Sommer Direct—Corrected Version filed on March 23, 2018).

[112] Ex. CEO-3, at 28 (Sommer Direct).

Furthermore, Ms. Sommer did not make adjustments to MP's assumptions for the MISO winter season resource adequacy construct, although she did note that MP's seasonal analysis was flawed as well. In addition to the fact that there is no MISO winter resource adequacy construct at the moment, Ms. Sommer argued that MP oversimplified the seasonal architecture of such a construct. For example, in its design, MP merely changed the month in which the reserve margin applies, from July to January. This is important, in Ms. Sommer's view, because "it is entirely possible that Minnesota Power would not have to self-supply any incremental capacity it might need to meet the winter requirement because the MISO system as a whole would have an excess of capacity during that period."[113]

Also, MP did not adjust its market capacity prices downward in order to account for the likely surplus of capacity within MISO during the winter. It could also be the case that MP's resources themselves would likely have different accredited capacities in the winter versus the summer, and specifically its wind resources could have higher accredited capacities.

Overall, Ms. Sommer's Strategist analysis showed that "the addition of NTEC leads to a significant oversupply of capacity, on the order of more than twice what is needed, even when considering the higher planning reserve margin ("PRM") that currently applies."[114] By making certain adjustments to MP's base case, "the PVSC of an expansion plan including NTEC was $10.41 billion, while the PVSC of an expansion plan that did not include NTEC and instead included 300 MW of wind and 100 MW of solar was $10.26 billion."[115]

iii. MP's Sensitivity Analysis

The CEOs emphasized the importance of modeling "reasonable combinations of alternatives,"[116] rather than running the model by changing just one variable at time. According to CEO, "it is crucial to consider reasonable combinations of resources. Minnesota Power did not do this and instead compared NTEC to one type of alternative resource at a time, rather than any reasonable combinations."[117] The CEOs applied the same reasoning to the Department's analysis as well: Ms. Sommer noted, for instance, "the combination of lower load and lower wind prices could have a meaningful impact on the modeling result, even if either change individually would not affect the modeling result."[118]

While MP repeatedly pointed to the frequency with which NTEC was selected in its Strategist analysis as justification that it is needed and reasonable, the CEOs believe this is a misleading argument due to the biases built into the model. The CEOs argued:

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[113] Ex. CEO-3, at 9 (Sommer Direct).

[114] Ex. CEO-7, at 8 (Sommer Rebuttal).

[115] CEO Reply Brief, at 27.

[116] CEO Reply Brief, at 15.

[117] CEO Reply Brief, at 2-3.

[118] Ex. CEO-4, at 8 (Sommer Rebuttal).

> [It] is not unusual for a utility to justify its preferred resource/plan on the basis of the number of runs in which that resource/plan was chosen and/or its cost in comparison to other portfolios of resources. However, it matters a great deal under which assumptions those runs were conducted; even with hundreds of runs, the same resource can be chosen again and again as the result of a few flawed assumptions.[119]

In addition to an upwardly biased load forecast and generally unreasonable assumptions, the CEOs argued the model was constructed in a way to specifically select NTEC. For example, (1) NTEC was only available for selection by the model in the year 2025; (2) renewable resources were only available for selection after 2025; (3) new wind and solar resources were assigned unreasonably low capacity credits; (4) new wind resources were assigned unreasonably high prices; and (5) alternatives such as a smaller portion of NTEC, capacity purchases, or market reliance were not available or unreasonably limited.[120] Therefore, it was not surprising that NTEC fared well in most sensitivity runs.

B. Department of Commerce – Division of Energy Resources

The Department's analysis of the AI agreements took place in four steps:[121]

The first step was a review of the analysis and outcome in MP's 2015 IRP. In doing so, the Department examined the modeling inputs the Company used and whether these fell outside the bounds studied in the 2015 IRP. The Department then determined if the IRP outputs support the acquisition of a resource of the general size, type, and timing proposed by MP. In this case, the 250 MW NTEC was consistently selected as part of the least-cost expansion plan, even using the most recently approved levels of externality values.

The second step was a review of MP's exposure to spot market energy prices. In part, this is because one of MP's chief justifications for the NTEC acquisition is a need for dispatchable capacity to mitigate potential exposure to spot market price spikes. The Department concluded that NTEC would have some value in mitigating exposure to price spikes. However, until (1) volatility in spot market prices increases, (2) further dispatchable capacity is removed from MP's system, or (3) load increases significantly, the level of risk appears to be manageable with the current resource mix.[122]

The third step was a review of MP's analysis of the bidding process to ensure that the resource alternatives to NTEC were analyzed in a reasonable manner. The Department recommended that MP improve its bidding process and, upon reviewing MP's proposed reforms, agreed the Company presented a reasonable outline.[123] Therefore, Department recommended that the

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[119] Ex. CEO-3, at 5-6 (Sommer Direct).

[120] CEO Initial Brief, at 19-20.

[121] *See* Department Initial Brief, at 12-15.

[122] Ex. DER-8, SRR-4, at 20 (Rakow Direct).

[123] Ex. DER-11, at 16 (Rakow Surrebuttal).

Commission require MP to include, in its next IRP, a proposed bidding process for the Commission's consideration and potential approval under Minn. Stat. § 216B.2422, subd. 5.

Finally, the fourth step was a review of the AI agreements under the affiliated interest statute. The Department ultimately concluded that the AI agreements under the CDA, Assignment of Rights: Construction Agent, and Assignment of Rights: Operating Agent are reasonable and in the public interest under Minn. Stat. § 216B.48, subd. 3.

i. Resource Planning Analysis

According to the Department, "the three key issues to focus on in the IRP topic are NTEC's variable costs relative to MP's other resources (which is reflected in its position in the dispatch order), NTEC's fixed costs, and MP's forecasted energy requirements."[124]

Also, the Department noted, the goal in IRP is to identify a preferred plan that is stable across a range of potential inputs for key variables, including the price of wind resources, solar resources, natural gas, energy forecast, demand forecast, and so forth. Therefore, the range of the inputs is what is important, and only so much attention should be given to the base case.

The Department's modeling results were clear for the intermediate, peaking, and wind units: One or two intermediate units were selected by 2025 in every single model run.[125] Also, 300 or 400 MW of wind (three or four units) was selected by 2020 in all but three of the model runs. A peaking unit (about 200 MW accredited capacity) was selected by 2025 in only 11 of out 300 model runs, and each time a peaking unit was selected, one intermediate unit and 400 MW of wind were still selected, but solar was not.[126]

Notably, wind pricing is not critical in this case. For instance, in the low wind prices contingency (base cost minus $20 per MWh), 600 MW of new wind resources was added to MP's system by 2024, but nonetheless, NTEC was still selected as part of the least-cost expansion plan.[127]

Overall, the modeling results for solar were mixed and depended to some extent on which forecast was being used.[128] (The Department's base case used the forecast from the 2015 IRP since the 2017 AFR was within the contingency range for the IRP dataset.) Using the 2015 IRP forecast, 100 MW of solar was selected by 2020 in 60% of the model runs, and no solar capacity was selected in 40% of the model runs. When the 2017 AFR was used, 100 MW of solar was selected by 2020 in 49% of the model runs and no solar capacity was selected in 51% of the model runs.

[124] Ex. DER-12, at 43 (Rakow Surrebuttal).

[125] Ex. DER-9, SRR-3, at 15 (Rakow Direct).

[126] Ex. DER-9, SRR-3, at 15-16 (Rakow Direct).

[127] Ex. DER-12, at 45 (Rakow Surrebuttal).

[128] Ex. DER-9, SRR-3, at 16 (Rakow Direct).

ii. MP's Energy Needs / Societal Costs

The Department frequently pointed out that NTEC was selected because its energy output reduces overall societal costs, not because NTEC is necessarily filling a capacity need.[129] For instance, Dr. Rakow explained:

> MP's energy needs are the driving factor in the addition of an intermediate resource in the modeling. If capacity were the main factor then Strategist would have selected a peaking unit instead. Further, the Strategist modeling considers both energy and capacity requirements.[130]

To explain using Strategist-specific terms, the Department tested NTEC as both a "superfluous" unit and a "not superfluous" unit. In Strategist, a unit that is "superfluous" can be added regardless of a capacity surplus or deficit if the unit reduces system costs. If a unit is designated as "not superfluous," it can only be added to the resource portfolio in a year in which there is a capacity deficit.

As Dr. Rakow explained, the use of the superfluous designation is an important consideration for any energy-intensive resource. The fact that NTEC was selected when designated as a superfluous unit means the unit decreases societal costs and is therefore a reasonable resource for MP's system:

> Societal costs go down because the incremental impact of the addition of NTEC is to decrease variable costs more than the fixed costs of this resource increase overall societal costs. The contingency analysis demonstrates that this result occurs virtually irrespective of the levels of forecasted demand, energy storage, demand response, and so forth. In other words, this modeling indicates that NTEC is a reasonable resource for MP's system.[131]

Thus, the Department's analysis found that NTEC is needed and reasonable for meeting MP's customers' energy needs under a range of potential futures when considering numerous potential alternatives.

iii. Risk Analysis / Dispatchability Needs

The Department's risk analysis sought to compare the costs MP might incur due to market exposure during price spikes to the cost of the proposed NTEC facility, based upon MP's current system. The Department's analysis showed that the Company's market risk in 2025 appears to be manageable with its existing resource mix. The Department reached this conclusion even with conservative assumptions that considered a number of resources qualitatively rather than

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[129] Ex. DER-12, at 42 (Rakow Surrebuttal).

[130] Ex. DER-12, at 10 (Rakow Surrebuttal).

[131] Ex. DER-12, at 42-43 (Rakow Surrebuttal).

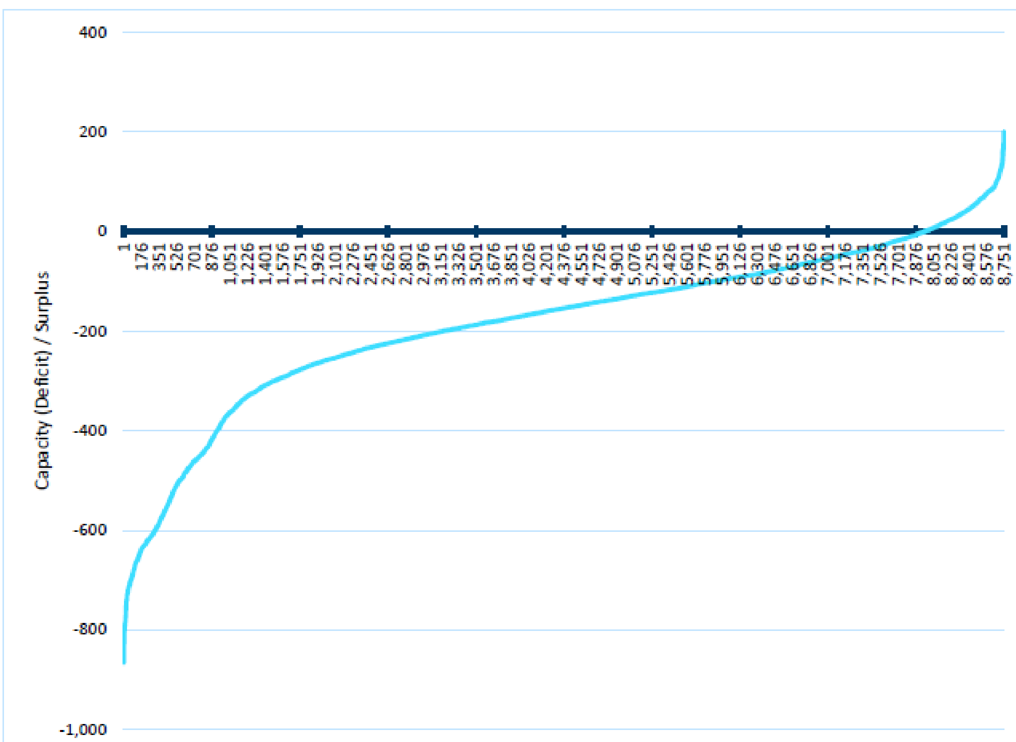
quantitatively. As such, the Department's analysis suggests that the addition of the 250 MW NTEC purchase is not necessary <u>for dispatch purposes</u> in 2025 as claimed by the Company.[132]

a. Measuring Risk: Prior to Mitigation Measures

To determine MP's exposure to spot market prices, the Department (1) determined an hourly load shape for 2025; (2) determined which units could be firm resources available to meet demand on an hourly basis; and (3) estimated the size (in MW) and timing (hour of the year) of MP's exposure to spot market prices, prior to any potential mitigation measures.[133]

The result is shown in the table below. According to the Department's analysis, prior to mitigation, MP has a capacity surplus for about 10% of the hours of the year and a deficit of more than 200 MW in about 35% of the hours during the year. The maximum deficit in one hour exceeds 850 MW:

Table 2: Estimated Capacity Surplus / (Deficit)



The Department concluded, "[s]ince the maximum potential deficit, based on a 50/50 forecast, was over 800 MW and the deficit exceeded 200 MW over one-third of the hours, the Department concluded that there is the potential for MP's customers to have significant exposure to spot market price spikes."[134]

[132] Department Exceptions, at 16.

[133] Ex. DER-8, SRR-4 at 5-7 (Rakow Direct).

[134] Ex. DER-8, SRR-4 at 8 (Rakow Direct).

b. Measuring Risk: Available Mitigation Measures

The Department's calculations estimate that, during 400 on-peak hours, MP has a capacity deficit of at least 401 MW. The Department assessed available mitigation measures which could reduce the number of hours with capacity deficits of 401 MW or more in order to determine if MP's current system is excessively vulnerable to market price spikes.

The Department identified as potential risk mitigation measures: intermittent generation facilities (solar and wind); non-dispatchable hydro generation facilities; load management resources; and Energy Exchange Agreements (EEA) with Manitoba Hydro.[135]

However, using MP's production pattern for solar from the Strategist model, solar generation is greater than 20% of installed capacity in only 178 of the 400 hours. Furthermore, with MP's plans to add only about 33 MW of solar by 2025, solar does not appear to be a significant mitigation measure for spot market price spikes. Besides, solar output is poorly correlated with MP's larger capacity deficits even during on-peak hours.

With regard to other mitigation measures, wind production can vary in an unpredictable manner, so the Department did not compare wind production patterns to MP's capacity deficits. Similarly, given the small amount of non-dispatchable hydro on MP's system, the Department did not investigate non-dispatchable hydro as a mitigation measure. And the EEAs with Manitoba Hydro may not always be available when needed, so these were not considered to be significant mitigation measures, either.

This leaves demand response as the only available mitigation measure for price spikes, specifically MP's Rider for Large Power Incremental Production Service (10 to 15 MW) and Replacement Interruptible Service (100 MW to 260 MW).

After all available mitigation measures were considered, the Department concluded, "assuming wind is not available, the available mitigation measures reduce the number of hours with capacity deficits of 401 MW or more **from 400 hours to 59 hours**"[136,137] (emphasis added by staff). From this, the Department concluded this level of risk appears to be manageable with the current resource mix.

iv. RFP Process

The Department observed there was significant overlap between MP's resource planning and resource acquisition processes. The 2015 IRP's long-term action plan included a plan to "[s]ecure and implement 200 to 300 MW of efficient natural gas CC generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs by 2024."[138]

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[135] Ex. DER-8, SRR-4 at 18 (Rakow Direct).

[136] The 59 hours include: 10 hours in spring and 48 hours in fall with capacity deficits of 401-600 MW, and 1 hour in the fall with capacity deficits of 601-800 MW.

[137] Ex. DER-8, SRR-4 at 20 (Rakow Direct).

[138] *In re Minn. Power's 2016–2030 Integrated Res. Plan*, Docket No. E-015/RP-15-690, 2015 Integrated Resource

MP issued an RFP for up to 400 MW of Capacity and Energy on October 15, 2015. But by the time the Commission had issued its 2015 IRP Order, in July 2016, the Commission determined that the 2015 IRP may overstate the size or timing of future needs.

The Department is concerned that the duration required by MP to complete negotiations for NTEC with South Shore was too long, and MP's inability to complete negotiations in a timely manner twice caused it to revise its estimated need for a new resource. MP reacted to the determination of revised needs by pursuing discussions only with a single source rather than issuing a new RFP, consistent with the revised needs, or allowing all bidders the opportunity to address the new need.

In the Department's view, RFPs should be released as soon as possible after the Commission's IRP Order is issued. The delay in releasing the RFP caused MP's resource acquisition to diverge from its approved IRP. Further, the extensive delay caused MP to attempt to simultaneously perform resource planning (determining what is needed) and resource acquisition (selecting from proposals to meet the specified need) resulting in a moving target for the resource acquisition process.

In the Department's Direct Testimony, Dr. Rakow requested that MP explain the steps it will take to improve its RFP process in Rebuttal Testimony. In Rebuttal Testimony, MP witness Mr. Frederickson provided six steps MP would commit to take for supply-side purchases of 200 MW or more lasting longer than five years.[139] The six steps are:

- Ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing;
- Provide the Department and other stakeholders with notice of RFP issuances;
- Notify the Department and other stakeholders of material deviations from those timelines;
- Update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
- Where Minnesota Power or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and
- Request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.

Plan, Petition for Approval, at 89 (Sept. 1, 2015).

[139] Ex. MP-24 at 14-16 (Frederickson Rebuttal).

The Department agreed that MP's proposed steps to improve its bidding process is a reasonable outline, although the threshold for applicability should be reduced to 100 MW.[140] The Department recommended the Commission require MP to include, in the Company's next IRP, a proposed bidding process for the Commission's consideration and potential approval under Minn. Stat. § 216B.2422, subd. 5.

v. Ownership Share

MP and the Department agreed upon (but do not have a strong opinion about) MP's 50% ownership share instead of 48%. The advantages of a 50% share of NTEC are that, technically, this amount may be consistent with MP's approved IRP, and it may provide for less complex accounting and reporting. The Department leaves it to the Commission regarding whether the share should be 48% or 50%.

vi. Financial Issues

Over the course of the proceeding, the Company and the Department resolved all disputed issues, including financial issues pertaining to amendments to the D&C and O&O agreements and compliance filings on the CDA. MP agreed to several conditions and commitments as proposed by the Department, listed at the end of the Department's Initial Brief.

In various filings, MP provided very useful tables which presented and summarized financial issues and conditions and compliance requirements raised by the Department. Since these summaries are several pages long, instead of showing them in this section, staff refers the Commission to (1) Exhibit A of MP's Proposed Findings of Fact, Conclusions of Law, and Recommendation and (2) Attachment A of MP's Exceptions. Attachment A of MP's Exceptions is included as Attachment C of these briefing papers.

C. Large Power Intervenors

LPI requests that the Commission accept the findings of fact, conclusions of law, and recommendation of the ALJ Report. LPI argued that MP has not met its burden to show that its proposal is reasonable and in the public interest for the following reasons:

- MP has not demonstrated that the 250 MW NTEC purchase is the best and lowest cost option to meet its projected energy and capacity needs due to deficiencies in its modeling and procurement process;
- MP's analysis does not support the size or timing of the 250 MW NTEC purchase;
- More robust analysis and further investigation of alternatives are necessary to ensure that the Company has identified the best and lowest cost resource options;

[140] Ex. DER-11 at 37 (Rakow Surrebuttal).

- MP should be directed to implement an industrial demand response product similar to LPI's proposal and consider the effect of implementation of that product on its generation capacity needs; and

- MP should provide further analysis to support its pricing structure—particularly levelized pricing similar to a traditional power purchase agreement structure.

i. Resource Planning Analysis

LPI had several concerns with the NTEC purchase, but two of LPI's primary criticisms were that (1) MP has not demonstrated that it has a 250 MW capacity need in 2025,[141] and (2) MP "skewed the entire analysis in favor of selecting NTEC."[142] As a result, LPI believes MP should further develop and analyze potential demand-side resources before any final decisions are made about capacity additions in this proceeding.[143]

According to LPI, "for the first five or six years it will primarily be an energy resource and that, as a primary energy resource for that period, it may not be an economical option for customers."[144] In addition, LPI noted the "significant change in the Company's energy and capacity forecast between the 2015 IRP and the 2017 Annual Forecast Report"[145] warrants further examination of other, perhaps smaller-sized, resource alternatives.

As discussed previously, during the proceeding MP revised its Strategist analysis to assess, among other things, an additional swim lane that evaluated a new, 200 MW NTEC option. LPI requested this new swim lane because South Shore provided the Company with a bid for only 200 MW of NTEC as part of its revised RFP response, but neither MP nor Sedway Consulting owned the decision to select the 250 MW option over the 200 MW.[146] However, according to the Company's own modeling, a portfolio with a 200 MW NTEC purchase was the lowest cost option in the majority of runs.[147]

LPI acknowledged that the 200 MW option is no longer available, and that the costs between the two options might be small, but the point is that the Company's proposal is neither needed nor least-cost. As Mr. Gorman stated, "[t]he significance of the reduced cost for a 200 MW facility is important when recognizing MP's resource mix did not need the additional 50 MW of

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141 LPI Initial Brief, at 9.

142 LPI Initial Brief, at 11.

143 LPI Initial Brief, at 23.

144 LPI Reply Brief, at 6.

145 LPI Initial Brief, at 9.

146 Ex. LPI-8, at 11 (Andrews Direct).

147 LPI Initial Brief, at 15.

NTEC capacity."[148] Thus, an additional 50 MW of NTEC would impose excess capacity costs on retail customers.

Like the CEOs, LPI identified several questionable modeling choices by the Company, which indicates—especially when viewed in the aggregate—that the model was constructed specifically to select NTEC. As Mr. Andrews explained in his Direct Testimony, the timing constraints MP imposed on the model were particularly suspicious:

> The 250 MW NTEC purchase was only allowed for selection in 2025. The generic 525 MW NGCC was available beginning in 2026, a year later than NTEC. All other generic generating options were available starting in 2025. The 50 MW bilateral bridge market capacity purchase was only available in 2023 and 2024.
>
> …
>
> MP provided no explanation of justification for these specific in-service dates. There is no reason to limit Strategist to add resources beginning in 2025. If the goal of resource planning is to deliver the least cost portfolio that meets MP's capacity and energy needs, other portfolio options, including the ability to build prior to 2025 need to be considered. Furthermore, the fact that the only other NGCC option, at over twice the capacity of NTEC, is not available until 2026, one year after NTEC is available and two years after the bilateral bridge purchases are no longer available is quite suspect, further leading me to believe the entire analysis is biased in favor of the selection of the 250 MW NTEC.[149]

In addition, not only is a 250 MW purchase excessive even under MP's own forecast,[150] but MP's assumption for demand response is far too low. The net impact results in a greatly inflated projection of need. According to Mr. Andrews:

> As a base case assumption, MP chose to model only 150 MW of industrial demand response. Currently, there is 265 MW of industrial demand response under contract. While MP's load forecast shows moderate growth throughout the study period, the level of interruptible load remains constant and a level far below what is currently available. The increase in load and the decrease level of demand response results in exaggerated need for capacity.[151]

In LPI Information Request No. 19, LPI requested MP to provide the level (in MW) of MISO-accredited demand response, by year, available to MP over the past 15 years. MP's response is shown below:[152]

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[148] Ex. LPI-5, at 19-20 (Gorman Direct).

[149] Ex. LPI-8, at 12 (Andrews Direct).

[150] Ex. LPI-8, at 6 (Andrews Direct).

[151] Ex. LPI-8, at 13 (Andrews Direct).

[152] Ex. LPI-5, Appendix B at 4 (Gorman Direct).

Planning Year	Accredited Demand Response (UCAP-MW)
2017-2018	265.4
2016-2017	208.0
2015-2016	107.6
2014-2015	107.0
2013-2014	105.9
2012-2013	131.8
2011-2012	131.8
2010-2011	161.3
2009-2010	88.6

MP's petition asks to fill an identified need in 2025, seven years from now. LPI believes the claimed need is exaggerated, particularly in light of an unreasonably low assumption for available demand response. LPI believes there is ample time for MP to continue to develop demand-side options instead of purchasing an excessively-sized supply-side resource at this time.

ii. Consideration of Demand-Side Resources

Before any final decisions are made about capacity additions in this proceeding, LPI urges the Commission to require MP to further develop and analyze potential demand-side resources. Specifically, MP should be directed to implement an expanded industrial demand response product.

LPI referred to MP's last rate case as one example why demand response is relevant to the Commission's consideration of NTEC. In the rate case, the Commission agreed with LPI that further discussion of demand response is warranted, with the following guidance given to the Company:

> The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The record to support the submission to the Commission may be developed in either Docket E015/AI-17-568 - OAH Docket 68-2500-34672 or a new miscellaneous docket. In the event the Company, LPI, and other stakeholders elect to proceed with a new miscellaneous docket filing, such filing shall be submitted for Commission approval within six months after the date of the final written order in this proceeding.[153]

LPI also noted that the Commission has previously decided that "the potential for demand response to aid the integration of renewable generation cannot be ignored," and has ordered

[153] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-15/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 115 (Mar. 12, 2018) ("Rate Case Order").

Minnesota's utilities, including MP, to "expand their investments in cost-effective demand response."[154,155]

Expanding interruptible load, for example, is an important component to utility planning because it does not require procuring capacity resources, the result of which is reduced capacity costs to all customers.[156] It can provide a "win-win-win" for the utility through avoiding expensive capital additions, for participating customers by helping them manage their energy costs, and for other customers by helping control the utility's overall capacity costs.

iii. MP's Demand Response RFP

MP's demand response RFP was designed to align with the response period for the wind and solar RFPs. The RFPs were issued around the same time so MP could simultaneously evaluate the top responses from all RFPs to determine the preferred mix of resources to meet customer requirements.

According to MP, it received only one bid to its RFP, for 96 MW of system capacity demand response available for energy curtailment events during MISO system emergencies or MP local system emergencies. MP determined that the price would not be cost-effective for its customers.[157] Mr. Stephens noted that it was not surprising MP did not receive a robust response, as the parameters of the RFP subjected the Large Power class to a significant amount of risk. Other factors might have been the RFP response time, uncertainty in the request, and uncertainty in the ability to interrupt under various parameters.[158]

iv. Tax Cuts and Jobs Act

According to LPI, "MP's resource plans are now obsolete and unreliable as a result of the federal government's passage of the Tax Cuts and Jobs Act of 2017 ("TCJA") in December 2017."[159] The change in the federal corporate tax rates from 35% to 21% will significantly impact the revenue requirement for the fixed capital costs of all generation resources. Importantly, the TCJA will not impact each resource option in the same manner, so it cannot be dismissed as an unnecessary modeling variable.[160] As a result, LPI argued the impact of the TCJA should be fully studied before a significant resource investment is approved.

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[154] Ex. LPI-1, at 5 (Stephens Direct).

[155] *In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly Into the MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A*, Docket No. E-999/CI-09-1449, Order Accepting Filings, Requiring Expanded Cost-Effective Demand Response Investments, and Soliciting Further Comments, at 5 (August 31, 2012).

[156] Ex. LPI-1, at 2 (Stephens Direct).

[157] Petition, Page 3-32.

[158] Ex. LPI-1, at 27-28 (Stephens Direct).

[159] Ex. LPI-5, at 5 (Gorman Direct).

[160] Ex. LPI-6, at 9 (Gorman Surrebuttal).

v. Affiliated Interest Agreements

As Mr. Gorman explained, MP's proposed pricing structure in the CDA will result in higher prices for customers in the early years of NTEC (e.g., the 2025-2030 period) when the Company has the least demonstrated need for NTEC capacity.[161] The declining balance methodology proposed by the Company will result in higher capacity costs for the NTEC facility from its initial in-service date of 2025 through approximately 2035.

In LPI's view, the CDA could be structured more like a PPA and provide for levelized fixed cost payment for capital investment costs and fixed O&M costs with a variable pricing component for fuel and variable O&M costs. Yet MP has failed to explain why treating NTEC as a rate base investment is better for customers other than to say that levelized cost treatment would be more expensive. The Company should modify its CDA to provide for levelized cost recovery or, at a minimum, provide a more detailed analysis comparing the pricing alternatives.

vi. Burden of Proof

LPI and the CEOs shared the view that MP wrongly attempted to shift the burden of proof to the intervenors. For instance, LPI argued, "it is not the intervenors' duty to demonstrate whether a project is viable"; "[t]he Company bears the burden of proving NTEC's viability. In this case, the Company has ignored that duty."[162]

D. Honor the Earth Comments

While Honor the Earth (HTE) did not file a Notice of Appearance and is not a party to this proceeding, it filed on a petition on June 29, 2018 for Minnesota Environmental Policy Act (MEPA) review of MP's gas plant proposal, even though the plant is not located in Minnesota. HTE filed its petition pursuant to Minn. R. 4410.1000, supb. 3(A), which provides that a discretionary Environmental Assessment Worksheet (EAW) shall be prepared for a project that is (1) not exempt from such an EAW pursuant to Minn. R. 4410.4600, and (2) has been determined by the governmental unit with approval authority over the project to have potential significant environmental effects because of its nature or location.

However, pursuant to Minn. R. 4410.1100, a discretionary EAW petition must be filed with the EQB, which first determines whether the petition meets the filing requirements of that Rule. If it does, the EQB designates the responsible governmental unit (RGU) that will determine whether the petition should be granted or not, and forwards the petition to the RGU. If the petition does not comply with the requirements of Rule 4410.1100, the EQB will return it to the petitioner with a written explanation of the how it fails to comply. HTE was advised that for these reasons, the Commission would not consider its Petition for MEPA Review of NTEC.

[161] LPI-4, at 22 (Gorman Direct).

[162] LPI Initial Brief, at 17.

V. ALJ Report

In the ALJ's "Summary of Conclusions and Recommendation," the Judge determined:

> Based on the evidence in the hearing record, the Administrative Law Judge concludes Minnesota Power has not met its burden to show that the proposed NTEC 250 MW purchase is needed and reasonable. As a result, the Administrative Law Judge concludes that Minnesota Power has failed to demonstrate that the affiliated interest agreements are consistent with the public interest and recommends that the Commission not approve the agreements.[163]

The ALJ then made two recommendations to the Commission:

- First, the ALJ recommended the Commission deny MP's request for approval of the Assignment of Rights Agreement (Construction Agent), the Assignment of Rights Agreement (Operating Agent), and the CDA because the Company has not demonstrated that these affiliated interest agreements are consistent with the public interest.

- Second, the ALJ recommended that MP, LPI, and other stakeholders continue to work to develop a demand response rider and corresponding methodology for cost recovery for submission to the Commission. The Commission should open a new miscellaneous docket to address the issue.

The ALJ made a number of conclusions on the disputed issues in this case, but perhaps the three main themes of these conclusions involve (1) MP's failure to demonstrate the underlying need, (2) flawed modeling assumptions and model bias, and (3) MP's failure to adequately consider state energy policies and statutory criteria.

i. Underlying Need

While the ALJ concluded that the base case of MP's forecasted energy sales and peak demand is reasonable for use in this proceeding, the ALJ agreed with the CEOs that MP failed to provide a reasoned explanation for not varying the residential and commercial energy use levels in the low and high scenarios. Furthermore, in ALJ Finding 149, the Judge reasoned why MP's low forecast scenario might be an insufficient low bound:

> 149. With regard to the low forecast, the Administrative Law Judge agrees that the Company should have included additional reductions beyond simply assuming that PolyMet will not be built in the forecast period. The recent closure of the Blandin Paper Mill 5 in December 2017 and the fact that permitting of the PolyMet plant is not guaranteed suggest the low forecast should include a reduction beyond simply assuming PolyMet will not be built. Nonetheless, this short-coming

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[163] ALJ Report, at 4.

> affects only the low forecast scenario, not the moderate growth scenario used by the Company in this proceeding.

The net capacity position also must take into account the supply- and demand-side capability of existing and expected resources. The ALJ disagreed with MP's assertion that there is a high degree of risk in assuming that MP's recent achievements in energy efficiency are sustainable. She also concluded that it was not reasonable for the Company to model 76.5 GWh (or +30 GWH incremental savings) as the maximum achievable energy efficiency amount. To be consistent with the Commission's 2016 IRP Order, as well as Minnesota law, the Company should have used 76.5 GWh (or +30 GWh) in its base case or, at a minimum, the mid-level sensitivity, but not the highest amount attainable.

In addition, the ALJ agreed with the CEOs and LPI that the Company's assumed level of 150 MW of industrial demand response is unreasonably low. The most current data shows that the Company has been able to acquire an average of 190 MW per year over the last five years (2014-2018). Also, MP's currently available levels—264 MW in 2018 and 265 MW in 2017—are even higher than the most recent five-year average.

Regarding the Company's ramp needs, the ALJ concluded that MP overstated its ramp need in 2025. As the CEOs noted, MP failed to include two existing dispatchable generation facilities, Laskin Energy Center and Hibbard Renewable Center, in its calculation of its existing ramp capability. Together, these facilities have a total nameplate capacity of at least 157 MW, and these units may be able to meet any remaining ramp needs.

MP claimed it did not include these resources because they are rarely dispatched by MISO,[164] but rare dispatch by MISO only means more cost-effective resources that are being dispatched, not that these dispatchable units are not physically able to provide ramping resources.[165] There was no reasonable basis for excluding these dispatchable resources, particularly if MP is actually analyzing whether its own resources can cover its own ramping needs.

The ALJ also concluded that MP failed to demonstrate that the 250 MW NTEC purchase is needed and reasonable as a dispatchable, flexible resource to balance its system and mitigate exposure to energy markets, for the following reasons:

First, as discussed above, the Judge determined MP overstated its ramp need, and MP failed to demonstrate that NTEC is needed and reasonable for that purpose.

Second, Mr. Brick's analysis failed to provide a meaningful comparison of NTEC to wind and other resources.

Finally, the Department's analysis of market exposure shows that the Company's market risk in 2025 appears to be manageable with its existing resource mix.

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[164] Ex. CEO-9 at 7 (Jacobs Surrebuttal) (quoting from Minnesota Power's Response to CEOs IR No. 118).

[165] Ex. CEO-9 at 8 (Jacobs Surrebuttal) (quoting from Minnesota Power's Response to CEOs IR No. 118).

ii. Strategist Analysis

Paragraphs 340-344 of the ALJ Report list the Judge's conclusions regarding MP's and the Department's Strategist results. In short, the ALJ concluded that MP's and the Department's results are not sufficiently robust or reliable for determining whether the 250 MW NTEC purchase is needed and reasonable because their analyses contained a number of unreasonable assumptions.[166] In particular, the ALJ was unpersuaded by the fact that Strategist chose NTEC as the least-cost resource in the vast majority of runs because she concluded MP's model was "systematically biased in favor of NTEC and away from alternatives."[167]

Because there were so many areas in which the Judge concluded MP's analysis was unreasonable, flawed, or biased, staff will simply list these conclusions below (all are discussed at greater length elsewhere in the briefing papers):

- The Company has not provided a reasonable explanation for constraints it placed on resource selection in the Strategist model.

- The Company's decision to make the NTEC purchase available only in 2025 and to place timing constraints on other resource options is contrary to the analysis required by the Notice and Order for Hearing.

- Because a size, type, and timing decision has not been made with respect to any new gas-fired generation on the Company's system, the alternatives analysis should not be dictated by the Company's NTEC contract.

- Because the Company placed unreasonable limitations on the in-service dates of resource options considered in its Strategist analysis, the Company has failed to analyze a reasonable range of alternatives to the NTEC proposal.

- The Company has failed to provide a reasonable basis for not including a 100 MW CT alternative which could provide more flexible resource portfolio options.

- The Company's claim that a 100 MW CT (a peaking resource) is not a viable resource option is not supported by the record.

- MP has not provided any reasonable explanation for not using smaller blocks of solar resources as an alternative choice to allow for more flexible portfolio options.

- The Company's assumed capacity credit of zero for wind and approximately 27% for solar are not reasonable. MISO's guidelines support a 50% capacity credit for

[166] ALJ Report, Finding of Fact 342, at 71.

[167] ALJ Report, Finding of Fact 341, at 70-71.

solar. With regard to the wind capacity rating, the MISO guidelines also support a capacity credit above zero.

- The energy efficiency assumptions used by the Company in its Strategist modeling are not reasonable; the Company should have used 76.5 GWh (or +30 GWh) in its base case or, at a minimum, as the mid-level sensitivity, but not the highest level sensitivity.

- MP should not ignore potential energy efficiency savings by the (Conservation Improvement Program (CIP)-exempt customers. Instead, the Company's estimate of future energy efficiency savings on its system should include a reasonable estimate of cost-effective savings that these large industrial CIP-exempt customers are likely to implement on their own.

- The Company's assumed level of 150 MW of industrial demand response is unreasonably low.

The ALJ concluded the Department's modeling also failed to demonstrate the need for the NTEC because it, like MP's modeling, incorporated several unreasonable assumptions. These findings are listed in full below:

> 314. The Administrative Law Judge agrees with the CEOs that the Department's Strategist modeling included some unreasonable assumptions. In particular, because the Department only allowed the NTEC resource option to be selected in 2025, the Department's modeling results were biased in favor of NTEC. Because the Commission has not made a decision that a resource of this type is need in 2025, the Department's modeling unreasonably constrains the resource options. Like Minnesota Power's Strategist analysis, the Department's Strategist analysis fails to analyze a sufficient range of alternatives to determine whether the NTEC resource is truly needed in 2025 or whether some other portfolio of resources would better meet the Company's resource needs in a cost-effective manner.
>
> 315. In addition, with regard to demand response, the Administrative Law Judge agrees that it was unreasonable for the Department to model of level of demand response lower than that used by the Company in its modeling.
>
> 316. Also, the Department's energy efficiency assumptions are unreasonably low for the reasons set forth above in paragraphs 253-274.
>
> 317. Because these underlying assumptions are not reasonable, the Department's Strategist results are not sufficiently robust or reliable for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable.

iii. Relevant Statutes

The Judge concluded that MP's energy efficiency assumptions were unreasonable in part because it was the amount of energy efficiency the Commission required in its 2016 IRP Order, but in addition, it is not consistent with Minnesota law. Since Minn. Stat. § 216B.2401 encourages utilities to aggressively pursue cost-effective energy efficiency savings, both the Commission's decisions and state law factored into the ALJ's conclusion on energy savings.

Also, the Judge concluded that MP has not established that the proposed 250 MW NTEC purchase is consistent with the requirements of Minn. Stat. § 216B.2422 and Minn. Stat. § 216.243, subd. 3a because its alternatives analysis was biased in favor of NTEC.

iv. Affiliated Interest Agreements

Because the ALJ concluded that MP did not meet its burden to show that the proposed 250 MW NTEC purchase is needed and reasonable, the Judge concluded that MP failed to demonstrate that the proposed affiliated interest agreements are consistent with the public interest.

However, to the extent the Commission reaches a different conclusion and decides the proposed NTEC purchase is needed and reasonable, the Judge recommended that the Commission find that the affiliated interest agreements are in the public interest, with the Department's Suggested Conditions and Compliance Requirements set forth in Attachment B to MP's Initial Brief.

v. Demand Response Rider

On March 12, 2018, the Commission issued its Findings of Fact, Conclusions, and Order in Minnesota Power's 2016 Rate Case. The Commission's Order directed MP, LPI, and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The Commission directed that the demand response issue be addressed either in the instant docket or in a new miscellaneous docket.[168]

The ALJ concluded that the record in this proceeding is not sufficiently developed to make a determination on a demand response rider and corresponding methodology for cost recovery.[169]

In addition, both MP and LPI acknowledged that since the 2016 Rate Case Order referral, the parties have continued to engage in thoughtful informal discussions outside of this proceeding and have demonstrated a commitment to continue working on this developing a demand

[168] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order (2016 Rate Case Order) at 115 (Order Point 72) (March 12, 2018).

[169] ALJ Report, Finding of Fact 511, at 102.

response product.[170] Moreover, the ALJ determined it is possible there may be those beyond the parties to this proceeding who may wish to provide input on such a proposal.[171]

For these reasons, the ALJ recommended that the demand response rider issue be addressed in a new miscellaneous docket.[172]

VI. Issues List

For this section, staff selected a few key issues the Commission might wish to explore in greater depth than the summaries provided above in the party comments section. Staff notes that these issues are not necessarily the most important ones, but they are issues which are disputed and involve relatively more technical detail, for example, the load forecast and the Strategist assumptions and methodological approaches.

A. Forecasting

As discussed earlier, in developing a refined forecast for this proceeding, MP made several modifications from its 2015 IRP forecast approach in its 2017 AFR, which, MP believes, reflects feedback and from the Commission's 2016 IRP Order. MP explained that its refined methodology "is far more conservative than the forecast that was submitted in the 2015 Plan."[173] MP further noted that "even if the Commission were to find that some of its forecasted or modeled values are too conservative or somehow inaccurate and thus order the Company to change the modeled value, it is likely that some other corresponding dynamic could reasonably offset that change."[174]

The Department's analysis compared the energy and peak demand forecast from the 2015 IRP and the 2017 AFR and noted that, while the 2017 AFR is lower, it is within the 2015 IRP contingency range. Moreover, the Department emphasized that "forecasting and modeling in an IRP must proceed with the understanding that the accuracy of any one forecast is of less importance than the accuracy of the overall forecast process and the robustness of the results of the analyses in light of these uncertainties."[175]

The CEOs, on the other hand, argued that was MP's was flawed for, among other reasons, relying on 26 years of history dating back to 1990. Considering more recent trends in growth and energy consumption suggests that the resource needs during the planning period are lower than MP claims. For instance, an analysis of the most recent 10 years of data paints a different picture of MP's 26-year dataset. Dr. Stanton argued that "a forecast that flips from strong

[170] ALJ Report, Finding of Fact 512, at 102.

[171] ALJ Report, Finding of Fact 513, at 102.

[172] ALJ Report, Finding of Fact 514, at 102.

[173] Petition, Page 2-8.

[174] Ex. MP-18, at 12 (Palmer Rebuttal).

[175] Ex. DER-12, at 7 (Rakow Surrebuttal).

negative growth to strong positive growth depending on which 10-year time period is used in the model is not robust."[176]

The CEOs broke down MP's historical residential and commercial energy use into three time periods: 1990-1996, 1996-2006, and 2006-2016.[177] This breakdown, shown below, indicates a clear trend of declining growth.

	Residential Growth (%)	Commercial Growth (%)
1990-1996	0.8%	1.1%
1996-2006	0.0%	0.4%
2006-2016	-0.3%	-0.6%

One explanation for declining growth is usage per customer. According to the CEOs, "usage per customer on Minnesota Power's system has been falling, on average, over the past ten years and has not been growing for 20 years."[178] As shown in the table above, both the residential and commercial sectors have actually had *negative* growth rates.[179]

The CEOs stopped short of arguing that it will definitely be the case that recent trends will continue. The main problem is that MP not only ignored recent energy consumption trends in the expected case, but it failed to test different possible growth scenarios in its Low, Base, and High forecasts: all three forecasts project the same steady growth in the commercial and residential sectors.[180] In other words, not only do the CEOs question the reasonableness of MP's expected case, but MP did not even consider a sensitivity that recent trends may continue, which does not allow the Commission to consider a truly comprehensive range.

In response to the use of a 10-year dataset, MP argued that this methodology both produces statistically-invalid results and, perhaps worse, it is wholly inconsistent with established forecasting practices in proceedings before the Commission. As an example, Schedule 4 of Ms. Pierce's Rebuttal Testimony includes MP's Response to CEO Information Request No. 69, in which MP produced results of the AFR 2017 low, base, and high load forecasts. MP provided the CEOs with a 10-year dataset, but noted that curtailing the historical years of data to include only the last 10 years has very problematic consequences:

> In establishing its longstanding and well documented monthly forecasting process, Minnesota Power worked with the Department of Commerce – Division of Energy Resources to identify and employ several best forecasting practices, including: use all available historical data in modeling/forecasting or provide some justification for not doing so. Minnesota Power was able to collect historical monthly data back to January of 1990 for most customer count and sales series, and 1996 for the

[176] CEO Initial Brief, at 9.

[177] Ex. CEO-4, at 14 (Stanton Direct).

[178] CEO Initial Brief, at 8.

[179] CEO Initial Brief, at 8.

[180] CEO Initial Brief, at 9.

> industrial and resale sector sales. Minnesota Power's forecast models leverage all available historical data because, at this point, the Company has not identified a valid reason for excluding any of this historical information from consideration in forecasting.
>
> Another best practice involves a full Specification Search step that examines and tests all plausible combinations of input ("X") variables to identify the optimal forecast models for the specified estimation timeframe (i.e. extent of historical data used). Changing the estimation timeframe to include only the last 10 years would require a full specification search process to ensure valid results. However, specification search, validation, and organization of the results would take approximately 2 weeks and depart from state-approved methods for forecasting.[181]

In addition to MP's response to CEO IR-69, Ms. Pierce explained in her Rebuttal Testimony:

> While limiting a historical dataset to a "relevant timeframe" is not uncommon or necessarily bad practice in econometrics, it is a subjective modeling decision on the part of the econometrician and must come with a robust and well-researched justification. Here, the regression models based on a 10-year historical timeframe that form the basis of Dr. Stanton's proposed forecast adjustment are statistically invalid, and their resulting forecasts are unusable.[182]

B. Model Constraints and Claimed Bias

One of main contested issues in this case is the constraints MP placed on the model. The ALJ concluded that MP "placed constraints on the model that resulted in its analysis being systematically biased in favor of NTEC and away from alternatives."[183]

The significance of this conclusion cannot be overstated: if the construction of the Strategist model, which is the foundation on which MP attempted to demonstrate NTEC is in the public interest, was determined to be "systematically biased," it is almost inconceivable that the Judge would ultimately conclude MP proved by a preponderance of the evidence that NTEC is needed and reasonable.

LPI and the CEOs both argued at length why the constraints MP imposed on the Strategist model biased the model to favor the selection of NTEC.[184] In particular, both LPI and the CEOs emphasized that the 250 MW NTEC purchase was only allowed for selection in 2025, and no other year. In addition, the CEOs noted that Strategist was not allowed to select any other

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[181] Ex. MP-14, Schedule 4 at 1-2 (Pierce Rebuttal).

[182] Ex. MP-14, at 39 (Pierce Rebuttal).

[183] ALJ Report, Finding of Fact 341, at 71.

[184] CEO Initial Brief, at 15; LPI Initial Brief, at 10.

resource until 2025 even though the "capacity deficit" claimed by MP begins to grow between 5 and 30 MW in 2019 to around 100 MW in 2025 (where it remains until 2029).[185]

MP responded that it was reasonable to place some constraints on the model:

> The record reflects that the purpose of this proceeding is to evaluate a mid-2020s resource addition to meet the identified need in 2025, consistent with past integrated resource plan outcomes. The Company appropriately structured the Strategist model to select more resource alternatives than would typically be evaluated in a traditional integrated resource plan due to limitations in the Strategist model. By permitting the selection of resource alternatives only in 2025, the Company was able to conduct the most robust analysis of resource additions using the Strategist model.[186]

The ALJ concluded that since "the Commission has made no prior determination as to size, type, or timing,"[187] "the Company's decision to make the NTEC purchase available only in 2025 and to place timing constraints on other resource options is contrary to the analysis required by the Notice and Order for Hearing."[188]

The Department, in its Exceptions, rejected the assertion that making NTEC available in 2025 created bias in the model. The Department stated, "while the NTEC was only available in 2025, a similar, generic unit was available in all years. Thus, intermediate capacity was available to Strategist in all years and the analysis was not biased by having intermediate capacity available in only one year."[189] Additionally, the Department explained, "[g]iven that the NTEC unit is selected because it minimizes energy costs (even including externality costs, also known as societal energy costs or system societal costs), if the Department made the NTEC unit available in additional years, Strategist would only have moved the in-service date from 2025 to another year if such a change would further reduce system costs."[190]

In the CEOs' Reply to Exceptions, it emphasized the phrase "identified need," which MP included in its rationale defending the timing constraint. In the CEOs' view, it was inappropriate for MP to structure the model according to the Company's identified need because doing so was inconsistent with the Commission's Order that required MP to update the load forecast before a determination on need could be made. The CEOs noted that "[t]he ALJ rightly found that the Company's application of this 'identified need' as a constraint on its modeling is

[185] CEO Initial Brief, at 20-21.

[186] MP Initial Brief, at 55.

[187] ALJ Report, Finding of Fact 214, at 48.

[188] ALJ Report, Finding of Fact 217, at 48.

[189] Department Exceptions, at 8.

[190] Department Exceptions, at 9.

inconsistent with the Commission's order in Minnesota Power's 2016 IRP and with its 2017 Notice and Order for Hearing in this docket."[191]

C. Inputs and Assumptions

i. Wind and Solar Assumptions

Below is a list of some of MP's assumptions used to evaluate renewable energy compared to the adjustments made by the CEOs:

Renewable Energy Assumptions		
Assumption	Minnesota Power (Appendix I)	Ms. Sommer Adjustments (CEO)
Wind unit base	Size: 100 MW Price: $45/MWh[192] Capacity credit: Zero for new wind.[193]	Price: Wind price without PTC based on NREL's Annual Technology Baseline price forecast ($39/MWh) Capacity credit: 18.3% for new wind projects (MISO Zone 1)
Solar unit base	Size: 100 MW Price: Trade Secret Capacity credit: 27%	Size: 25 MW Capacity credit: 50%
Wind price sensitivity	Wind LCOE in $5/MWh increments from $25/MWh to $35/MWh	
Solar price sensitivity	Solar LCOE in $10/MWh increments from $35/MWh to $75/MWh.	
Wind capacity credit	Capacity credit of existing wind farms was reduced by 20 percent from base.	No apparent change for existing wind.

Staff refers the Commission to Mr. Palmer's Rebuttal Testimony, at pages 53-57, for MP's response to Ms. Sommer's adjustments. Notably, it does not appear as though the CEOs' assumption for wind prices is remarkably different than MP's, and Ms. Sommer did not make an adjustment to MP's solar price. Also, the CEOs did not raise any objections to MP's wind sensitivities, which included a levelized cost that "varied in $5/MWh increments from $25/MWh to $35/MWh."[194] The Department did not believe wind pricing is a critical factor because NTEC was selected regardless of the wind price.

[191] CEOs Reply to Exceptions, at 3.

[192] In Appendix I, MP designated the base wind price as Trade Secret. However, in Mr. Palmer's Public Rebuttal, Mr. Palmer publicly refers to the $45/MWh wind price.

[193] In the 50% Renewable and 75% Renewable swim lanes, the generic wind assumed a 15% accredited capacity credit. A $5/MWh adder was included in the energy cost to capture the likely cost for MISO system upgrades that would be required as part of the interconnection agreement.

[194] Petition, Page I-11.

Thus, as will be discussed in the next section, the CEOs' primary objection seems to be MP's assumptions for wind and solar capacity accreditation.

ii. Wind and Solar Capacity Credits

One modeling adjustment the CEOs made was to increase the wind capacity credit: Ms. Sommer assigned new wind projects an 18.3% capacity credit, which is the average effective load carrying capacity for wind resources in MISO Zone 1 (where MP's service territory is located).

Ms. Sommer argued that high wind zones, such as those in which the Company's wind farms are located, justify higher wind capacity credits relative to the MISO system-wide average (or 15.2% as of the time of the analysis).

In Table 2 of her Direct Testimony, Ms. Sommer illustrated the accredited capacity (resource adequacy) and capacity factor (energy output) of the Company's existing wind farms. According to Table 2, wind facilities in North Dakota (Bison, Oliver) and Minnesota (Taconite Ridge) have generally operated at higher capacity factor relative to the broader MISO footprint; in turn, they have received relatively higher accredited capacity values:[195]

Table 2. Capacity Credit and Capacity Factor of Minnesota Power's Current Wind Farms

		2014	2015	2016
Bison	Capacity Credit	13.3%	18.0%	21.7%
	Capacity Factor	37%	35%	40%
Oliver	Capacity Credit	13.8%	17.1%	19.4%
	Capacity Factor	42%	39%	40%
Taconite Ridge	Capacity Credit	12.8%	14.4%	15.6%
	Capacity Factor	30%	31%	22%

Mr. Palmer addressed Ms. Sommer's adjusted wind capacity credit on two fronts. First, he noted that Ms. Sommer did not assume any network upgrade costs, which are required in order to receive capacity accreditation. Second, Mr. Palmer argued that due to potential transmission constraints, it is most reasonable to assume MISO will not give new wind any capacity credit.

Notably, in MP's 50%/75% Renewables swim lanes, MP assumed a capacity credit of 15% and a $5/MWh adder "to capture the likely cost for MISO system upgrades."[196] Thus, staff believes the total price per-MWh of wind PPAs can be reasonably inferred, and the lack of an interconnection cost is only minimally relevant to Ms. Sommer's broader point, which is that

[195] Ex. CEO-3, at 24 (Sommer Direct).

[196] Petition, Appendix I, Page I-7.

there is no reason to believe MISO will cease assigning new wind any capacity credit. Nevertheless, Mr. Palmer responded to Ms. Sommer's assumption as follows:

> I believe it is a flaw in Ms. Sommer's analysis to include a wind capacity credit when the network upgrade cost often required in order to receive a capacity credit was excluded from her cost assumptions. As Minnesota Power mentioned in its response to CEO IR-25, the Department also concluded that modeling wind resources at a zero capacity credit is reasonable:
>
> > "The Department concluded that MP's assumption of no accredited wind capacity was reasonable given MP's difficulty in obtaining accredited capacity prior to major transmission lines coming in-service connecting Minnesota with load centers further east (expected around 2020) and also considering that significant transmission costs may not be justified to obtain the small quantity of accredited capacity wind offers. Lastly, note that lack of transmission for accreditation may also lead to wind energy being curtailed—another factor that led the Department to reduce the overall wind capacity factor."
>
> Minnesota Power agrees with the Department's conclusion that, due to limited transmission capacity existing in the high wind zones located in MISO, using no capacity credit is justifiable.[197]

With regard to new solar resources, Ms. Sommer assumed a 50% solar capacity credit. She explained that a 50% solar capacity credit is "in line with MISO guidance for new solar resources with less than 30 days of metered data. This number is also consistent with how Minnesota Power proposed to treat its Camp Ripley solar project in recent rate case testimony."[198]

MP disagreed with Ms. Sommer's adjustment assigning solar a 50% capacity credit, arguing that she "failed to consider how solar capacity values will vary in a multi-season resource adequacy construct."[199] MP continued that, because MP is a winter-peaking utility, assigning solar capacity credit in the winter would charge customers twice for capacity:

> Based on estimates of when MISO's system peaks in the winter (early morning/evening) and solar production in Minnesota, it is estimated that solar would receive zero capacity credit for the winter season. Because Minnesota Power is winter peaking, this would create a scenario where solar capacity would need to be replaced by building or purchasing additional capacity, effectively charging customers twice for capacity.[200]

[197] Ex. MP-18, at 54 (Palmer Rebuttal).

[198] Ex. CEO-3, at 22 (Sommer Direct).

[199] MP Initial Brief, at 56.

[200] Ex. MP-16, at 34-35 (Palmer Direct).

Staff notes that the discussion above refers both to a 27% solar capacity credit as well as MP's argument that solar should receive zero capacity credit in the winter. Staff suggests the Company clarify whether solar received 27% accreditation in both seasonal constructs or different capacity credit in the summer versus the winter construct.

Staff also notes that, as stated earlier, Dr. Stanton's load forecast adjustments change MP's capacity deficit to 23 MW in 2025, increasing to 103 MW by 2030. In many of the CEOs' Futures run by Ms. Sommer, the optimized expansion plan added 300 MW of new wind and 100 MW of new solar in 2025-2030. With the 18.3% wind capacity credit and 50% solar capacity credit, this translates to about 105 MW, thus covering the 103 MW need by 2030. (Embedded demand response could provide additional capacity; as staff understands it, Dr. Stanton did not adjust available demand response in her adjusted forecast, but Ms. Sommer assumed more than MP.)

iii. End Effects

As MP explained in its Reply Brief, the Strategist analysis evaluated the proposed NTEC 250 MW purchase for the period 2017 through 2031, with power supply costs incorporated through 2034. Strategist also factored in 15 years of "end effects," which is a simplified extrapolation of costs beyond the planning period, to capture the cost impact over the life of the facility.[201]

According to Ms. Sommer's Surrebuttal Testimony, "[t]he end effects period merely assumes that the results of the last year of the planning period can be carried forward modified by whatever escalation rates might apply to the various costs contained in the last year of the planning period … the projected benefits of NTEC over alternatives only accrue to customers 18 years from now. That introduces a significant level of uncertainty and unreliability about the benefits of adding NTEC over alternatives."[202] The CEOs argued that "if one were to look at the 'planning period' rather than the end-effects period, the runs without NTEC are consistently less expensive than the runs with NTEC."[203]

In response, MP contended, "the CEOs' argument that the 250 MW NTEC purchase was suboptimal but for the end effects is based on a single set of scenarios. The CEOs attempted to use this approach to make the broader, incorrect argument that the end effects are what make the NTEC 250 MW purchase the preferred plan. As with the CEOs claim that NTEC should not be approved because there is a single low-load, summer-focused scenario in which it may not be needed, the CEOs end effects argument attempts to improperly extrapolate a single outlier to support a false premise."[204]

In summary, the back-and-forth between the CEOs and MP on end effects seems to be as follows: the CEOs claim that the NTEC purchase tends to lower the overall societal costs only if

[201] MP Reply Brief, at 22-23.

[202] Ex. CEO-10, at 21 (Sommer Surrebuttal).

[203] CEO Initial Brief, at 43.

[204] MP Reply Brief, at 23.

end effects are included, which is to say the post-planning period extrapolations—which absorb higher levels of uncertainty—favor the NTEC purchase. MP's response is that incorporating end effects is not only standard practice in capacity expansion modeling, but it aligns with the impact to customer costs over the life of the facility and are therefore reasonable to include.[205] Since a primary benefit of NTEC is that it decreases variable costs more than it increases fixed costs over time, it would be unreasonable *not* to assume financial benefits of a capital-intensive resource beyond the IRP timeframe.

iv. Superfluous Unit Designation

As explained above, in the Department's analysis, Dr. Rakow designated the NTEC unit both as "not superfluous" (can only be added if there is a capacity deficit) and "superfluous" (can be added regardless of a deficit/surplus if it reduces cost). When NTEC was not labeled as superfluous, it was not selected very often; however, once NTEC was labeled as superfluous, NTEC was selected in virtually every case.[206]

The superfluous designation also arose in Mr. Palmer's critique of the CEOs' Strategist analysis. According to Mr. Palmer, the CEOs only modeled NTEC as "not superfluous," or "set to 0." [207] When Mr. Palmer allowed NTEC to be "superfluous," or "set to 1," and turned off the energy market, NTEC was selected amongst the top 1,000 expansion plans.[208]

Ms. Sommer responded that MP mischaracterized her modeling. Ms. Sommer noted that when MP delivered its Strategist databases and macros to the CEOs, "the superfluous unit setting for NTEC [was] "0" – meaning that the unit could not be picked for economic reasons."[209] In any case, she argued, being aware of the limitations of the superfluous unit setting, Ms. Sommer chose to present the results with NTEC forced and with the model optimized.[210]

D. Dispatchability and Risk

i. Renewable Energy Integration Studies

The CEOs cited three renewable energy integration studies—from 2004, 2006, and 2014—which address higher levels of renewable energy as a percentage of electricity supply. The CEOs argued these studies are important in light of MP's claim that it needs a dispatchable and flexible unit like NTEC to balance the variability of renewable generation.

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[205] MP also noted that the Step 2 analysis did *not* include end effects, yet in Step 2 NTEC was still selected approximately 90% of the time. However, staff decided to leave that fact as a footnote because it is probably best to discuss the overall value of the Step 2 analysis (or lack thereof) as a separate issue.

[206] Ex. DER-12, at 42 (Rakow Surrebuttal).

[207] Ex. MP-18 at 63 (Palmer Rebuttal).

[208] Ex. MP-18 at 63 (Palmer Rebuttal).

[209] Ex. CEO-10, at 19 (Sommer Surrebuttal).

[210] Ex. CEO-10, at 19 (Sommer Surrebuttal).

CEO witness Mr. Jacobs asserted that "[h]our-by-hour analyses, such as conducted in the Minnesota wind integration studies, allow for an understanding of the variations in both supply and demand without the preconceptions of 'dispatchable capacity' definitions or the exclusion of 900 MW of renewable generation."[211] In particular, the 2014 Minnesota Renewable Energy Integration and Transmission Study (MRITS), which included four members of MP's staff on its technical study team, identified sources of grid flexibility that can support integration of higher levels of renewable energy as a percentage of the electricity supply.[212] According to Mr. Jacobs:

> The MRITS Report described 40 percent and 50 percent renewable energy (wind and solar) in Minnesota, with the rest of the MISO system at 15 percent and 25 percent renewable energy, respectively. The MRITS Report demonstrated how to identify variability in loads and production, and also errors in wind production forecasts that would be available hours or a day in advance, to capture any additional need for response from flexible resources. The MRITS Report discussed how to adapt to the decreased ramp-down capacity in the MISO conventional generation fleet when the supply mix has less conventional generation.[213]

In its Reply Brief, MP noted that the MRITS Study was an engineering study, not a cost study, and while integrating large amount of renewable energy is technically possible, that argument is misplaced in the instant proceeding:

> Fundamentally, the MRITS Study stands for the proposition that the regional transmission system can support the deployment of a significant percentage of energy from wind generation sources on an engineering basis. Specifically, the MRITS Study analyzed whether it is technically feasible to integrate up to 40 percent variable wind energy in the upper-Midwest. It concludes that variable renewable generation to supply 40 percent of Minnesota's annual electric retail sales on an energy basis can be reliably accommodated by the electric power system with appropriate upgrades to the regional transmission system. By contrast, the MRITS Study acknowledges that substantial further analysis would be needed to assess whether the electric system could support 50 percent variable renewable generation penetration on an energy basis. The MRITS Study acknowledges the need to study the system to assess whether and how system performance would be impacted by variable production at such high levels. In addition, the MRITS Study acknowledges that $2.6 billion of new transmission investment could be needed to support such additional variable generation.[214]
>
> …
>
> Minnesota Power is not suggesting that that the MRITS Study was flawed or that its conclusions are not relevant to the instant proceeding; however, it is

[211] Ex. CEO-6 at 12 (Jacobs Rebuttal).

[212] Ex. CEO-2, at 5 (Jacobs Direct).

[213] Ex. CEO-2, at 7 (Jacobs Direct).

[214] Ex. MP-20, at 5 (Brick Rebuttal) (citing Ex. CEO-2, Schedule 3, at 1-4 (Jacobs Direct) (MRITS Study)).

> indisputable that MRITS was not an economic study and has no relevant cost information.[215]

MP did note that the MRITS Study is informative in that it raises concerns with increasing wind penetration. According to Mr. Brick, for instance, the MRITS Study is "instructive to assessing Minnesota Power's situation. The State of Minnesota is already experiencing significant wind penetration. Additional variable generation could begin to raise issues concerning the regional system's ability to absorb it."[216]

The CEOs argued that analyses such as the wind integration studies are more appropriate for assessing resource variability than that which was done by the Company in this proceeding. Particularly problematic was MP's inaccurate characterization of potential variability on its system, as well as the inadequate tools MP used for assessing renewable integration.

For example, MP stated in its Petition that, as a result of its wind investments, it will be faced with a challenge of having output vary by as much as 850 MW per hour. Mr. Jacobs argued this is an inaccurate representation of wind integration.[217] In addition, Mr. Jacobs argued, the modeling on which MP relied to form the basis of its claimed need for flexibility and dispatchability is simply not capable to justify it:

> Minnesota Power indicated that Strategist software does not provide it the opportunity to use time-series data to identify hour-to-hour change in wind production or otherwise quantify the need for flexibility. The Company's efforts to establish a need for flexibility are not based on the sequence or series of hour-to-hour changes in renewable energy generation and the corresponding changes in load for the same time. Instead, Strategist uses hourly generation curves that represent a typical week of generation from the Company's wind resources.[218]

To mention one final issue on renewable energy integration, staff notes that several witnesses cited the statistic that, with Nobles 2 Wind, MP will have the highest wind penetration as a percentage of peak demand of any other Minnesota utility. The Commission might wish to ask MP to elaborate on this, since the "percentage of peak demand metric" was frequently introduced in the context of reliability and dispatchable capacity, yet the meaningfulness of this metric is not immediately obvious. In addition, in Mr. Brick's Rebuttal Testimony, in the very same answer Mr. Brick directly associated the MRITS Study of a 50% renewable generation penetration *on an energy basis* to MP's 50% *of peak demand* metric,[219] but without making any distinction between energy and peak demand.

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[215] MP Reply Brief, at 41.

[216] Ex. MP-20, at 6 (Brick Rebuttal)

[217] Ex. CEO-2, at 19 (Jacobs Direct).

[218] Ex. CEO-2, at 20 (Jacobs Direct).

[219] Ex. MP-20, at 5-6 (Brick Rebuttal).

E. Demand Response

i. Historical/Current versus Assumed Demand Response

MP assumed 150 MW of industrial demand response capability, which is an amount the CEOs, LPI, and the ALJ considered to be unreasonably low. While MP did not dispute that currently available levels of demand response are relatively higher than that incorporated into the Strategist base case, MP maintained that 150 MW of demand response was the most reasonable level to use. Note, for example, MP's Redlined Exception to ALJ Finding 285, in which the Company did not dispute the higher levels, only the conclusion that 150 MW was unreasonable:[220]

> 285. The ~~The Administrative Law Judge agrees with the CEOs and LPI that the~~ Company's assumed level of 150 MW of industrial demand response is reasonable. ~~unreasonably low.~~ The most current data shows that the Company has been able to acquire an average of 190 MW per year over the last five years.11 In addition, the Company's currently available levels even higher -- 264 MW in 2018 and 265 MW in 2017.12 nevertheless, such savings are by no means assured and the record supports the Company's approach and assumptions.

Furthermore, according to MP, "the ALJ's criticism of the Company's demand response assumptions is misplaced, again overlooks key Strategist planning scenarios, and, ultimately, is irrelevant to the outcome of these proceedings."[221]

In making this claim, MP again referred to its revised Strategist analysis, which, in one additional swim lane, "offered up to 300 MW of demand response in two blocks of 150 MW," far more than the 190 MW amount suggested by the ALJ, yet the Strategist model still selected NTEC as the best available resource.[222] This result occurred because demand response is akin to a peaking resource and does not meet the Company's intermediate energy need.

Mr. Gorman argued that MP's additional study of 300 MW of industrial interruptible load was flawed because MP assumed a cost associated with interruptible load, but not the benefit of avoiding the need to purchase capacity.[223] On pages 10-12 of his Direct Testimony, Mr. Gorman provided additional explanation of why the existence of interruptible customers has no cost to MP or its firm service customers.

ii. Peaking versus Intermediate Need

LPI did not reject the possibility that MP might need an intermediate resource eventually. Rather, LPI's main criticisms were that MP's capacity need in 2025 is much less than 250 MW; MP's proposed cost recovery structure will result in higher prices for customers in the early

[220] MP Exceptions, Exhibit 1: Redlined Exceptions to ALJ Report, at 4.

[221] MP Exceptions, at 43.

[222] MP Exceptions, at 43.

[223] Ex. LPI-4, at 10 (Gorman Direct).

years of NTEC (e.g., the 2025-2030 period) when there little to no capacity need; and MP did not adequately consider smaller or differently timed resource alternatives.

LPI also disagreed with how demand response as a resource and a product was discussed. For example, with regard to the Department's claim that demand response is merely a peaking resource that is comparable to a combustion turbine, LPI responded that if demand response is to be characterized in this way, it would seriously limit demand response opportunities in Minnesota. LPI explained, contrary to a typical supply-side resource, "demand response is solicited from utility customers who are not otherwise in the business of developing energy generation facilities or energy products. Customers are best able to evaluate and enroll in an established program and adapt their operations over time to best take advantage of such a program."[224]

LPI acknowledged that demand response is not directly comparable to a unit like NTEC. However, even though demand response cannot be used to produce energy, "avoiding peak capacity costs can result in higher utilization of existing resources and potentially result in a portfolio of MP resources that is the best and least cost resource option available."[225]

In addition, an expanded demand response portfolio reduces overall energy use. LPI witness Mr. Stephens outlined a demand response program that provides incentive payments designed to induce lower electricity use at times when wholesale market prices are high (economic interruptions) or when system reliability is jeopardized (reliability interruptions). Such incentives, Mr. Stephens argued, can reduce energy usage and avoid the construction of new generating facilities, which has a lower environmental impact than maintaining higher energy usage and constructing additional fossil fuel resources.[226] One problem with MP's analysis of demand response is that there is no credit for the energy cost savings, which would clearly be realized "due to the up to 400 hours per year of economic interruptions."[227]

The CEOs argued the Company's analysis of demand response alternatives was incomplete:

> Minnesota Power limited its consideration of demand response to only a few options. The Company considered it in the form of its Central Air Conditioning Cycling Peak Shave Program and Electric Hot Water Heater Cycling Peak Shave Program in the initial screening process and in the Strategist model. It was not considered in a larger context, such as with the Large Power Intervenors, resulting in underestimated values in the modeling result. Minnesota Power was ordered by the Commission to consider demand response as an alternative to NTEC. To limit its consideration to a few options and to grossly underestimate available savings does not comply with this order.[228]

[224] LPI Reply Brief, at 13.

[225] Ex. LPI-6, at 17 (Gorman Surrebuttal).

[226] Ex. LPI-3, at 20 (Stephens Surrebuttal).

[227] Ex. LPI-3, at 13 (Stephens Surrebuttal).

[228] CEO Initial Brief, at 19.

Mr. Jacobs found MP's lack of consideration of demand response as a complement to renewable energy to be particularly troubling:

> There appears to be no review of the potential for demand response resources to provide integration of renewable generation, either inside the existing peak-shaving programs or in a more specific air conditioning load control or hot water load control program. There was no discussion of the adaptation and value of using the existing load control infrastructure during an increased number of hours to meet renewable integration needs.[229]

Pages 40-41 of Dr. Rakow's Surrebuttal Testimony discussed the quantity of demand response resources available in the Department's model. Dr. Rakow noted that he only revised inputs that changed beyond the band studied in the last IRP, and demand response did not warrant a separate contingency band. The amount of demand response the Department made available to Strategist was the minimum amount within the historical range (about 100-260 MW).[230] Additional demand response resources were also available to be selected in small quantities (2 units of about 7 MW each) early in the expansion plan.

Ultimately, the Department's analysis showed that the addition of NTEC decreases societal costs, and in the contingency analysis, this result occurred virtually irrespective of the levels of forecasted demand, energy storage, and demand response.[231]

F. Energy Efficiency

i. Background

Before considering the different views on the optimal amount of energy savings, or the extent to which incremental energy savings impacts whether NTEC is needed and reasonable, some context might be helpful to explain MP's approach to analyzing energy savings.

First, MP has a number of large industrial customers that have applied for and received exemptions (opt-outs) from the Conservation Improvement Program (CIP) investment and expenditure requirements under Minn. Stat. §216B.241. As MP noted in its 2015 IRP:

> Minnesota Power is unique among utilities in that more than half of its load comes from a few large industrial customers. Moreover, roughly 66 percent of the Company's load comes from 15 customers who are exempt from participating in and paying for CIP. As a result, CIP goals, funding and design focus on the remaining 3,000 GWh of the Company's total retail load.[232]

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[229] Ex. CEO-2, at 26 (Jacobs Direct).

[230] Ex. DER-12, at 41 (Rakow Surrebuttal).

[231] Department Initial Brief, at 22.

[232] Docket No. 15-690, Appendix B, Page 11.

Second, as discussed in MP's 2017 AFR, MP's load forecast excludes exogenous DSM/CIP data from the energy sales and demand forecasts because "[t]he impact of conservation and DSM/CIP programs are present in the historical data upon which all AFR 2017 models were constructed."[233] In other words, some existing amount of annual energy savings is embedded in MP's load forecast, and, in Strategist, MP tests incremental energy savings—in this case, +11 GWh, +15 GW, and +30 GWh. This is shown in the figure below from the Commission's 2016 IRP Order.[234] Again, the percent of sales refers to non-CIP-exempt savings.

Savings Plan	Annual Energy Savings (GWh)	Percent of Sales	Incremental Cost (millions)
Existing	46.5	1.5%	$0.0
+11 GWh	57.3	1.87%	$2.7
+15 GWh	61.2	2.0%	$4.1
+30 GWh	76.5	2.5%	$10.5

As a matter of clarity, it is staff's understanding that the "embedded energy savings," or 46.5 GWh, has remained the same since the 2015 IRP. This is noted by CEO witness Mr. Mellinger, for instance, who stated that "Minnesota Power believes that 46 [GWh] of incremental energy efficiency per year are embedded in its load forecast."[235] And as explained by Dr. Stanton, "[w]hen conducting Strategist modeling, the Company's base case assumed it would save 11 GWh above what the Company claims is already embedded in the load and energy forecast,"[236] or approximately 57 GWh of energy savings.

Staff wished to clarify this point, in part because there are several values discussed, but also because of other areas of the record where achievement is mentioned. MP explained in the Petition, when referring to the 2017 AFR, "Minnesota Power achieved 64,117,319 kWh in energy savings and 9,489 kW in demand savings in 2016."[237] As staff understands it, this 64.1 GWh of energy savings in 2016 is separate from the 46.5 GWh of energy savings MP claims as "embedded energy savings," and more than the total 57 GWh (+11 GWh) MP assumed in the Strategist base case (although the Commission might wish to confirm this with the Company).

In summary, as noted, MP evaluated +11 GWh, +15 GWh, and +30 GWh energy savings scenarios in Strategist. Three noteworthy distinctions among the scenarios include:

- The +11 GWh scenario (or the 57 GWh amount) is the conservation level approved in the Company's 2017-2019 CIP;

[233] MP's 2017 Annual Elec. Util. Forecast Report, Docket No. E999/PR-17-11, at 14 (June 29, 2017).

[234] Commission 2015 IRP Order, at 12 (July 18, 2016).

[235] Ex. CEO-1, at 5 (Mellinger Direct).

[236] Ex. CEO-4, at 7 (Stanton Direct).

[237] Petition, Page 2-5.

- The +11 GWh scenario (or the 57 GWh amount) is what MP assumed in the base case Strategist analysis; and

- The +30 GWh scenario (or 76.5 GWh amount) is equivalent to the Commission's approved level from the resource plan. It is also the maximum amount considered in the analysis.

ii. CIP and CIP-exempt customers

There are at least two reasons why this context is important. First, one reason why the ALJ determined MP's analysis of energy efficiency was flawed was because MP only tested up to +30 GWh of energy savings. The Judge reasoned that (1) the Commission's approved amount should not be the cap and (2) "Minnesota law encourages utilities to aggressively pursue cost effective energy efficiency savings."[238,239] The Commission is being asked to decide whether these three scenarios are adequate; if they are not, it could be argued MP failed to appropriately apply the requisite IRP and CN criteria to this proceeding.

Second, an important finding by the ALJ was with regard to energy savings from CIP-exempt customers. The ALJ determined "the Company should not ignore potential energy efficiency savings by the CIP-exempt customers. Instead, the Company's estimate of future energy efficiency savings on its system should include a reasonable estimate of cost-effective savings that these large industrial CIP-exempt customers are likely to implement on their own."[240] The Judge reasoned this in part because "CIP-exempt customers have the financial incentive to undertake new energy efficiency projects that are cost-effective on their own, resulting in energy savings by these large customers which are reflected on the Company's system as a whole."[241]

MP took a very different view on both fronts. Below is an excerpt from Mr. Palmer's Rebuttal Testimony, which staff believes well-encapsulates many of the underlying reasons for MP's arguably conservative energy efficiency assumptions and scenarios:

> While it is true that the Company's CIP program has exceeded expectations over the last five years, it is not likely that the Company will continue to exceed its goals going forward. The recent success of the CIP program is largely attributable to certain large, irregular, and customer-specific industrial projects that may account for as much as 41% of overall savings in any one year. Without new, large CIP projects being undertaken, it is unrealistic to expect the Company to continue exceeding its CIP goals. And with regard to the savings resulting from residential or commercial conservation measures, deeper incremental savings will be

[238] ALJ Report, Finding of Fact 269, at 57.

[239] Minn. Stat. § 216B.2401.

[240] ALJ Report, Finding of Fact 273, at 58.

[241] ALJ Report, Finding of Fact 273, at 58.

> increasingly difficult (and expensive) for the Company to achieve on a going-forward basis, as many of the low-cost savings opportunities have already been captured.[242]

MP is essentially arguing that even though it has exceeded CIP goals in recent years, a main reason for this were large, unique CIP projects, and it would be risky to assume similar opportunities will emerge in the long-term. But there are three additional, notable takeaways from this excerpt: (1) MP exclusively references CIP as its mechanism for system energy savings; (2) MP chose the word "irregular" to describe energy efficiency projects; and (3) MP believes the low-hanging fruit has already been picked. In its Exceptions, MP again addressed all three themes, noting, "it is difficult to predict whether new opportunities for industrial conservation projects will materialize," and "it is unrealistic to expect the Company to continue exceeding its [CIP] goals."[243]

As it did many times throughout the rounds of testimony and briefs, MP returned to the frequency with which NTEC was selected in Strategist as a primary justification that it reasonably considered energy efficiency as an alternative to NTEC. MP emphasized that its revised Strategist analysis evaluated +30 GWh energy savings in the revised base case, and in that supplemental analysis, increasing the base case energy savings "did not materially change the overall results … nor did it eliminate the need for the 250 MW NTEC purchase."[244]

iii. CEOs' Alternative Analysis

The CEOs challenged MP's conclusions about the availability of energy savings. For example, according to modeling conducted by the CEOs, incremental annual electric energy savings could increase by more than 100,000 MWh by 2022, and the cumulative impacts of the previous year's incremental annual savings reaches over 700,000 MWh by 2029.[245] These additional savings are also affordable; levelized utility costs to acquire incremental energy efficiency savings are around $0.01 per kWh.

The CEOs further contended that it is appropriate to include CIP-exempt customers in the analysis of potential savings. According to Mr. Mellinger, "a Strategic Energy Management" (or SEM) concept could provide significant potential for "new and sustained energy savings in commercial and industrial environments."[246] Mr. Mellinger calculated that, under such a program, MP could achieve more than 50 GWh per year of incremental annual savings.[247]

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[242] Ex. MP-18, at 13-14 (Palmer Rebuttal).

[243] MP Exceptions, at 39.

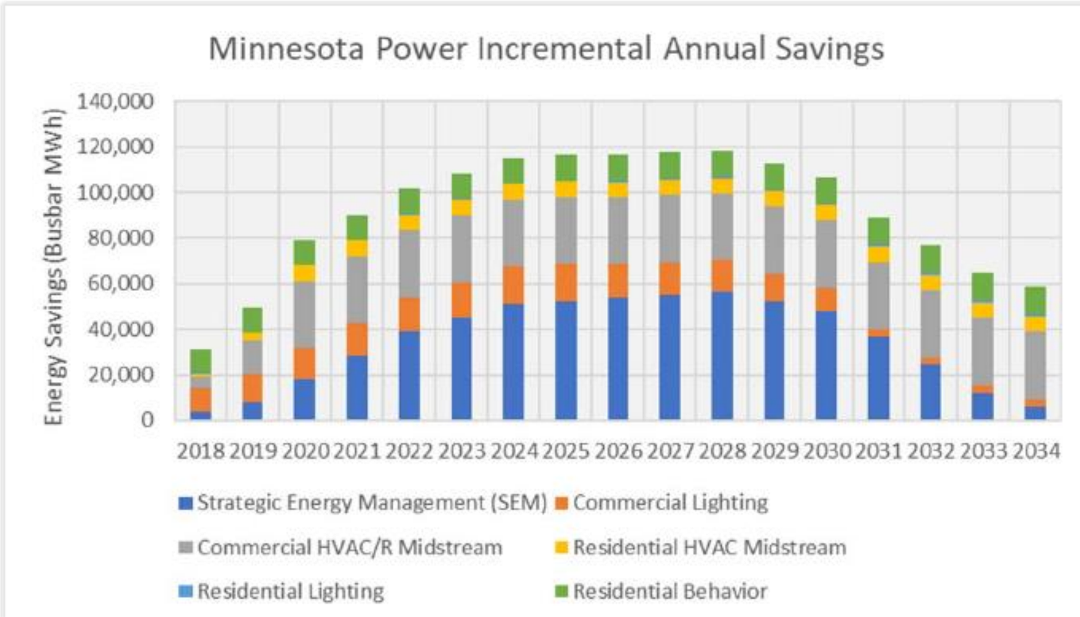
[244] MP Exceptions, at 41.

[245] Ex. CEO-1, at 4 (Mellinger Direct).

[246] Ex. CEO-1, at 11 (Mellinger Direct).

[247] Ex. CEO-1, at 9 (Mellinger Direct).

Incorporating the SEM concept along with other energy efficiency measures typically part of a CIP—e.g. commercial and residential lighting and behavior-based programs—Mr. Mellinger illustrated the 100,000+ MWh of potential in Figure 17 of his Direct Testimony:[248]



iv. Department Response

The Department addressed the CEOs' comments about energy efficiency achievability by framing them within the context of how supply-side resources such as coal and natural gas fueled units are dispatched in Strateigst. This is because resources such as NTEC are dispatched last, after the model accounts for non-dispatchable resources such as energy efficiency. To Strategist, the following changes to the model all have the same effect:[249]

- a decrease in the demand and energy forecast;
- an increase in energy conservation;
- an increase in the supply of non-dispatchable resources (such as wind); and
- an increase in the must-run segment of dispatchable resources.

The Department explained this point further in its Exceptions:

> Any potential error in the levels of energy efficiency input to Strategist is dwarfed by the forecast contingencies. As with the discussion of demand above, decreases in the forecast inputs have the same impact in Strategist as increases in energy

[248] Ex. CEO-1, at 31 (Mellinger Direct).

[249] Ex. DER-12, at 47 (Rakow Surrebuttal).

conservation inputs. Again, the Department ran Strategist with energy and demand forecast contingencies higher and lower by two-and-a-half and five percent. The base forecast used in the analysis was between 11,000 GWh and 12,500 GWh most years. Therefore, the five percent forecast contingency accounts for a potential energy requirements decrease of 550,000 GWh to 625,000 GWh annually. In essence, **any potential error in energy efficiency achievement becomes rounding error** when compared to the energy forecast bands.[250] (Emphasis added by staff.)

G. Energy Storage

MP's requirement to consider energy storage as an alternative resource was not included in the Commission's 2016 IRP Order. As a result, unlike solar, wind, demand response, and combined heat and power, MP was not required to solicit bids for energy storage alternatives to be compared to the natural gas RFP bids MP sought in October 2015.

The Commission's September 19, 2017 referral order did, however, require that MP evaluate energy storage as a resource alternative to NTEC. Accordingly, MP evaluated a 10 MW / 40 MWh lithium ion battery facility with an estimated capital cost, in 2017 dollars, of $3,671/kW, or $917,750/MWh, decreasing at a rate of -3.37 percent until the end of 2024.[251] MP stated that its assumed cost for energy storage was "based on research from the International Finance Corporation report named Energy Storage Trends and Opportunities in Emerging Markets"[252] (although as staff reviewed the report, for some reason, MP's assumed price for a lithium ion battery is vastly higher than the price forecast included in the report it cites).[253] Nevertheless, a battery option was not selected in any of MP's Strategist runs.

The CEOs argued that MP used unreasonably high cost assumptions for energy storage in its Strategist analysis. It cited Lazard, a firm with industry expertise that regularly prepares reports on the costs of electric generation technologies, which predicts significant cost declines for energy storage in the near-term. The CEOs noted that Lazard projected that "[i]n specific use case of four-hour duration, the 2017 observed lithium-ion peaker-plant cost is $1,338 per kW and $335 per kWh."[254]

In addition, CEO witness Mr. Jacobs explained how MP failed to properly assess energy storage as a potential source of grid flexibility. For example, MP did not model any of the benefits of energy storage, such as ancillary services. While the Company makes numerous statements

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[250] Department Exceptions, at 13-14.

[251] Petition, Appendix I, Page I-8.

[252] Petition, Appendix I, Page I-8.

[253] See Energy Storage Trends and Opportunities in Emerging Markets, INTERNATIONAL FIN. CORP. (2017), available at

https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStoragereport.pdf?MOD=AJPERES at Table 2.1, page 8.

[254] Ex. CEO-2, at 13 (Jacobs Direct).

throughout the record about the importance of "balancing wind," there is "no measure or consideration of the benefits, value, or cost reductions resulting from the use of advanced battery storage, either separately or in combination with other resource options,"[255] according to Mr. Jacobs.

Attachment 2 of Dr. Rakow's Direct Testimony includes a lengthy discussion of energy storage technologies (ESTs). For example, Dr. Rakow explained why the Department did not model ESTs as well as what some likely impacts ESTs would have been if it did:

> For IRP purposes, ESTs [energy storage technologies] can be thought of as providing peaking services … Since energy storage is a peaking technology, at this time it is not necessary to separately model ESTs as doing so would merely duplicate units already being considered and needlessly complicate the model.
>
> …
>
> If ESTs were modeled, the ESTs would create an increase in demand during off-peak hours (ESTs buy energy when it is cheap) and create an increase in supply during on-peak hours (ESTs sell energy when it is expensive).[256] In Minnesota IRPs, the load-following unit during most off-peak hours is likely to be coal for most utilities. Coal retirements, additions of new natural gas units and other adjustments to the electric systems may change this fact in the future. During on-peak hours, the load-following unit is likely to be natural gas in an IRP for utilities that have significant quantities of natural gas generation.[257] This information on Minnesota utilities is consistent with the information above regarding load-following units in MISO. Therefore, in current IRPs, **ESTs are likely to increase coal generation when charging and decrease natural gas generation when discharging with no direct impact on renewable generation**"[258] (emphasis added by staff).

Dr. Rakow further explained in his Surrebuttal Testimony why pairing renewable energy with energy storage is a flawed assumption. First, he argued, it would necessarily be a higher-cost outcome because Strategist determines which resources address system needs when wind is not available. Second, energy storage would not necessarily "balance the wind" because it would be used to purchase energy when the price is high and sell energy when the price is low. There is no strong correlation between wind output and market prices.[259]

[255] Ex. CEO-2, at 26 (Jacobs Direct).

[256] If the difference between on-peak and off-peak prices is greater than the cost of the EST, then the IRP model would select the EST alternative because net revenues would exceed costs.

[257] Among the IRP utilities, Xcel and Great River Energy have significant amounts of natural gas generation. MMPA and SMMPA also own natural gas generation, as does Missouri River Energy Services (but only in the Southwest Power Pool region). Otter Tail Power plans to add significant natural gas generation in 2021 and Minnesota Power plans to add natural gas in 2024.

[258] Ex. DER-9, SRR-3 of Rakow Direct, at Page 39 of 40.

[259] Ex. DER-12, at 63-64 (Rakow Surrebuttal).

Mr. Brick made similar arguments, noting that storage could actually increase CO_2 emissions given MISO's relative coal-intensity and current, low natural gas prices.[260] In addition, according to MP's modeling, "the majority of current and planned wind resources are used to serve current load."[261] In fact, less than two percent of MP's wind is projected to be surplus. Additional wind would merely generate surplus to power storage to be used at a later time.

VII. Staff Discussion

A. MP's RFP Process

In several instances, MP suggested that its NTEC proposal is consistent with prior Commission orders. Mr. Palmer, for example, stated that the Commission "directed the Company to evaluate natural gas additions as well as a full range of alternatives."[262] Ms. Pierce noted the Commission's 2016 IRP Order "expressly acknowledges that a natural gas RFP relating to 'efficient combined-cycle generation' is permitted for consideration at this time."[263] Such statements, while not necessarily incorrect, might benefit from some context.

MP has indeed expressed its intention in several consecutive IRP proceedings that it would pursue a natural gas combined cycle resource to be in-service at some point in the 2020s. It is also true that past planning cycles have consistently indicated the need for resources of an "intermediate" type. But the Commission has not ordered MP to pursue natural gas generation, nor given any indication that natural gas generation was least-cost relative to other resource options. If anything, Commission orders have stated the opposite: The Commission's 2016 IRP Order, for instance, made specific findings determining optimal amounts (or ranges of amounts) of energy efficiency, solar, and wind;[264] MP's pursuit of natural gas generation, on the other hand, was merely allowed to proceed given that MP decided to initiate an RFP on its own, and the Commission saw no benefit in stopping MP from evaluating bids when the natural gas RFP process was at its end stages. So when the Company references pursuing natural gas generation in the context of past Commission orders or directions, it is worth noting that no Commission order implied anything about the *need* to pursue natural gas resources specifically, nor was it ever established that natural gas generation was superior to other alternatives.

According to MP witness Mr. Frederickson, "the [natural gas] RFP timing was appropriate and allowed the Company to target long-term resources at a time when the need for a long-term solution had become clear. The RFP sought resources to be in service in the 2022-2024 time frame."[265] MP further noted:

[260] Ex. MP-21, at 4 (Brick Surrebuttal).

[261] Ex. MP-21, at 4 (Brick Surrebuttal).

[262] Ex. MP-16, at 4 (Palmer Direct).

[263] Ex. MP-15, at 10 (Pierce Surrebuttal).

[264] *See* 2016 IRP Order, ordering paragraphs 9, 10, 11, and 12 (July 18, 2016).

[265] Ex. MP-24, at 3 (Frederickson Rebuttal).

> [T]he record demonstrates it was entirely reasonable for Minnesota Power to take the steps necessary to secure the proposed 250 MW NTEC purchase in the way that it did.[266] Further, the timeline of the RFP was consistent with the July 2016 IRP Order.[267]

Staff does not agree with the Company that the RFP timing was appropriate. While a long-term solution may have been clear to MP, the 2015 IRP record did not support it because the record had not yet been developed. Moreover, associating the timeline of the RFP to the July 2016 IRP Order is very confusing because the July 2016 IRP Order was issued almost a year after the RFP.

MP issued its natural gas RFP, which led to the selection of NTEC, on October 15, 2015, just six weeks after the September 1, 2015 filing date of the Company's 2015 IRP. MP witness Mr. Taylor (of Sedway Consulting), who oversaw MP's solicitation for 200 - 400 MW of natural gas-fired capacity,[268] noted that MP selected NTEC as a preferred resource on April 28, 2016,[269] roughly three months prior to the Commission's July 18, 2016 Order.

To agree with MP that the timing of the natural gas RFP was appropriate would be to agree that competitive bidding for large-scale, non-renewable resources should precede not only Commission orders but comments from intervening parties. At the very minimum, its issuance was premature, since the Commission ultimately determined in its July 2016 Order that MP may have overstated its needs, and such a finding could have helped shape any RFP that MP might have issued thereafter. But in addition, statutory criteria in resource planning and certificate of need proceedings require utilities to first demonstrate to the Commission that additional renewable resources are not in the public interest or that needs cannot be met more cost-effectively by demand-side management. These criteria cannot possibly be met when RFPs and IRPs are issued and filed, respectively, at essentially the same time.

While staff generally agrees with the Department's comments on procedural issues, one area where staff disagrees with the Department is the connection it makes to MP's 2013 IRP, rather than the 2015 IRP. For instance, the Department was critical of MP for "[waiting] nearly two years after the 2013 IRP Order came out to issue the RFP."[270] The Department further noted that "[i]t is concerning that MP/ALLETE waited so long after the 2013 IRP to begin the process to acquire **the resources required** in the Commission's 2013 IRP Order"[271] (emphasis added).

Notably, in its 2013 IRP, MP's proposed action plan was to secure its near-term resource needs through bilateral contracts, not through a competitive bidding process for large-scale, non-renewables resources. The 2013 IRP Order stated:

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[266] *See* Ex. MP-26 and MP-27, at 10-11 (Supinski Rebuttal) (Public and Nonpublic); Ex. MP-24, at 10-13 (Frederickson Rebuttal).

[267] Ex. MP-24, at 10-13 (Frederickson Rebuttal).

[268] Ex. MP-22, at 4 (Taylor Rebuttal).

[269] Ex. MP-22, at 9 (Taylor Rebuttal).

[270] Ex. DER-9, at 23 (Rakow Direct).

[271] Ex. DER-9, at 24 (Rakow Direct).

> The Commission agrees with the Department that the Company's proposed near-term plan to obtain 200 MW of intermediate capacity and energy through bilateral contracts, assuming they are cost effective, is appropriate to address Minnesota Power's system needs over the next five years.[272]

Issuing a natural gas RFP would not have been consistent with MP's 2013 IRP for a few reasons. First, MP did not propose adding a natural gas resource upon approval of its IRP; instead, the Company proposed to "[b]egin investigation, **for inclusion in its next resource plan**, of an intermediate natural gas generation resource for Minnesota Power's customers"[273] (emphasis added by staff). Second, the long-term need projection in the 2013 IRP was much lower than the "up to 400 MW of capacity" solicited in the natural gas RFP; in the 2013 IRP Petition, MP projected it had "less than 200 MW of capacity need for the majority of the 15-year planning period, most of which is required after 2020."[274] Third, to justify the Company's issuance of a natural gas RFP, the Commission would have needed to approve a natural gas resource in the IRP or make some general finding that a natural gas resource was least-cost.

According to its 2013 IRP Order, the Commission did not require *any* resources beyond MP's five-year action plan, nor make a size, type, and timing finding beyond the five-year action plan; the Commission also did not explicitly address, procedurally or otherwise, MP's long-term plans for natural gas acquisition:

> 1. The Commission approves Minnesota Power's 2013 – 2027 resource plan. This approval does not extend to particular projects that are currently under review in other proceedings or will be subject to review in future proceedings, but is a general finding that the plans filed by Minnesota Power appear to be reasonable in light of the entire record.[275]

Another argument MP made to justify the timing of its RFP was the lead-time required for development, construction, and permitting. Staff notes this argument was already considered by the Commission, as MP defended its RFP timing in the exact same way in its IRP reply comments,[276] yet the Commission required further analysis of resource alternatives in the next IRP.[277] Of course, the Commission may reach a different conclusion now, especially since the deadline for MP's next IRP has been extended from February 2018 to October 2019. The point

[272] *In the Matter of Minnesota Power's 2013 – 2027 Integrated Resource Plan*, Docket No. 13-53, Commission Order (November 12, 2013), at 5.

[273] MP 2013 IRP Petition, 15.

[274] MP 2013 IRP Petition, at 56.

[275] *In the Matter of Minnesota Power's 2013 – 2027 Integrated Resource Plan*, Docket No. 13-53, Commission Order (November 12, 2013), ordering paragraph 1 at 8.

[276] MP 2015 Resource Plan Reply Comments, at 17 (March 4, 2016).

[277] Commission order, 2015 IRP, ordering paragraph 8 (July 18, 2016).

is the CEOs' and LPI's claims that MP proceeded too quickly to fill the identified need were not, as MP contended,[278] unsupported by the record.

It is quite apparent that, moving forward, resource planning and acquisition proceedings could benefit greatly from improvements to the process. Staff believes the agreement reached between MP and the Department—to establish a new bidding process for the Commission's consideration and approval under Minn. Stat. § 216B.2422, subd. 5[279]—does just that.

In the Department's Exceptions, it outlined its "New Finding DER-9," which listed six steps for supply-side purchases of 100 MW or more lasting longer than five years.[280] This is also Recommendation #6 of the Department's Initial Brief. Staff supports the Department's recommendation, as these reforms will hopefully mitigate the possibility that future IRP proceedings will be confronted with the challenges of navigating a utility-initiated RFP for a non-renewable resource issued prior to the Commission's evaluation of the record.

B. Resource Need

i. Forecasting

In Ms. Pierce's Surrebuttal Testimony, she explained the standards that should be applied when determining whether MP's forecast is reasonable:

> Minnesota Power believes that all stakeholders should insist that econometric forecasts used in resource planning meet certain standards: models should meet some basic statistical criteria; these statistics should be presented honestly to stakeholders; and any subjective modeling decisions on the part of the forecaster should be well-researched, presented in the appropriate context, and justified via written explanation. In every respect, the Company has met these standards.[281]

The ALJ concluded that "the Company's moderate growth 2017 AFR forecast of its future energy sales and peak demand is reasonable for use as the base case forecast in this proceeding."[282] The ALJ also concluded that "[w]hile the Administrative Law Judge recognizes the forecast included in the Petition could be improved in some regards … the concerns raised by the CEOs and LPI do not make the base case forecast unreasonable or otherwise inappropriate for use in this proceeding."[283]

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[278] MP Initial Brief, at 70.

[279] Department Exceptions, at 17.

[280] *See also* Department Initial Brief, at 76, Recommendation No. 6; Ex. MP-24, at 14-15 (Frederickson Rebuttal).

[281] Ex. MP-15, at 7 (Pierce Surrebuttal).

[282] ALJ Report, Finding of Fact 150.

[283] ALJ Report, Finding of Fact 152.

Because the ALJ did not identify any statistically-flawed, unsupportable methods MP used to derive the load forecast, and since the Judge explicitly concluded that MP's forecast is reasonable, staff does not question Ms. Pierce's claim that the Company has met every standard with respect to developing a reasonable forecast.

To the extent the Commission is concerned with forecast uncertainty in the modeling, staff notes that the Company ran a low load sensitivity and a high load sensitivity, and the Department ran a scenario using the base forecast as well as four additional contingencies, +/- 2.5% and +/- 5%. As an additional step, even though the 2017 AFR is already covered by the Department's forecast bands around the 2016 AFR, the Department performed a supplemental analysis using the 2017 AFR, which did not change its modeling findings.[284]

With this being said, staff believes CEO witness Dr. Stanton fairly critiqued MP's lack of variation in forecasted residential and commercial load growth. As noted, MP's low load scenario includes assumptions identical to those in MP's base case scenario, with the exception of PolyMet. The CEOs further contended that "[t]he last 20 years have shown no or negative load growth in the commercial and residential sectors,"[285] yet MP did not consider flat or declining growth even as a low sensitivity. If MP failed to either reasonably account for a full range of uncertainty or to consider recent trends in declining customer usage, this could be a valid consideration. This is because the sensitivity analysis might not be particularly informative if there is little to no variation across load sensitivities.

According to the 2017 AFR, MP's 5-year forecast error—the difference between the actual energy sales for a particular year and the predicted energy sales for that year five years prior—has been volatile, which could justify considering a broader range of uncertainty. The table below shows the forecast error in each AFR since 2000; it presents the year-ahead forecast error (red cells), the current year forecast error (green cells), and the 5-year ahead forecast error (blue cells).

Considering as an example the 5-year ahead forecast error for the most recent year with actual sales, 2016, MP's 2011 AFR over-predicted 2016 energy sales by 15.7%. The average 5-year ahead error was 6.4%,[286] meaning the AFRs have, on average, over-predicted energy sales by 6.4% on a 5-year ahead basis (although the average is greatly impacted by the forecast error during the economic recession, particularly in years 2009-2011). In addition, the column on the right showing the average AFR error, which staff outlined with a red box, includes many values above the Department's 5% forecast contingency (although these averages are heavily skewed by 2015-2016 data).

[284] Ex. DER-9, SRR-3, at 13 (Rakow Direct).

[285] CEO Initial Brief, at 8.

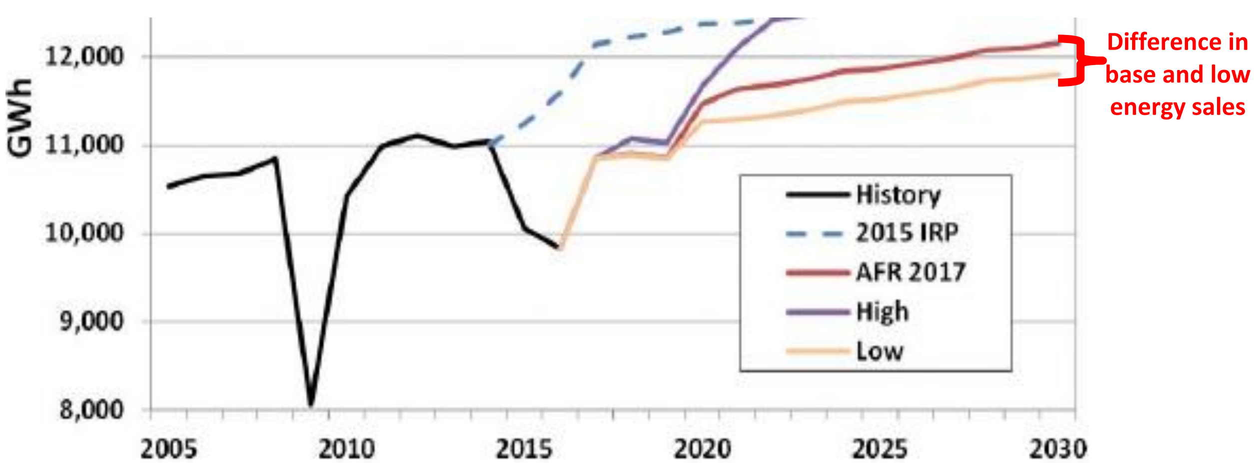
[286] MP's 2017 Annual Elec. Util. Forecast Report, Docket No. E999/PR-17-11, at 42 (June 29, 2017).

Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	-3.9%	1.5%	0.5%	1.9%	-0.6%	-2.2%	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%			0.1%	1.5%
AFR 2001		-2.0%	0.3%	3.4%	-1.0%	-3.1%	-4.1%	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%		0.4%	0.3%
AFR 2002			-0.9%	3.1%	0.2%	-2.4%	-3.6%	-3.8%	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%	0.2%	3.1%
AFR 2003				3.6%	-1.8%	-2.9%	-2.9%	-2.1%	-2.7%	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.9%	4.6%	1.8%
AFR 2004					0.6%	-0.3%	-0.5%	0.0%	0.6%	36.1%	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	8.2%	0.3%
AFR 2005						-0.3%	-0.5%	0.6%	4.1%	41.5%	11.0%	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	12.2%	0.5%
AFR 2006							-0.3%	1.4%	1.8%	41.8%	11.1%	7.4%	8.0%	10.0%	10.5%	22.3%	26.2%	12.7%	1.4%
AFR 2007								0.0%	-0.5%	37.0%	6.0%	2.8%	3.4%	5.7%	6.0%	17.4%	21.0%	9.9%	0.5%
AFR 2008									-2.0%	34.8%	8.9%	5.1%	4.0%	4.8%	4.1%	15.6%	19.3%	10.5%	34.8%
AFR 2009										4.8%	-16.8%	-13.9%	-8.1%	-3.1%	-0.9%	11.0%	15.9%	-1.4%	16.8%
AFR 2010											-0.8%	-1.8%	-1.0%	0.7%	1.1%	11.6%	15.2%	3.6%	1.8%
AFR 2011												-0.3%	-1.1%	0.5%	1.0%	11.9%	15.7%	4.6%	1.1%
AFR 2012													-1.4%	0.5%	0.7%	11.5%	15.4%	5.3%	0.5%
AFR 2013														-0.2%	-0.4%	18.1%	24.6%	10.5%	0.4%
AFR 2014															-0.3%	13.9%	24.2%	12.6%	13.9%
AFR 2015																2.4%	5.9%	4.1%	5.9%
AFR 2016																	-1.4%	-1.4%	

N.n%	*= Year-Ahead Foreast*	Avg Year-Ahead Error =	2.4%
		Avg Year-Ahead Error (No Downturns) =	-0.9%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.1%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	6.4%
		Avg 5 Year Error (No Downturns) =	2.9%

Note that the figure above does not indicate anything about likely future growth rates over the next 15 years, nor does it suggest emerging trends; it merely illustrates recent volatility, which could be relevant since MP's assumed growth rates across sensitivities are almost identical.[287] Below, for example, staff excerpted a portion of Figure 9 of MP's Petition (also on page 20 of the briefing papers), which shows actual sales, 2015 IRP projected sales, and the AFR 2017 Base, High, and Low projected energy sales forecast that were used in this proceeding. Staff added a bracket to show that the base case and low scenario: (1) run parallel to each other (they use the same or a very similar growth rate); (2) each predict continued, positive growth; (3) produce very little difference in total energy sales; and (4) do not, as the CEOs further observed,[288] explore any possibility of an economic downturn.



Why this is also important is because, despite what appear to be rather small differences between the base and low load scenarios, according to MP's modeling, the difference appears to be meaningful enough to determine whether NTEC is selected. For example, MP's modeling showed that under the low load sensitivity, NTEC "was not selected in the Summer Season

[287] MP's 2017 Annual Elec. Util. Forecast Report, Docket No. E999/PR-17-11, at 45-46 (June 29, 2017).

[288] CEO Initial Brief, at 10.

resource adequacy case," but it was selected "in all the Winter Season resource adequacy cases."[289] MP stated that "[t]he difference in results was immaterial in regards to how often the 250 MW NTEC purchase was selected between the summer and winter resource adequacy seasons,"[290] but this conclusion does not seem to be consistent with Figure 16 of MP's Petition, which shows that under the low load sensitivity, NTEC was selected only half the time.[291]

If the Commission is not persuaded by MP's arguments emphasizing the need to assume a winter season MISO resource adequacy construct—which does not yet exist—and if the Commission agrees with the CEOs that MP did not develop a reasonable low load sensitivity, then the Commission could determine MP did not evaluate NTEC under a reasonable range of load sensitivities.

ii. Could NTEC still be prudent even if MP overstated its resource needs?

Previous sections have discussed the CEOs' recommended adjustments to MP's forecast, including higher levels of energy efficiency and using a 10-year data set instead of a 26-year data set; however, even if these adjustments were considered to be reasonable, it would not necessarily follow that NTEC would be an imprudent resource addition, for a few reasons:

First, the CEOs' adjusted forecasted need still projects a capacity deficit (although the CEOs cited several factors which may erase MP's adjusted capacity need). To the extent purchasing NTEC results in surplus capacity, what constitutes unreasonably excessive surplus capacity is largely a policy choice. One could argue it is much less risky to have some surplus than to meet a forecasted capacity need down to the megawatt and thus risking a deficit. If, for instance, MP might not need a unit like NTEC in 2025, but could very likely need a unit like NTEC by 2030, a few years of capacity insurance is not inherently unreasonable if NTEC is otherwise determined to be a purchase that is competitively priced and operationally a good fit for MP's system.

Second, as the Department's modeling revealed, even under the lowest forecast contingency, purchasing NTEC could still lower societal costs, so in a sense, the capacity need might not even matter. If there is some capacity need, even if it is possibly less than what MP projects, then NTEC could provide capacity that will be needed at some point, but the much larger benefit could be in its production of inexpensive energy, which will displace generation from high dispatch cost units and avoid potential overreliance on the spot market.

Third, the Commission could determine NTEC provides other benefits that are more difficult to quantify in Strategist, such as dispatchability and fuel diversity, which might outweigh concerns about having surplus capacity for a few years.

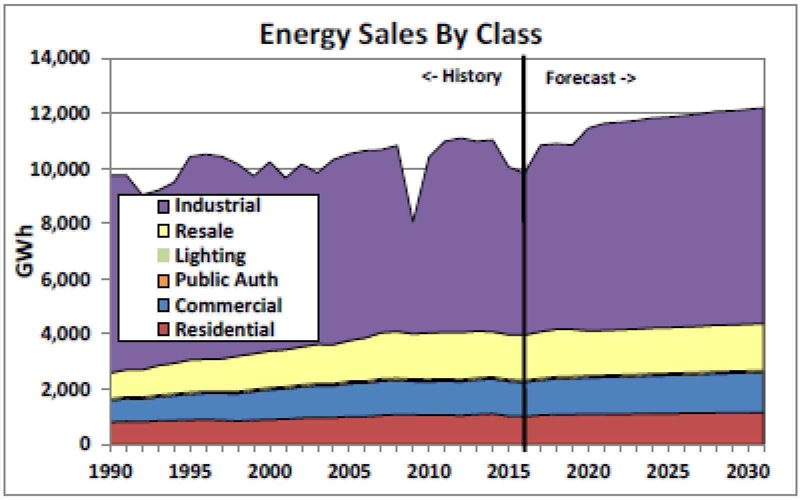
Finally, while MP's low load sensitivity does not significantly alter the growth rate relative to the baseline forecast, the same is true for the high sensitivity as well: the high load scenario

[289] Petition, Page 3-40.

[290] Ex. MP-18, Schedule 13, at 15 (Palmer Rebuttal).

[291] Petition, Page 3-40.

assumes a moderate rate of national economic growth and, like the low load scenario, assumes little variation in the energy and peak demand growth rates relative to the base case (in percentage terms). It is worth noting that, as shown by the figure below, MP's industrial energy sales are much greater than the commercial and residential classes combined, so even slightly higher-than-expected industrial load growth could vastly overwhelm flat or declining load growth among the residential and commercial classes, in terms of total energy sales:



Moreover, the sensitivity analysis should not be weighted to favor either the high or low bound, necessarily. If higher-than-expected growth—or even moderate growth in line with the national rate of economic growth—occurs in the industrial class in particular, it would be a very undesirable outcome if MP could not accommodate this growth without relying on the spot market or securing possibly more expensive bilateral contracts as short-term solutions.

As Ms. Pierce noted, "taconite and paper mill customers are energy-intensive and are subject to significant macro-economic industry changes over time."[292] This means that uncertainties exist at both sides of the spectrum. One could at the same agree that Dr. Stanton raised fair points about the possible variation among MP's residential and commercial customers, while concluding that her adjustments would not change the need to provide dispatchable, flexible electricity for MP's customers under a reasonably broad range of growth conditions.

iii. What has changed since MP's 2015 IRP?

The ALJ correctly observed that up to this point "the Commission has made no prior determination as to size, type, or timing of the addition of any gas-fired generation resource for the Company."[293] However, to put this in context, staff's interpretation of the Commission's July 2016 IRP Order was that the 2015 IRP record clearly demonstrated there would be *some* need for capacity and associated energy. The Commission may, with updated information, reach a different conclusion in this proceeding, but to be clear, the IRP Order anticipated that

[292] Ex. MP-13, at 9 (Pierce Direct).

[293] ALJ Report, Finding of Fact 214.

MP would have to replace capacity and energy lost from retiring Boswell 1 and 2, even without specifying exactly what that replacement would be:

> The Commission concurs with the Department and the Clean Energy Organizations that the most reasonable course of action on this record is to retire Boswell Units 1 and 2 **when sufficient replacement energy and capacity are available**, but no later than 2022 … The Department believed that replacement generation could be in place by 2022. In light of the Department's analysis, the Commission sees no reason to delay these units' retirement beyond 2022.[294] (Emphasis added by staff.)

While the expectation was that MP's next resource plan would consider a broad range of alternatives, the 2015 IRP record supported the conclusion that replacement energy and capacity would be required after the retirement of Boswell 1 and 2, even beyond MP's procurement of additional wind. (Of course, the instant proceeding presents a new record with a new forecast for the Commission's review, so staff's point is limited to the ALJ's interpretation of the Commission's 2016 IRP Order.)

It is also worth noting that the Commission relied heavily on the Department's modeling in MP's 2015 IRP to support its decision to retire Boswell 1 and 2, as well as other actions such as directing MP to procure more wind than MP included in its initial petition (which was none). The Department's analysis in the resource plan, cited in the Commission's Order, referred to the "Department's Preferred Plan," which through 2025 was as follows:[295]

Table 9: Department's Preferred Expansion Plan
(2016-2030, nameplate capacity)

Year	CC	CT	Solar Options	Solar Standard Compliance	Wind Options
2016	-	-	-	11	-
2017	-	-	-	-	-
2018	-	-	-	-	300
2019	-	-	-	-	-
2020	-	-	-	12	-
2021	-	-	-	-	-
2022	200 to 400	-	Up to 50	-	Up to 200
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	10	-

Consistent with the table above, the Department recommended the following long-term action plan, with the key phrase being "once the CC generation is online":[296]

[294] Commission 2015 IRP Order, at 7 (July 18, 2016).

[295] The Department's Preferred Plan included 76.5 GWh of energy savings.

[296] Ex. DER-12 SRR-S7, Page 2 of 9 (Rakow Surrebuttal).

A long-term action plan that includes MP:

- procuring approximately 100 MW of wind, 50 MW of solar, and 200 MW of combined cycle (CC) generation, partly to replace Boswell units 1 and 2, and
- shutting down Boswell units 1 and 2 once the CC generation is online.

There are two reasons why this context is important. First, one basis on which the ALJ recommended denial of NTEC was her (correct) observation that the Commission never made a size, type, or timing determination in the IRP, nor did the Commission specify a need for intermediate generation.[297] However, keeping in mind the Department's analysis on which the Commission relied to direct MP to retire Boswell 1 and 2, the lack of a specific finding on the size, type, and timing of MP's future resource needs does not mean the IRP record indicated no need at all. At least according to the Department's analysis, MP had a substantial energy need through 2022, and the Department found that a package of up to 500 MW of new wind, up to 50 MW of solar, and 200-400 MW of combined cycle capacity (and associated energy) would be least-cost. The Company has since brought forward proposals for 250 MW of wind, 10 MW of solar, and 250 MW of combined cycle capacity (and associated energy).

The second reason why this context is important is because, for this proceeding, the Commission is basically being asked to determine what has changed since its July 2016 IRP Order. MP is asking the Commission to approve the gas plant now because very little has changed, and the urgency in achieving commercial operation of a combined cycle plant by 2025 is the same as it was in the Company's IRP. The CEOs, on the other hand, requests the Commission consider the updated load forecast, lower renewable energy prices, and higher energy efficiency, among other things, as evidence showing MP has not demonstrated an underlying need for the NTEC purchase.

According to the CEOs, "there are a number of ways in which the assumptions contained in Dr. Rakow's base case are now stale,"[298] which is a statement that questions the fundamental validity of the Department's modeling. In response, staff notes two main, intertwining reasons which support the validity of the Department's model used in the instant proceeding.

First, the Department began the analysis with its base case from MP's prior IRP—in other words, it worked independently from but arrived at the same modeling result as MP—and as staff explained above, the Commission relied on the Department's modeling as a basis for many of its findings and decisions in the 2016 IRP Order. Thus, the Department's modeling was considered to be valid and reasonable as of July 18, 2016.

Second, for this proceeding, the Department revised its base case in accordance with new information, specifically: (1) MP's updated forecast; (2) the price of wind; (3) the price of solar; and (4) a new, optional CC unit based upon the project-specific inputs for NTEC. The Department determined that these four inputs have changed enough since the Commission's IRP Order such that a new, updated base case should be developed.

[297] ALJ Report, Finding of Fact 236, at 51.

[298] Ex. CEO-7, at 4 (Sommer Rebuttal).

Staff believes all four of the Department's updates were reasonable changes to make, and it was further reasonable for the Department to consider a broad range of values around the new baseline assumptions. With these updates, coupled with the fact that the Department's analysis was determined to be reasonable only two years ago, staff does not believe the Department's model lacks validity or is "stale." This does not mean, however, that every assumption is a correct representation of the future or that there are not additional or new circumstances and conditions for the Commission to consider. Rather, it means that the Department considered new information and updated the model if such information fell outside the bounds of the previous IRP model, which staff believes was a reasonable approach.

C. Consideration of Alternatives

i. Burden of Proof

In MP's Exceptions, the Company disagreed with the ALJ's conclusion that "the Company's consideration of alternatives was inadequate;" [299] MP contended the Judge's conclusion was based on speculative assertions made by the CEOs and LPI which do not reflect resource alternatives actually available to the Company. MP argued that intervenors cannot merely list other options; they need to support them with "substantial evidence." For instance, MP stated, "[i]f a party wants an alternative to be considered, it must provide **substantial evidence**—and not mere speculation—establishing that the proposed alternative is both available and the more reasonable and prudent option"[300] (emphasis added by staff).

A recurring theme throughout the filings and ALJ report is how robust MP's case must be in order to prove NTEC *is* needed and reasonable versus how much "substantial evidence" is required of intervening parties to show that NTEC *is not* needed and reasonable. LPI stressed this point repeatedly; in its Reply to Exceptions, for instance, LPI argued that "the Company has inappropriately attempted to argue that its burden should be limited to providing resource-specific analysis and that other parties bear the burden of showing that alternatives are reasonable and available."[301]

As it pertains to the consideration of resource alternatives—e.g., solar, demand response, energy efficiency, and energy storage—on the one hand, any threshold requiring that an intervening party must produce "substantial evidence" should not mean that NTEC is presumed to be needed and reasonable unless the intervenors disprove it, as this would shift the burden of proof to the intervenors. On the other hand, MP cannot be expected to consider every permutation of every size and type of resource imaginable, as doing so would not only be overly burdensome, but likely leave less time for the sensitivity analysis, and a robust sensitivity analysis, it could be argued, is more important than testing several versions of the same technology only to get the same result.

[299] ALJ Report, Conclusion 10, at 104.

[300] MP Exceptions, at 30.

[301] LPI Reply to Exceptions, at 5-6.

As an example of this balancing act—and this example will be discussed more in later sections—MP did not consider smaller blocks (25 MW) of solar units, instead only considering 100 MW solar units. The CEOs found through its analysis that it would be less expensive to add a 25 MW solar unit or four 25 MW solar units, depending on the scenario, in combination with additional wind power. MP argued in its Exceptions, however, that "[t]he intervenors failed to provide 'substantial evidence' that smaller blocks of solar presented a superior alternative to NTEC."[302] The CEOs argued that MP is missing the point: the CEOs do not believe a resource the size of NTEC is needed in the first place, and to the extent there is a need, additional solar could be part of a package that has a smaller total size.

In this example, MP implies that the intervenors have the burden to show, overwhelmingly, that resource alternatives (solar in this case) are more reasonable than NTEC, when in fact, it is the other way around: MP has the burden to show NTEC is both needed and reasonable relative to other alternatives. This is particularly important given (1) the renewable preference provision of the IRP Statute and (2) the certificate of need criteria requiring that no proposed large energy facility shall be certified without showing energy conservation and load-management measures are not more cost-effective.[303]

It is simply a fact that solar projects around 25 MW in size were available in the solar RFP process and would likely be available again should MP seek them, yet MP chose not to consider them in the Strategist analysis. At a minimum, there is evidence presented by the CEOs showing that different combinations of resources could be available at less cost than NTEC, and a 25 MW solar unit could be among them. But from MP's perspective, 25 MW solar blocks make no difference at all as to whether NTEC is needed and reasonable, so it would have been a waste of time to consider such resources; thus, additional, smaller-sized solar options should instead be considered as part of MP's next resource plan.

The Commission is being asked to resolve this and similar issues, basically as two different but not mutually exclusive questions:

- Could smaller blocks of solar be part of a least-cost expansion plan, and if so, does this impact whether NTEC is needed and reasonable? And,

- Is the record sufficiently complete to answer this question, and if not, did MP fail to comply with the Commission's orders requiring MP to evaluate a comprehensive set of resource alternatives?

Clearly MP has the burden of proving NTEC is superior to other alternatives, and the intervenors presented alternatives they believe are not only worthy of consideration, but are least-cost. At the same time, however, staff agrees with MP that, generally speaking, choices

[302] MP Exceptions, at 33.

[303] Minn. Stat. § 216B.243, Subd. 3.

must ultimately be made to practicably perform a robust sensitivity analysis in the deadlines set forth, and this will inevitably exclude sizes and types of some resource options.

ii. ALJ Conclusions on Resource Alternatives Considered

The ALJ concluded that MP's Strategist modeling failed to consider a reasonable range of alternatives in a number of ways:

- MP failed to provide a reasonable basis for not including a 100 MW CT alternative *(ALJ Finding of Fact 235)*;
- MP's claim that a 100 MW CT is not a viable resource option is not supported by the record *(ALJ Finding of Fact 236)*;
- MP has not provided any reasonable explanation for not using smaller blocks of solar resources as an alternative choice to allow for more flexible portfolio options *(Finding of Fact 237)*; and
- With regard to the 200 MW NTEC purchase, the Administrative Law Judge recognizes that the Company analyzed this option in a new swim lane (Swim Lane 6) and the power supply costs were similar. Nonetheless, the 200 MW option was selected in 56 percent of the scenarios, calling into question whether the 250 MW NTEC purchase is actually the least cost option even with the biases built into the Company's Strategist analysis. *(Finding of Fact 238)*.

As a matter of clarity, the reasonableness of MP's inputs and assumptions is separate to the question of whether MP considered a complete list of alternatives consistent with the Commission's prior orders. For example, whether the range of wind prices MP considered in Strategist was reasonable is separate to the question of whether it was reasonable that MP evaluated wind units in 100 MW blocks. As staff will explain in the following sections, staff believes that, with the exception of possibly solar, and without making any comments on the reasonableness of MP's assumptions at this time, there is justification for the Commission to conclude that MP's analysis complies with the Commission's requirement for MP to consider a full range of alternatives. This is not to say all of the ALJ's findings listed above are wrong, necessarily, but the Commission might apply a different standard and decide the evidence suggests there would be nothing more to learn had MP considered these options.

iii. Resource Alternatives Considered: Screening Process

Appendix J of the Petition includes a thorough explanation of which alternatives were considered and how they were considered. Appendix I and Appendix J discuss the Company's assumptions for each resource alternative the Commission's orders required, as well as many others. Page J-10 of Appendix J (Detailed Resource Planning Analysis) provides a full list of the resource options the Strategist model was allowed to consider. Below, staff lists only the dispatchable thermal resource options (because assumptions for renewable energy and storage are discussed elsewhere):

<u>RFP Alternatives</u>

- 250 MW share (approximately 48 percent) of a natural gas-fired 1x1 combined-cycle turbine (NTEC – "1x1 H CC 250MW")

<u>Generic Alternatives</u>

- 525 MW of natural gas-fired 1x1 CC ("1x1 H CC 525MW")
- 223 MW natural gas-fired combustion turbine ("CT 223MW")
- 112 MW natural gas-fired aeroderivative turbine ("LMS100 112MW")
- 55 MW natural gas-fired reciprocating engines ("Wartsila 54MW")

While MP used the Strategist Proview model to develop a least-cost resource portfolio, its "screening analysis" was done by developing and comparing each resource over a 20-year period using a "levelized busbar cost" or "levelized cost of electricity" (LCOE) approach:

> The levelized busbar cost approach is a simple and effective method to screen generation alternatives for consideration in expansion planning by removing the higher cost alternatives. The levelized busbar cost for each power generation alternative included estimated capital, transmission, operation and maintenance (fixed and variable), and fuel costs (combustible fuel or purchased electrical energy). Busbar costs for resources were compared with and without a carbon emission penalty cost at the base regulation level of $21.50 per ton starting in 2022. All of the alternatives were grouped together with the purpose of selecting the most cost-competitive resources for further evaluation in the expansion planning process.[304]

Figure 3 of Appendix J of the Petition, below, displays the levelized costs for the screened generic resources; the LCOE was calculated over a range of assumed capacity factors (i.e. utilization rates) for each resource alternative. Because the resource alternatives are capital-intensive (except for wind and solar, which were modeled as PPAs), the LCOEs decline at higher capacity factors:

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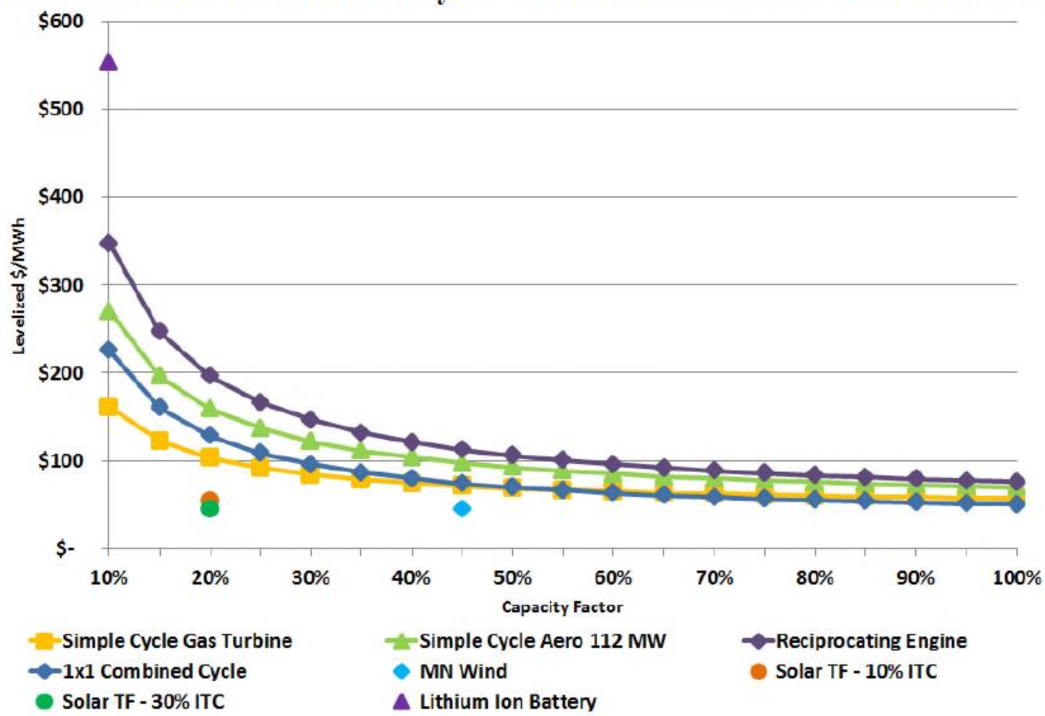
[304] Petition, Appendix J, Page J-5.

Figure 3: Resource Alternatives 20-year Levelized Busbar Cost – No Carbon Penalty



MP noted that NTEC is expected to operate at a 40% capacity factor. Using the generic 1 X 1 combined cycle as a proxy, this translates to a LCOE of roughly $80-90/MWh at a 40% capacity factor (although capacity factors can rise and fall significantly depending on system conditions). According to Figure 3, the 40% capacity factor is also the breakeven cost for the CT and CC, meaning that on a levelized basis a CC would be more expensive if it operated at capacity factors lower than 40%. At lower capacity factors, the LCOE for a CC unit would be in the range of $150-$225/MWh, much higher than the LCOE for the less capital-intensive simple cycle CT.

Staff raises the LCOE method in part because this was how MP performed their resource screen. In addition, comparing the LCOE of different resource types at various capacity factors can help illustrate the tradeoff between high capital cost, efficient resources like CCs and lower capital cost, less-efficient resources like CTs. But perhaps most relevant to the resource planning analysis is how the LCOE method differs from a Strategist analysis.

Comparing resources of different types using the LCOE method has several weaknesses relative to using a capacity expansion model such as Strategist. Primarily, the LCOE method compares resources based solely on their costs and does not account for avoided costs, such as displaced energy from MP's highest-cost generators or the spot market. LCOE is more common when comparing similar projects, for example, by ranking wind bids, because a group of wind projects can be expected to have roughly similar production profiles and thus have similar avoided costs and energy value. The same would not be true, however, when comparing a 525 MW intermediate CC unit to a 223 MW peaking CT, for example.

iv. Resource Alternatives Considered: Natural Gas Options

As listed above, MP considered a 223 MW CT, a 112 MW aeroderivative turbine, and a 50 MW reciprocating internal combustion engine (RICE) as generic peaking options. With each option, there is a trade-off in the technology's size versus its capital cost ($/kW)—generally, the smaller the size, the higher the $/kW. In staff's view, MP appropriately considered three peaking options, which demonstrate the economies of scale associated with larger units across turbine sizes.

LPI argued that a 100 MW conventional CT, like the LM-6000, which can also be configured as a combined cycle unit,[305] should have been included as a generic resource option.[306] Below is an excerpt from LPI witness Mr. Andrews's Public Surrebuttal Testimony, noting the substantial price difference between the aeroderivative turbine versus the 223 MW CT:[307,308]

> The annual fixed cost and the capital cost modeled for the 100 MW aeroderivative turbine is significantly higher than the large frame 228 MW CT that was included as a resource alternative. The modeled 2025 fixed cost for the aeroderivative turbine is **[TRADE SECRET DATA BEGINS**
>
> **TRADE SECRET DATA ENDS]** 2025 fixed cost of the large CT.[1] The capital cost is also significantly greater; for the aeroderivative, the 2017 capital cost is **[TRADE SECRET DATA BEGINS**
>
> **TRADE SECRET DATA ENDS]** 2017 capital cost of the CT.[2]

Staff shows the excerpt above because, first, the ALJ cited it in her conclusion that "the record suggests that the 100 MW aeroderivative turbine analyzed in the Company's Strategist is more expensive than a 100 MW CT option."[309] In other words, the ALJ agreed with LPI that it was a flaw in MP's analysis not to consider a 100 MW CT and only evaluate a roughly 100 MW aeroderivative turbine. Second, it is notable that the ALJ used the phrase "more expensive," because the Judge is referring only to the $/kW. In the LCOE screen discussed above, "more expensive" would have compared two technologies at various capacity factors. A superior means would be to compare the two based on how they fared in Strategist. But to say one technology is more expensive than another technology based solely on the difference in capital costs is incomplete.

In addition, staff did not interpret Mr. Andrews's testimony in the same way as the ALJ. As staff interpreted it, Mr. Andrews compared the capital cost of a 223 MW CT to the capital cost of a

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[305] Ex. LPI-7, at 11 (Andrews Direct).

[306] Ex. LPI-7, at 10-11 (Andrews Direct).

[307] This excerpt is from the PUBLIC version of Mr. Andrews's Surrebuttal Testimonty, so staff refers the Commission to the TRADE SECRET version for the entirety of his argument.

[308] Ex. LPI-10, at 3 (Andrews Surrebuttal).

[309] ALJ Report, Finding of Fact 235, at 51.

100 MW aeroderivative turbine; it would not be surprising that an aeroderivative turbine would have a higher $/kW than a simple cycle CT because, like with wind farms and solar projects, combustion turbines have quite substantial economies of scale. In fact, these economies of scale is one reason why MP is seeking 48% of a 525 MW combined cycle plant rather than 100% of a 250 MW combined cycle plant. It seems, though, that the ALJ's reference to "a 100 MW CT option" means that it can be procured at the same $/kW cost as a 223 MW CT. But the size of a 223 MW CT cannot simply be cut in half while keeping the $/kW cost the same, since a CT of half the size would be a different turbine technology with a different capital cost per-kW.

In MP's Exceptions, the Company noted that "a stand-alone 100 MW traditional CT option does not exist without a partnership."[310] MP addressed the possibility of a partnership (or rather, the lack thereof) prior to the ALJ Report as well. Mr. Palmer, for instance, noted in his Rebuttal Testimony that "such a partnership does not exist today for a CT."[311] In addition, MP noted that an aeroderivative turbine is the only technology available for a stand-alone gas turbine of 100 MW.[312] Again, this raises the question of what the Commission requires MP to prove in order to satisfy a complete list of alternatives. It seems the standard the ALJ placed on MP, for this particular alternative, was to either prove a 100 MW conventional CT does not exist at the same $/kW cost as a 223 MW CT, or to prove the possibility of a partnership does not exist.

LPI's references to, for example, the LM-6000 as a resource option seem fairly light on support, so this could be one instance in which an intervenor, while not bearing the burden of proof, failed to provide sufficient evidence in support of its claim. Other than that it can be configured as a combined cycle, operationally or on economics, it is not clear why the LM-6000 or a turbine like it was determined to be a reasonable alternative option. LPI stated that "what the U.S. Energy Information Administration ("EIA") considers as a conventional CT facility is 100 MW and consists of two LM-6000 units,"[313] but Mr. Andrews did not cite this statement or provide any $/kW information. LPI should be able to explain how EIA's "conventional CT facility" sized at 100 MW is different than an aeroderivative turbine, what its cost is, and what the technological capabilities are that make it a reasonable alternative to NTEC.

v. Resource Alternatives Considered: Smaller Solar Units

As staff briefly discussed earlier, MP evaluated solar options as 100 MW units. The CEOs argued MP should have allowed Strategist to choose solar in 25 MW blocks since the Company has "relatively little need for capacity."[314] The ALJ concluded that "MP has not provided any reasonable explanation for not using smaller blocks of solar resources as an alternative choice to allow for more flexible portfolio options."[315]

[310] MP Exceptions, at 30.

[311] Ex. MP-17, at 74 (Palmer Rebuttal).

[312] MP Reply Brief, at 54.

[313] Ex. LPI-7, at 10 (Andrews Direct).

[314] Ex. CEO-16 at 21-22 (Sommer Direct); Ex. CEO-18 at 12 (Sommers Surrebuttal).

[315] ALJ Report, Finding of Fact 237, at 51-52.

The size of solar options (i.e. smaller blocks) could be immaterial for two reasons. First, even if solar units were selected, the model could still also select NTEC (which was the case in the Department's modeling). Second, MP assumes solar has very little capacity value, especially in the winter. Although solar has its own unique production pattern in the Strategist model that provides energy value, given the relative cost premium of solar and its little to no capacity benefit, additional solar by 2025 is cost-prohibitive according to MP's modeling. (Even in MP's 75% Renewable swim lane, the model adds 1,950 MW of wind and no solar from 2020 through 2031, further illustrating the lack of capacity value which MP assumes solar can provide.)

At the same time, however, staff believes there are valid reasons to question some aspects of MP's analysis of solar options, but for different reasons than the CEOs'. It was abundantly clear in the documents pertaining to the solar RFP process that MP never had any intention of acquiring larger solar units. For example, in Sedway Consulting's "Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation,"[316] Sedway discussed MP's preference for small projects over large projects, even though larger solar bids (75 MW or greater) were much less expensive than smaller ones (25 MW or less):

> Several bidders had contacted MP and Sedway Consulting during the evaluation process and noted that technology costs had declined and they could improve their bid pricing. In all such cases, MP and Sedway Consulting made it clear to such bidders that unsolicited, "one-off" repricing of proposals would not be entertained. However, **given the results of the preliminary shortlisting analysis and the decision to focus on smaller projects, MP and Sedway Consulting agreed that it would be appropriate to return to a sizable portion of the top-ranked bidders with projects in the 25 MW and smaller category and afford them all the opportunity to reprice their proposals and scale down any that were greater than 10 MW**.[317] (Emphasis added by staff.)

Why the independent evaluator was involved in sizing MP's solar portfolio is strange, but nevertheless, MP decided prior to filing its petition that it would not consider solar projects even remotely close in size to the 100 MW generic solar option considered in the instant case. In fact, bidders of projects greater than 25 MW offered to reprice their proposals as solar costs continued to decline, yet MP declined to entertain such proposals. Bidders in the smallest category, however, were granted the opportunity to reprice bids, although only if they could be resized at 10 MW. (This led to the selection of the 10 MW Blanchard Solar Project.)

At a minimum, MP's resource planning analysis should have been aligned with the size of solar projects it was actually considering during the RFP process. MP's explanation for assuming 100 MW solar blocks in the instant proceeding was that, "[c]onsistent with Order Point 11 from the July 2016 IRP Order, Minnesota Power also evaluated adding solar in 100 MW block sizes."[318]

[316] Appendix R of July 28, 2017 Energy*Forward* Petition.

[317] Appendix R of July 28, 2017 Energy*Forward* Petition, at 5.

[318] Ex. MP-16, at 25 (Palmer Direct).

The Commission never indicated anything about the size of the solar project MP should pursue, only the total amount of solar that could be cost-effective for MP's system. Actually, it could be argued that, given the Commission's interest in cost-effective solar projects (as well as the legislature's[319]), a better interpretation of Order Point 11 would be that MP should have sought the absolute lowest-priced solar bids among all size categories and presented a group of projects for the Commission's review. This would have been particularly reasonable in light of the bidders' willingness to reduce prices due to ongoing declines in solar costs.

What is not clear from the discussion provided in Sedway's report is (a) what group of bidders offered to reprice their bids and (b) what the price of a group of bids, possibly as much as 100 MW in total, could have been. Unfortunately, the record cannot show what the lowest cost of ITC-available solar could have been in an amount close to 100 MW. What is known, though, is that the prices of solar bids were far lower than the generic solar price assumed in the IRP.

The overall cost impact of additional solar is further complicated by the fact that MP did not allow Strategist to add any solar sooner than 2025 (after the ITC is assumed to expire), even though the Commission's 2016 IRP Order expressly stated that up to 100 MW of additional solar could be cost-effective by 2022.[320] MP's rationale for the 2025 model constraint was because that year aligned with the identified need. However, MP forecasts an energy need of over 1 million MWh in year 2020,[321] so ITC-available solar could have helped meet this short-term energy need. Additionally, this constraint frankly ignores the Commission's "100 MW by 2022" solar finding in the IRP and implies the year 2022 is now too meaningless and antiquated to be worth modeling.

Nevertheless, as MP argued in its Exceptions, "the cost and capacity deficiencies will not change with the size of the solar resource,"[322] so from MP's perspective, there would be no value in considering smaller-sized blocks of solar in the NTEC analysis. Also, it should not be forgotten that the ultimate issue in this case is whether NTEC is needed and reasonable. Whether or not more solar is added may be inconsequential to the decision for this case. According to the Department's analysis, additional solar up to 100 MW could still be cost-effective (and frequently is), but additional solar does not impact the selection of NTEC. Therefore, even if the Commission believes it was unreasonable for MP to exclude smaller-sized solar projects as a resource alternative, this might have no bearing on whether NTEC is in the public interest.

vi. Energy Storage

[319] Minn. Stat. § 216B.1691, Subd. 2.f.(e) states, "It is an energy goal of the state of Minnesota that, by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy."

[320] Commission 2016 IRP Order, ordering paragraph 11, at 15.

[321] MP Initial Brief, at 48.

[322] MP Exceptions, at 32.

The CEOs' criticisms of MP's analysis of energy storage is another area where the Commission might find the intervening party did not produce sufficient evidence to demonstrate a viable alternative to NTEC, for a few reasons.

First, the CEOs cited a Lazard report to challenge MP's cost assumptions for battery storage; the report provided a cost range for "four-hour duration lithium-ion systems."[323] If the Commission agrees with the Company that there is a benefit or need for around-the-clock, dispatchable, and flexible generation, a "four-hour duration" lithium-ion battery may not be a good fit for the load profile of MP's system.

Second, the CEOs' Strategist modeling expert did not adjust the cost assumption for battery storage when running her analysis, so the CEOs did not produce capacity expansion modeling showing how storage could affect the least-cost expansion plan.

Third, it is not clear, exactly, what the CEOs request the Commission do as it relates to battery storage, other than to deny NTEC. For instance, if the Commission finds MP has a need to add resources, the CEOs did not elaborate on what size or type of battery can eliminate or delay the need for NTEC and why. The CEOs qualitatively refer to certain benefits of energy storage, such as ancillary services, as well as the limitations of Strategist in showing these benefits, but if true, the same limitations would presumably apply to modeling combined cycle plants. As Ms. Pierce noted, NTEC will have the capability "to augment the system with ancillary services such as regulation, frequency, and voltage support."[324] Perhaps Strategist failed to capture the full suite of benefits NTEC can provide as well.

Notably, MP is not completely dismissive of energy storage technology; MP simply determined that, for this proceeding, energy storage is cost-prohibitive and not a viable alternative to NTEC. MP explained, "battery storage was never selected across the 292 sensitivities evaluated. As costs decline for battery storage, Minnesota Power will continue to consider it as a resource alternative or solution to transmission and distribution investment."[325] Staff believes this is a perfectly reasonable approach in light of the facts presented in this case.

D. Modeling Assumptions and Resource Selection

There were a number of disputes regarding the reasonableness of various assumptions used in MP's, the Department's, and the CEOs' modeling. Some of the most frequently disputed assumptions were the load forecast, wind prices, wind and solar capacity credits, demand response, and levels of energy efficiency.

Also, there were several disagreements concerning the methodological approaches to the Strategist analysis. For example, the Department argued the CEOs focused excessively on the

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[323] Ex. CEO-2, at 13 (Jacobs Direct).

[324] Ex. MP-13, at 29 (Pierce Direct).

[325] Ex. MP-18, at 38 (Palmer Direct).

base case rather than the range of values,[326] while the CEOs argued that the model was so heavily biased toward selecting NTEC that the sensitivity analysis has questionable value.[327]

Below, staff will discuss a few of the issues raised, including different methodological approaches and some of the specific assumptions used in the model, but first, staff will discuss how the ALJ's standard of review might differ from how the Commission could view this case.

i. The ALJ's Legal Standard

In the Company's Reply to Exceptions, MP cautioned the Commission from adopting the Judge's recommendations, stating that doing so would have drastic consequences for future resource acquisition proceedings. MP argued that "the record was developed according to the Commission's prior directives and followed well-settled norms and practices dating back decades," and "resetting the Commission's analytical approach would impact all utilities and would certainly create delay as all stakeholders come to grips with the new approach advocated by the CEOs."[328]

In staff's view, the Company's warning is perhaps too vague and strongly worded to support. First, the "Commission's prior directives" were for the Company to update the load forecast and examine several resource alternatives alongside its desired gas plant in the next resource plan; it was the Company's request to pursue the route of a contested case.

Second, in the previous IRP, the Commission clearly established that just because the Company was allowed to proceed with its natural gas RFP—which MP initiated without Commission direction—there would be no presumption that any natural gas generation would be approved. MP appears to imply that any decision other than approving NTEC would fly in the face of past Commission orders and practices.

Third, it is unclear what MP is referring to when it characterizes the ALJ Report as a deviation from "norms and practices dating back decades," or mentions the "new analytical approach advocated by the CEOs." The CEOs' analytical approach, like MP's and the Department's, was to similarly run the Strategist model—albeit in a more limited, streamlined way—by modifying a handful of assumptions.[329] It was neither the CEOs' intention nor its responsibility to construct the type of bottom-up Strategist analysis required of MP as the petitioner. Rather, the CEOs' aim was to show that when certain adjustments are made, the record does not support the need for a resource of the size, type, and timing of NTEC. This is much different, in staff's view, than advocating for an overhaul to the Commission's IRP and resource acquisition proceedings.

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[326] Ex. DER-12, at 44-45 (Rakow Surrebuttal).

[327] Ex. CEO-3, at 4-5 (Sommer Direct).

[328] MP Exceptions, at 1.

[329] CEOs Reply Brief, at 16-17.

The CEOs' modeling showed that by using alternative assumptions, NTEC was not least-cost or needed. The Judge considered these modified assumptions, as well as statutory requirements such as the renewable preference provision of the IRP statute, and concluded MP did not meet its burden of proof. The Commission may agree or disagree with the Judge, or be unpersuaded by the CEOs' arguments, but it is unclear how the CEOs—as an intervenor without a burden of proof, who challenged the Company's ability to demonstrate need and meet relevant statutory criteria—will "certainly create delay" in future resource acquisition proceedings as a result of its argument that MP did not meet the preponderance standard in this case.

MP also argued in its Exceptions that the ALJ's recommendation to deny the Petition "is based on a very specific view of the world that may or may not come to fruition, and ignores the fundamental focus of resource modeling on outcomes that occur over a broad range of future scenarios."[330]

Staff does not agree with the Company that the Judge either (1) expressed "a very specific view of the world" or (2) neglected to consider a broad range of values. First of all, a critical takeaway from the ALJ Report is that the Judge did *not* conclude MP has no need for capacity and energy over the typical, 15-year resource planning timeframe, nor did she recommend any particular expansion plan; rather, the Judge concluded that MP did not meet its burden of proof demonstrating the need for NTEC in 2025. While the ALJ agreed with the CEOs and LPI in several areas, there were no recommendations for MP's 2015 approved IRP, which, as staff discussed earlier, is still in effect and has previously demonstrated a substantial need for capacity and energy in some form over the long-term. At some point the size, type, and timing question—previously left unresolved—will need to be addressed, but the ALJ chose not to do so because that was not her task.

In other words, the ALJ did not find that any of the CEOs' alternative expansion plans—shown in Table 3 of Ms. Sommer's Direct Testimony[331]—were necessarily more reasonable than MP's and should therefore be adopted; rather, the Judge disagreed with several of MP's modeling assumptions, including: the wind capacity credit, the solar capacity credit, demand response capability, embedded energy efficiency, and the number of resource alternatives considered. These conclusions, along with the statutory requirement that MP must meet the renewable preference provision of the IRP Statute[332,333], ultimately led the Judge to conclude that the underlying need for NTEC did not meet the legal standard that was applied. In the ALJ's view, MP failed to demonstrate the reasonableness of so many of its assumptions, as well as assess a reasonably comprehensive range of alternatives, that the collective erroneousness and bias in the model did not prove by a preponderance of the evidence that the NTEC 250 MW purchase was needed.

[330] MP Exceptions, at 5.

[331] Ex. CEO-3, at 28 (Sommer Direct).

[332] Minn. Stat. § 216B.2422, subd. 4.

[333] *See* ALJ Report, Findings of Fact 87, 326, and 401.

Regarding the issue of the ALJ's purported overreliance on a singular base case as opposed to a range, staff can understand why MP took this view. Indeed, the Judge referenced the base case several times, and the NTEC purchase was selected in the vast majority of cases in both MP's and the Department's modeling analysis. However, in several instances the ALJ Report referred to the importance of ranges. For example, on wind prices, the Judge found that "while the wind price assumed by the Company appears to be on the high side, the Company's lower range of sensitivities include much lower prices and thereby address this pricing concern."[334] Additionally, the ALJ rejected LPI's request for additional analysis of the TCJA's impact on capital costs, finding that the impact of the TCJA is likely within the +/- 30% range of uncertainty MP assumed for capital costs.[335]

But for many reasons, staff does not believe the Commission must review the instant proceeding in the exact same way as the ALJ. In part, this is because the ALJ did not focus on long-term issues, such as MP's resource need through the remainder of the planning period. In addition, the ALJ did not weigh in on how expeditiously the Company could move through additional regulatory proceedings, which could be an important factor to consider depending on the Commission's determination on size, type, and timing. The Commission might decide that NTEC is the best resource currently available, and that among all generic alternatives evaluated, NTEC will best satisfy and balance the factors to consider listed in the Commission's IRP Rules, which are reliability, rates, environmental and socioeconomic concerns, and risk.[336] Whether MP appropriately followed the process or not, NTEC is currently the only project known to be available that can meet the Company's resource needs.

Additionally, while the ALJ concluded that many of the assumptions used by the CEOs were more reasonable than those used by the Company,[337] it is important to note that the Judge also found[338] that the CEOs' modeling was not sufficient for selecting a resource plan:

> 339. While the CEOs' Strategist results showed that NTEC was not the most economic choice to meet the Company's potential needs in the late 2020s, these results are not necessarily sufficient by themselves for making a resource decision as they are based on a small number [of] runs.[339] The CEO's modeling was not intended to substitute for the full analysis that should proceeding a size, type, and timing decision for a utility's resource selection but rather "were merely intended to show that a reasonable set of alternatives can provide a very different picture than that painted by the Company."[340]

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[334] ALJ Report, Finding of Fact 251.

[335] ALJ Report, Finding of Fact 298.

[336] Minn. Rule. 7843.0500, Subpart 3.

[337] ALJ Report, Finding of Fact 338, at 70.

[338] ALJ Report, Finding of Fact 339, at 70.

[339] Ex. CEO-18 at 24 (Sommer Surrebuttal).

[340] Ex. CEO-18 at 25 (Sommer Surrebuttal).

The conclusion of MP's last IRP proceeding left some issues unresolved, such as the load forecast and renewable energy prices. Even though a contested case was not envisioned at the time, staff believes there is sufficient information in this record for the Commission to (1) make a size, type, and timing finding and (2) determine whether NTEC is in the public interest over the span of MP's planning period. The ALJ did not go this far. The Commission, alternatively, might decide that the evidence suggests it is more likely than not that an intermediate unit is needed and reasonable within MP's planning period, and it would place undue risk on MP and its customers to deny a competitively priced project only to examine the same issues again in future regulatory proceedings. Again, the Judge did not conclude wind and/or solar were superior resources to NTEC, yet the Commission could determine that NTEC is a sensible fit for MP's system, operationally and economically, over the long-term.

ii. Methodological Approaches to the Strategist Analysis

What is important to note about the base case is that it is merely a reference point. The purpose of a sensitivity analysis is to analyze how a range of values across a set of variables affect a resource portfolio's revenue requirements and societal costs. Ideally, among a broad range of futures, trends can be observed which can inform whether a generation resource or resource plan is in the public interest.

In the Commission's IRP Rules, one factor to consider in the Commission's review of resource plans is to "limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."[341] One reason why it is important to assess a broad range of values is because this is the primary means by which to measure the exposure to risk.

One example of how the base case values could be stressed across a broad range is the Commission's environmental externalities values. In some cases MP included the Commission-approved low, mid, and high environmental externality values as sensitivities, and MP added two new futures which included mid-externality values as a base assumption.[342] Either way, what is important is that all externality values, including zero, are evaluated and considered in order to be able make a well-informed determination of how a particular resource plan impacts society and the environment.

With this being said, staff agrees with the CEOs that the frequency with which a particular resource option is selected does not automatically mean that that resource is in the public interest. For instance, if it is the case that a model is constructed in a way that is flawed or biased, the fact that a resource is selected 90% of the time might not be particularly informative, as the stress test of a sensitivity analysis would merely evaluate a series of unreasonable ranges. This, ultimately, is what the ALJ concluded; in Finding of Fact 341, for example, the Judge explained that the flawed construction of the model rendered the frequency argument unpersuasive.

[341] Minn. Rule. 7843.0500, Subpart 3(e).

[342] Ex. MP-18, at 58-59 (Palmer Rebuttal).

iii. Model Constraints

In staff's view, the ALJ and CEO/LPI raised valid points regarding the 2025 timing constraint. The whole point of this proceeding was to determine whether the 250 MW NTEC purchase was needed in light of an updated forecast. The Commission refrained from making a size, type, and timing finding because it was concerned MP overstated its resource needs. While the Department argued the price of wind and solar did not influence whether or not NTEC was selected, this is an after-the-fact assessment of the modeling results, not a reason to initially construct the model in such a way that precluded ITC- and PTC-available renewable energy from being selected. The Department noted that its analysis made intermediate units available in all years, but the Department is not the petitioner, and it should not be incumbent upon the Department to clear up unreasonable modeling choices on behalf of the Company.

According to MP's own projections, MP's capacity and energy needs escalate gradually over time and do not simply appear in 2025; they begin in roughly 2019-2020.[343] As stated previously, MP's claimed capacity deficit "begins to grow from between 5 and 30 MW in 2019 to around 100 MW in 2025." [344] In forecasting its energy requirements, MP projects "growing energy needs starting in 2020, around 1 million MWh and increasing to 2.4 million MWh by 2031."[345] Yet despite this gradually increasing need, MP explained that timing constraints were imposed in 2025 due to the "identified need," which is not even totally consistent with the Company's outlook and is entirely inconsistent with the Commission's 2016 IRP Order. As Mr. Palmer explained:

> **Q. Was it reasonable for the Company to not allow Strategist to choose generic wind and solar resources until 2025?**
>
> A. Yes. The purpose of this proceeding is to evaluate a mid-2020s resource addition to meet the identified need in 2025, consistent with the Company's past IRP outcomes. Therefore Minnesota Power's approach to the Strategist modeling was to allow the maximum number of resource alternatives for consideration in that timeframe. Furthermore, in its base case, Minnesota Power already assumes the addition of 250 MW of wind in 2020 and 10 MW of solar in 2020, consistent with the Energy*Forward* Resource Package.
>
> In addition, focusing on the need starting in 2025 enabled Minnesota Power to enhance its Strategist expansion planning analysis by allowing the Company to evaluate more resource alternatives than would typically be evaluated in a traditional IRP due to limitations in the Strategist model. In addition to the proposed capacity purchase, the Company was able to evaluate small, medium, and large peaking resources; solar and wind; battery storage; and new customer

343 *See* Figure 7 (Page 2-13) and Figure 11 (Page 3-12) of MP's Petition.

344 CEOs Initial Brief, at 20.

345 Petition, Page 2-13.

> demand response programs. In previous IRPs the list of resource alternatives would need to be condensed for the Strategist model to be able to solve. By permitting the selection of resource alternatives only in 2025, the Company was able to conduct the most robust analysis of resource additions using the Strategist model.[346]

As explained by the testimony above, in addition to the identified need, MP makes an additional argument that attempts to demonstrate a need to balance limitations of the model with the Commission's requirement for MP to consider several resource alternatives. But it is not clear why the Strategist analysis in this docket was more challenging than in previous IRPs. First, as with previous IRPs, MP performed a resource screen to limit the number of resources Strategist could select. Second, the number of resource alternatives analyzed in this proceeding does not appear to be much different than MP's 2015 IRP. In the table below, for example, staff shows the exact language of MP's description of resource alternatives considered in this case, and the exact language of MP's description of resource alternatives in the IRP:

[346] Ex. MP-18, at 60 (Palmer Rebuttal).

Resource Alternatives by Proceeding	
NTEC Proceeding (Appendix J, Page J-10)	**2015 Resource Plan** (Appendix K, Page 17)
250 MW share (approximately 48 percent) of a natural gas-fired 1x1 combinedcycle turbine (NTEC – "1x1 H CC 250MW")	200 MW share of a natural gas-fired 2x1 combined cycle ("200 MW CC")
525 MW of natural gas-fired 1x1 CC ("1x1 H CC 525MW")	198 MW natural gas-fired combustion turbine ("198 MW CT")
228 MW natural gas-fired combustion turbine ("CT 2238MW")	55 MW natural gas-fired reciprocating internal combustion engine ("55 MW Reciprocating Eng")
112 MW natural gas-fired aeroderivative turbine ("LMS100 112MW")	150 MW bilateral bridge purchase ("150 MW Bridge")
50 MW lithium-ion battery storage ("Battery Storage 50MW / 200MWh")	50 MW request for proposal ("RFP") baseload purchase ("50 MW RFP")
55 MW natural gas-fired reciprocating engines ("Wartsila 54MW")	102 MW wind farm located in North Dakota ("102 MW N.D. Wind")
100 MW wind farm located in Minnesota ("MN Wind 100MW")	50 MW Solar
100 MW solar farm located in Minnesota ("Solar 100MW")	Backup generation program ("DG Backup P1" & "DG Backup P2")
50 MW bilateral bridge transactions ("Intermediate Bridge Purchase")	CAC load control ("CAC DSM")
Air conditioning load control ("Air Conditioning Direct Load Control") and hot water load control ("Water Heater Direct Load Control")	HW load control ("Water Heater DSM")
	Energy efficiency

MP will likely be able to provide the Commission with more information regarding the timing constraint and why the number of resource alternatives necessitated this constraint. But at this time, it appears the record is missing more information than it likely gained as a result MP's constraint, a prime example being MP choice not to model up to 100 MW of ITC-available solar by 2022, per the Commission's 2016 IRP Order.

On the other hand, if MP had not imposed this constraint, perhaps the result would not have been any different. According to the Department's modeling at least, it would likely not have mattered at all. In fact, the Department noted that intermediate capacity was available to

Strategist in all years, Strategist optimized the model based on provided assumptions, and Strategist selected NTEC in 2025.[347]

iv. Combinations of Disputed Assumptions

One of the CEOs' primary criticisms of MP's and the Department's modeling was that they did not model reasonable assumptions *in combination* with one another. Ms. Sommer argued that, for example, "[m]odeling the combination of lower load and lower wind prices could have a meaningful impact on the modeling result, even if either change individually would not affect the modeling result."[348] In the CEOs' view, the Department's analysis is flawed because it "presents no runs in which the combination of lower wind prices and lower load are modeled together."[349]

Staff generally agrees with MP's and the Department's response, which is that picking certain assumptions—for example, low wind prices *and* lower load—and grouping them together as the most reasonable combination implies that one particular future is necessarily more reasonable than all other values in that range. This can be problematic because, as the Department noted, for example, "it is not known today what the price of wind will be 10 years in the future and arguments over which forecast of wind prices to use as the base case for units available a decade from now is not productive."[350]

That said, there should be evidentiary support for the low, base, and high values within any given range. A reason why it could have appeared the ALJ focused too narrowly on the base case is because the Judge concluded certain ranges were not reasonable. This was the case with energy efficiency: the Judge concluded that should not have assumed the Commission-required amount, 76.5 GWh of energy savings, is the maximum amount attainable.[351]

Staff does not agree, however, with the CEOs' claim that the Department failed to test robust ranges of values in combination with one another; to the contrary, staff believes the Department's analysis clearly considered a rather wide range of combinations.

Consider, for example, "Table 2: Selected Model Results," from Attachment 1 (SRR-3) of Dr. Rakow's Direct Testimony, a portion of which is shown below. Staff selected this portion of Table 2 because it seems to most closely align with the CEOs' preferred plan, in that it includes: (1) "Structure 3," which includes CO_2 costs and a social discount rate and (2) the highest amount of energy efficiency (EEHH).

Staff added red boxes to the selected portion of Table 2 to illustrate the following: (1) a CC unit was selected in all EEHH (highest energy efficiency) contingencies; (2) a CC unit was tested

347 Department Exceptions, at 8.

348 Ex. CEO-3, at 8 (Sommer Rebuttal).

349 Ex. CEO-7, at 8-9 (Sommer Rebuttal).

350 Ex. DER-12, at 44 (Rakow Surrebuttal).

351 ALJ Report, Finding of Fact 271, at 57.

across a broad range of wind prices; (3) one CC unit and four wind units were selected under both the mid-low forecast contingency (FCSL, or -2.5%) and lowest forecast contingency (FCSLL, or -5%). Also, these combinations were run under various "Structures," which in the example below is Structure 3. The CEOs are correct that this table does not show an EEHH (energy efficiency highest) + FCSLL (forecast lowest) + WNDLL (wind lowest) combination, but Dr. Rakow can probably easily explain the likelihood that a CC unit would have dropped out of the model under such a scenario.

Table 2: Selected Modeling Results

Structure	Scenario	Forecast	Capital Cost	CO2 Price	Coal Price	Natural Gas Price	Wind Price	Solar Price	Market Price	Energy Efficiency	Wind Units	Solar Units	CT Units	CC Units
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2H	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2L	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRLL	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRL	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRH	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRHH	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDLL	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDL	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDH	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDHH	SLRM	MKTM	EEHH	3	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLL	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPL	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLH	GASM	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPH	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASLL	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASL	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASH	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASHH	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSLL	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSL	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	0	0	1
3	TEBE	FCSH	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSHH	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTM	EEHH	4	2	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTL	EEHH	4	0	0	1
3	TEBE	FCSM	CAPM	CO2M	CLM	GASM	WNDM	SLRM	MKTH	EEHH	4	2	0	1

There are two additional takeaways staff would note with regard to Table 2. First, the amount of units selected—which is frequently 4 wind units, 2 solar units, and 1 CC unit—indicates that MP a substantial energy need. Second, in meeting this need, what fluctuates is the number of solar units, not the number of CC or wind units. Thus, procuring a CC unit and some amount of new wind always lower system costs under the Structure 3+EEHH condition, whereas additional solar in conjunction with the CC and new wind sometimes lowers system costs.

v. MISO Winter Resource Adequacy Construct

CEO witness Ms. Sommer stated in her Direct Testimony that, "while I agree with the Company that MISO has previously stated its intention to explore a seasonal resource adequacy construct, it does not have one in place nor has it proposed a specific construct."[352]

[352] Ex. CEO-3, at 8 (Sommer Direct).

MP was questioned at great length during evidentiary hearings about why MP assumed a MISO winter resource adequacy construct when there is not one at present. MP defended its assumption to use a winter resource adequacy construct in one instance by noting, "it's not any different than us including carbon regulation penalties where today there's not a [Clean Power Plan] in place, or CO_2 regulation, but yet we include that because there's a chance of that being included in the future."[353]

Staff believes that MP's comparison of CO_2 regulation uncertainty to the uncertainty of a future MISO winter resource adequacy construct draws a false equivalence, for two main reasons: First, it is a goal defined in statute to reduce CO_2, and Minn. Stat. § 216H.06 requires CO_2 pricing to be used in resource planning. Therefore, staff does not believe uncertainty with regard to internalizing CO_2 costs should be weighed equally to an unknown MISO winter season resource adequacy construct.

Second, Minn. Stat. § 216H.06 further requires that the Commission to establish "likely" values. Thus, while MP may question the validity of assuming CO_2 regulation when it does not exist at present, the Commission addresses the uncertainty of CO_2 regulation in a separate docket and determines there what is likely. The Commission has not previously addressed the likelihood of whether MISO may or may not establish a winter season resource adequacy construct.

Furthermore, staff agrees with Ms. Sommer that the details of a winter season construct are speculative at this time. In order to propose assumptions of a winter resource adequacy construct, MP bears the burden to do the proper analysis and study what it means for the Company to participate in a MISO winter season construct. MP justifies its need to plan for a MISO winter resource adequacy qualitatively largely by citing communications MISO has had with stakeholders and white papers that discuss emergency events:

> Combining the higher forced outage rate with lower capacity levels due to retirements and increasing reliance on non-dispatchable renewables significantly reduces the generation that is available during these non-summer months. According to MISO, the impacts are being felt today with a "dramatic" increase in emergency declarations during the non-summer months. These trends foreshadow the significant risk of there not being adequate capacity available during the winter season.[354]

Staff does not dispute these broader challenges are real, and of course, it is up to the Commission how to consider these issues in resource acquisition proceedings. However, MP is very critical of the CEOs and LPI for introducing speculation and hypotheticals. To be consistent with its criticisms of the intervenors, MP must be able to demonstrate, relying on the evidence introduced in this case, not only what winter season construct MISO might design, but what impact a 2025/2026 winter season construct would have on MP's load and capability. According to MP's position on many other issues, hypotheticals are insufficient.

[353] Hearing Transcript, at 90-91 (March 26, 2018).

[354] Ex. MP-18, at 44 (Palmer Rebuttal).

Staff believes pages 7-9 of Ms. Sommer's Direct Testimony raised fair points which highlight the limitations of making assumptions regarding a winter season resource adequacy requirement for the instant proceeding. MP responded to Ms. Sommer's critique on pages 40-46 of Mr. Palmer's Rebuttal Testimony, but again, the Company's response largely notes emerging trends and discusses both the challenges of incorporating new technologies like solar and the benefits of dispatchable resources like natural gas. Overall, staff agrees with Mr. Palmer that dispatchability could be beneficial to MP in the winter, and that there could be no solar available when MP's system peaks. But this is quite different than making definitive assumptions about how much capacity credit MISO will assign solar resources, or what PRM MISO will require in a 2025/2026 winter season resource adequacy construct.

vi. Wind Capacity Credit

The ALJ concluded that it was unreasonable for MP to assign no capacity credit for new wind resources because current MISO guidelines assign wind capacity accreditation, and future transmission constraints are likely to be addressed by MISO's planning process to some extent.[355] Staff agrees with the ALJ that MP did not provide persuasive arguments that MISO will assign new wind zero capacity credit because MP did not provide any evidence at all to suggest that MISO indicated it would do this.

Similar to the arguments in support of a winter season resource adequacy construct, MP cites MISO's "Resource Availability and Need" white paper (included as Schedule 4 of Mr. Palmer's Rebuttal Testimony) as justification for assigning zero capacity value to new wind. But according to the white paper MP cites, the challenges posed by increasing intermittent renewable generation on the system are actually, as the paper concludes, "currently manageable."[356] MP extrapolated from the white paper—which is a discussion paper not an engineering study—that MISO will alter its capacity credit assignment practices for renewable resources, yet there is no evidence of proposed MISO reforms.

Staff notes that it is possible the seasonal construct and capacity credit assumptions are not issues for which the Commission needs to take any action. Both largely affect the Company's net capacity position, but as the Department explained, "the NTEC unit is selected because it minimizes energy costs."[357] This being said, in MP's modeling, under certain conditions, NTEC was selected less under a summer season construct than under the winter season construct, so the structure could matter.

vii. Environmental Externalities Futures

As discussed previously, during the proceeding MP conducted a revised Strategist analysis that incorporated two new Futures incorporating the Commission's updated environmental

[355] ALJ Report, Finding of Fact 250, at 54.

[356] Ex. MP-17, Schedule 4 at 1 (Palmer Rebuttal).

[357] Department Exceptions, at 9.

externalities as base case assumptions. Under these two new Futures, the NTEC purchase was selected in 100% of the cases. The parameters of these two Futures are shown below as "NEW—Future 9" and "NEW—Future 10":

Table 1. Ten Futures Considered in the Combined-Cycle Analysis

Futures	Strategist Case Name	Resource Adequacy Season	CO_2 Regulation Penalty	Mid-Environmental Externality Values	Turn Energy Market Off	Excess Energy Sold Into Wholesale Market
Future 1	C1S	Summer	No	No	No	Yes
Future 2	C2S	Summer	No	No	No	No
Future 3	C3S	Summer	Yes	No	No	Yes
Future 4	C4S	Summer	Yes	No	No	No
Future 5	C1W	Winter	No	No	No	Yes
Future 6	C2W	Winter	No	No	No	No
Future 7	C3W	Winter	Yes	No	No	Yes
Future 8	C4W	Winter	Yes	No	No	No
NEW–Future 9	C5S	Summer	Yes	Yes	Yes	No
NEW–Future 10	C5W	Winter	Yes	Yes	Yes	No

Staff believes the Commission could benefit from more explanation from the Company with regard to the construction of these scenarios. For example, in these two scenarios, MP turned off the model's ability to buy and sell market energy, and the scenarios apply both CO_2 regulation costs and externalities. No other Future was constructed with either of these modeling parameters.

MP did not elaborate on its reasons for assuming both CO_2 regulatory costs and externalities; however, the Company explained that it decided to exclude market energy from being bought or sold "so that the application of externality values is equitable across all energy sources."[358]

For obvious reasons, it is important that an economic dispatch model aligns with reality. Given the unique construction of MP's environmental externalities scenarios specifically and the significance of environmental considerations in electric utility planning generally, staff believes it is important the Commission is aware of the details of these scenarios and their outcomes.

Without market energy to buy or sell, it would seem the model assumes MP's system functions basically as a large microgrid, which is obviously not how MP's system operates. And with assuming both CO_2 regulatory costs and externalities, it is possible the costs of operating MP's other carbon-emitting resources are so high that the relative value of NTEC is greatly (but unrealistically) enhanced. With all other modeling constraints held constant, the economic outcome could be that NTEC dispatches as often as a coal-fired baseload unit, and coal-fired baseload units operate like an intermediate unit, which one could argue is an unrealistic representation of the future.

Instead of ramping down coal units and ramping up NTEC due to a substantial, additive CO_2 price, an alternative way MP may have modeled CO_2 regulatory costs and externalities together would be to apply the regulatory cost to the dispatch cost and the externalities *after* the resource plan was selected—in other words, re-ranking the expansion plans at the end but not

[358] MP Initial Brief, at 37.

re-selecting resources. Perhaps this method could have dispatched MP's generators more realistically. On the other hand, as Ms. Sommer noted in her Direct Testimony, MP's modeling was incomplete, partially because MP did not allow renewable resource to be selected pre-2025, or explore unit retirement. Thus, the re-ranking could have improved a unit retirement scenario or a scenario without modeling constraints that disadvantaged renewable energy.

In either case, staff is merely raising possibilities, not suggesting these are probable outcomes, because it is worth exploring how environmental externalities were applied in the modeling. Further, MP did not provide much detail regarding the operation of its system under the environmental externalities scenarios, instead only claiming NTEC lowered societal costs in all cases.

In other areas of the record, witnesses commented on the operational limitations of MP's current fossil fuel generators, which the Strategist analysis should take into account. Mr. Brick, for example, noted that Boswell 3 and 4 have limited ramp capability and cannot increase or decrease output quickly, efficiently, or flexibly.[359] According to Dr. Rakow, a unit such as Hibbard "would not be able to be dispatched down in response to NTEC's addition."[360] In MP's Exceptions, the Company noted "Laskin is not often running and takes over eight hours to come online."[361]

At this time, staff is unaware how MP's environmental externalities scenarios accounted for operational limitations in the absence of the energy market and with the combination of CO_2 regulatory costs and externalities. Presumably the presence of both costs had some effect of displacing significant amount of energy at Boswell 3 and 4, Laskin, and Hibbard in particular, but how the units dispatched—as well as whether the units could realistically dispatch in MISO as dispatched by Strategist—was not explained in much depth.

To be clear, staff is not arguing the externalities scenarios are decidedly unreasonable, but rather that they lack detailed explanation, which staff believes is important in light of the uniqueness of their construction. Perhaps it will be unsatisfactory for the Commission to just accept that NTEC lowered societal costs in scenarios which had questionable parameters; therefore, the Commission might wish to ask the Company, for example, how the dispatch of various generating units changed or whether additional renewable energy was added under these important Futures.

E. Carbon Dioxide (CO_2) Emissions

Shown below is a comparison of MP's base case energy position and its energy position with NTEC.[362] What is particularly noteworthy is that MP's energy supplied by its existing coal units,

[359] Ex. MP-19, at 10 (Brick Direct).

[360] Ex. DER-12, at 23 (Rakow Surrebuttal).

[361] MP Exceptions, at 48.

[362] Figure 7 (on the left) is shown on page 57 of Pierce Direct, and Figure 21 (on the right) is shown on page 53 of Palmer Direct.

Boswell 3 and 4, seems to change only slightly with or without NTEC. In either case, together, the Boswell units are projected to supply roughly half of MP's total energy (roughly 6,000 GWh out of 12,000 GWh) throughout the planning period. In addition, the total energy generated by carbon-emitting resources appears to increase:

Figure 7: Base Case Energy Position

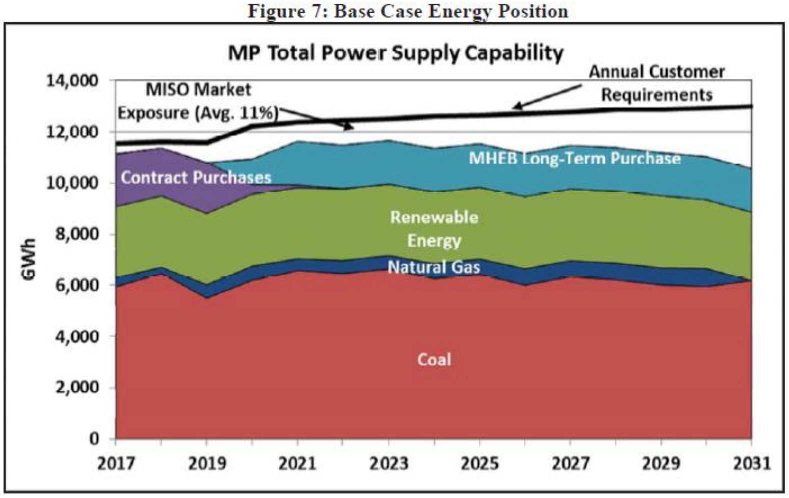
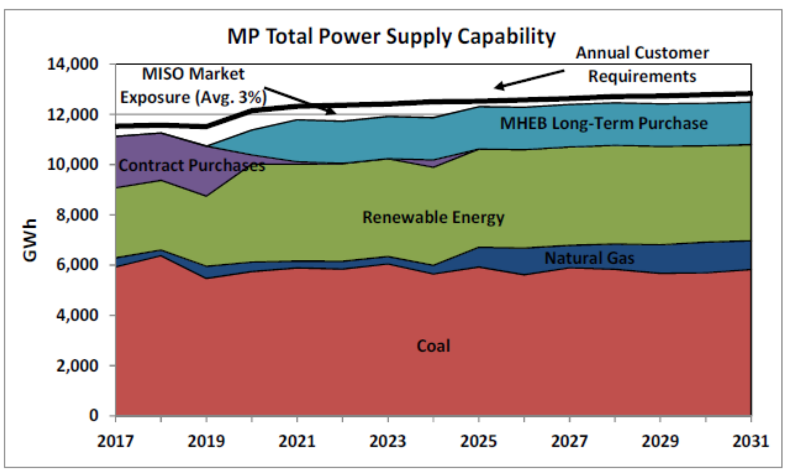


Figure 21: Energy Position Outlook with NTEC[42]



According to the Department, NTEC will reduce overall system societal costs, and NTEC will displace more CO_2-intensive generation.[363] And as MP noted in its Petition, NTEC has a carbon intensity that is about 65% lower than MP's coal-fired generation.[364] Moreover, according to MP, the addition of NTEC "does not increase overall CO_2 emissions in the Company's portfolio."[365] In short, NTEC's lower emissions intensity explains why CO_2 emissions do not increase even if the combined energy from coal and natural gas generation appears to increase.

The CEOs emphasized that "[i]n order to justify the proposed gas facility, Minnesota Power must first show that its construction is consistent with meeting Minnesota's 2050 greenhouse

363 Department Initial Brief, at 2.

364 Petition, at 4-9.

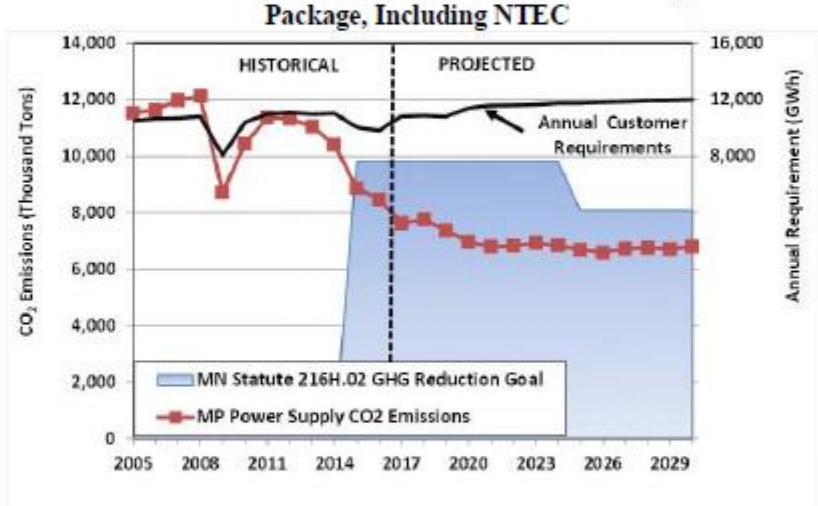
365 Ex. MP-16, at 9 (Palmer Direct).

gas goals as set in the Next Generation Energy Act."[366,367] Furthermore, "in order to meet its greenhouse gas emission reduction goals in 2050, Minnesota's greenhouse gas 'budget' can only accommodate very few fossil fuel electricity-generating plants, if any."[368]

MP responded to CEOs' concerns about the State's greenhouse gas goals by citing many steps the Company has taken thus far to reduce its CO_2 emissions. These actions have, to date, removed about 2 million tons of CO_2 from the Company's resource portfolio.[369]

MP claimed it is "on [its] way to the 2050 target." However, as shown by Figure 25 of the Petition,[370] below, CO_2 emissions reductions will begin to plateau in the 2020s:

Figure 25: Greenhouse Emission Reductions Achieved with Energy*Forward* Resource Package, Including NTEC



In fact, as Ms. Hamilton observed, MP's CO_2 emissions are actually projected to *increase* between 2025 and 2034.[371] And as shown by the figures above illustrating MP's energy position with and without NTEC, roughly half of MP's energy will be generated by coal (Boswell 3 and 4) for the foreseeable future in either case, meaning that additional sharp reductions in CO_2 emissions will be hard to come by.

MP has clearly made great strides in reducing its CO_2 emissions, but with no plans to retire or refuel the Boswell 3 and 4 units,[372] staff agrees with the CEOs that it is unlikely MP will

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[366] Ex. CEO-12, at 5 (Hamilton Surrebuttal).

[367] Minn. Stat. 216H.02, Subdivision 1 states that "[i]t is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050."

[368] Ex. CEO-5, at 3 (Hamilton Direct).

[369] Ex. MP-14, at 63 (Pierce Rebuttal).

[370] Petition, Page 3-48.

[371] Ex. CEO-12, at 3 (Hamilton Surrebuttal).

[372] Hearing Transcript, at 23 and 24.

continue its pace of CO_2 reductions. While MP is very critical of Ms. Hamilton in particular about meeting the 2050 State Greenhouse Gas Goal, calling her comments "thoroughly unfounded"[373] and a "simplistic formulation that renewable energy must necessarily equal the best means of reducing these emissions,"[374] the foundation of Ms. Hamilton's argument is actually quite relevant. The IRP Statute, for example, requires utilities to include in their resource plans a discussion of the "costs, opportunities, and technical barriers" of meeting *all* goals set forth in Minn. Stat. § 216H.02 (Greenhouse Gas Emissions Control):

> **Subd. 2c. Long-range emission reduction planning.** Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the **costs, opportunities, and technical barriers** to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.[375] (Emphasis added by staff.)

The barrier in meeting MP's 2050 goal is obvious: Without retiring one or both Boswell unit(s), it may be challenging (if not impossible) for MP to be able reduce its CO_2 emissions by 80%. At the same time, there is no evidence to suggest one or both Boswell unit(s) can be retired without severe reliability or rate impact concerns. MP noted that "analyzing an early retirement of Boswell units 3 and 4 is outside the scope of the instant proceeding" and "such evaluation appropriately belongs in a resource planning analysis, not in a resource acquisition proceeding."[376] Staff agrees, but notes that the relationship of the Boswell units to NTEC is appropriate to discuss in a petition seeking an additional CO_2-emitting resource.

MP and the Department share the view that, since in the Strategist model NTEC displaces generation from Boswell and other carbon-emitting resources, the net reduction in CO_2 emissions indicates NTEC is good for society. The CEOs' perspective is different, but also has merit. A 50% share of NTEC would mean committing to approximately 262 MW of additional CO_2-emitting generation, which is projected to operate at a projected 40% capacity factor[377] for at least 40 years (the term of the CDA).[378] With no plans to retire its coal-fired Boswell 3 and 4 units, and with these units operating around-the-clock as baseload power, but without the ability to efficiently or flexibly curtail,[379] what NTEC represents from the CEOs' point of view is another large-scale carbon-emitting resource to a system that generates about half of its electricity from coal.

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[373] Ex. MP-14, at 63 (Pierce Rebuttal).

[374] Ex. MP-20, at 15 (Brick Rebuttal).

[375] Minn. Stat. § 216B.2422, Subd. 2c.

[376] MP Initial Brief, at 55.

[377] Ex. MP-21, at 2 (Brick Surrebuttal).

[378] Petition, Page 4-42.

[379] Ex. MP-19, at 10 (Brick Direct).

However, in response to the CEOs' argument that "[t]he state's climate goals will not be achieved if energy served by anticipated retirement of remaining coal plants and nuclear plants is replaced with gas,"[380] this appears to be a claim about the State's greenhouse gas budget, not MP's. In other words, the CEOs appear to argue that if some sectors of the economy fall short on emissions targets, others, like electric utilities (and MP specifically) must achieve greater than 80% reductions to comply with state law.

Staff is reluctant to agree that this what the goal set forth in the law implies, but in any case, there is no quantitative analysis in the record to show what MP's greenhouse gas reduction will be by 2050 if one or both Boswell units are replaced with NTEC plus renewables. What is clear is that the Commission's factors to consider in resource planning and resource acquisition proceedings involve least-cost planning after taking into account costs to the environment. If NTEC is indeed least-cost once taking into account environmental externalities, then MP would be planning at the socially optimal level of pollution.

Second, this argument does not consider the potential reliability concerns with replacing massive coal plants only with renewable energy, as there is no engineering study to support it. With what is known today, nothing suggests the uniquely high load factor of MP's system will materially change, and for all of the contentiousness regarding dispatchability needs and spot market exposure discussed in this proceeding, one could expect those concerns would be greatly amplified in the context of retiring Boswell Energy Center, which, as explained, supplies nearly half of MP's energy.

While staff agrees with MP that early retirement of Boswell units 3 and 4 is outside the scope of the instant proceeding, the Commission could direct MP to evaluate Boswell replacement or retirement, from operational and economic perspectives, in the Company's next resource plan. The purpose of such an analysis would not necessarily intend to send MP down a path of retiring Boswell Energy Center, but to assess, as stated in Minn. Stat. § 216H.02, "the costs, opportunities, and technical barriers" of removing Boswell from MP's system.

On the other hand, there are three reasons why the Commission may not wish to require MP to study retiring Boswell 3 and 4 at this time. First, the Commission might determine that requiring such an analysis is completely outside the scope of this proceeding. Second, requiring this analysis now might signal or establish some presumption that the Commission is nudging the Company to retire Boswell, even if it is not the Commission's intent to do so. Third, the Commission may simply prefer to keep the decision in the instant proceeding limited to whether or not NTEC is in the public interest and to assume the Boswell retirement or replacement issue will arise naturally in future planning proceedings.

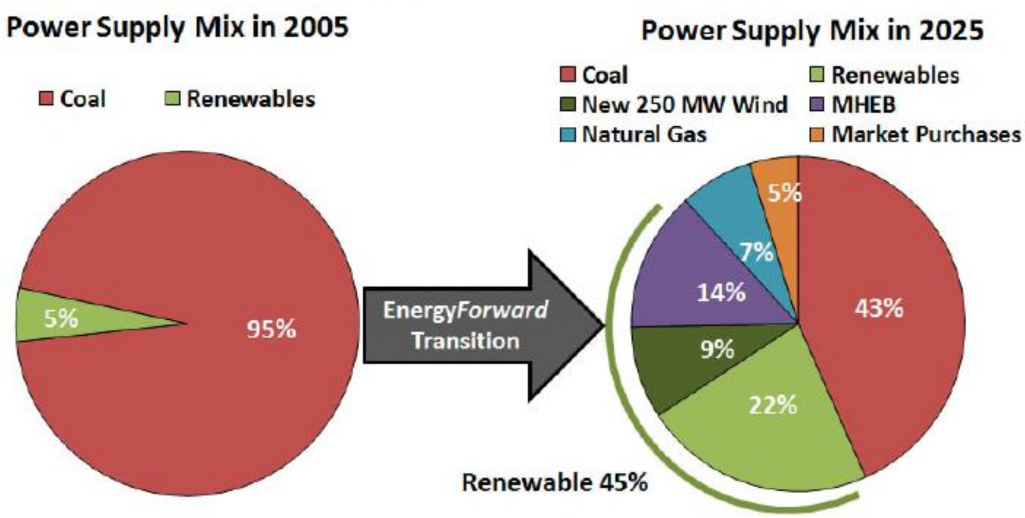
F. Flexibility and Fuel Diversity

Currently, MP has essentially no natural gas on its system. (Its Laskin Energy Center was refueled from coal to natural gas in 2015, although Laskin does not run very often due to its high dispatch cost.) As shown below in Figure 22 from MP's Petition, by adding NTEC, MP will

[380] Ex. CEO-5, at 9 (Hamilton Direct).

continue to diversify its generation portfolio and increase its natural gas position to about 7% by 2025:

Figure 22: Power Supply Mix Transformation by 2025



Even with NTEC, MP projects that, in 2025, 43% of its electricity will be generated by coal, and 45% of its electricity will be generated by renewable energy (including Manitoba Hydro). As noted in the previous section, this 43% of electricity from coal refers to Boswell 3 and 4, and according to Mr. Brick's Direct Testimony, these units are not ideal resources to balance increasing renewable integration:

> Boswell Units 3 and 4 can ramp to a limited extent and already provide some of that function. However, these units are limited in the amount of load following capability and cannot increase or decrease output as quickly or efficiently or flexibly as an NGCC, which is better suited to that function. Adding 250 MW of rapid-response capability from an NGCC resource on top of the existing system will be important to fully and flexibly match the generation swings attendant with nearly 900 MW of variable resources on a 1,800 MW overall system.[381]

Beyond meeting its load requirements, the addition of an intermediate natural gas resource could allow MP to accomplish two things at the same time: from a financial/risk management perspective, MP would be more fuel diverse, and having at least some natural gas on its system would balance its generation portfolio. Accepting it as true that natural gas prices "are expected to remain lower and less volatile than historical values for the foreseeable future,"[382] it is understandable why MP would want to incorporate natural gas into its generation portfolio, even though NTEC will only increase the percent of supply by natural gas to 7%.

Second, from an operational perspective, no party disputes that NTEC would have the capability "to quickly start up, ramp up and down, and go off-line more often than traditional baseload

[381] Ex. MP-19, at 10-11 (Brick Direct).

[382] Ex. MP-13, at 33 (Pierce Direct).

generation."[383] The dispute is whether these capabilities of combined cycle plants are *needed*. The ALJ concluded that MP "failed to demonstrate that the NTEC 250 MW purchase is needed as a flexible, dispatchable resource,"[384] but she did not reject MP's claims that combined cycle plants have certain attributes and advantages. So even if MP did not show by a preponderance of the evidence that it will have a dispatchability need, this does not mean NTEC will not enable operational efficiencies on MP's system or mitigate its risk to some extent.

For example, MP claimed that the NTEC project was specifically located and selected in part for its availability for firm transportation service in both the summer and winter months. More specific capabilities of the NTEC facility are detailed in Ms. Supinski's Direct Testimony; she explained, for instance:

> NTEC will be designed to operate in daily cycling mode with normal operation consisting of Maximum Load and automatic generation control operation for 16 hours per day during weekdays. In addition, NTEC will be designed to be capable of running in a stable, continuous, and controllable operation, at any load level, while operating from the minimum to Maximum Load. NTEC will also be designed to be capable of starting in all weather conditions, from freezing cold winter conditions to hot summer conditions.[385]

The ALJ did not reject Ms. Supinski's claims that NTEC will have these capabilities.

Additionally, while dispatchability is usually discussed in the context of intermittent renewables, the ALJ did not appear to address long-term, unexpected outages or failures at MP's existing baseload generators. But as Ms. Pierce discussed in her Rebuttal Testimony and as MP noted in its Exceptions, there could be potential scenarios that call for available local generation in order to address system contingencies, for instance, in the event MP's baseload is down:

> It is entirely conceivable that Minnesota Power's remaining baseload units (Boswell Energy Center units 3 and 4) could be unexpectedly down at the same time when wind and solar is unavailable. The presence of dispatchable natural gas combined cycle capacity adjacent to the Company's service territory would make it much easier to ride through this type of local contingency.[386]

The ALJ did not address the possibility of unavailable local generation as noted by Ms. Pierce.

The ALJ concluded that the Company failed to demonstrate the need for a flexible, dispatchable resource, in part by citing the Department's analysis of market exposure, which showed that "the Company's market risk in 2025 appears to be manageable with its existing resource

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383 Ex. MP-13, at 17 (Pierce Direct).

384 ALJ Report, Finding of Fact 441, at 89.

385 Ex. MP-25, at 7 (Supinski Direct).

386 MP Exceptions, at 50.

mix."[387] But the phrase "appears to be manageable" might not be particularly comforting in scenarios in which the system could be unusually strained or if generators experience prolonged outages or failures. And as staff understands it, the Department's assessment of MP's exposure to the spot market only took into account scheduled maintenance, but it did not stress test the system under potentially problematic local contingencies (which, to be clear, is not a criticism of the analysis).[388]

G. ALJ's Recommendation for a Miscellaneous Docket for Demand Response

As discussed previously, the ALJ recommended that MP, LPI, and other stakeholders develop a demand response rider and corresponding cost recovery mechanism for Commission approval. Further, the Judge recommended the Commission open a new miscellaneous docket to address the issue.

According to the Company's recommended order, as stated in its Exceptions, MP recommends the Commission order that:

> Minnesota Power, LPI, and other stakeholders shall continue to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, in a new miscellaneous docket filing, and such filing shall be submitted for Commission approval **within six months after the date of the final written order** in the 2016 Rate Case proceeding. (Emphasis added by staff.)

The 2016 Rate Case Order was issued on March 12, 2018; six months from the order was September 12, 2018. On September 10, 2018, MP filed a notice of a demand response stakeholder workshop in dockets 16-664, 15-690, and 17-568 to take place in Duluth on September 25, 2018, but has not filed a specific rider or cost recovery mechanism.

In reference to the demand response rider, the 2016 Rate Case Order stated in part: "The record to support the submission [of the demand response rider] to the Commission may be developed in either Docket E015/AI-17-568 - OAH Docket 68-2500-34672 or a new miscellaneous docket."[389] If the Commission agrees with the ALJ's determination that the demand response issue in the instant proceeding was not developed sufficiently to comply with the Commission's 2016 Rate Case Order, then the Commission could direct staff to create a new miscellaneous docket.

H. Taconite Harbor 1 and 2

MP's future plans for Taconite Harbor 1 and 2 were not a disputed issue in this proceeding. However, during the last IRP, the Commission approved MP's proposal to idle Taconite Harbor

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[387] ALJ Report, Finding of Fact 440, at 88.

[388] Ex. DER-9, SRR-4 of Rakow Direct, Page 6.

[389] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order (2016 Rate Case Order) at 115 (Order Point 72) (March 12, 2018).

Energy Center Units 1 and 2 in 2016, retain the ability to restart them to address reliability or emergency needs on the transmission system, and cease coal-fired operation by the end of 2020. In addition, the Order stated that future refueling and re-mission opportunities will be considered in planning and optimization of the facility for the next resource plan.[390]

The 2016 IRP Order also required MP to submit an annual report by August 1 of each year, to include, among other things:

- Whether Taconite Harbor Energy Center Units 1 and 2 were selected in MISO's annual capacity auction;
- Whether Taconite Harbor Energy Center Units 1 and 2 will receive capacity accreditation in each MISO planning year; and
- How often the units were dispatched in the previous planning year.

MP has filed two reports on Taconite Harbor 1 and 2 since the 2016 IRP Order. Staff has summarized the reports below, so that the Commission is able to have a full picture of MP's plans for its existing generation:

[390] Commission order, Docket 15-690, ordering paragraph 3 (July 18, 2016).

Question	**2017 THEC Report**	**2018 THEC Report**
Were THEC 1 & 2 selected in MISO's annual capacity auction?	THEC1&2 were not selected in the MISO annual capacity auction for Planning Years 2016-2017 and 2017-2018. The units were offered into the Planning Resource Auction for both Planning Years, but did not clear because the offer price was greater than the clearing price.	THEC1&2 were not selected in the Midcontinent Independent System Operator's ("MISO") annual capacity auction for Planning Year 2018-2019. The units were offered into the Planning Resource Auction, but did not clear because the offer price was greater than the clearing price.
Did THEC 1 & 2 receive capacity accreditation?	THEC1&2 met all MISO Resource Adequacy requirements to qualify as a Planning Resource (i.e. receive capacity accreditation) for Planning Years 2016-2017 and 2017- 2018, and was given a UCAP (unforced capacity) value for both planning years.	THEC1&2 met all MISO Resource Adequacy requirements to qualify as a Planning Resource (i.e. receive capacity accreditation) for Planning Year 2018-2019, and was given a UCAP (unforced capacity) value.
How often were THEC 1 & 2 dispatched?	The Net Capacity Factor (NCF) for THEC1&2 for MISO Planning Year 2016-2017 was 21 percent. This is a decrease of 43 percentage points from the prior planning year (Planning Year 2015-2016 was 64 percent).	The Net Capacity Factor (NCF) for THEC1&2 for MISO Planning Year 2017-2018 was zero percent. This is a decrease of 100 percent from the prior planning year (Planning Year 2016-2017 was 21 percent).

It its Initial Brief, MP provided an update on its plans for Taconite Harbor 1 and 2, as well as its relationship to the need for NTEC. Staff believes MP's update is helpful, and it provides the Commission with enough information such that the Company's next IRP can re-visit Taconite Harbor 1 and 2, regardless of the Commission's decision with respect to NTEC:

> The Company indicated in its 2015 Plan that it has considered re-missioning Taconite Harbor under different fuel alternatives, including biomass. The Company has concluded, however, that natural gas is not a potential fuel source for THEC1&2. For this reason, the potential to find a flexible, dispatchable, efficient fuel source that would be a direct alternative to the NTEC facility at this proposed location is very low. Moreover, if the Company needs a Taconite Harbor unit to come back online for reliability purposes, Minnesota Power will consider its overall fuel options using information available during that period. So while the Company will continue to evaluate Taconite Harbor and include any viable and reasonable options in Minnesota Power's 2019 integrated resource plan, this is

not a solution to Minnesota Power's need for flexible, dispatchable, energy and capacity.[391]

I. Discussion of Decision Options

The Commission Decision Options are largely a replication of Exhibit 2, Section C. of MP's Exceptions,[392] which is MP's "Proposed Order." (Of course, there are also options to accept the ALJ report or adopt the CEOs' and/or LPI's recommendations.)

Staff chose to present the Decision Options this way because, first, MP and the Department agree on all issues, and since MP's Proposed Order is more succinct than the Department's 51 "New Findings" and 1 "New Conclusion," staff believes adopting MP's Proposed Order would be less time-consuming than going one-by-one through the Department's "New Findings" and "New Conclusion," yet would have the same outcome.

However, if the Commission wishes to address the Department's findings and conclusion one-by-one, instead of the MP's Proposed Order, staff included them as Attachment B to the briefing papers.

[391] MP Initial Brief, at 66-67.

[392] MP Exceptions, Exhibit 2: Supplemental Findings, Conclusions and Order Points for ALJ Report, Section C. Proposed Order, at 15-16.

VIII. Decision Options

A. ADMINISTRATIVE LAW JUDGE REPORT

1. Adopt the Findings of Fact, Conclusions of Law, and Recommendations of the Administrative Law Judge's Report. (CEO, LPI)
2. Not adopt the ALJ's recommendations, or adopt only as modified consistent with the Department's recommendations included in the Department's July 23, 2018 Exceptions (DOC)
3. Adopt the Findings of Fact, Conclusions of Law, and Recommendations of the Administrative Law Judge's Report with the following modifications:

   a. The Report as modified consistent with the Department's recommendations as presented in the Department's July 23, 2018 Exceptions summarized in Attachment A (DOC, MP)

   b. The Report as modified consistent with the Department's recommendations as presented in the Department's July 23, 2018 Exceptions summarized in Attachment A as modified by the Commission.

   c. The Report as modified consistent with Minnesota Power's recommendations as presented in the MP's July 23, 2018 Exceptions summarized in Attachment A (MP)

   d. The Report as modified consistent with Minnesota Power's recommendations as presented in the MP's July 23, 2018 Exceptions summarized in Attachment A as modified by the Commission.

   e. Take some other action deemed appropriate.

B. AFFILIATED INTEREST AGREEMENTS

1. Determine that Minnesota Power's 250 MW NTEC purchase, as proposed, is needed and reasonable based on all relevant factors identified by the Commission in the Order for Hearing and by the Administrative Law Judge in the Second Prehearing Order. (MP)

2. Determine that Minnesota Power has met the renewable resource requirements set forth in Minn. Stat. § 216B.2422, and Minn. Stat. § 216B.243, subd. 3a. (MP)

3. It is reasonable for Minnesota Power to take either 50 percent or 48 percent of the NTEC capacity in light of the identified need. On balance, the Commission concludes that Minnesota Power should take 50 percent of the NTEC capacity as within the margin of reasonableness for the identified need and the 50 percent alternative would simplify the accounting and reporting related to the transaction. The

Commission concludes that a 50 percent share is most reasonable in light of the evidence provided by the Department, which was acknowledged by the Company.

4. Determine that Minnesota Power's affiliated interest agreements are consistent with the public interest under the affiliated interest statute, Minn. Stat. § 216B.48, and Minn. R. 7825.1900-.2300.

5. Determine that the proposed revisions to Minnesota Power’s FPE Rider are in the public interest under Minn. Stat. § 216B.16, subd. 7(3) and Minn. R. 7825.2390 through 7825.2600. (MP)

6. Determine that Minnesota Power’s proposed variances to the FPE Rider are justified consistent with Minn. R. 7829.3200. (MP)

7. Determine that the Guaranty Agreement is reasonable and proper and in the public interest and will not be detrimental to the interests of the consumers and patrons affected thereby; and the Commission should approve the Guaranty Agreement, subject to the applicable condition set forth in Exhibit A. (MP)

8. Determine that Minnesota Power has met the requirements of all other applicable statutory provisions including Minn. Stat. §§ 216B.50, 216B.2422 and 216B.1694. (MP)

OR,

9. Deny Minnesota Power’s request for approval of the Affiliated Interest Agreements because the Company has not demonstrated that these affiliated interest agreements are consistent with the public interest. (CEOs, LPI)

    a. Determine Minnesota Power’s consideration of alternatives was inadequate to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable for meetings its customers’ capacity and energy needs. (CEOs, LPI)

    b. Determine that Minnesota Power failed to establish that the 250 MW NTEC purchase is needed and reasonable for dispatchability purposes. (CEOs, LPI)

    c. Determine that the alternatives analysis was not consistent with the requirements of Minn. Stat. §§ 216B.2422 and 216B.243, subd. 3a. (CEOs, LPI)

C. DEMAND RESPONSE RIDER

1. Minnesota Power, LPI, and other stakeholders should continue to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, in a new miscellaneous docket filing, and such filing shall be

submitted for Commission approval within six months after the date of the final written order in the 2016 Rate Case proceeding. (MP, DOC, LPI)

D. PROPOSED BIDDING PROCESS

1. Require Minnesota Power to include a proposed bidding process for Commission consideration and potential approval in its next IRP filing as set forth in Exhibit A. (MP, DOC)

E. COMPLIANCE REPORTING

1. The Commission's final written order will incorporate the conditions and compliance requirements and Minnesota Power's commitment to comply, as summarized herein and set forth in Attachment A to this Report.

Attachment A: Summary of Proposed Changes to ALJ Report

TOPIC AND SECTION	Finding(s) of Fact Number	New Findings	Sponsor
SUMMARY AND CONCLUSIONS (Page 4)			MP
PROJECT AGREEMENT (Section I)	11	DER-1	DOC DER
OVERVIEW OF NTEC PROJECT AND AIAs		MP-15(a)-(d), MP-32(a)-(c)	MP
MP's PROJECTED RESOURCE NEEDS AND STATED NEED OF 250 MW NTEC		MP-155(a)-(c), MP-162(a)-(d)	MP
LEGAL STANDARDS (Section VI)	89	DER-1 to DER-8	DOC DER
EVALUTATION OF ALTERNATIVES – STRATEGIST ANALYSIS (Section IX.A)	193, 214, 235	MP-193	MP
EVALUTATION OF ALTERNATIVES – STRATEGIST ANALYSIS – CEO & LPI (Section IX.B)	214, 235, 236, 237, 238, 239, 250, 268, 271, 272, 273, 274, 285, 286, 287, 288, 289	MP-214(a)-(e), MP-268(a)-(f), MP-285(a)-(e)	MP
DOC STRATEGIST MODELING (Section IX.C)	314, 315, 316, 317	MP-314(a)-(j)	MP
DOC STRATEGIST MODELING (Section IX.C)	314, 315, 316		DOC DER
DOC STRATEGIST MODELING AND CONCLUSIONS (Sections IX.C and E)	317, 342		DOC DER
CEOs STRATEGIST MODELING (Section IX.D)	338, 339, 340, 341, 342 343, 344	MP-344-(a)-(g)	MP
PACE GLOBAL REPORT (Section IX.F)	356, 357, 358, 359		MP
CONCLUSIONS ON ALTERNATIVE ANALYSIS (Section IX.G)	360, 361		MP
MP NEED FOR DISPATCHABLE RESOURCES (Section X.A)	375, 376, 377, 378		MP
MR. BRICK's ANALYSIS (Section X.B.1.iii)	401, 402, 403		MP
DOC ANALYSIS OF NEED FOR DISPATCHABLE RESOURCES (Section X.C)	416, 417		DOC DER
ANALYSIS OF NEED FOR DISPATCHABLE RESOURCES (Section X.D)	440		DOC DER

ANALYSIS OF NEED FOR DISPATCHABLE RESOURCES (Section X.D)	437, 438, 439, 440, 441		MP
NTEC RFP PROCESS (Section XI)	460	DER-9	DOC DER
NTEC RFP PROCESS (Section XI)	460		MP
NTEC AFFILIATED INTEREST AGREEMENTS (Section XII)	509	DER-10	DOC DER
NTEC AFFILIATED INTEREST AGREEMENTS (Section XII)	509		MP
CONDITIONS ON APPROVAL		MP-518 to MP-523	MP
GUARANTY AGREEMENT (Footnote 770)	Footnote 770	DER-11 to DER-18	DOC DER
FPE RIDER REVISION		DER-19 to DER-23	DOC DER
CAPITAL COSTS AND RELATED TRANSMISSION UPGRADES		DER-24 to DER-28	DOC DER
UNDERLYING REVENUE REQUIREMENT ASSUMPTION		DER-30 to DER-35	DOC DER
STATUTORY ISSUES – INNOVATIVWE ENERGY PROJECT STATUTE (MS § 216B.1694)		DER-36 to DER-37	DOC DER
STATUTORY ISSUES – PROPERTY ACQUISITION STATUTE (MS § 216B.50)		DER-38 to DER-46	DOC DER
STATUTORY ISSUES – SECURITIES STATUTE (MS § 216B.49)		DER-47 to DER-51	DOC DER
CONCLUSIONS OF LAW	Conclusion 5		MP
CONCLUSIONS OF LAW	Conclusion 9		MP
CONCLUSIONS OF LAW	Conclusion 9		DOC DER
CONCLUSIONS OF LAW	Conclusion 10		MP
CONCLUSIONS OF LAW	Conclusion 11		MP
CONCLUSIONS OF LAW	Conclusion 12		MP
CONCLUSIONS OF LAW	Conclusion 12	Conclusion DER-1	DOC DER

Attachment B: Department New Findings and Conclusion

Project Agreement – Section I

11. The NTEC transaction includes two agreements between South Shore and Dairyland, and three proposed affiliated interest agreements between South Shore and Minnesota Power. Finally, there is an agreement between MP and Dairyland in which the Company provides certain guaranties to Dairyland. The affiliated interest agreements are the subject of Minnesota Power's request for approval in this case. In addition, MP requested approval of the Guaranty Agreement in this case or deferral to Minnesota Power's annual capital structure petition.[4]

[New Finding DER-1]. The Guaranty Agreement provides a guaranty from MP to Dairyland for South Shore's obligations under the D&C and O&O Agreements.[5]

4 Second Prehearing Order at 4 (Final Issues List).

5 Ex. DER-1 at 2-6 (Amit Direct); Ex. MP-26 at 48-50 (Supinski Rebuttal).

Legal Standards – Section VI

[New Finding DER-2]. Minn. Stat. § 216B.49, subd. 1, defines a security as including "assumption of any obligation or liability as a guarantor, endorser, surety or otherwise in the security of another person." Further, pursuant to Minn. Stat. § 216B.49, subd. 3 "it is unlawful for any public utility organized under the laws of this state to offer or sell any security or, if organized under the laws of any other state or foreign country, to subject property in this state to an encumbrance for the purpose of securing the payment of any indebtedness unless the security issuance of the public utility is first approved by the Commission."[7]

[New Finding DER-3]. The Commission shall approve the issuance of a security if the Commission finds "that the proposed security issuance is reasonable and proper and in the public interest and will not be detrimental to the interests of the consumers and patrons affected thereby."[8]

[New Finding DER-4]. Pursuant to Minn. Stat. § 216B.50, subd. 1, "no public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000 " However, this requirement "does not apply to the purchase of property to replace or add to the plant of the public utility by construction."[9]

[New Finding DER-5]. The Commission shall approve the acquisition of property if "the Commission finds that the proposed action is consistent with the public interest."[10]

[New Finding DER-6]. Minn. Stat. § 216B.1694, subd. 1 provides a definition of an "innovative energy project." Pursuant to Minn. Stat. § 216B.1694, subd. 2 (4) an innovative energy project "shall, prior to the approval by the Commission of any arrangement to build or expand a fossil-fuel-fired generation facility, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option."[11]

[New Finding DER-7]. Pursuant to Minn. Stat. § 216B.1694, subd. 2, the Commission shall ensure consideration of an alternative Innovative Energy Project and "take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers."[12]

89. Consistent with the Commission's Notice and Order for Hearing, Minnesota Power has the burden of proof in this case to show that the proposed NTEC "gas plant or any portion thereof is needed and reasonable" and the NTEC affiliated interest agreements are in the public interest. MP also has the burden of proof to demonstrate that the proposed security issuance is reasonable, proper, in the public interest, and will not be detrimental to the interests of the consumers and that the proposed property lease is in the public interest.[13]

7 Minn. Stat. § 216B.49, subds. 1 and 3 (2016).

8 Minn. Stat. § 216B.49, subd. 4 (2016).

NTEC Availability – Section IX.C

~~314. The Administrative Law Judge agrees with the CEOs that the Department's Strategist modeling included some unreasonable assumptions. In particular, because the Department only allowed the NTEC resource option to be selected in 2025, the Department's modeling results were biased in favor of NTEC. Because the Commission has not made a decision that a resource of this type is need in 2025, the Department's modeling unreasonably constrains the resource options. Like Minnesota Power's Strategist analysis, the Department's Strategist analysis fails to analyze~~ By allowing the NTEC-specific option to be selected only in 2025 the Department accurately reflected South Shore's proposal and the project agreements. By allowing NTEC to be available in 2025 and generic intermediate capacity to be available in all years, the Department analyzed a sufficient range of alternatives to determine whether the NTEC resource is truly needed in 2025 or whether some other portfolio of resources would better meet the Company's resource needs in a cost-effective manner.[30]

315. In addition, with regard to demand response, ~~the Administrative Law Judge agrees that it was unreasonable for~~ while the Department ~~to~~ modeled ~~of~~ a level of demand response lower than that used by the Company in its modeling, considering the contingencies used, the Department modeled a sufficient range of net demand to determine whether the NTEC resource is truly needed in 2025. In particular, the Department's modeling demonstrates that the need filled by NTEC is to reduce overall system costs through NTEC's energy output and not to address a capacity deficit.[50]

316. Also, the Department's energy efficiency assumptions are ~~unreasonably low for the reasons set forth above in paragraphs 253-274.~~ reasonable in light of the forecast contingency bands employed by the Department.[59]

30. Ex. DER-8, SRR-3 at 14 (Rakow Direct).

50 *See* Ex. DER-12 at 42-47 (Rakow Surrebuttal).

59 Ex. DER-12 at 47 (Rakow Surrebuttal).

DOC Strategist Modeling and Conclusions – Sections XI.C and E

317. Because ~~these~~ the underlying ranges for key variables are ~~assumptions are not~~ reasonable, the Department's Strategist results are ~~not~~ sufficiently robust ~~or~~ and reliable for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable.[60]

342. ~~Similarly, the~~ The Department's Strategist results are ~~not~~ sufficient~~ly robust or reliable~~ for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable because the underlying ranges for key variables are reasonable ~~its analysis also used a number of unreasonable assumptions~~.[]

60 *See* Ex. DER-12 at 44-45 (Rakow Surrebuttal).

DOC Analysis of Need for Dispatchable Resources – Section X.C

416. The Department estimated the Company would have about 875 MW of wind capacity but indicated that "wind production can vary in an unpredictable manner."[] "Therefore, the Department did not compare wind production patterns to MP's capacity deficits."[] While the Department did not consider wind generation to be a viable mitigation measure, the Department did recognize that the Company's wind resources "potentially offer a price spike mitigation measure if the wind is blowing."[] When reviewing the calculated capacity deficits the Department considered wind resources qualitatively rather than quantitatively.[64]

417. The Department also did not consider non-dispatchable hydro power quantitatively because of its limited size on the Company's system.[] The Department noted that Minnesota Power has about 35 MW of non-dispatchable hydro power generation on its system currently and further additions are unlikely.[] Instead when reviewing the calculated capacity deficits small hydro resources were considered qualitatively by the Department.[65]

64 Ex. DER-8, SRR-4 at 18 (Rakow Direct); Ex. DER-12 at 53 (Rakow Surrebuttal).

65 Ex. DER-8, SRR-4 at 18 (Rakow Direct); Ex. DER-12 at 53-55 (Rakow Surrebuttal).

Analysis of Need for Dispatchable Resources – Section X.D

440. Finally, the Department's analysis of market exposure shows that the Company's market risk in 2025 appears to be manageable with its existing resource mix.[] The Department reached this conclusion even with conservative assumptions that considered a number of resources qualitatively rather than quantitatively ~~excluded a number of resources that could provide additional mitigation to market exposure~~. As such, the Department's analysis suggests that the addition of the 250 MW NTEC purchase is not necessary for dispatch purposes in 2025 as claimed by the Company.[66]

66 Ex. DER-8, SRR-4 at 18 (Rakow Direct), Ex. DER-12 at 52-55 (Rakow Surrebuttal).

NTEC RFP Process – Section XI

~~460. In the view of the Administrative Law Judge, it is not necessary to determine whether the RFP process was reasonable. Because the Administrative Law Judge concluded that the Company has failed to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable, there is no need to make a determination regarding the reasonableness of the RFP or LPI's request that Minnesota Power be required to update and reissue its RFP.~~

[New Finding DER-8]. First, the Commission finds that the Department's analysis demonstrated that the proposed NTEC purchase is needed and reasonable. Second, the Department's analysis of the Company's RFP process demonstrates that whether to focus on South Shore's revised proposals or return to the market for more bids was a judgment call, alternative offers likely would not have been competitive with the 250 MW NTEC purchase, and a process for instituting improvements to MP's bidding process has been agreed upon by MP and the Department. As such, the Department's analysis demonstrates that the Company's RFP process was reasonable.[69]

69 Report at 65, 71 (Proposed Findings 317 and 342 as revised); *see also* Report at 90 (Proposed Findings 452-454).

[New Finding DER-9]. MP commits to take the following steps for supply-side purchases of 100 MW or more lasting longer than five years. The six steps are:

- Ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing;
- Provide the Department and other stakeholders with notice of RFP issuances;
- Notify the Department and other stakeholders of material deviations from those timelines;
- Update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
- Where Minnesota Power or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and
- Request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.

NTEC Affiliated Interest Agreements – Section XII

~~509. Because the Administrative Law Judge concluded above that the Company has not met its burden to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable, the Administrative Law Judge concludes that the Company has failed to demonstrate that the proposed affiliated interest agreements are consistent with the public interest.~~[755]

[New Finding DER-10]. The Commission finds that the Department's analysis demonstrated that the proposed NTEC purchase is needed and reasonable to reduce MP's system societal costs for its ratepayers. The Department's analysis shows that, under certain conditions, the affiliated interest agreements are in the public interest. Therefore, the Commission finds it necessary to address the affiliated interest agreements. The Commission finds that the affiliated interest agreements are in the public interest with the Department's suggested conditions and compliance requirements set forth in Attachment B to Minnesota Power's Initial Brief.

The Guaranty Agreement

~~Footnote 770. Because the Administrative Law Judge has concluded that the affiliated interest agreements are not consistent with the public interest, there is no need to address whether the related, proposed revisions to Minnesota Power's FPE Rider are in the public interest under Minn. Stat. § 216B.16, subd. 7(3) or whether the proposed variances to the FPE Rider are consistent with Minn. R. 7829.3200. Similarly, there is no need to address whether the guaranties by Minnesota Power referenced in the O&O are subject to the requirements of Minn. Stat. § 216B,.40. Or, whether the affiliated interest agreements are subject to the requirements of Minn. Stat. § 216B.50. See Second Prehearing Order, Final Issues List, Issues 3-5.~~

[New Finding DER-11]. Guaranties by MP are referenced in the Ownership and Operating Agreement (the O&O Agreement) between South Shore and Dairyland. Ex. MP-6, App. G (Petition).

[New Finding DER-12]. The guaranties referenced in the O&O Agreement are set forth in a separate contract, the Guaranty Agreement.[77]

[New Finding DER-13]. The Commission has jurisdiction over the Guaranty Agreement which is referenced in the O&O Agreement between South Shore and Dairyland under Minn. Stat. § 216B.49 (2016).[78]

[New Finding DER-14]. The Department initially recommended that the Commission approve the Guaranty Agreement under Minnesota Statues § 216B.49 with the express condition that MP's ratepayers shall not be charged for any obligations or payments made by MP under the Guaranty Agreement.[79]

[New Finding DER-15]. Minnesota Power replied that approval of the Guaranty Agreement should be conditioned on Minnesota Power not seeking to charge customers for any obligation or payments under the agreement absent express prior Commission approval and that the Company would bear the burden of proving the reasonableness of any such proposed charge.[80]

[New Finding DER-16]. The Department generally agreed with MP's proposed revised condition.[81]

[New Finding DER-17]. The Commission approves the Guaranty Agreement with the express condition that ratepayers shall not be charged for any obligations or payments made by MP under the Guaranty Agreement. To ensure this condition, if MP incurs costs under the Guaranty Agreement, in order to recover any such costs from its rate payers, MP shall be required to demonstrate to the Commission that the incurrence of such costs is rare, unforeseen, and reasonable to charge to ratepayers.[82]

[New Finding DER-18]. The Commission finds that the Department's analysis demonstrated that the proposed NTEC purchase is needed and reasonable. Therefore, the Commission finds it necessary to address the Guaranty Agreement. The Department's analysis also shows that, under certain conditions, the Guaranty Agreement is in the public interest. The Commission finds that the Guaranty Agreement is reasonable, proper, and in the public interest as long as the Department's suggested conditions and compliance requirements set forth in Attachment B to Minnesota Power's Initial Brief are met.

77 Ex. DER-1 at 2 (Amit Direct). 78 Ex. DER-1 at 3-5 (Amit Direct). 79 Ex. DER-1 at 6 (Amit Direct).

80 Ex. MP-26 at 49-50 (Supinski Rebuttal).

81 Ex. DER-3 at 2 (Amit Surrebuttal).

82 Ex. DER-3 at 2 (Amit Surrebuttal).

FPE Rider Revision

[New Finding DER-19]. Minnesota Power requested approval of variances and associated tariff amendments to the Company's FPE Rider, necessary to ensure that fuel costs Midcontinent Independent System Operator, Inc. (MISO) market costs, and MISO market revenues will be recovered through MP's FPE Rider.[84]

[New Finding DER-20]. The Commission has jurisdiction over the variances and associated tariff amendments to the Company's FPE Rider under Minn. Stat. § 216B.16, subd. 7(3) (2016), Minn. R. 7825.2390-.2920 (2017), and Minn. R. 7829.3200 (2017).[85]

[New Finding DER-21]. The Department concluded that MP's proposed tariff language was reasonable and consistent with MP's clarified request for recovery via the FPE.[86]

[New Finding DER-22]. Minnesota Power agreed with the Department's recommendations for the FPE Rider.[87]

[New Finding DER-23]. The Commission finds that the Department's analysis demonstrated that the proposed NTEC purchase is needed and reasonable. The Department's analysis also shows that, under certain conditions, the affiliated interest agreements are in the public interest. Therefore, the Commission finds it necessary to address MP's proposed variances and associated tariff amendments to the Company's FPE Rider. Consequently, the Commission finds that the proposed variances and associated tariff amendments to the Company's FPE Rider are in the public interest with the Department's suggested conditions and compliance requirements set forth in Attachment B to Minnesota Power's Initial Brief.

84 Ex. MP-13 at 66-74 (Pierce Direct); Ex. DER-5, at 43 (Campbell Direct).

85 Ex. MP-13 at 68-69 (Pierce Direct).

86 Ex. MP-13 at 68-69 (Pierce Direct).

87 Ex. MP-14 at 34 (Pierce Rebuttal); Ex. DER-7, at 17 (Campbell Surrebuttal).

Capital Costs and Related Transmission Upgrades

[New Finding DER-24]. The Department clarified that reasonable capacity costs, fixed O&M costs, and variable O&M costs may not be recovered until MP's future general rate case, once the proposed plant is in-service or will be in-service during the test year.[88]

[New Finding DER-25]. The Department concluded that the capital costs for NTEC and related interconnection costs, including capitalized interest or AFUDC, should be approved in today's dollars without escalation, at a certain amount assuming fifty percent ownership or forty-eight percent ownership, if the Commission prefers.[89]

[New Finding DER-26]. The Department also recommended that an additional $10 million in decommissioning costs be included in capital costs.[90] The Department agreed, however, that it would be reasonable to use the Handy-Whitman index for purposes of escalating total gas plant and related interconnection costs, within the soft cap, at the time of a future rate case, as MP recommended.[91]

[New Finding DER-27]. NTEC and related interconnection costs, including capitalized interest or AFUDC, should be approved in today's dollars without escalation, at a certain amount assuming fifty percent ownership or forty-eight percent ownership, if the Commission prefers. The ALJ also recommends that an additional $10 million in decommissioning costs be included in capital costs, and that the Company's use of the Handy-Whitman index is responsible for escalating total gas plant and related interconnection costs, within the soft cap, at the time of a future rate case.

[New Finding DER-28]. Regarding costs of third-party transmission upgrades, the Department testified that the amounts provided in response to Department Information Request No. 22 provide a reasonable soft cap amount that should be used to evaluate the costs in future rate recovery proceedings.[92] Specifically, the costs of third-party transmission upgrades should be set at a certain soft cap assuming a fifty percent ownership share, which reflects fifty percent of the negotiated amount, plus capitalized interest, or forty-eight percent ownership, which reflects forty-eight percent of the negotiated amount, plus capitalized interest, if the Commission prefers.[93]

[New Finding DER-29]. The Commission agrees that the costs of third-party transmission upgrades should be set at a certain soft cap assuming a fifty percent ownership share, which reflects fifty percent of the negotiated amount, plus capitalized interest.

88 Ex. DER-5 at 33-34 (Campbell Direct).

89 Ex. DER-5 at 9 (Campbell Direct); DER-6, DER-7 at 2-7 and 30 (Campbell Surrebuttal) (public and trade secret versions), Ex. MP-14 at 31 (Pierce Rebuttal); *see also* DER-8 at 6 (Rakow Direct). The actual cap amounts are classified as trade secret and are included in Ms. Campbell's trade secret testimony.

90 Ex. DER-7 at 7 (Campbell Surrebuttal).

91 Ex. DER-7 at 6–7 (Campbell Surrebuttal).

92 Ex. DER-5 at 13–14, NAC-5 (Campbell Direct); Ex. DER-7 at 7–9 (Campbell Surrebuttal).

93 Ex. DER-7 at 9 (Campbell Surrebuttal). The actual costs of third-party transmission upgrades, at respective ownership interests, are classified as trade secret and are included in Ms. Campbell's trade secret testimony.

Underlying Revenue Requirement Assumptions

[New Finding DER-30]. After review of MP's rebuttal testimony, the Department believed that it had resolved most of its concerns with revenue requirement assumptions, by MP providing additional support and updating the numbers as reflected on Schedules 5 and 6 of Ms. Supinski's Rebuttal Testimony, referred to as Exhibits C-1 and D-1.[94]

[New Finding DER-31]. MP did not demonstrate the reasonableness, or authority, to recover or true up recovery of capital costs, related revenue requirement assumptions, or operating and maintenance (O&M) expenses outside of a rate case.[95]

[New Finding DER-32]. The only remaining concern for the Department at the close of the record regarding MP's proposal, as revised in rebuttal testimony, was the amount assumed for decommissioning.[96]

[New Finding DER-33]. The Department recommended that the Commission require MP to provide its independent engineering study and that decommissioning costs should be estimated at $10 million, at a minimum.[97] MP should file a corrected Exhibit C-1 to reflect $10 million in decommissioning costs.[98] That is, the Department requested that MP provide the updated Exhibit C-1 with $10 million in decommissioning costs and Exhibit D-1 with updated numbers electronically with formulas intact.[99]

[New Finding DER-34]. The Commission requires MP to provide its independent engineering study and finds that decommissioning costs be estimated at a minimum of $10 million.
[New Finding DER-35]. The Commission requires MP to file a corrected Exhibit C-1 to reflect the updated decommissioning costs and Exhibit D-1 with updated numbers electronically with formulas intact.

94 Ex. DER-7 at 10–16 (Campbell Surrebuttal).

95 Ex. DER-7 at 16 (Campbell Surrebuttal).

96 Ex. DER-7 at 16 (Campbell Surrebuttal).

97 Ex. DER-7 at 13, 16 (Campbell Surrebuttal).

98 Ex. DER-7 at 16 (Campbell Surrebuttal).

99 Ex. DER-7 at 16 (Campbell Surrebuttal).

The Innovative Energy Statute

[New Finding DER-36]. The Department testified that the Commission should determine whether the Innovative Energy Project Statute (IEP Statute) applies to the NTEC resource acquisition. The record is unclear as to whether the IEP Statute was intended to apply to a project like the NTEC. The Department, however, testified that the Commission could determine that it does.[102]

[New Finding DER-37]. In this case, NTEC is a fossil-fuel-fired generation facility and MP has entered into agreements to purchase capacity or energy from NTEC for a term exceeding five years. Thus, while MP and the Department disagreed as to the applicability of the IEP Statute, they agreed that, based on the analysis in the case, MP's proposal fulfills the statutory requirements.[103]

102 *See* Minn. Stat. § 216B.1694 (2016); *see also* Ex. DER-8 at 17 (Rakow Direct); Ex. DER-11 at 4–5 (Rakow Surrebuttal); Ex. MP-14 at 26–29 (Pierce Rebuttal).

103 Ex. DER-8 at 17 (Rakow Direct); *see also* Ex. DER-11 at 5 (Rakow Surrebuttal).

The Property Acquisition Statute

[New Finding DER-38]. The Department testified that Minn. Stat.§ 216B.50 applies to the Company's acquisition of resources from the NTEC.[107]

[New Finding DER-39]. First, acquisition of resources under the AI Agreements regarding the NTEC resource qualifies as an operating unit or system in Minnesota. The Commission clarified the definition of an operating unit or system in the following order:

> Otter Tail claimed that the Commission lacked authority over this property transfer because the sale of the Wahpeton Division Office did not meet the statutory standard of the sale of "any plant as an operating unit or system." Minn. Stat. § 216B.50, subd. 1. The Company pointed to an earlier Commission decision finding that NSP's sale of an abandoned truck maintenance and repair center did not meet the statutory standard.
>
> The Commission finds that the Wahpeton Division Office is an essential part of Otter Tail's Minnesota operating system and is therefore covered by the statute. Providing electric service requires not just power plants, but the repair, meter reading, customer service, and administrative functions performed in the Wahpeton Division Office. As Otter Tail notes in its reply comments, all these activities "play an integral role in keeping the lights on."
>
> The Commission decision on which the Company relies is not on point, since the finding of no jurisdiction in that case rested not just on the fact that the facility was not a generating plant, but on the fact that, at the time the sales agreement was reached, it was not being used for any company purpose.[108]

[New Finding DER-40]. The Commission noted that it "has long held that out-of-state property which is an integral part of a utility's Minnesota operating system is subject to the provisions of

Minn. Stat. § 216B.50, subd. 1."[109] MP described why the NTEC resource is needed and how NTEC would fit in MP's portfolio of generation resources if the AI Agreements are approved.[110]

[New Finding DER-41]. More recently, Northern States Power Company, doing business as Xcel Energy (Xcel), proposed to acquire several wind generating units, which were located in Minnesota, North Dakota, and South Dakota.[111] In that case, the Commission granted Xcel a variance (exception) to providing the information required by Minn. R. 7825.1400 (A)–(J), as required by Minn. R. 7825.1800, for each of the wind generating units Xcel acquired and found that Xcel's acquisition of the units was consistent with the public interest.[112]

[New Finding DER-42]. Under the unusual terms of MP's proposed resource acquisition, the Department concluded that MP's AI Agreements fall under Minn. Stat. § 216B.50. According to the preamble of the CDA, MP "is entitled under this CDA to utilize forty-eight percent (48%) of the Accredited Capacity of NTEC for all purposes on the same basis as if Minnesota Power owned such Accredited Capacity in its own name as a rate-based utility asset"[113] Also, under the AI Agreements, MP would be both the Construction Agent and the Operating Agent.[114]

[New Finding DER-43]. Finally, the Department testified that the consideration under the CDA is in excess of $100,000, meaning MP pays money in exchange for energy and capacity output of NTEC. Therefore, the issue is whether MP being entitled to use NTEC "as if Minnesota Power owned" NTEC, combined with MP being the Construction Agent and the Operating Agent, is effectively acquiring, leasing, or renting plant through the CDA. Under the ARA-OA, O&O Agreement, and CDA, MP will operate NTEC to create the energy and capacity outputs of NTEC. Finally, MP has stated in numerous places in the record that MP's NTEC resource acquisition is designed "to mimic" a utility-owned asset. Therefore, the Department concluded that section 216B.50 applies to the AI Agreements.[115]

[New Finding DER-44]. While MP did not agree that section 216B.50 applies to the NTEC resource acquisition, it nevertheless stated that it has supplied all required information under Minn. R. 7825.1400 A–D, but that it has requested a variance from supplying required information under Minn. R. 7825.1400 E–J. MP stated that it has met the criteria for granting a variance. The Department agreed with MP that the criteria for granting a variance (Minn. R. 7829.3200) have been met, and the Department recommended that the Commission grant the requested variance to Minn. R. 7825.1400 E–J. Nevertheless, the Department continued to conclude that the proposed NTEC must be evaluated under Minn. Stat. § 216B.50.[116]

[New Finding DER-45]. The applicability of Minn. Stat.§ 216B.50 does not alter the decision criteria.[117]

[New Finding DER-46]. The Commission finds the Department's assessment credible and agrees that section 216B.50 applies to the AI Agreements. However, the Commission finds that the criteria for granting a variance have been met under Minn. R. 7829.3200, and the Commission grants MP's requested variance.

107 Ex. DER-8 at 9–17 (Rakow Direct); *see also* Ex. DER-11 at 2–4 (Rakow Surrebuttal).

108 *In re Otter Tail Power Co.'s Petition for Approval of the Transfer of Property to the City of Wahpeton*, Docket No. E017/PA-98-1345, Order Finding Jurisdiction and Approving Property Transfer at 3 (MPUC Dec. 14, 1998) (footnote omitted).

109 *Id*. at 4.

110 Ex. MP-13 at 14–38 (Pierce Direct).

111 *See generally In re Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Co.'s 2016–2030 Integrated Res. Plan*, Docket No. E-002/M-16-777, Order Approving Petition, Granting Variance, and Requiring Compliance Filing (MPUC Sept. 1, 2017).

112 *Id*. at 7–11. The statutory authority for Minn. R. 7825.1800 is Minn. Stat. § 216B.50.

113 Ex. MP-5, App. H at H-5 (Petition).

114 Ex. DER-8 at 13 (Rakow Direct); *see also* Ex. MP-5, App. H at H-5 (Petition).

115 Ex. MP-5, App. H at H-5 (Petition); *see also* Ex. MP-26 at 22–23 (Supinski Rebuttal); Ex. DER-8 at 13 (Rakow Direct). The Department also concluded that the NTEC does not qualify for the exemption under section 216B.50, subd. 3.

116 Ex. MP-14 at 23-24 (Pierce Rebuttal); *see also* Ex. DER-11 at 4 (Rakow Surrebuttal).

117 Ex. DER-11 at 4 (Rakow Surrebuttal).

The Securities Issue

[New Finding DER-47]. In general, the Guaranty Agreement requires MP to guaranty to Dairyland all South Shore obligations under the O&O Agreement.[120]

[New Finding DER-48]. Because the guaranties by MP to Dairyland qualify as an assumption of an obligation as a "guarantor, endorser, surety or otherwise in the security of another person . . . the Guaranty Agreement is subject to the requirements of Minn. Stat. § 216B.49, including approval of the Commission."[121]

[New Finding DER-49]. The Department initially recommended that the Commission approve the Guaranty Agreement with the express condition that MP's ratepayers shall not be charged for any obligations or payments made by MP under the Guaranty Agreement.[122]

[New Finding DER-50]. After reviewing MP's rebuttal testimony, although the Department continued to conclude that the Commission should approve the Guaranty Agreement subject to the condition that MP's customers be reasonably protected from any obligations or payments made under the Guaranty Agreement, the Department modified its recommendation. The Department ultimately concluded that if MP incurs costs under the Guaranty Agreement, MP must not recover any such costs from its ratepayers unless and until the Company demonstrates to the Commission that the incurrence of such costs is rare, unforeseen, and reasonable to charge to its ratepayers. In addition, the Department recommended that MP would have the burden of demonstrating that it would be reasonable to recover any such rare and unforeseen costs from its customers. The Department concluded that this approach should protect MP's ratepayers from undue exposure to risks regarding MP's unregulated affiliate, South Shore.[123]

[New Finding DER-51]. The Commission finds the Department's analysis and recommendation credible and concludes that the Commission should approve the Guaranty Agreement with the express condition that ratepayers shall not be charged for any obligations or payments made by MP under the Guaranty Agreement. To ensure this condition, if MP incurs costs under the Guaranty Agreement, in order to recover any such costs from its ratepayers, the Commission requires that MP demonstrate that the incurrence of such costs is rare, unforeseen, and reasonable to charge to ratepayers.

120 Ex. DER-1 at 2–6 (Amit Direct). MP-26 at 48 (Supinski Rebuttal).

121 Minn. Stat. § 216B.49, subds. 1, 2 (2016).

122 Ex. DER-1 at 6 (Amit Direct).

123 Ex. DER-3 at 2 (Amit Surrebuttal).

Conclusions of Law

Conclusion 9. Minnesota Power has failed to establish that approval of these affiliated interest agreements, without conditions or other requirements, is consistent with the public interest because it has failed to demonstrate that the underlying 250 MW NTEC purchase is needed and reasonable.[770] However, the Department's analysis established that approval of the affiliated interest agreements is consistent with the public interest as the Department's suggested conditions and compliance requirements set forth in Attachment B to Minnesota Power's Initial Brief are met. The Department's analysis demonstrated that the underlying 250 MW NTEC purchase is needed and reasonable under a range of potential futures.

Conclusion 10. As explained in detail above, the Company's consideration of alternatives was inadequate to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable for meetings its customers' capacity and energy needs. However, the Department's analysis established that NTEC is needed and reasonable for meetings its customers' energy needs under a range of potential futures when considering numerous potential alternatives.

Conclusion 12. Nor has the Company established that the proposed 250 MW NTEC purchase is consistent with the requirements of Minn. Stat.§ 216B.2422 and Minn. Stat. § 216.243, subd. 3a because its alternatives analysis was biased in favor of NTEC. However, the Department's analysis established that the proposed NTEC purchase is consistent with the requirements of Minn. Stat.§ 216B.2422 and Minn. Stat. § 216.243, subd. 3a.

[New Conclusion DER-1]. The Department's analysis established that approval of the Guaranty Agreement is reasonable, proper, and in the public interest as long as the Department's suggested conditions and compliance requirements set forth in Attachment B to Minnesota Power's Initial Brief are met.

Attachment C: MP Compliance Requirements (Attachment A of MP Exceptions, pages 17-23)

Attachment A
Additional Compliance Requirements

Conditions of Approval	Comments
Affiliated Interest Statute. Recommends that the Commission "approve MP's affiliated interest agreements as being reasonable and in the public interest under Minnesota Statutes § 216B.48, subd. 3."[393]	Minnesota Power accepts this condition.
Property Acquisition Statute. Recommends that the Commission "grant MP's requested variance to Minnesota Rules part 7825.1400, Items E to J."[394] Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.50."[395]	Minnesota Power accepts this condition if this statute is found applicable.[396]
Innovative Energy Project Statute. Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.1694, subd. 2(4)."[397]	Minnesota Power accepts this condition if this statute is found to apply. [398]
Environmental Externality Values. Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.2422, subd. 3(a)."[399]	Minnesota Power agrees that the requirements have been met.[400]

[393] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[394] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[395] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[396] *See* Ex. MP-14, at 23, 25 (Pierce Rebuttal).

[397] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[398] *See* Ex. MP-14, at 29 (Pierce Rebuttal).

[399] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[400] *See* Ex. MP-17 and MP-18, at 2, 30; (EJP) Rebuttal Schedule 2 (Palmer Rebuttal) (Public and Nonpublic).

<table>
<tr><th>Conditions of Approval</th><th>Comments</th></tr>
<tr><td>Bidding Process in Next IRP.
Recommends that the Commission “order MP to include, in the Company’s next IRP, a proposed bidding process for Commission consideration and potential approval under Minnesota Statutes § 216B.2422, subd. 5; the process should:

• Apply to supply-side acquisitions of 100 MW or more and lasting longer than five years; and
• Include the six reforms provided by Mr. Frederickson.”[401]

The six steps are:

1. Ensure that the RFP is consistent with the Commission’s then-most-recent IRP order and direction regarding size, type, and timing;
2. Provide the Department and other stakeholders with notice of RFP issuances;
3. Notify the Department and other stakeholders of material deviations from those timelines;
4. Update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
5. Where Minnesota Power or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and

Request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.[402]</td><td>Minnesota Power accepts this condition.[403] [404]</td></tr>
<tr><td>250 MW of Dedicated Capacity.
Recommends that Commission approval “should include MP’s commitment regarding at least 250 MW of dedicated capacity in the approval.”[405]</td><td>Minnesota Power accepts this condition and agrees “the amount of installed capacity dedicated to it under the CDA will not be lower than 250 MW.”[406]</td></tr>
</table>

[401] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[402] Ex. MP-24, at 14-16 (Frederickson Rebuttal).

[403] Ex. MP-24, at 14-15 (Frederickson Rebuttal).

[404] *See* Ex. MP-28 (Pierce Opening Statement).

[405] Ex. DER-11 and DER-12, at 27, 71 (Rakow Surrebuttal) (Public and Nonpublic).

[406] Ex. MP-26 and MP-27, at 15 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	Comments
D&C Agreement Amendments. Recommends that Commission approval should "include MP's commitment regarding amendments to the D&C Agreement in the approval."[407]	Minnesota Power agrees: "During the pendency of this contested case proceeding and prior to approval of the assignment, the Company does not anticipate that any changes to the D&C Agreement would occur. But, to address Dr. Rakow's comment, Minnesota Power will require SSE to allow the Commission to review and pre-approve any amendments if they do occur. Once the assignment becomes effective, the D&C Agreement could only be amended if Minnesota Power, as the Construction Agent, consents to such an amendment. Minnesota Power commits that, in its role as Construction Agent, it will not agree to any material changes to the D&C Agreement that adversely impact customer costs without seeking regulatory concurrence."[408]
O&O Agreement Amendments. Recommends that Commission approval should "include MP's commitment regarding amendments to the O&O Agreement in the approval."[409]	Minnesota Power agrees to the following commitment: "As with the issue of potential amendments to the D&C Agreement …, during the pendency of this contested case proceeding and prior to approval of the Assignment, the Company does not anticipate any changes to the O&O Agreement would occur. Nevertheless, Minnesota Power commits that it will require SSE to allow the Commission to review and pre-approve any amendments if they do occur. Once the assignment becomes effective, the O&O Agreement could only be amended if Minnesota Power, as the Operating Agent, consents to such amendment. Minnesota Power commits that it will not agree to any material changes to the O&O Agreement that adversely impact customer costs without seeking regulatory concurrence."[410]
Abandoned Plant. Recommends that Commission approval should "include MP's commitment regarding abandoned plant in the approval."[411]	Minnesota Power agrees that "prior to obtaining cost recovery for an abandoned investment, Minnesota Power would need to obtain Commission approval either in a rate case or another proceeding. In particular, the Company would bear the burden of requesting recovery of its share of abandoned plant costs and would be required to prove the reasonableness of such cost recovery under the circumstances."[412]

[407] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[408] Ex. MP-26 and MP-27, at 17 (Supinski Rebuttal) (Public and Nonpublic).

[409] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).

[410] Ex. MP-26 and MP-27, at 22 (Supinski Rebuttal) (Public and Nonpublic).

[411] Ex. DER-11 and DER-12, at 72 (Rakow Surrebuttal) (Public and Nonpublic).

[412] Ex. MP-26 and MP-27, at 32 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	**Comments**
CDA Amendments. Recommends that Commission approval should "require MP to make a compliance filing to address the following issues in the CDA: • the definition of ANUC in section 6.1.2; • clarification of "it" in section 11.6; • clarification of "either" in section 13.1; and • the footnotes in Appendix H[.]"[413]	Minnesota Power agrees to make a compliance filing to correct the following issues in the CDA: • the definition of ANUC in section 6.1.2; • clarification of "it" in section 11.6; and • the footnotes in Appendix H[.]"[414] However, the extraneous word "either" is in the first sentence of Section 13.1 of the O&O Agreement, not the CDA.[415] Minnesota Power agrees to correct this item as well.
Capital Costs without Escalation. Recommends that "the capital costs for the gas plant and related interconnection costs including capitalized interest and AFUDC should be approved in today's dollars without escalation," assuming either a 50% or 48% ownership.[416]	Minnesota Power accepts this condition and is willing to proceed with unescalated costs, provided that costs are escalated using a pre-agreed index, such as Handy-Whitman.[417] [418]
Handy-Whitman Index – Escalation. Agrees to the Company's "use of the Handy-Whitman index for purposes of escalation in the Company's future rate case where MP includes the total in-service costs of the gas plant and related interconnection costs."[419]	Minnesota Power accepts this condition.[420]
Decommissioning Costs. Recommends the inclusion in capital costs of an additional $10 million for decommissioning costs (assuming either a 50% or 48% ownership).[421] Recommends that the additional $10 million for decommissioning be reflected as an increase in the soft cap.[422]	Minnesota Power accepts this condition.[423]
Independent Engineering Study – Decommissioning. Recommends that, for decommissioning, "MP be required to provide an independent engineering study and to use at least $10 million for decommissioning costs.[424]	Minnesota Power will provide an independent engineering study to the Department at the time of rate recovery request.[425]

[413] Ex. DER-11 and DER-12, at 72 (Rakow Surrebuttal) (Public and Nonpublic).

[414] *See* Ex. MP-25, at 3-4 (Supinksi Direct); Ex. MP-26 and MP-27, at 39-40 (Supinski Rebuttal) (Public and Nonpublic).

[415] Ex. MP-6, at G-61 (Initial Petition – Volume 4 Appendices F-J) (Nonpublic); Ex. DER-8 and DER-9, SRR-5, at 4 (Rakow Direct) (Public and Nonpublic) (DOC IR-18).

[416] Ex. DER-6 and DER-7, at 30-31 (Campbell Surrebuttal) (Public and Nonpublic).

[417] Ex. MP-26 and MP-27, at 33-36 (Supinski Rebuttal) (Public and Nonpublic).

[418] *See* Ex. MP-26 and MP-27, at 36 (Supinski Rebuttal) (Public and Nonpublic).

[419] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).

[420] Ex. MP-26 and MP-27, at 36 (Supinski Rebuttal) (Public and Nonpublic).

[421] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).

[422] Ex. DER-6 and DER-7, at 7, 13, 31 (Campbell Surrebuttal) (Public and Nonpublic).

[423] *See* Ex. MP-26 and MP-27, at 42 (Supinski Rebuttal) (Public and Nonpublic).

[424] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).

[425] *See* Ex. MP-26 and MP-27, at 42 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	Comments
Third-Party Transmission Soft Cap. Concludes that the third-party transmission amounts provided by Minnesota Power in response to DOC IR 22 "provide a reasonable soft cap amount that should be used to evaluate the costs in future rate recovery proceedings."[426] Specifically concludes that "MP's plan to reconsider the cost-effectiveness of the project, in the event that costs exceed the negotiated third-party transmission upgrades amount, appears to be reasonable."[427]	Minnesota Power accepts this condition.[428]
Updating Exhibits C-1 and D-1 (Supinski Rebuttal Testimony, Schedules 5&6). "The $10 million in decommissioning costs should be reflected and updated on Exhibit C-1 which MP should file as a corrected Exhibit C-1. I also recommend that MP provide the update Exhibit C-1 with $10 million in decommissioning costs and Exhibit D-1 electronically with formulas intact."[429]	Minnesota Power agrees to provide the electronic versions of Exhibits C-1 and D-1 with formulas intact. The $10 million in decommissioning costs are already accurately shown in Exhibit C-1, which reflects 50% of the overall plant decommissioning costs.[430]
Future Rate Case Recovery. "[R]ate case recovery means final cost recovery including the related assumptions that will be determined in MP's future rate case. However, the capital costs approved in this docket including the soft cap and O&M costs used in the Strategist Modeling on Schedule 3 of Ms. Supinski's Rebuttal Testimony, will be the starting point for review in the rate case, and recovery of any higher costs would require MP to support that it is reasonable to charge the costs to its ratepayers."[431]	Minnesota Power accepts this condition.
FPE Rider. Minnesota Power's proposed rate recovery of fuel costs, MISO market costs, and MISO market revenues through the FPE Rider "appears to be consistent with Minnesota requirements and appears to be correctly reflected in MP's tariff language."[432] "MP also clarified that it will not be recovering its O&M costs, depreciation costs, and MISO administrative costs through its FPE Rider."[433]	Minnesota Power accepts this condition.[434]

[426] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).
[427] Ex. DER-6 and DER-7, at 9 (Campbell Surrebuttal) (Public and Nonpublic).
[428] *See* Ex. MP-26 and MP-27, at 37-38 (Supinski Rebuttal) (Public and Nonpublic).
[429] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).
[430] Ex. MP-26 and MP-27, at 42, 47-48, Rebuttal Schedules 5 and 6 (Supinski Rebuttal) (Public and Nonpublic).
[431] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).
[432] Ex. DER-6 and DER-7, at 17, 33 (Campbell Surrebuttal) (Public and Nonpublic).
[433] Ex. DER-6 and DER-7, at 17, 33 (Campbell Surrebuttal) (Public and Nonpublic).
[434] *See* Ex. MP-2 and MP-3, at 4-54 to 4-61 (Initial Petition – Volume 2) (Public and Nonpublic).

Conditions of Approval	Comments
True-Up Mechanism. "[R]ate recovery for the gas and transmission facilities and related O&M costs should occur in a future MP rate case, which would not result in a true-up mechanism. MP has not demonstrated that any proposed recovery of capital or variable O&M costs in a rider outside of a rate case is reasonable or permitted under Minnesota law."[435] "Again, to be clear, the Department does not agree that a rider outside of MP's rate cases to recover capacity costs or non-fuel fixed or variable costs would be reasonable or permissible."[436]	Minnesota Power accepts this condition and will seek cost adjustments for capital costs and fixed and variable O&M costs through rate cases on the same basis as it does for Minnesota Power-owned generating facilities.
Revenue Requirement Method vs. PPA. "Overall, [Campbell] conclude[s] that, if this facility is approved, the rate case recovery using either a revenue requirement or PPA method would provide the necessary rigorous review and would be the best method to protect ratepayers."[437]	Minnesota Power accepts the rate case recovery mechanism proposed by the Department for review of the revenue requirement method for capacity costs and fixed and variable O&M recovery.[438]
Resource Center Accounting. Campbell is satisfied that "MP agreed to set up locational or 'resource center' accounting to track costs of this investment and allow for direct assignment and allocation of costs."[439]	"Minnesota Power agrees to set up locational or 'resource center' accounting to track costs for this investment and allow for direct assignment and allocation of costs. We are happy to work with the Department to ensure that the accounting mechanisms we propose are satisfactory to them."[440]
Full Access to MP/South Shore Books. Recommends that "MP be required to provide full access to MP's/ South Shore's books and records including all billings related to the NTEC gas facility and transmission and all related costs.[441]	Minnesota Power accepts this condition.[442]
Sharing Costs. Accepts MP's commitment to advise the Department and interested parties anytime shared costs are not divided 50/50 between Dairyland and South Shore.[443]	Minnesota Power accepts this condition.[444]
48% vs. 50% Ownership Share. The Department could support Minnesota Power's ownership share at either 48% or 50%.[445]	Minnesota Power agrees that either outcome is supported and defers to the Commission.[446]

[435] Ex. DER-6 and DER-7, at 33 (Campbell Surrebuttal) (Public and Nonpublic).

[436] Ex. DER-6 and DER-7, at 19 (Campbell Surrebuttal) (Public and Nonpublic).

[437] Ex. DER-6 and DER-7, at 22 (Campbell Surrebuttal) (Public and Nonpublic).

[438] *See* Ex. MP-25, at 32-33 (Supinksi Direct); Ex. MP-26 and MP-27, at 22-23 (Supinski Rebuttal) (Public and Nonpublic).

[439] Ex. DER-6 and DER-7, at 34 (Campbell Surrebuttal) (Public and Nonpublic).

[440] Ex. MP-14, at 33 (Pierce Rebuttal).

[441] Ex. DER-6 and DER-7, at 28, 34 (Campbell Surrebuttal) (Public and Nonpublic).

[442] Ex. MP-14, at 34 (Pierce Rebuttal).

[443] Ex. DER-6 and DER-7, at 28, 34 (Campbell Surrebuttal) (Public and Nonpublic).

[444] Ex. MP-14, at 34 (Pierce Rebuttal).

[445] Ex. DER-6 and DER-7, at 34 (Campbell Surrebuttal) (Public and Nonpublic).

[446] Ex. MP-14, at 30-31 (Pierce Rebuttal).

Conditions of Approval	Comments
Costs under the Guarantee Agreement. Dr. Amit agrees with Minnesota Power's proposal. "If MP incurs costs under the Guarantee Agreement, MP must not recover any such costs from its ratepayers unless and until the Company demonstrates to the Commission that the incurrence of such costs is rare, unforeseen, and reasonable to charge to its ratepayers. MP has the burden of demonstrating that it would be reasonable to recover any such rare and unforeseen costs from its ratepayers. This approach should protect MP's ratepayers from undue exposure to risks regarding MP's unregulated affiliate, South Shore. Thus, I believe MP and I are in agreement on all issues that I have raised in this proceeding."[447]	Minnesota Power agrees. "While Minnesota Power agrees that it would not attempt to recover any costs in the unlikely event that payment is required under the Guaranty Agreement without express Commission approval, there may be (rare and unforeseen) circumstances where it would be appropriate that such costs are collected from customers, who will receive all of the benefit of Minnesota Power's share of NTEC. Therefore, the Company recommends that instead of conditioning approval of the Guaranty Agreement on a condition that Minnesota Power's customers shall not be charged for any obligations or payments made under that agreement, the approval be conditioned on Minnesota Power not seeking to charge customers for any obligation or payments under the agreement absent express prior Commission review approval. And of course, Minnesota Power recognizes that it would bear the burden of proving the reasonableness of any such proposed charge."[448]
D&C and O&O Agreement. Dr. Amit concludes that MP's ratepayers are appropriately protected from the financial risks and business risks of the NTEC project under the D&C Agreement and the O&O Agreement.[449]	Minnesota Power agrees. "The terms of the D&C Agreement are intended to reasonably and appropriately allocate the risks of the NTEC project among the Construction Agent and NTEC Owners. Dr. Amit analyzed the various potential risks and agreement provisions addressing the allocation of those risks. The Company agrees with the conclusion that the provisions of the Agreements are reasonable and that the potential risks related to the NTEC project are reasonably and appropriately allocated among the parties."[450] "The terms of the O&O Agreement are intended to reasonably and appropriately allocate the risks of the project among the Construction Agent/Operating Agent and NTEC Owners. The Department witnesses analyzed the various potential risks and agreement provisions addressing the allocation of those risks. I agree with their conclusions, as discussed above, that the provisions of the Project Agreements and Assignment Agreements are reasonable and that the potential risks related to the NTEC project are reasonably and appropriately allocated among the parties."[451]

[447] Ex. DER-3, at 2-3 (Amit Surrebuttal).

[448] Ex. MP-26 and MP-27, at 49-50 (Supinski Rebuttal) (Public and Nonpublic).

[449] Ex. DER-1 and DER-2, at 21 (Amit Direct) (Public and Nonpublic).

[450] Ex. MP-26 and MP-27, at 16 (Supinski Rebuttal) (Public and Nonpublic).

[451] Ex. MP-26 and MP-27, at 21 (Supinski Rebuttal) (Public and Nonpublic).