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VIA EMAIL: Env.Review@state.mn.us

October 8, 2018

Will Seuffert
Executive Director
Environmental Quality Board
520 Lafayette Road North
Saint Paul, MN 55155

Re: Citizens' Petition for Review Under Minnesota Environmental Policy Act of Pending Decision by the Minnesota Public Utilities Commission for the Proposed Nemadji Trails Energy Center

Dear Mr. Seiffert:

Please find enclosed a Petition submitted by 129 individuals, who reside or own property in the State of Minnesota (Petitioners), pursuant to Minn. R. 4410.1100, for preparation of an Environmental Assessment Worksheet for Minnesota Power's proposed Nemadji Trails Energy Center (NTEC) proposal, approval of which is currently pending before the Minnesota Public Utilities Commission ("Commission") in its Docket No. E015/AI-17-568.

In addition, I have enclosed a copy of the notice letter, required by Minn. R. 4410.1100, subp. 4, sent to Minnesota Power notifying it of the filing of this petition.

Although not stated in Minn. R. 4410.1100, the various guides to this process provided by the Environmental Quality Board (EQB) state that it will initially determine if a project qualifies for environmental review. Here, the Petitioners anticipate that the EQB may need to address whether or not this project is exempt by virtue of the fact that it is proposed to be constructed in Superior, Wisconsin, within a few miles of Minnesota. In this regard, the petitioners understand that nothing in the Minnesota Environmental Policy Act, Minn. Stat. Ch. 116D (MEPA), or its implementing regulations expressly exempts projects based on their location out-of-state. Rather, Petitioners understand that MEPA jurisdiction is dependent on both agency jurisdiction to approve a project and the potential for a project to have environmental effects within Minnesota.

To facilitate your review of this jurisdictional matter, Petitioners have included, as Attachment F to the enclosed Petition, Honor the Earth's Petition for Minnesota Environmental Policy Act Review of Minnesota Power's Petition for Approval of Gas Plant Proposal, which Honor the Earth submitted directly to the Commission on June 29, 2018. Honor the Earth's petition lays out the jurisdictional arguments with regard to Minnesota agency environmental review of out-of-state facilities.

As more fully described in Honor the Earth's Petition, Petitioners note that the Commission in its notice of the public comment period for this project expressly requested public comments on NTEC's environmental effects. This notice indicates that the Commission has made a judgment that the NTEC may have environmental effects that are appropriate for consideration by the Commission. Further, the Commission allowed formal evidence into the record on the Project's environmental effects, and this also indicates that the Commission has found it practical and relevant to consider evidence of the NTEC's environmental effects.

Moreover, even Minnesota Power, in its October 24, 2017, Petition for Approval of Gas Plant Proposal included evidence of NTEC's environmental effects. It recommended that the Commission "utilize the criteria set forth in Minn. R. 7849.0120 to determine whether the proposed purchase is reasonable and consistent with the public interest . . . ," criteria C of which states that the Commission must consider whether the NTEC would "protect[] the natural and socioeconomic environments, including human health." Accordingly, Minnesota Power included substantial information and evidence into the hearing record about the environmental effects of NTEC. Thus, Minnesota Power also recognizes that consideration of NTEC's environmental effects by the Commission is appropriate.

Thus, the Commission and Minnesota Power apparently agree that it is practical and legal for the Commission to consider the NTEC's environmental effects. Therefore, the question of the need and appropriateness of Commission consideration of environmental data and information would not appear to be in dispute. In these circumstances, it would seem entirely inconsistent with MEPA for the EQB to refuse to apply MEPA to the Commission's extant environmental review of this out-of-state project. All that compliance here with MEPA would do is ensure that the Commission's existing review of environmental information conforms with MEPA information and data <u>standards</u>. An EQB decision here to require compliance with MEPA would not require consideration of environmental data and information where no prior consideration was allowed – it would only apply MEPA's environmental review standards to an existing environmental review process.

Since the Commission and Minnesota Power accept that it is reasonable and practical for the Commission to consider the environmental effects of this project, Petitioners argue that the Commission's environmental review should comply with MEPA rather than be accomplished by informal review. Such assertion that environmental review here is practical is consistent with MEPA's explicit direction to state agencies that they "use all practicable means, consistent with other essential considerations of state policy, to improve and coordinate state plans, functions, programs and resources . . . ." Minn. Stat. § 116D.02, subd. 2. Moreover, the fact the environmental review of NTEC is practical means that it should afforded environmental review, because "[t]he legislature authorizes and directs that, to the fullest extent practicable the policies, rules and public laws of the state shall be interpreted and administered in accordance with the policies set forth in sections 116D.01 to 116D.06." Environmental review here is also consistent with MEPA's requirement that the State, "minimize the environmental impact from energy production and use . . . ." Minn. Stat. § 116D.02, subd. 2(9).

Petitioners assert that the failure of the Commission to comply with MEPA's information standards means that:

- the Commission lacks sufficient information to assess the environmental effects of the NTEC on Minnesota's environmental and people to the extent required by MEPA;
- the Commission lacks an adequate record on which to base its decision on whether or not ratepayer funding of NTEC is in the public interest; and
- Petitioners and other citizens could not participate meaningfully in the public comment period provided by the Commission for the NTEC project, because the information provided by the

Commission to Minnesotans about the potential environmental and socioeconomic impacts of and alternatives to NTEC was extremely limited and incomplete, which lack of information is one of the primary policy concerns addressed by MEPA.

Petitioners also argue that as a general proposition the State of Minnesota should retain jurisdiction to conduct environmental review of Minnesota agency approvals of projects on or near the border with Minnesota, otherwise project proponents would have an incentive to locate projects immediately outside of the boundaries of Minnesota, as doing so would lessen the regulatory requirements and costs of projects. Energy generation projects located far from Minnesota's borders would be less likely to be subject to MEPA review because of their lack of direct and significant impacts on the State. To the extent there is gray area based on geography, RGU's should be required to use the EAW process to provide clarity about the appropriate scope of environmental review, rather than apply a one-size-fits-all rule that exempts all out-of-state projects approved by Minnesota agencies – regardless of the proximity of a project to the state and the degree of impact of a project on Minnesotans and their environment.

Assuming that the EQB finds that the Commission's NTEC decision is not exempt from MEPA review, the Petitioners request that the EQB review their Petition as required by Minn. R. 4410.1100, subp. 5, and then, if the Petition complies with Minn. R. 4410.1100, subps. 1 and 2, forward it within five days of your receipt of it to the Commission, which is the responsible government unit. If the Petition is not in compliance with Minn. R. 4410.1100, subps. 1 and 2, the Petitioners request that you return the Petition to me within five days of receipt with a written explanation of why it does not comply. If convenient, please direct any future correspondence on this matter to me at paul@honorearth.org.

Thank you for your time and attention.

Very truly yours,

Paul C. Blackburn

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CITIZEN'S PETITION

FOR

MINNESOTA ENVIRONMENTAL POLICY ACT REVIEW OF

MINNESOTA POWER'S PETITION FOR APPROVAL OF GAS PLANT PROPOSAL

OCTOBER 8, 2018

CITIZEN'S PETITION

We, the 129 undersigned Petitioners, pursuant to Minn. R. 4410.1100, hereby request that the Minnesota Public Utilities Commission ("Commission") prepare an Environmental Assessment Worksheet ("EAW") for the for the proposed Nemadji Trails Energy Center ("NTEC") in accordance with the requirements of the Minnesota Environmental Protection Act, Minnesota Statute Chapter 116D ("MEPA").

The NTEC is a proposed 525 megawatt ("MW") 1x1 combined-cycle, natural gas power plant which is being jointly developed by Minnesota Power's ("MP") affiliate, South Shore Energy, LLC ("South Shore"), and Dairyland Power Cooperative ("Dairyland") for siting in Superior, Wisconsin.[1] The Commission is currently considering whether or not to approve certain affiliated interest agreements for the NTEC under Minn. Stat. § 216B.48, which consideration is in response to MP's October 24, 2017, Petition for Approval of Gas Plant Proposal ("October 24 Petition") (Attachment A) in Commission Docket No. E015/AI-17-568, which docket was referred by the Commission to the Office of Administrative Hearings for a contested case proceeding and docketed there as Docket 68-2500-34672.

Petitioner's assert that the Commission's decision under Minn. Stat. § 216B.48 is a major governmental action by an agency of the State of Minnesota that would authorize the commencement of the NTEC project, which project might result in significant environmental effects within the State of Minnesota, such that the Commission must at a minimum prepare an EAW prior to making any decision that approves the project. The location of the NTEC in Wisconsin does not relieve the Commission from its obligation under MEPA to evaluate the environmental impacts on the people, land, air, water, and climate of Minnesota resulting from a decision to allow Minnesota Power to commence construction of the NTEC.

REQUIRED INFORMATION

Minn. R. 4410.1100 requires that this Petition include five categories of information. This information is provided below.

A. Description of the Proposed Project

The NTEC is a proposed 525 megawatt ("MW") 1x1 combined-cycle, natural gas power plant that would be sited in Superior, Wisconsin.[2] MP's October 24 Petition describes the NTEC as follows:

> **4.3.1 Overview of Proposed Project**
> The NTEC project will be jointly owned and developed by South Shore and Dairyland. Each owner will have the rights to 50 percent

[1] Petition for Approval of Gas Plant Proposal at 1-1, MNPUC Docket No. E015/AI-17-568 (Oct. 24, 2017).
[2] October 24 Petition at 1-1.

of NTEC capacity (approximately 262.5 MW of an assumed 525 MW plant). As part of the affiliated interest transaction that is the subject of this proceeding, South Shore has agreed to dedicate 48 percent of the capacity of NTEC(approximately 250 MW) to Minnesota Power. NTEC is to be located in Superior, Wisconsin, at a site identified as part of a broad-range site selection study performed by Burns & McDonnell, on behalf of Minnesota Power in its evaluation of potential joint development of a combined cycle power plant, completed in 2014 (the "Combined-Cycle Site Selection Study"). Minnesota Power's consultant is working on an update of this evaluation that will be submitted into the record of this proceeding upon its completion.

NTEC will consist of one 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. The total facility output is estimated at 525 MW.

The NTEC project will include the installation of a new 345 kV collector bus to interconnect the output from the generating plant to a new offsite 345 kV substation near the NTEC site. Existing transmission lines that traverse the site will also be relocated elsewhere on the site.

NTEC will be designed to operate as a dispatchable, variable load power plant and have the capability of operating up to the level of the GTG at full load with inlet evaporative coolers plus supplemental duct firing of the HRSG ("Maximum Load"). 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.[3]

[3] October 24 Petition at 4-18 to 4-19 (footnotes omitted).

B. Proposer of the Project

The NTEC has been proposed by Minnesota Power, a public utility operating division of ALLETE, Inc.

C. The Name, Address, and Telephone Number of the Representative of the Petitioners

Paul Blackburn
Honor the Earth
607 Main Avenue
PO Box 63
Callaway MN 56521
612-599-5568
paul@honorearth.org

D. A Brief Description of the Potential Environmental Effects Which May Result From the Project

The NTEC would have significant environmental effects on Minnesota's environment in the form of air and water pollution, due both to direct air and water pollution emissions resulting from the process of combusting natural gas to generate electrical power in the NTEC itself, but also via indirect emissions, including from natural gas fugitive emissions resulting from the natural gas production and transmission infrastructure needed to provide the NTEC with its fuel. The gaseous emissions from the NTEC will be in the form of NO_x, CO, SO_2, VOCs, PM10, and CO_2.[4] These and possibly other polluting substances will be emitted by the NTEC into the atmosphere, from which some of them will be transported into the air within the State of Minnesota, onto land within the State of Minnesota, and into the waters of the State of Minnesota. The CO_2 and methane emissions resulting from fueling and operating the NTEC would also contribute substantial amounts of greenhouse gas emissions into our global atmosphere, thereby producing global warming and climate change.[5] While the NTEC would produce fewer greenhouse gas emissions than coal-fired power, it would produce far more emissions than those produced by renewable energy generation facilities.

Due to the very limited amount of publicly available information about the NTEC project's design or emissions, Petitioners do not and cannot provide estimates about the amounts of pollutants that would be emitted by the project. This being said, at over 500 MW of capacity, the project would be one of the largest electric generation facilities constructed to serve Minnesota electric customers. The Project is significantly larger than the recently approved Mankato Energy Center Expansion Project, which increased that station's capacity by 345 MW,

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[4] October 24 Petition at 4-9.
[5] Direct Testimony of Anna Sommer, January 19, 2018. PUC Docket No. E-015/AI-17-568.

for which the state prepared an EAW.[6] Further, the NTEC would be located near a number of other large air pollution emission sources, including the Husky Superior Oil Refinery and the Enbridge Superior Crude Oil Terminal, such that the NTEC's cumulative impacts on air quality in Minnesota could be significant and should be investigated.

The NTEC would have a substantial impact on the socioeconomic environment within Minnesota resulting from construction and operation, because its approval and construction would reduce demand for cleaner renewable energy facilities, particularly those that might be located within the State of Minnesota. As such, approval of the affiliated interest agreements would likely also have a long-term impact on the socioeconomic wellbeing of Minnesota. The October 24 Petition shows that construction of the NTEC and its related transmission upgrades would cost approximately $700 million.[7] MP, and by extension its ratepayers, would be responsible for 48 percent ($336 million) of this amount via a monthly capacity payment.[8] In addition, MP's ratepayers would also pay for 48 percent of project costs, which include costs related to "planning, permitting, design, construction, acquisition and procurement, completion, renewal, addition, replacement, modification, operation, maintenance, repair, or decommissioning" of the NTEC, as well as its fuel commodity and transportation costs and MISO market costs.[9] Over the project life of the NTEC, post-construction costs would add hundreds of millions of dollars more to the financial commitment of MP's ratepayers, thereby producing significant socioeconomic effects within the State of Minnesota. MP asserts that its "[r]egional economic impacts are expected to exceed $1 billion over NTEC's first twenty years of operation,"[10] which also is a significant socioeconomic effect.

To the extent that construction of the NTEC would supplant the use of energy efficiency to meet energy needs, it also would have the potential to produce significant environmental effects in the form of unneeded electricity generation and its resulting emissions.

E. Material Evidence Indicating That, Because of the Nature or Location of the Proposed Project, There May Be Potential for Significant Environmental Effects

The Petitioners provide the following material evidence related to the NTEC's potential for significant environmental effects within Minnesota:

- MP's October 24 Petition (Attachment A);

[6] Project documents for the Mankato project may be found at: https://mn.gov/eera/web/project/636/.
[7] October 24 Petition at 4-44.
[8] October 24 Petition at 4-45.
[9] October 24 Petition at 4-47.
[10] October 24 Petition at 4-27.

- ***EAW for the Mankato Energy Center II***, a 245 MW expansion of the Mankato Energy Center (Attachment B);[11] and

- ***Section 4.1 of the Draft Environmental Impact Statement for the Deer Creek Station***, a 300 MW natural gas facility in Brookings County, South Dakota (Attachment C);[12]

- The written testimonies of the following witnesses in Commission Docket E-015/AI-17-568:
  - ***Direct Testimony of J. Drake Hamilton***, dated January 19, 2018, related to whether or not the NTEC is consistent with Minnesota's statutory greenhouse gas goals Minn. Stat. section 216H.02, subd. 1 (Attachment D);
  - ***Direct Testimony of Anna Sommer***, dated January 19, 2018, related to the potential future CO_2 emissions of the NTEC (Attachment E);

The evidence contained in the foregoing attached documents is summarized below.

Attachment A – October 24 Petition: The October 24 Petition contains: (a) a description of the NTEC (pages 1-1, 4-18 to 4-19); (b) descriptions of the NTEC's air pollution emissions, including greenhouse gas emissions (page 4-27); (c) descriptions of the NTEC's socioeconomic impacts (pages 4-26 to 4-27; and (d) descriptions of some of the possible alternatives to the Project (pages 3-19 to 3-40). MP provided this document to the Commission for its consideration, presumably because MP understood that it was within the Commission's jurisdiction to consider the environmental and socioeconomic impacts of the Project on Minnesota, as well as alternatives to the Project that are available for consideration by the Commission.

Attachment B – EAW for Mankato Energy Center II: The EAW for the Mankato Energy Center II ("MACII") contains descriptions of its air emissions in its section 4.4. In particular, Table 5 shows that emissions from this expansion, which are significant. Among other emissions include 1.6 million tons per year of CO_2e, 382.58 tons per year of VOC; and 768.64 tons per year of CO. The impacts of the NTEC would be similar in type and likely larger than those of MACII.

Attachment C – DEIS for the Deer Creek Station, Sections 1-4: The DEIS for the Deer Creek Station contains detailed information showing the impacts resulting from this 300 MW natural gas-fired project. The description of the project's air quality impacts are contained in its Section 4.1. The air pollution impacts of the NTEC would be similar in kind, but possibly greater than those of the Deer Creek Station, due to the larger generation capacity of the NTEC.

[11] Project documents for the Mankato project may be found at: https://mn.gov/eera/web/project/636/.
[12] The DEIS is provided rather than the FEIS, because the FEIS for this project incorporated the DEIS as a whole with minor changes. The FEIS available at: https://www rd.usda.gov/files/UWP ND45-Basin DeerCreek FEIS.pdf

Attachment D – Direct Testimony of J. Drake Hamilton: Ms. Hamilton's testimony discusses the greenhouse gas emissions of the NTEC and its negative impact on achievement of the State's greenhouse gas emissions goals on pages 5 to 14.

Attachment E – Direct Testimony of Anna Sommer: Ms. Sommer's testimony discusses the projected greenhouse gas emissions from the NTEC at pages 30 to 31.

Petitioners are unable to provide detailed estimates of other pollution emissions from the NTEC due to the very limited evidence in the record about the design or projected air and water emissions from the project, which lack of public information is further reason for the Commission to prepare at least an EAW for the NTEC.

LEGAL DISCUSSION

Petitioners assert that the Commission's decision under Minn. Stat. § 216B.48 is a major governmental action by an agency of the State of Minnesota that would authorize the commencement of the NTEC project, which project might result in significant environmental effects within the State of Minnesota, such that the Commission must at a minimum prepare an EAW prior to making any decision that approves the project. The location of the NTEC in Wisconsin does not relieve the Commission from its obligation under MEPA to evaluate the environmental impacts of its NTEC decision on the people, land, air, water, and climate of Minnesota, due to its location near the border between Minnesota and Wisconsin. In particular, Petitioners assert that the air pollution emissions of the NTEC will be transported through the atmosphere to Minnesota and therein cause significant adverse environmental effects to the State's air, water, and land, as well as adverse health impacts to Minnesota residents. Petitioners also assert that approval of the affiliated interest agreements for the NTEC would have significant socioeconomic impacts within Minnesota, both in terms of the socioeconomic impact such approval would have on Minnesota Power's ratepayers, and due to the adverse socioeconomic impacts that would result from building a natural gas fueled generation facility in Wisconsin, rather than building additional renewable energy generation facilities in Minnesota. To address the jurisdictional issues more thoroughly, Petitioners attach the Petition of Honor the Earth for Minnesota Environmental Policy Act Review of Minnesota Power's Petition for Approval of Gas Plant Proposal, which was filed directly with the Commission in Docket E-015/AI-17-568 on June 29, 2018 (Attachment F). The Petitioners hereby incorporate the arguments presented by Honor the Earth into this Petition.

NOTICE TO NTEC PROPOSER

The Petitions have notified MP of this petition through filing of this petition in Commission Docket E-015/AI-17-568 via the Department of Commerce's eFiling system. In addition, the Petitioners have also emailed a copy of the petition to the following MP employees:

David R. Moeller (dmoeller@allete.com)
Lori Hoyum (lhoyum@mnpower.com)
Minnesota Power
30 West Superior Street
Duluth, MN 55802

REQUEST FOR ENVIRONMENTAL ASSESSMENT WORKSHEET

Pursuant to Minn. R. 4410.1100, the below signed Petitioners respectfully request that the State of Minnesota prepare an EAW for the NTEC project in accordance with MEPA and its regulations. Petitioners assert that “the evidence presented by the petitioners, proposers, and other persons or otherwise known to the RGU demonstrates that, because of the nature or location of the proposed project, the project may have the potential for significant environmental effects,” such that the Commission must order the preparation of an EAW for NTEC. Should our Petition fail to comply with the requirements of Minn. R 4410.1100, subpart 1 or 2, please provide a written explanation to our above listed representative for why it does not comply, within 5 days of your receipt of it, as required by Minn. R. 4410, 1100, subpart 5.

October 8, 2018

Respectfully submitted,

The 129 Undersigned Citizens of Minnesota

October 5 MEPA Citizens' Petition

For Proposed Nemadji Trails Energy Center

Attachment Index

Attachment A	Minnesota Power Petition for Approval of Gas Plant Proposal
Attachment B	EAW for the Mankato Energy Center II Project near Mankato, MN
Attachment C	Draft Environmental Impact Statement for the Deer Creek Station Energy Facility Project in Brookings County, South Dakota
Attachment D	Direct Testimony of J. Drake Hamilton dated January 19, 2018, in Minnesota Public Utilities Commission Docket E-015/AI-17-568
Attachment E	Direct Testimony of Anna Sommer dated January 19, 2018, in Minnesota Public Utilities Commission Docket E-015/AI-17-568
Attachment F	Petition of Honor the Earth for Minnesota Environmental Policy Act Review of Minnesota Power's Petition for Approval of Gas Plant Proposal, June 29, 2018 , in Minnesota Public Utilities Commission Docket No. E-015/AI-17-568

Attachment A

Minnesota Power Petition for Approval of Gas Plant Proposal

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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Docket No. E015/AI-17-568

In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package	PETITION FOR APPROVAL OF GAS PLANT PROPOSAL

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Submitted by:

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SECTION 1 SUMMARY OF FILING

1.1 INTRODUCTION

Minnesota Power, a public utility operating division of ALLETE, Inc. ("Minnesota Power" or the "Company"), respectfully resubmits this Petition for Approval to the Minnesota Public Utilities Commission ("Commission"). This Petition seeks Commission approval of the affiliated interest agreements and associated tariff changes for Minnesota Power's purchase of a 48 percent share (approximately 250 MW) of the capacity from the approximately 525 MW Nemadji Trail Energy Center ("NTEC") 1x1 combined-cycle, natural gas power plant which is being jointly developed by Minnesota Power's affiliate, South Shore Energy, LLC ("South Shore") and Dairyland Power Cooperative ("Dairyland").[1]

Initially, on July 28, 2017, Minnesota Power filed a joint Petition in this Docket seeking Commission approval of a package of resources. It is comprised of (i) a power purchase agreement ("PPA") for 250 MW of wind generation, (ii) a PPA for 10 MW of solar generation, and (iii) affiliated interest agreements for approximately 250 MW of dispatchable natural gas capacity (collectively the "Energy*Forward* Resource Package").[2] This refiled Petition is submitted in compliance with the Commission's September 19, 2017, Order Referring Gas Plant for Contested Case Proceedings, and Notice and Order for Hearing ("Order for Hearing") in this Docket. In its Order for Hearing, the Commission directed the Company to seek separate approval in this Docket of the natural gas component of the Energy*Forward* Resource Package.

The approximately 250 MW of dispatchable natural gas capacity (the "NTEC 250 MW" purchase) that is the subject of this Petition, provides low-cost and reliable dispatchable capacity

[1] Specifically, the Company requests approval of (1) affiliated interest agreements for the purchase of approximately 250 MW of dispatchable natural gas capacity from the NTEC plant; and (2) associated tariff changes/variances. Miscellaneous filing information under Minn. R. 7829.1300 is provided in Appendix A. Affiliated interest agreement filing information is provided in Appendix B.

[2] The Energy*Forward* Resource Package has its genesis in part from the Commission's decisions approving the Company's 2015 Integrated Resource Plan ("2015 Plan"). *In the Matter of Minn. Power's 2015-2029 Integrated Res. Plan*, Docket No. E015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS (July 18, 2016) (the "July 2016 IRP Order"). That package of resources was designed to support Minnesota Power's larger "Energy*Forward*" initiative, to replace retiring coal generation and expand the Company's renewable energy portfolio. In the July 2016 IRP Order, the Commission directed the Company to competitively solicit wind and solar resources and authorized the Company to pursue natural gas resources.

to serve customers' long-term needs. The NTEC 250 MW purchase, in conjunction with the other elements of the Energy*Forward* Resource Package, advances Minnesota Power's ongoing system transformation. This includes retiring older coal facilities and focusing more on cleaner energy technologies such as renewable wind, hydroelectric, and solar generation as well as renewable-enabling dispatchable natural gas capacity.

Specifically, the current proposal to add the NTEC 250 MW purchase to the system was selected to ensure sufficient capacity is available to serve customer requirements and to support increasing levels of renewable generation on the system. This increment of capacity was selected through a robust resource planning and Request for Proposal ("RFP") process that was supported by independent evaluation. Economic modeling demonstrates that the proposed natural gas resource serves long-term customer needs with at a competitive power and is aligned with Minnesota's least cost philosophy for providing electric supply.

Adding dispatchable natural gas capacity (along with the wind and solar generation arising out of the 2015 Integrated Resource Plan ("2015 Plan")) is necessary to serve the Company's long-term customer requirements, many of which have load factors approaching 80 percent and a critical need for reliable power around the clock. It is noteworthy that by 2026, Minnesota Power will have retired or idled almost 700 MW of coal generation from active service on its system, resulting in the retirement of more than one-third of the Company's legacy power supply. Although eliminating this coal generation substantially reduces emissions, it also eliminates reliable and dispatchable around-the-clock capacity that needs to be replaced in order to serve customer requirements. Extensive modeling has shown it is not prudent to rely only on renewable generation for that replacement capacity.[3] Rather than risk the potential delay or deferral of the contemplated coal retirements, the NTEC 250 MW purchase will work

[3] Minnesota Power has already added 620 MW of wind and 11 MW of solar energy, and is contracting for 250 MW of hydroelectric capacity (plus an additional 133 MW of hydroelectric market energy). As part of its Energy*Forward* Resource Package, the Company is seeking the addition of 250 MW of incremental wind and 10 MW of incremental solar generation. Further, by 2026, Minnesota Power will have removed almost 700 MW of coal-fired generation from its 2,050 MW generation portfolio. Additional dispatchable generation (such as the proposed NTEC 250 MW purchase proposed in this Petition) is necessary to properly balance the system and to ensure reliable supply for all customer needs.

synergistically with planned renewable additions to ensure adequate and reliable capacity for the long-term.

The proposed natural gas resource also continues the Company's long-term Energy*Forward* initiative, which focuses on a fleet transformation toward an overall mix of two-third renewables plus renewable-enabling natural gas, and one-third compliant coal. This combination will reduce emissions and increase renewable penetration without sacrificing cost competitiveness and the reliability of Minnesota Power's power supply. This transformation calls for the strategic addition of resources to ensure adequate energy and capacity to meet existing and future customer needs. Implementation of the resource package arising out of the 2015 Plan, including the proposed NTEC 250 MW purchase, will result in a resource mix of 45 percent renewables (including hydroelectric) and more than a 40 percent reduction in greenhouse gas emissions by 2030 from 2005 levels.

1.2 OVERVIEW OF FILING

Minnesota Power respectfully requests approval of the affiliated interest agreements consummating the NTEC 250 MW purchase. By this transaction, Minnesota Power's affiliate – South Shore – is dedicating the capacity from a 48 percent share (approximately 250 MW) from NTEC, a 525 MW 1x1 natural gas combined-cycle facility in Superior, Wisconsin to Minnesota Power with a proposed commercial operation date in 2024.[4] Specifically, Minnesota Power proposes a Capacity Dedication Agreement ("CDA") purchasing the NTEC 250 MW. NTEC will be jointly owned by Minnesota Power's Wisconsin affiliate — South Shore — and Dairyland (collectively the "NTEC Owners"). Joint NTEC ownership between South Shore and Dairyland allows Minnesota Power to secure this highly-competitive resource that benefits from a larger plant's economies of scale.

[4] NTEC is expected to be between 525-550 MW depending on final turbine selection. Minnesota Power's 48 percent share under the CDA is expected to equal somewhere between 250-264 MW.

Subject to Commission affiliated interest approvals in this proceeding,[5] Minnesota Power will take the lead to develop, construct, operate, and maintain NTEC.[6] Minnesota Power will purchase 48 percent of the plant's output for the entire useful life of the plant at prices and on terms and conditions that effectively replicate utility ownership.[7] This structure provides the Commission with cost prudence oversight associated with the asset.[8]

The NTEC 250 MW purchase[9] was selected because it is the least-cost resource in the RFP that satisfies the identified need for approximately 250 MW of dispatchable capacity.[10] The NTEC 250 MW purchase adds flexible, efficient, and cleaner generation to replace retiring baseload coal-fired generation; helps to ensure reliable electric service; and complements the Company's expanding renewable portfolio.

Pricing under the CDA reflects a regulated cost recovery model approach that ensures customers receive all of the benefits of the capacity purchase. The price for the NTEC 250 MW purchase in the first year is **[TRADE SECRET DATA BEGINS…** …**TRADE**

[5] NTEC is owned by South Shore (rather than directly by Minnesota Power) because of a specific Wisconsin statute that restricts power plant ownership only to Wisconsin entities. This required structure, in turn, necessitates use of affiliated interest agreements that are subject to Commission approval. The reason for this transaction structure is addressed in Section 4.4 of this Petition.

[6] *See* Appendix F: Development and Construction Management Agreement between Dairyland and South Shore; Appendix G: Ownership and Operating Agreement between Dairyland and South Shore; Appendix H: Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power. Under these contracts, South Shore is designated the responsible agent on behalf of the NTEC Owners, tasked with taking the actions necessary to complete development, construction and operation of the plant. The NTEC contracts contains an Assignment of Rights Agreement that assigns South Shore's role as responsible agent to Minnesota Power, subject to affiliated interest approval of those assignments

[7] Minnesota Power would prefer to own its share of NTEC directly, but recognizes Wisconsin ownership makes that challenging. However, the Company would support the Commission adopting the CDA directly as a rate based asset under the broad authority under Minn. Stat. § 216B.16, subd. 6 if the Commission deems it appropriate.

[8] The CDA is conceptually similar to Minnesota Power's long-standing purchase of a portion of the output of the Milton R. Young Unit 2 generating station in North Dakota from Square Butte Electric Cooperative ("Young 2"). Under the Young 2 transaction (which is one of the legacy coal facilities being replaced by NTEC), the resource is priced to recover the actual cost of service equivalent to a rate-based asset.

[9] South Shore will retain 2 percent (approximately 12 MW) of NTEC to its own account.

[10] This 250 MW need translates into about 48 percent of NTEC's current proposed configuration as a 525 MW plant. However, depending upon final turbine selection, NTEC could be slightly larger (i.e., 550 MW). As a result, Minnesota Power's 48 percent share of NTEC will be approximately 250-264 MW. Notably, the Company would support a Commission determination that Minnesota Power take South Shore's entire 50 percent interest in NTEC (262-275 MW) if the Commission would prefer that Minnesota Power purchase the entire position.

SECRET DATA ENDS]] which will decline each year, plus an additional amount assumed to be not more than **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** for transmission network upgrade costs.[11]

Energy associated with the NTEC 250 MW purchase will be bid into the Midcontinent Independent System Operator, Inc. ("MISO") market on the same basis as energy from Minnesota Power's other plants. NTEC is expected to provide cost-effective energy into the MISO market, operating with a projected net capacity factor ranging from 40 to 80 percent,[12] depending on fuel cost, demand, and carbon regulation.[13]

1.3 Overview of Load Forecast and Need

The development of the proposed natural gas addition as part of the more comprehensive package of resources arising out of the 2015 Plan, was based on an overall analysis of future customer needs and evaluation of available alternatives to those needs. The Company projects a capacity deficit beginning in 2018, increasing to approximately 500 MW in 2031. This deficit is caused in part because Minnesota Power is in the process of idling, removing, or refueling resources, including nearly 700 MW of coal-fired capacity that have already been or are planned. The net effect requires that Minnesota Power deploy significant additional resources by the mid-2020s.

In its Order for Hearing, the Commission ordered the Company to update its load forecast.[14] The updated forecast developed to evaluate this Petition is found in Section 2 of this Petition and

[11] MISO-required network upgrades will not be known for some time. For purposes of the transaction, Minnesota Power assumes that NTEC will not incur more than**[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** in network upgrades. If those costs are determined to exceed this amount, Minnesota Power will reassess the economics of the overall project before proceeding with construction of the plant.

[12] The net capacity factor of a power plant is the ratio of its actual output to its potential output. So in other words, the NTEC facility is anticipated to run 40 to 80 percent of the time.

[13] This filing requests a variance and associated tariff amendments to the Company's Fuel and Purchased Energy ("FPE") Rider to ensure that all of the revenues received by Minnesota Power from the MISO market sale of energy flow back to the benefit of customers. With this variance, customers will be treated the same as if the generating asset was owned directly by the utility.

[14] *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Docket No. E015/AI-17-568, ORDER REFERRING GAS PLANT FOR CONTESTED CASE PROCEEDINGS, AND NOTICE AND ORDER FOR

reflects a reasonable overall outlook of customer demand and is not overly optimistic. The analysis assumes that the 250 MW of wind and 10 MW of solar components of the Energy*Forward* Resource Package will proceed and will be part of the Company's resource mix by 2024 when NTEC is scheduled to achieve commercial operation. It also assumes the taconite facilities currently idled will remain so and only one of the several large-scale mining projects on the horizon will start operations during the planning period. This forecasting strategy ensures Minnesota Power does not over-commit to adding resources, and maintains flexibility for the future.[15]

1.4 THE NATURAL GAS PLANT IS IN THE PUBLIC INTEREST

The current Petition continues Minnesota Power's efforts to transform its generation portfolio without sacrificing reliability and affordability of service. Adding dispatchable natural gas capacity is in the public interest for a variety of reasons described in this filing. In particular, the proposed natural gas plant addition, along with the other components of the proposed package of resources:

- Enables increased overall renewable penetration to approximately 45 percent (including increases wind (250 MW) and solar (10 MW) energy from current levels;
- Meets growing needs during a period of declining planning reserve margins in MISO;
- Replaces coal plants with cleaner-burning dispatchable natural gas generation;
- Contributes to material decreases in carbon dioxide ("CO_2") emissions;
- Ensures flexible and reliable power supply for Minnesota Power customers;
- Facilitates future renewable development; and
- Delivers the least-cost portfolio across hundreds of potential outcomes.

HEARINGS at 8 ("Minnesota Power shall refile an updated petition limited to those portions relevant to consideration of the proposed gas plant, with a revised forecast and updated alternatives.") (Sept. 19, 2017).

[15] The Company also considered higher and lower forecast sensitivities. The combination of resources represented by the Energy*Forward* Resource Package (including 250 MW of wind, 10 MW of solar and 250 MW of gas) is the overall least cost under those scenarios as well, further supporting the reasonableness of the proposed packages.

This is a unique opportunity to deploy resources that align cost and non-cost considerations. Based on review of numerous alternatives for meeting growing customer needs, this combination and timing of resources is in the best interest of customers.

1.4.1 Cost Effective

The addition of the NTEC 250 MW purchase is a cost-effective way to meet customer needs. It replaces high-cost legacy resources with highly-efficient combined-cycle natural gas capacity. Assuming the Commission also separately approves the wind and solar components of the Energy*Forward* Resource Package, the result will be a highly-competitive set of capacity and energy resources that will successfully replace the contemplated coal retirements. As described in Section 3 of this Petition, the proposed system addition is the least-cost alternative relative to doing nothing, a 75 percent renewable alternative, 50 percent renewable alternative, or large combustion turbine peaking alternative.

Other alternatives that were analyzed included: (i) reduced capacity need as a result of additional demand response programs, (ii) conservation, (iii) low load growth, (iv) alternative forms of generation, (v) a no build alternative, and (vi) energy storage. In addition, the Company analyzed whether increased penetration of renewable generation resources could meet the identified need in a cost-effective and reliable manner. None of the investigated alternatives were found to be preferable to the Company's proposal.

1.4.2 Strategist Analysis

The Company's Strategist Proview modeling ("Strategist") analysis confirms that the proposed natural gas addition provides the most advantageous resource mix available across various load, energy market, gas price, investment, and environmental sensitivities, as well as under alternative seasonal capacity requirements.

Strategist provides a robust review of these various criteria and evaluates possible alternatives under nearly 300 unique combinations and sensitivities. Minnesota Power used Strategist to fully vet the options and confirm the direction provided in the July 2016 IRP Order. The Strategist analysis confirmed that the natural gas addition provides the most prudent and flexible resource in light of coal retirements and corresponding renewable additions to meet customer requirements with an overall balanced, reliable, and affordable power supply portfolio. This is consistent with the results from the previous two IRP's showing a natural gas addition is the most prudent resource to meet customer needs during this period.

1.4.3 Other Considerations

Beyond pure economics, the Company's proposal, in conjunction with its other initiatives, provides additional benefits described in this filing:

- ***Reduces CO_2 Emissions***: It continues Minnesota Power's commitment to less carbon-intense resources to meet customer needs. The Company will substantially exceed its pro rata contribution to Minnesota's CO_2 emissions goals (if applied on an individual utility basis) by (1) replacing nearly 700 MW of coal generation with a combination of wind/solar generation and natural gas capacity and (2) bringing Minnesota Power's renewable portfolio (including hydroelectric) to over 1,200 MW. This, together with industry-leading energy efficiency outcomes, positions the Company well to align with and exceed future greenhouse gas regulations.
- ***Enhances Supply Diversity***: Minnesota Power's resulting diverse resource mix contains a strategic combination of renewable and natural gas generation to work alongside the remaining coal resources to stabilize the power supply. This results in a balanced and diverse supply portfolio that will serve customer needs 24-hours a day.
- ***Mitigates Energy Markets Risk***: Minnesota Power's need for dispatchable generation currently has the potential to vary up to 600 MW (increasing to 850 MW with the addition of 250 MW of wind that is part of the Energy*Forward* Resource Package) in any hour due to variable renewable generation. Adding dispatchable capacity will help mitigate and balance the exposure to potentially volatile energy markets arising from such variability on the grid.
- ***Replaces Coal-fired Generation***: Adding the NTEC 250 MW in conjunction with the other resources that are part of the Energy*Forward* Resource Package effectively replaces

a portion of the nearly 700 MW of baseload coal-fired generation that has been or will be retired, removed, refueled, or idled by 2025.

- ***Winter Peaking Benefit***: Minnesota Power's system typically peaks in the evening hours during the coldest days of the year. 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. Natural gas fired generation is available during these time periods on a consistent basis.
- ***Location Benefit***: NTEC is advantageously located to serve Minnesota Power's customers, has access to the grid and is in close proximity to multiple interstate natural gas pipelines.
- ***Socioeconomic Benefit***: Finally, the gas plant provides socioeconomic benefits to the Duluth/Superior area, providing significant construction and operation jobs for the skilled labor force in and around the Iron Range, in addition to indirect jobs supporting the project.

1.5 OVERVIEW OF PROCESS

Minnesota Power requests decisions on a number of specific but interdependent elements in this proceeding. Specifically, the Company requests:

- Approval of the affiliated CDA, dedicating the NTEC 250 MW purchase to Minnesota Power and energy cost recovery through the Fuel and Purchased Energy ("FPE") Rider;
- Approval of the affiliated Assignment of Rights Agreements between Minnesota Power and South Shore, authorizing Minnesota Power to act as responsible agent on behalf of the NTEC Owners under the NTEC Agreements; and
- Approve necessary variances and associated tariff amendments to the FPE Rider to ensure that fuel costs related to Minnesota Power's share of NTEC are recovered and that MISO revenues realized under the CDA flow back to customers.

The Company is seeking Commission approval of the affiliated interest agreements pursuant to Minn. Stat. § 216B.48, which calls for the Commission to assess whether the agreements are "reasonable and consistent with the public interest." Minnesota Power recognizes that there are important factual, legal, and policy considerations involved in this proceeding that may be more complicated than the typical affiliated interest filing. Minnesota Power views this Petition to be an opportunity for the Commission and stakeholders to evaluate the proposed natural gas resource and alternatives considered.

In assessing the reasonableness of the affiliated interest agreements, the Commission will assess whether the capacity being acquired is needed by Minnesota Power to serve its customers and whether the terms and conditions of the purchase are reasonable. The inquiry into the need for capacity and the terms and conditions of the purchase implicate issues of size, type, timing, and ownership of generation, which in turn implicate the type of review conducted under the Minnesota Certificate of Need statute, Minn. Stat. § 216B.243. Since NTEC is not located in Minnesota, it is not subject to the Minnesota Certificate of Need statute. Nevertheless, Minnesota Power has provided in this Petition the type of information that the Commission would use in assessing the need for the NTEC 250 MW purchase and Minnesota Power recommends that the Commission use the Certificate of Need criteria to assess whether the affiliated interest agreements satisfy the relevant public interest test.

Specifically, Minnesota Power recommends that the Commission utilize the criteria set forth in Minn. R. 7849.0120 to determine whether the proposed purchase is reasonable and consistent with the public interest:

A. The probable result of denial would be an adverse effect upon the future adequacy of reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;

B. A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;

C. By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and

D. The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[16]

[16] Minn. R 7849.0120.

These criteria and the prior implementation and interpretation of these criteria provide a logical basis for assessing the reasonableness and public interest in Minnesota Power's purchase of the NTEC 250 MW for the benefit of ratepayers. Minnesota Power has provided information in this Petition that allows the Commission to address each of these criteria.[17]

In its September 19, 2017 Order for Hearing, the Commission referred this matter to the Office of Administrative Hearings ("OAH") for a contested case to allow for full consideration of the important resource planning and generation need considerations that are fundamental to evaluating the Company's Petition. The following schedule and timeline is proposed based on agreement among the parties to this proceeding:

Proposed Contested Case Schedule For Consideration of Natural Gas Petition

Milestone/Event	Date
Commission Referral to Contested Case Proceeding	September 19, 2017
Minnesota Power Refiles Petition	October 24, 2017
Initial ALJ Prehearing Conference	October 25, 2017
Minnesota Power Direct Testimony	November 6, 2017
Deadline for Intervention	November 17, 2017
Intervenor Direct Testimony	January 19, 2017
All Parties' Rebuttal Testimony	February 23, 2018
Public Hearing – Duluth	Week of March 5, 2018
All Parties' Surrebuttal Testimony	March 16, 2018
Public Comment Deadline	March 23, 2018
Prehearing Conference	TBD or March 26, 2018
Evidentiary Hearings	March 26-29, 2018
Initial Briefs	May 1, 2018
Reply Briefs/Proposed Findings of Fact	May 22, 2018

[17] For purposes of this Petition and the analyses underlying it, Minnesota Power assumes that the Commission will separately approve the wind and solar components of the Energy*Forward* Resource Package. Appendix C provides a summary of the type of information generally found in a certificate of need application, as well as information for the affiliated interest filing and compliance with the July 2016 IRP Order and September 19, 2017 Order for Hearing.

Milestone/Event	Date
ALJ Report	July 2, 2018
Exceptions to ALJ Report	July 23, 2018
Replies to Exceptions	July 30, 2018
Commission Agenda Meetings	September 13 and 20, 2018

This schedule reflects Minnesota Power's understanding of the schedule that is agreeable to all the parties to the proceeding.

Timing is a significant consideration as the Company has important project deadlines in the third and fourth quarters of 2018 and regulatory certainty by that time will be very helpful. The NTEC CDA contains conditions precedent calling for Commission approval by October 2018.[18] The proposed contested case timeline will ensure adequate information is before the Commission in a manner that allows the Company to act under these deadlines. Minnesota Power respectfully requests that the Commission act on all of the decisions requested in this Petition by the end of September 2018.

1.6 CONCLUSION

Moving forward with the natural gas plant as proposed as part of the Company's larger resource efforts will provide customers with safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, and adding substantial renewable resources to the system. Minnesota Power respectfully requests that the Commission approve this Petition.

[18] The PPAs covering the wind and solar components of the Energy*Forward* Resource Package contain similar conditions precedent that call for approval of the entire package as a set of resources for the Minnesota Power system.

SECTION 2 ENERGY AND DEMAND FORECAST AND RESOURCE NEED

This Section provides the results of Minnesota Power's updated forecast for customer energy and peak demand (the "2017 Annual Forecast Report" or "2017 AFR") utilized in the Company's evaluation of resource options in selecting the 48 percent share in the approximately 525 MW 1x1 combined-cycle natural gas NTEC power plant to be located in Superior, Wisconsin and placed in service by the end of 2024 (the "NTEC 250 MW" purchase) as the natural gas component of the Energy*Forward* Resource Package.[19] Consistent with the Commission's findings in its July 2016 IRP Order that need exists, but also seeking refinement of Minnesota Power's load forecast scenarios, the Company took steps to enhance its forecasting methodology to ensure an accurate and reasonable forecast that would be sufficiently robust to support discussions regarding the size and timing of proposed resource additions. Additionally, consistent with the Commission's September 19, 2017 Order for Hearing in this docket, Minnesota Power's refiling of this Petition includes a revised forecast based on the Company's recently completed 2017 AFR.[20] As described in this Section 2, this updated forecast fully supports the proposed size, type, and timing of Minnesota Power's resource additions.

While a certificate of need is not required for the NTEC 250 MW purchase,[21] the criteria used to evaluate a certificate of need may be helpful in review of this filing. Under the certificate of need rules, the Commission is to analyze the need for the proposed natural gas generation addition in comparison with reasonable alternatives and to determine whether "the probable result of denial

[19] As described in Section 1 of this Petition, the Energy*Forward* Resource Package is a combination of three resources that Minnesota Power proposes to serve customers' long-term energy and capacity needs. That package is comprised of 250 MW of wind energy procured via PPA from a wind farm in southwestern Minnesota, 10 MW of solar energy procured via a PPA from a solar array in Minnesota Power's service territory, and the current NTEC 250 MW purchase. In its September 19, 2017 Order for Hearing in the instant Docket, the Commission ordered the Company to seek approval of the natural gas capacity purchase separate from the other elements of the Energy*Forward* Resource Package.

[20] In particular, Minnesota Power's original Petition included an analysis of the need for the Energy*Forward* Resource Package based on the Company's 2016 AFR, updated to reflect additional refinements and updates regarding projected customer demand. The analysis contained in this resubmitted Petition is based on the Company's most recent 2017 AFR forecast.

[21] NTEC is located in Wisconsin, and thus does not require a Minnesota certificate of need. However, Minnesota Power is procuring capacity from NTEC via a series of affiliated interest agreements, which do require Commission approval pursuant to Minn. Stat. § 216B.48. That statute imposes a "public interest" standard on the Commission's consideration of the proposed affiliated interest agreements.

would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states."[22]

Ultimately, the expected case forecasts are projections of anticipated future need based on what Minnesota Power knows today, and this outlook is bound by high and low scenarios to test the potential resource requirement impacts of different futures. Based on the analysis discussed below, consideration of a reasonable set of likely assumptions, and evaluation of a range of potential forecast scenarios, the Company concludes that there is a need to add resources to ensure adequate capacity and energy are available to serve customers during periods of high demand and periods of low wind production in coming years.

Minnesota Power is committed to being responsive to Commission and stakeholder feedback on its forecasting, process improvement, forecasting transparency and accuracy, and gaining additional customer insight. The forecast presented in this filing demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, implementation of increasingly systematic and replicable processes, and thorough vetting of results.

Specifically, in Minnesota Power's 2015 Integrated Resource Plan ("2015 Plan"), the Company identified a need for approximately 200 MW of new capacity from 2017 to 2019 and approximately 200–300 MW of capacity in 2025. Since the 2015 Plan, Minnesota Power has refined its peak demand and energy forecasts to reflect updated assumptions and circumstances and to address the feedback from the Commission and stakeholders in the 2015 Plan proceeding. As discussed in detail below, the Company's current analysis concludes that without adding reliable natural gas capacity, Minnesota Power would have a capacity deficit of approximately 300 MW by 2025, increasing to approximately 500 MW in 2031, and would have an energy need of over 1 million MWh growing to 2.4 million MWh by 2031.

[22] Minn. R. 7855.0120.

Actions already taken in furtherance of Minnesota Power's Energy*Forward* initiative are contributing to the Company's projected resource need, including: (1) the retirement of Boswell Energy Center Units 1 and 2 ("BEC1&2") in 2018, eliminating approximately 135 MW of capacity from Minnesota Power's system; (2) the idling of Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2") in 2016 and termination of coal-fired operations at THEC1&2 by the end of 2020, eliminating 150 MW of capacity;[23] and (3) the retirement of Taconite Harbor Energy Center Unit 3 in 2015, eliminating 75 MW of capacity.

In the remainder of this Section, Minnesota Power details its forecast methodology for this Petition and presents its updated forecast results, both in terms of its base case and high and low sensitivities.

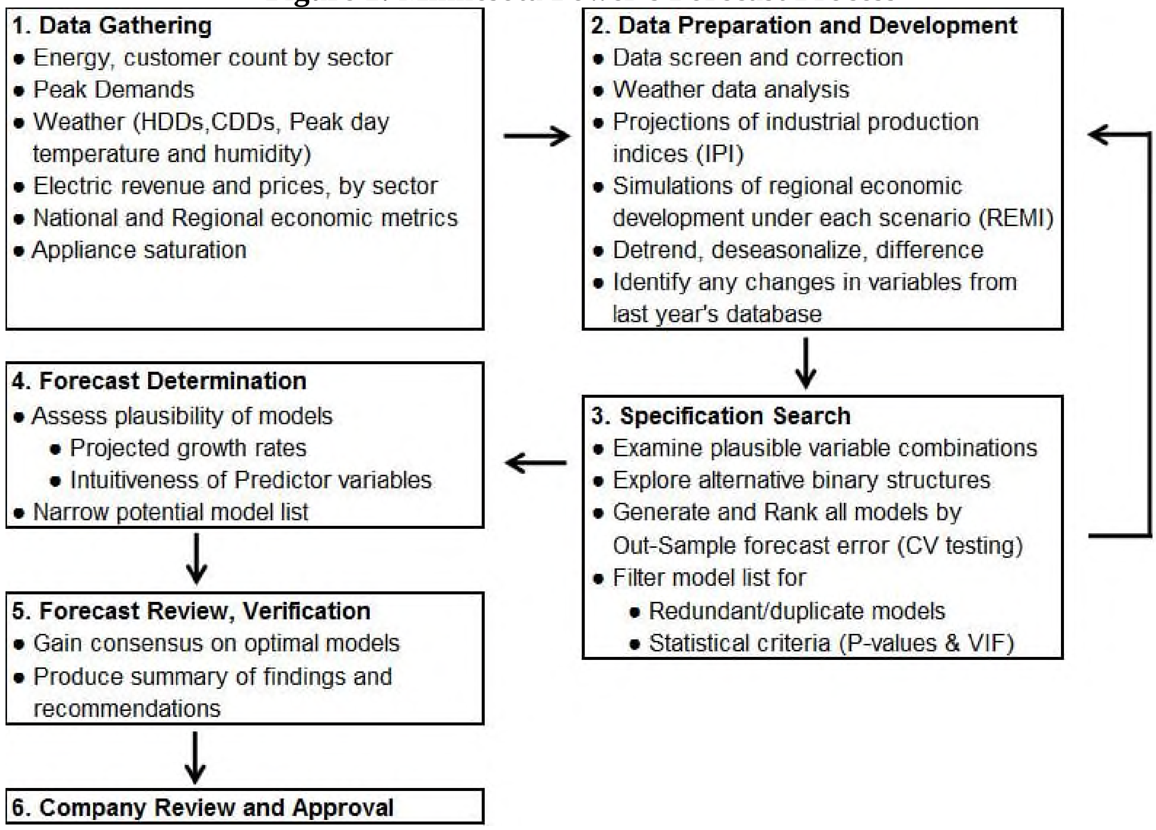
2.1 OVERVIEW OF FORECAST METHODOLOGY

Minnesota Power's forecast process is the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models of customer energy use, customer count, and demand are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50" — given the inputs, there is a 50 percent probability that actual results will be less than forecast and a 50 percent probability that actual results will be more than forecast.

Minnesota Power's forecast process involves several interrelated steps: (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. As illustrated in Figure 1 below, the steps of the forecast process are sequential, although because of the research dimension, the process involves feedback loops between steps 2 and 3.

[23] In its July 2016 IRP Order, the Commission required that "Minnesota Power shall idle Taconite Harbor 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. Future refueling and re-mission opportunities will be considered in planning and optimization of the facility for the next resource plan." July 2016 IRP Order at 14 (Order Point 3). At this time, the Company has not identified a re-missioning opportunity for THEC1&2 and therefore did not consider any re-missioning alternatives in its analysis.

Figure 1: Minnesota Power's Forecast Process



In order to determine the resources necessary to meet Minnesota Power's customer needs in the coming years, the Company prepared an updated sales and demand forecast based on the 2017 AFR. The Company's annual forecast methodology, data sources, analytical techniques, results of statistical tests, and 2017 forecast scenario results are documented in Minnesota Power's 2017 AFR, which was filed in Docket No. E999/PR-17-11 on June 29, 2017.[24] The Company's 2017 AFR filing also discusses the methodology's inherent strengths and weaknesses and any process enhancements implemented in developing the 2017 AFR forecast, which built on the forecast

[24] Minnesota Power submits an Annual Electric Utility Forecast Report to the Department by July 1 each year. Minnesota Power began its analysis for this filing by reviewing the forecast supporting the Commission's July 2016 IRP Order. The Company updated that forecast with the latest load outlook available to use as a baseline for the refined analysis and implemented a number of methodological improvements as discussed in this filing.

results presented in the Company's 2015 Plan, while addressing stakeholder feedback and updates for customer projections and additional historical data.[25]

As discussed in Minnesota Power's 2017 AFR report, Conservation Improvement Program ("CIP")/Demand-Side Management ("DSM") impacts to demand are reflected in the Company's forecast through historical data, which reflect Minnesota Power's historic energy savings achievements.[26] Through its conservation program efforts, Minnesota Power achieved 64,117,319 kWh in energy savings and 9,489 kW in demand savings in 2016. This is equivalent to 2.1 percent of non-exempt retail energy sales, well above the 1.5 percent energy-savings goal established in Minn. Stat. § 216B.241, and 138 percent of the approved energy-savings goal for the year.[27]

Minnesota Power's forecast process combines econometric modeling with a sensible approach to modifying the raw model outputs for assumed changes in large customer loads. An econometric approach utilizing regression modeling is optimal for estimating a baseline projection or the long-term industry trends with a given economic outlook. However, a fully econometric process would not project the kind of sudden and substantial swings in industrial customer load, particularly in mining, that occur with some frequency given the volatility of domestic steel prices. Therefore, econometric forecasts for the industrial and resale sectors must be informed by the Company's market intelligence and customer-specific information. This customer-specific information is utilized to ensure an accurate and reasonable overall forecast.

2.2 FORECASTING PROCESS REFINEMENTS FROM PRIOR FILINGS

This Section provides an overview of the AFR forecast methodology, identifies refinements to the methodology that were used following the 2015 Plan proceeding, and discusses additional

[25] *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, REPORT at 14 (June 29, 2017).

[26] *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, REPORT at 13 (June 29, 2017).

[27] *In the Matter of Minn. Power's Conservation Improvement Program 2016 Status Report*, Docket No. E015/CIP-13-409.03, DECISION at 1 (June 30, 2017).

updates based on the most current outlooks for large industrial and resale customers that were applied to the 2017 AFR filed on June 29, 2017.

On September 1, 2015, Minnesota Power filed its 2015 Plan for the period of 2015 through 2029.[28] The 2015 Plan, shaped with the Company's broader Energy*Forward* strategy in mind, indicated minimal need for near-term resource additions, but projected a growing capacity deficit starting in the mid-2020s. This capacity deficit stemmed in part from the Company's forecast, which projected considerable customer growth over the 15-year period, and from the need to replace the coal-fired generation facilities that are slated for retirement or change in use, including THEC1&2, BEC 1&2 and reduced offtake from Young 2.

The 2015 Plan used the forecast from Minnesota Power's 2014 Annual Forecast Report ("2014 AFR"), which showed significant industrial customer expansion and growth over the 15-year forecast period. This anticipated growth was due in part to an expectation that new and existing large customers would add about 190 MW of demand by 2020, as industry outlooks indicated growth for both mining and pipeline customers. On average, energy sales and peak demand were projected to grow at about 1.1 percent per year from 2014 through 2028.

During the 2015 IRP proceeding, the Clean Energy Organizations ("CEOs")[29] argued that there were flaws in the Company's load forecast, causing it to overestimate future demand. In particular, the CEOs argued that the forecast overstated industrial demand based on overly-optimistic assumptions about when or whether several major proposed projects, including PolyMet's copper-nickel mine, Enbridge's Sandpiper oil pipeline, and Essar Steel's taconite plant, would come to fruition. The Department of Commerce, Division of Energy Resources ("Department") disagreed with most of the CEOs' criticisms of Minnesota Power's forecast, arguing that lower demand would support adding less renewable generation but would not affect the timing of coal-plant retirements. The Department maintained that the Company had evaluated a reasonable range of forecasts in developing its resource plan.

[28] *In the Matter of Minn. Power's 2015-2029 Integrated Res. Plan*, Docket No. E015/RP-15-690, 2015 INTEGRATED RESOURCE PLAN (Sept. 1, 2015).

[29] The CEOs include Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires.

The Commission, in its 2016 IRP Order, made the following conclusions with respect to Minnesota Power's 2015 Plan forecast:

> The Commission concurs with the Department that Minnesota Power's range of load forecasting used for its 2015 resource plan is reasonable for planning purposes. However, the Clean Energy Organizations' comments serve to highlight the economic trends that have led to lower demand projections in recent forecasts. In light of these trends, Minnesota Power's load forecast scenarios used in its 2015 resource plan may overstate the size or timing of future needs. The Commission bears this fact in mind as it evaluates the Company's preferred plan in the following sections.[30]

Minnesota Power took steps to address those inputs and Commission conclusions from its 2015 Plan proceeding in developing its refined forecast for this petition to evaluate the need for the proposed natural gas capacity purchase continued to be the best fit as part of the larger Energy*Forward* Resource Package. The Company's forecasting efforts draw on the Commission's forecasting findings. In particular, Minnesota Power made the following modifications from its 2015 Plan forecast approach in its 2017 AFR annual forecast.

The 2017 AFR filed June 29, 2017:

- Assumed more conservative large industrial customer outlooks;
- Accounted for the secondary economic impacts of large industrial customers;
- Implemented several methodological enhancements, including:
    - Adjusting the historical sales series to avoid the potential for double-counting of load in the econometric outputs;
    - Applying binary and trend variables to econometrically account for inflection of the sales growth trajectory since the 2007 recession; and
    - Enhancing the specification search (the model generating and identification) processes.

[30] July 2016 IRP Order at 4; *see also* July 2016 IRP Order at 14 (Order Point 2).

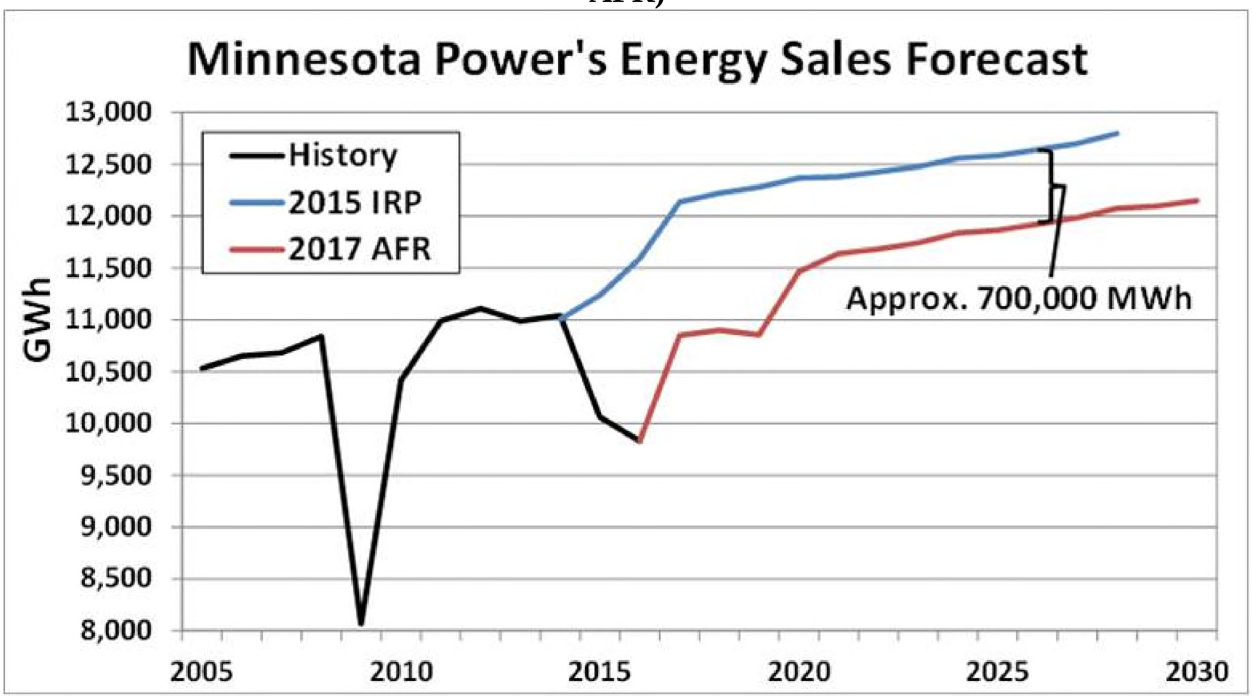
In light of these additional refinements, the Company's 2017 AFR forecast reflects improvements in the Company's statistical analytic capabilities, continuous validation of forecast model inputs, and close cooperation with customers and other interested stakeholders. These efforts result in an overall reasonable and reliable forecast for Minnesota Power customers. The 2017 AFR forecast also addresses feedback from the Commission, the Department, and the CEOs regarding the Company's forecast methodology and is far more conservative than the forecast that was submitted in the 2015 Plan. Further, the outlook represents the most current information available to the Company. The broader outcomes of the 2017 AFR forecast are described in the next section.

2.3 FORECAST RESULTS AND NEED

2.3.1 2017 AFR Forecast Results

Figure 2 below compares the current energy sales outlook ("2017 AFR" in Red) to the 2015 Plan forecast (Blue).

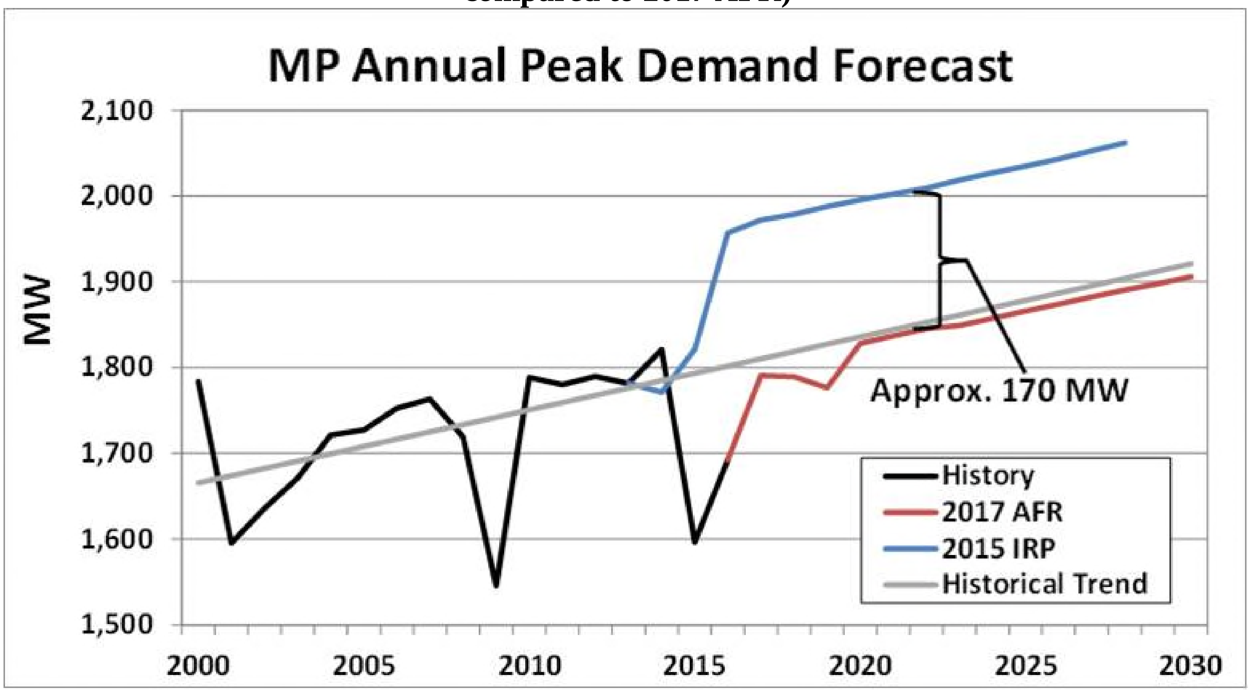
Figure 2: Minnesota Power's Energy Sales Forecast (2015 Plan Compared to the 2017 AFR)



In the long term, the 2017 AFR sales forecast is about 700,000 MWh per year lower than the 2015 Plan forecast due primarily to more conservative overall assumptions concerning Minnesota Power's large mining customers. By 2025, the majority of the decrease in sales from the 2015 Plan is attributable to Mesabi Metallics and Magnetation Plants 2 and 4 being removed from the forecast. Overall, Minnesota Power's current energy sales outlook grows at about 0.9 percent per year compound annual growth rate from 2017 to 2030.

The Company's peak demand is also projected to increase. Figure 3 below compares the current annual peak demand outlook ("2017 AFR" in Red) to the 2015 Plan's forecast (Blue).

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



The Company's current long-term annual peak demand forecast is more modest than the 2015 Plan levels, responding in part to Commission concern that the 2015 Plan forecast may have overestimated future demand growth. Post 2020, the 2017 AFR forecast is about 170 MW lower than the 2015 Plan forecast. This still reflects a slight increase in system demand above recent historical levels; the projected 2020 peak is about 35 MW higher than the recent, pre-downturn period when the average peak demand from 2010 to 2014 was 1,792 MW.

2.3.2 MISO Planning Reserve Margin Requirements

The MISO tariff, along with North American Electric Reliability Corporation ("NERC") reliability standard BAL-502-RFC-02, requires Minnesota Power to maintain adequate resources to serve its system load and to add the planning reserve margin requirement in compliance with MISO's Resource Adequacy tariff. The current MISO planning reserve margin requirement is 7.8 percent Unforced Generating Capacity ("UCAP"), which means Minnesota Power must have sufficient capacity resources to meet it summer peak demand coincident with MISO peak plus an additional 7.8 percent reserve on top of that peak demand. The 7.8 percent planning reserve margin is from MISO's Planning Year 2017-2018 Loss of Load Expectation Study Report.[31]

2.3.3 Minnesota Power's Resource Need

Actions that Minnesota Power has already taken under its Energy*Forward* strategy will result in the removal or idling of nearly 700 MW of baseload coal-fired generation from the Company's power supply between 2013 and 2019. These include THEC,[32] Young 2,[33] BEC1&2,[34] and Laskin Energy Center ("LEC").[35] These reductions, together with growing industrial customer demand discussed above, as well as the changing shape of hourly energy requirements caused by the existing and additional variable renewable generation in 2020, have resulted in a growing capacity and energy need in the mid-2020s. Figure 4 demonstrates Minnesota Power's projection for the capacity need to reach nearly 300 MW by 2025 and grow to around 500 MW by 2031. Minnesota Power is a winter peaking utility, which results in a slightly greater capacity need during the winter season, as also reflected in Figure 4 below.

[31] MISO's Planning Year 2017-2018 Loss of Load Expectation Study Report (Oct. 31, 2016), *available at* https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf.

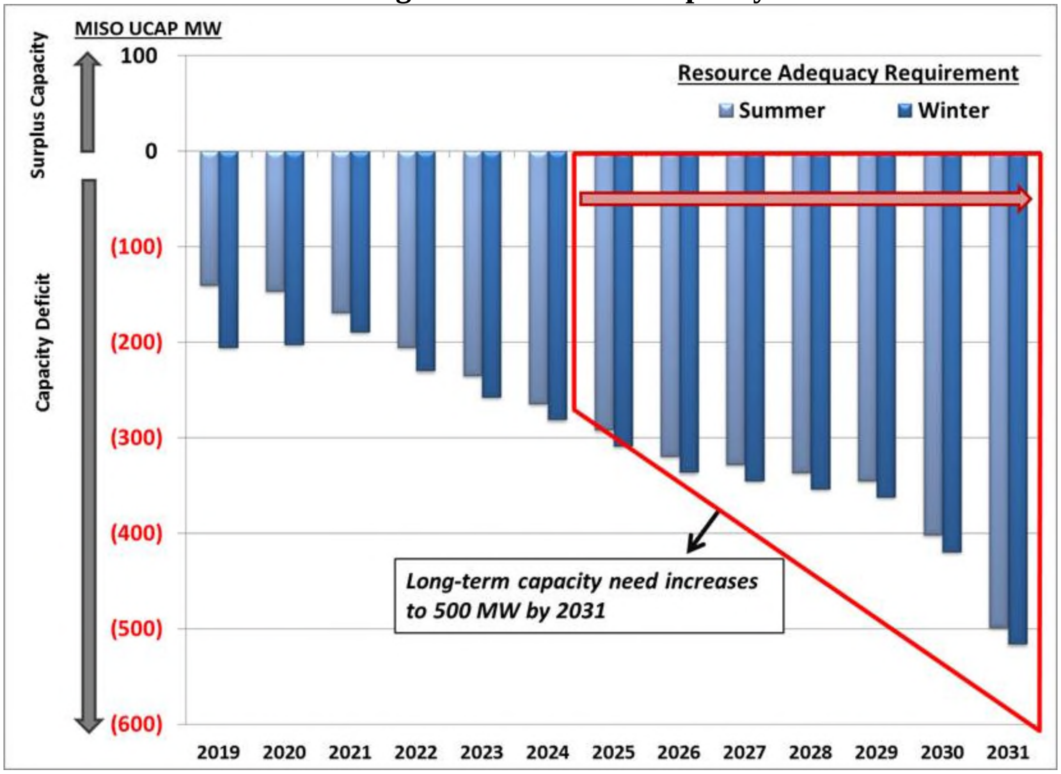
[32] THEC3 was shut down in June 2015. Subsequently, THEC1&2 were idled in 2016, with coal-fired operation of these units scheduled to cease by the end of 2020.

[33] Reductions to Minnesota Power's Young 2 capacity from 227.5 MW to 100 MW occurred as of August 2014 with a phase out of Young 2 by 2026.

[34] Press Release, Decision to Retire Two Small Coal Units Consistent with Minnesota Power's Energy*Forward* Plan, (Oct. 19, 2016), *available at* https://www mnpower.com/Content/Documents/Company/PressReleases/2016/2016 1019_NewsRelease.pdf (announcing plans to retire BEC1&2 by the end of 2018).

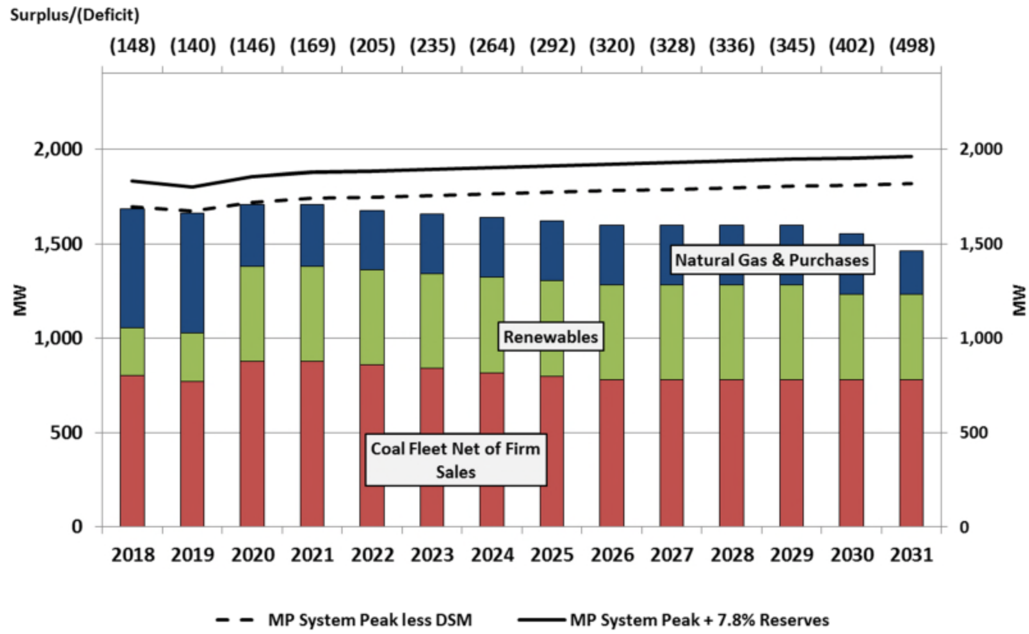
[35] LEC was repowered to run on natural gas in early 2015.

Figure 4: Base Case Capacity Position



The detailed capacity position for the base case with the summer demand and capacity outlook is shown in Figure 5. For the summer period, Minnesota Power's capacity need increases to 292 MW by 2025 and by 2031 the need is 498 MW. The load growth from AFR 2017 combined with the Energy*Forward* power supply changes coming by 2026 work together to create Minnesota Power's outlook for capacity need.

Figure 5: Base Case Summer Season Capacity Outlook



The detailed capacity position for the base case with the winter demand and capacity outlook is shown in Figure 6. For the winter period, Minnesota Power's capacity need increases to over 300 MW by 2025. By 2031, the need exceeds 500 MW. Minnesota Power's winter peak is typically between 15 and 20 MW higher than its summer season peak; therefore, the surplus and deficit outlook is slightly different when shown for the winter season peaks.

Figure 6: Base Case Winter Season Capacity Outlook

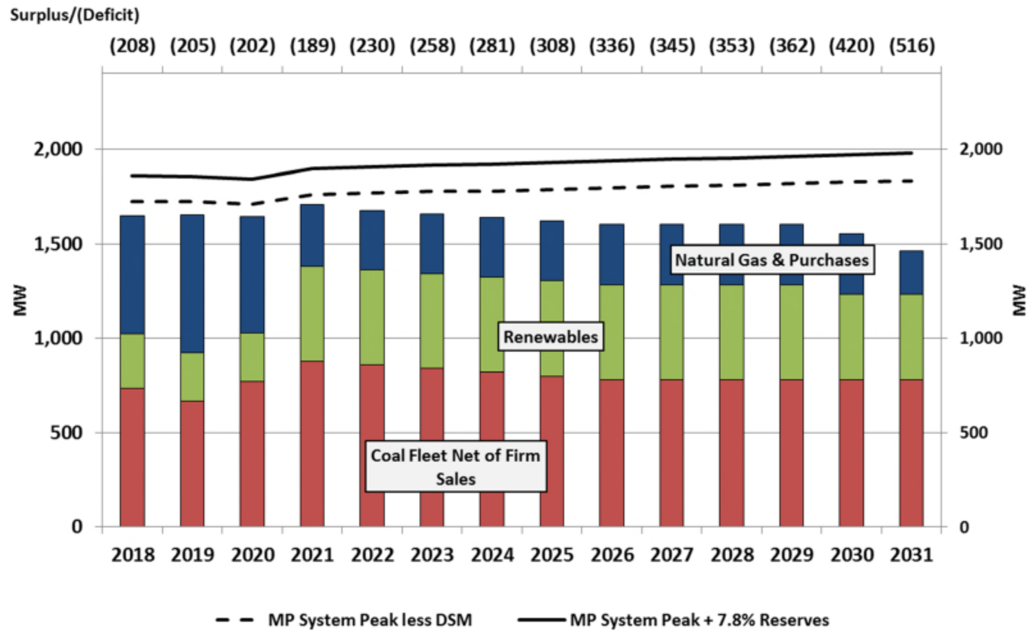
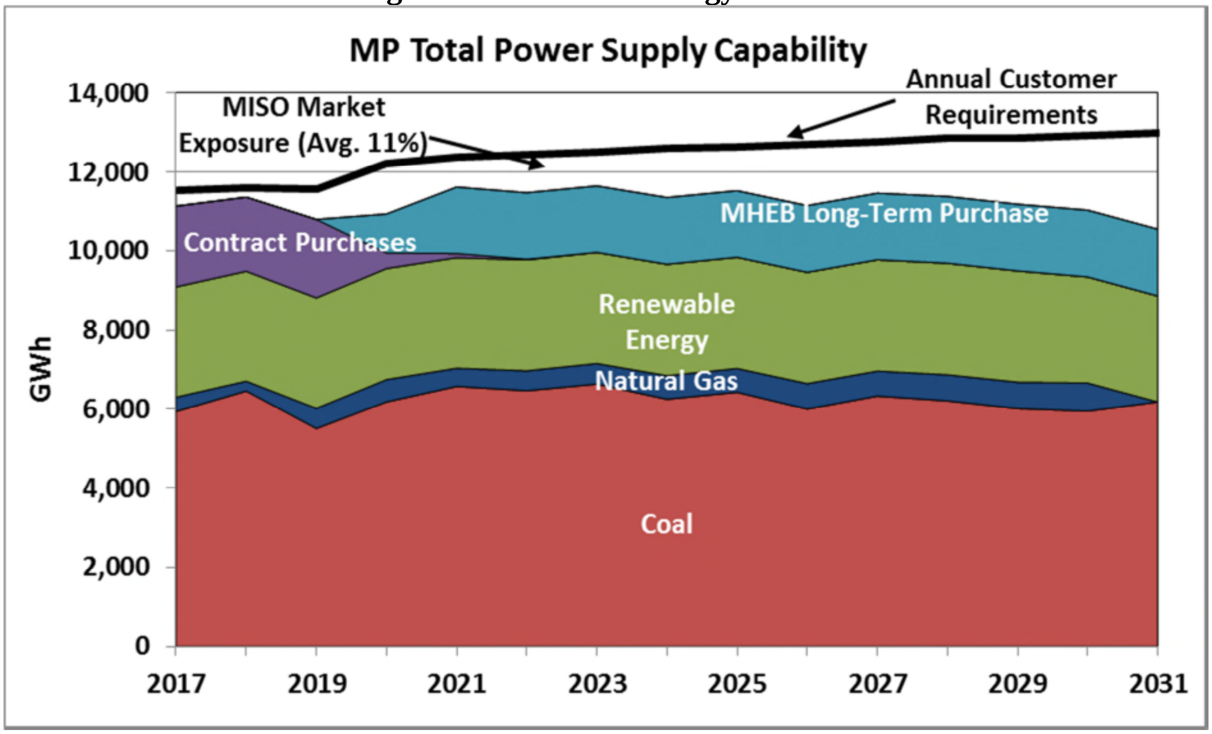


Figure 7 below further shows that under its base case, Minnesota Power has growing energy needs starting in 2020, around 1 million MWh and increasing to 2.4 million MWh by 2031, as BEC1&2, along with Young 2's baseload energy, are removed from the power supply and customer energy needs grow. In the absence of resource additions, by 2031 nearly 20 percent of Minnesota Power's total demand would not be met by its power supply capabilities.

The combination of capacity need and energy need forms the starting point for the Company's evaluation. Figure 7 below shows current power supply capability and projected need through 2031.

Figure 7: Base Case Energy Position



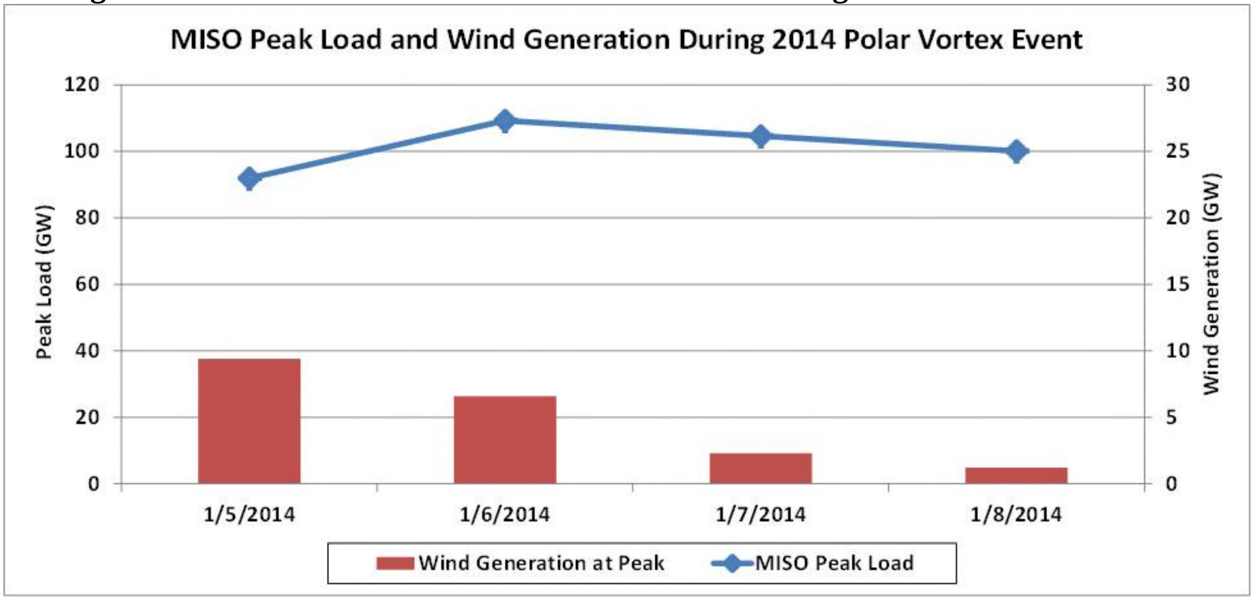
What the above Figure 7 does not demonstrate well is the shape of Minnesota Power's energy needs on a day-to-day basis. Minnesota Power's current energy position can vary by 600 MW in an hour as a result of the variability of the Company's renewable generation. With the addition of another 250 MW of wind proposed as part of the Energy*Forward* Resource Package, Minnesota Power's energy position could vary up to 850 MW in an hour, creating additional need for dispatchable capacity and flexible energy to be available to mitigate and balance the exposure to energy markets.

The variable characteristic of wind energy can create rapidly changing energy profiles that a utility needs to plan for to minimize market exposure risk for customers. These drastic changes in wind energy can cause rapid decreases and increases in energy, long periods of time where no energy is available, and days where there are multiple peaks and valleys in energy production. The unique characteristic of wind not having a predictable pattern of energy production requires utilities to plan for dispatchable generation resources that can respond quickly to changing wind generation levels inherent in a resource that is dependent on the availability of wind to operate. For Minnesota Power, this challenge is exacerbated by the fact that it has both a high concentration of wind generation and a high load factor, creating additional risk of exposure to high energy prices in the event high demand corresponds with low or no wind availability.

This is different from a typical utility with a lower load factor where, depending on the period when the wind energy is not available, there might be no need for additional energy resources. Considering Minnesota Power's high load factor and the needs of its large industrial customers for 24/7 generation capability, this volatility creates a particular and unique need for dispatchable capacity and flexible energy. Below are a few examples of how the availability of wind energy can change in Minnesota Power's system and in MISO.

- Between 10:00 am and 12:00 pm on July 5, 2015, as energy demand was increasing, Minnesota Power went from 516 MW of wind energy available to customers to 29 MW.
- Minnesota Power can also experience multiple large swings in wind generation throughout a day that needs to be offset by dispatchable generation. For example, during the morning of October 31, 2016, wind energy available was around 350 MW; however, as a low pressure system moved through, wind production decreased to zero for a three hour period and by 2 pm it had increased to 500 MW.
- Changes in wind availability can also be experienced across the MISO footprint. Figure 8 shows the wind generation available in MISO at the time MISO peaked for the day during the 2014 Polar Vortex weather event. On January 5, 2014, the first day of the Polar Vortex, MISO-wide wind energy was near 9.4 GW at the time of the daily peak. By January 8, 2014, the fourth day of the weather event, wind energy during MISO's daily peak was only 1.2 GW and the system peak demand was greater than day one. This drastic change in wind availability was reflected in the volatility of Locational Marginal Prices at Minnesota Power's load node, MP.MP, where the average energy price doubled from January 5 to January 8 ($57/MWh to $117/MWh). During this period, Minnesota Power utilized the 700 MW of coal generation that has been or is being idled or removed from the power supply. Without that coal-fired generation, Minnesota Power customers would have been exposed to the higher energy prices on that day. Additionally, during this period, the daily peaks in MISO occurred during either the early morning or late evening when solar energy is not available. Having a dispatchable resource such as NTEC will help provide energy and help protect against higher energy prices when the wind is not available. While natural gas prices also increased during that period, an efficient combined-cycle resource would have mitigated market price pressure since combined-cycle energy would have been less expensive than combustion-turbine based peaking energy from the market.

Figure 8: MISO Peak Load and Wind Generation During 2014 Polar Vortex Event



Consistent with the Commission's findings in its July 2016 IRP Order that need exists, but also seeking refinement of Minnesota Power's load forecast scenarios, Minnesota Power took significant steps to enhance its forecasting methodology to ensure an accurate and reasonable forecast. Under several variations, this forecast fully supports the proposed size and timing of the proposed natural gas plant addition in conjunction with the remainder of the proposed Energy*Forward* Resource Package. Based on the updated 2017 AFR forecast and evaluation of a range of potential forecast scenarios, the proposed natural gas resource addition is needed and the size and timing of the proposed resource is appropriate in light of projected capacity and energy needs.

2.3.4 High and Low Sensitivities for Demand and Energy

To capture the plausible ranges of uncertainty in Minnesota Power's customer outlooks, which are inherent to the forecasting of future sales, two additional sensitivities were included for this petition: the 2017 AFR High and 2017 AFR Low scenarios. The outlooks, shown in Figure 9 and Figure 10, were used in the resource evaluation to recognize the range of uncertainty that exists with the Company's unique customer base.

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

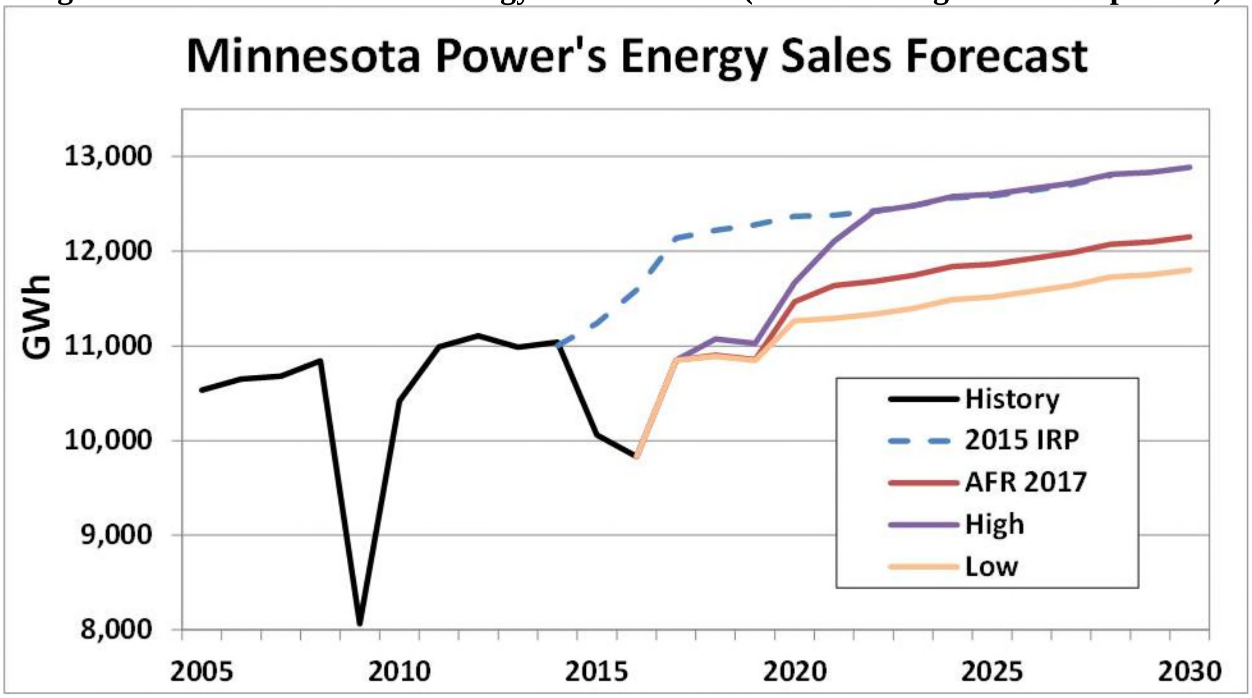
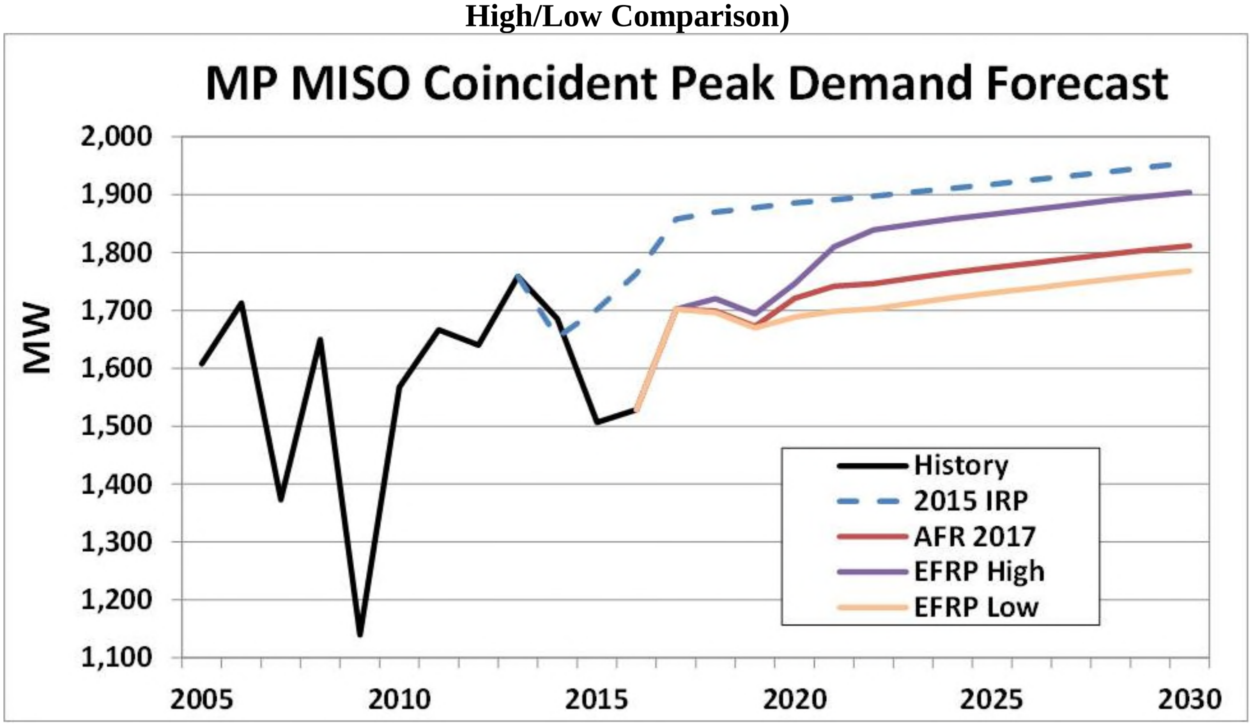


Figure 10: Minnesota Power's MISO Coincident Peak Demand Forecast (2017 AFR High/Low Comparison)



The “2017 AFR High” outlook assumes the resumption of operations by two recently-idled iron concentrate facilities and the startup of Mesabi Metallics, resulting in nearly 100 MW of additional growth. The “2017 AFR Low” forecast evaluates a “status-quo” assumption with regards to the mining sector, where currently-idled facilities remain idled and PolyMet does not commence mining operations in the forecast timeframe. Appendix I: Assumptions and Outlooks contains additional detail on each scenario.

Minnesota Power continually monitors the potential for industrial growth in northeastern Minnesota and recognizes the key role the mining and paper industries play in customer make-up and system needs and costs. The viability of these customers is the engine that helps drive the economy in this region. Making prudent and reasonable power supply plans for meeting the future electric needs of large industrial and all other customers is critical to help keep economic balance in place to best serve all customers.

SECTION 3 RESOURCE PLANNING ANALYSIS AND SELECTION OF PROPOSED COMBINED-CYCLE FACILITY

In this Section of this Petition, the Company presents its current resource planning analysis that resulted in and supports the proposed 48 percent share in the approximately 525 MW 1x1 combined-cycle natural gas NTEC power plant to be located in Superior, Wisconsin and placed in service by the end of 2024 (the "NTEC 250 MW" purchase) that provides low-cost capacity and energy and enables the wind and solar generation included in the Energy*Forward* Resource Package.[36]

Since the Commission issued its July 2016 IRP Order, Minnesota Power has spent considerable time and conducted significant analysis to develop the Energy*Forward* Resource Package proposal to serve customers' capacity and energy needs. Minnesota Power has refined and updated its outlook on major factors driving power supply decisions and has evaluated numerous responses to various RFPs for (1) wind, (2) solar, (3) dispatchable natural-gas-fired capacity (combined-cycle), and (4) demand response, all in accordance with the Commission's July 2016 IRP Order. Additionally, consistent with the Commission's September 19, 2017 Order for Hearing in this docket, Minnesota Power's refiling of this Petition includes updated analysis of alternatives.

Building on the Company's outlook for customer energy and demand and resource need set forth in Section 2 of this Petition, this Section provides an overview of the Company's refined analysis and evaluation of alternatives to meet projected future energy and capacity needs starting in 2025. Additionally, through the issuance of RFPs, the Company has identified and evaluated actual resource proposals, providing a more detailed analysis regarding the configuration, timing, and cost-effectiveness of resource alternatives. The NTEC 250 MW purchase, along with the proposed 250 MW of wind and 10 MW of solar in 2020 included in the Energy*Forward*

[36] As described in Section 1 of this Petition, the Energy*Forward* Resource Package is a combination of three resources that Minnesota Power proposes to serve customers' long-term energy and capacity needs. That package is comprised of 250 MW of wind energy procured via a PPA from a wind farm in southwestern Minnesota, 10 MW of solar energy procured via a PPA from a solar array in Minnesota Power's area, and the current NTEC 250 MW purchase. In its September 19, 2017 Order for Hearing in the instant Docket, the Commission ordered the Company to seek approval of the natural gas capacity purchase separate from the other elements of the Energy*Forward* Resource Package.

Resource Package presents the most cost-effective combination of alternatives to meet Minnesota Power's system need and addresses the Commission's directives from Minnesota Power's 2015 Plan proceeding.

The Company's resource planning analysis focused on meeting the customer energy and capacity needs over a fifteen-year period from 2017 through 2031. Strategist was used to evaluate various generation alternatives from the least-cost offers received in response to RFPs. The Strategist software allows a utility to offer many resource types into a production cost evaluation, and optimize the technologies that best fit to meet the projected customer needs over a defined study period. The goal of this analysis is to determine the optimal resource or mix of resources to meet customer needs. The results from this evaluation form the baseline for recommending the NTEC 250 MW purchase as part of the Energy*Forward* Resource Package.

The Company identified the least cost option from the offers received through the natural gas RFP processes, and then fully evaluated and compared those options based on relevant evaluation criteria. Consistent with the Commission's September 19, 2017 Order for Hearing, Minnesota Power's analysis included alternatives to some or all of the gas plant energy and capacity proposed, including but not limited to alternatives such as additional wind and solar resources, storage, demand response, and additional energy efficiency.[37] Also consistent with the Commission's Order for Hearing, the Company's evaluation included consideration of costs, including socioeconomic and environmental costs consistent with the most recent externality values established by the Commission in Docket No. E999/CI-14-643.[38]

As discussed in greater detail below, and in Appendix J: Detailed Resource Planning Analysis, this analysis supports the conclusion that the proposed NTEC 250 MW purchase is in the public interest, presents the best available alternative to meet projected customer needs, and will further transform the Company's power supply to align with its Energy*Forward* strategy. Including the NTEC 250 MW purchase in the Energy*Forward* Resource Package continues Minnesota Power

[37] Order for Hearing at 9 (Order Point 4.C.).

[38] Order for Hearing at 9 (Order Point 4.B.).

on the path toward reducing emissions and ensuring competitive, cost-effective rates for customers, while complying with state and federal environmental regulations and goals.

3.1 EVALUATION FRAMEWORK

3.1.1 Past Analyses of Company Resource Needs

Beginning with its 2010 Integrated Resource Plan (“2010 Plan”),[39] the Company identified that power supply diversification and environmental pressure on its coal-fired generating facilities would be key themes over the next decade. The February 2012 Baseload Diversification Study[40] framed up the high-level cost ranges for Minnesota Power’s coal-fired generating facilities to meet a wide range of potential outcomes for air, water, and waste regulations being contemplated at the federal and state level. As more information and certainty with the final United States Environmental Protection Agency (“EPA”) Mercury and Air Toxics Standards (“MATS”) Rule became known, the Company was able to continue the process of designing and evaluating detailed alternatives for its coal-fired generation facilities. Using engineering and site-specific detail, Minnesota Power determined specific quantifiable and actionable options for each alternative available during the development of its 2013 Integrated Resource Plan (“2013 Plan”). The 2013 Plan[41] finalized the Company’s preferred plan for MATS compliance by identifying each facility impacted by MATS, and communicating the best compliance path for serving customer power supply needs. To comply, Minnesota Power took action in 2014 and 2015 to refuel LEC to natural gas and cease coal-fired operations at THEC Unit 3 (“THEC3”).[42]

[39] *In the Matter of Minn. Power’s 2010-2024 Integrated Res. Plan*, Docket No. E015/RP-09-1088, MINNESOTA POWER 2010 RESOURCE PLAN (Oct. 5, 2009).

[40] *In the Matter of Minn. Power’s 2010-2024 Integrated Res. Plan*, Docket No. E015/RP-09-1088, MINNESOTA POWER’S BASELOAD DIVERSIFICATION STUDY COMPLIANCE REPORT (Feb. 6, 2012).

[41] *In the Matter of Minn. Power’s Application for Approval of its 2013-2027 Res. Plan*, Docket No. E015/RP-13-53, 2013 RESOURCE PLAN (Mar. 1, 2013).

[42] *See In the Matter of Minn. Power’s Application for Approval of its 2013-2027 Res. Plan*, Docket No. E015/RP-13-53, ORDER APPROVING RESOURCE PLAN, REQUIRING FILINGS, AND SETTING DATE FOR NEXT RESOURCE PLAN at 7 (Nov. 12, 2013) (finding Minnesota Power’s proposals to refuel LEC1&2 to natural gas by 2015 and to remove THEC3 from Minnesota Power’s system by the end of 2015 to be reasonable).

3.1.2 Commission Order Approving 2015 Plan With Modification

The proposed NTEC 250 MW purchase, along with the renewable projects proposed in the Energy*Forward* Resource Package, was developed in large part to address the specific findings, conclusions, and directives from the Commission's July 2016 IRP Order. As noted earlier in this Petition, those findings, conclusions, and directives formed the baseline for the Company's evaluation and analysis in identifying the resources proposed in the Energy*Forward* Resource Package.

With respect to generation resources, the Commission determined that 200–300 MW of combined-cycle natural gas generation may be the best option, and directed the Company to evaluate natural gas additions as well as a full range of alternatives.[43] The Commission authorized Minnesota Power to "pursue an RFP to investigate the possible procurement of combined-cycle natural gas generation to meet its energy and capacity needs in the absence of Boswell 1 and 2 and Taconite Harbor Units 1 and 2."[44] The Commission also directed the Company to "initiate a competitive-bidding process to procure 100–300 MW of installed wind capacity" and "acquire solar units of 11 MW by 2016, 12 MW by 2020, and 10 MW by 2025 to meet its SES obligations,"[45] and found that up to 100 MW of solar generation may be an economic resource by 2022.[46] The Commission also directed the Company to issue a demand-response competitive-bidding process.[47]

The 2015 Plan finalized the evaluation of the Company's small coal fleet relative to continued economic pressures from environmental regulations and low natural gas prices. These pressures resulted in the economic idling of THEC1&2 beginning in late 2016, and contributed to the

[43] July 2016 IRP Order at 8-9, 15 (Order Point 8).

[44] July 2016 IRP Order at 15 (Order Point 7).

[45] July 2016 IRP Order at 9-10, 15 (Order Points 9 and 10).

[46] July 2016 IRP Order at 15 (Order Point 11).

[47] July 2016 IRP Order at 15 (Order Point 13). The Commission also directed the Company to investigate the potential for an energy-efficiency competitive-bidding process. July 2016 IRP Order at 15 (Order Point 14). The Company is addressing this requirement outside this filing by providing a summary of the investigation and reporting the findings of such investigation in the next resource plan. Additional discussion of the Company's plans to comply with this Order Point is provided in Section 3.4.8.

decision to cease coal-fired operations at BEC1&2 by the end of 2018. At the time of the Commission's July 2016 IRP Order, Minnesota Power had projected that with the near-term idling of THEC1&2, it would need approximately 200 MW of new capacity from 2017 to 2019, with the Manitoba Hydro-Electric Board ("MHEB") contracts filling much of that need beginning in 2020.[48]

While Minnesota Power had initially filed its 2015 Plan proposing investments to improve efficiency of BEC1&2, and keep them operational through 2024, the Commission ultimately determined that Minnesota Power should retire BEC1&2 when sufficient energy and capacity are available, but no later than 2022.[49] Following the decision of the Commission, thorough environmental and economic analyses of the two generation units showed the feasibility of and rationale for entirely shutting BEC1&2 down in 2018 — four years earlier than the Commission's order required. Both the Commission's directions from the most recent July 2016 IRP Order and the Company's subsequent analyses created a baseline for purposes of determining next steps with respect to the Company's generation portfolio.

3.1.3 Additional Evaluation Considerations

The Company's analysis, as reflected in this Petition, also addresses the Commission's September 19, 2017 Order for Hearing, which required Minnesota Power to demonstrate that the proposed natural gas combined-cycle plant is needed and reasonable based on consideration of all relevant factors, including (1) an updated forecast of demand, as discussed in Section 2, (2) costs including socioeconomic and environmental costs, and (3) alternatives to some or all of the as plant energy and capacity proposed, including but not limited to consideration of additional wind and solar resources, storage, demand response, and additional energy efficiency.

While Minnesota Power is not required to obtain a certificate of need for approval of the NTEC 250 MW purchase, the Company determined that a decision regarding the size and type of

[48] *In the Matter of Minnesota Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro*, Docket No. E-015/M-11-938, ORDER (Feb. 1, 2012); 7 *In the Matter of Minnesota Power's Petition for Approval of a 133 MW Power Purchase Agreement with Manitoba Hydro*, Docket No. E-015/M-14-960, ORDER (Jan. 30, 2015).

[49] *In the Matter of Minn. Power's Application for Approval of its 2015-2029 Res. Plan*, Docket No. E015/RP-15-690, 2015 INTEGRATED RESOURCE PLAN (Sept. 1, 2015).

generation resource or mix of generation resources for which it is forecasting future need would benefit from consideration of the types of information evaluated in certificate of need proceedings. The Company therefore conducted an analysis that incorporates the Commission's prior resource planning guidance from the most recent July 2016 IRP Order, as well as further refined analysis based on the Commission's September 19, 2017 Order for Hearing and the Commission's criteria for evaluation in a certificate of need set forth in Minn. R. 7849.0120. In particular, Minn. R. 7849.0120 requires granting a certificate of need when the probable result of denial would be an adverse effect on future adequacy, reliability, or efficiency of energy supply; when a more reasonable and prudent alternative to the proposed facility has not been demonstrated; and when the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.

Consistent with these resource type and impact criteria and prior resource evaluations, Minnesota Power also applied key planning principles to help guide the analysis process. This ensured the outcome of its updated resource evaluation was robust and in the best interest of all its customers, and shaped the recommended NTEC 250 MW purchase:

1. **Reliability** – Dispatchable natural gas capacity enhances power supply reliability by ensuring adequate power supplies to serve all customers (including high load-factor industrial customers) under all circumstances.

2. **Diversity –** A power supply mix that cost-effectively manages risks in environmental regulation, fuel cost, and generation technology.

3. **Flexibility –** A power supply adaptable to industry changes and fleet transitions.

4. **Reduced Carbon Emissions –** Effectively reduce carbon emissions of the power supply while managing customer costs.

5. **Efficiency –** A reliable power supply that serves customer needs with the appropriate level of capital investment.

These principles, combined with the findings, conclusions, and directives from the July 2016 IRP Order, and the factors identified in the September 19, 2017 Order for Hearing, led to identification of a set of key questions to evaluate and optimize resource planning decisions over the planning period. The Company's refined resource planning analysis takes into consideration the questions listed below, and identifies the NTEC 250 MW purchase along with the renewable resources included in the Energy*Forward* Resource Package as the least-cost and most reasonable way to answer these questions.

- *How will the Company augment its power supply to balance the swings in generation that are inherent to variable resources such as wind?*

  With the addition of the 250 MW of wind generation identified in the Energy*Forward* Resource Package, Minnesota Power's portfolio of wind resources will reach over 870 MW of installed capacity. Because wind production varies up and down from hour to hour as well as daily and seasonally, a source of dispatchable capacity must be available to balance energy production with demand in an efficient and responsive manner. Minnesota Power's updated and refined analysis continues to identify the NTEC 250 MW purchase as the best resource to support increasing variable renewable generation resources in a cost-effective manner.

  This conclusion is consistent with prior Resource Planning analysis. In Minnesota Power's 2015 Plan, the Company proposed to add 200–300 MW of combined-cycle natural gas generation by 2024. In its Order, the Commission authorized Minnesota Power to continue pursuing its RFP to investigate the possible procurement of combined-cycle natural gas generation to meet its energy and capacity needs, but also ordered that the Company include an analysis of alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response. The Company has done so, and its analysis concludes that the natural gas generation described in this Petition will best help to balance the variable resources being added.

- *How will Minnesota Power continue to provide resource adequacy as MISO considers moving toward a seasonal construct including both summer and winter?*

  The Company's analysis evaluated both summer and winter resource adequacy requirements. Given that resource decisions are often being made for assets with long operating lives to meet customer needs over a 20 to 40-year period, Minnesota Power's preference is to consider only capacity resources that are available during both winter and summer seasons. Some resource alternatives that were evaluated, particularly solar, only provide capacity benefits for the summer resource adequacy season. This does not preclude Minnesota Power from considering the addition of large scale solar generation to the power supply, but rather supports evaluation of solar additions as energy-only resources with limited capacity value.

- *How will the proposed purchase from the NTEC combined-cycle plant support regional and local reliability?*

  Consistent with Minn. R. 7849.0120 (A), which requires consideration of the impact of denial on the future adequacy, reliability, and efficiency of energy supply to the utility or the people of Minnesota and neighboring states, Minnesota Power's analysis of resource alternatives considered the need to ensure reliable supply to Minnesota Power customers and the region. While additional wind is helpful to improve the Company's renewable resource mix at affordable prices, variable generation requires additional considerations. As the national power supply continues to transform away from baseload coal-fired generation to more variable renewable and distributed resources, the operational flexibility and power supply benefits provided by dispatchable, economical combined-cycle generation such as NTEC will become more valuable to customers and the region.

- *How is Minnesota Power positioned to meet potential future CO_2 regulations (e.g., the (recently withdrawn) Clean Power Plan ("CPP")) and State greenhouse gas goals?*

  Minnesota Power is positioned well to exceed the State greenhouse gas goals and minimize any cost impacts from future CO_2 regulations. The Company's Energy*Forward* strategy to diversify the power supply mix with a higher penetration of renewable generation, projected to be 45 percent by 2025 with acceptance of the Energy*Forward* Resource Package, along with actions taken on Minnesota Power's small coal-fired generation, has significantly reduced CO_2 emission in the power supply. And while additional solar and wind generation will aid this result, their variable nature requires a balance of considerations. Natural gas is a natural addition that supports these goals. The Energy*Forward* Resource Package results in 1.2 million tons of CO_2 reductions by 2025 when compared to the 2015 Plan. After the initial reduction from implementation of the Energy*Forward* Resource Package resources, CO_2 emissions through 2030 remain flat, indicating that the addition of a combined-cycle gas facility does not increase overall CO_2 emissions in the Company's portfolio. Moreover, the proposed NTEC project's CO_2 emission profile is significantly less than other dispatchable resources in Minnesota Power's energy supply; NTEC's emission profile is approximately 65 percent lower than Minnesota Power's coal-fired generation on a per MWh basis.

  While the Company cannot predict the future of CO_2 regulation, it can take prudent steps at a reasonable pace that balance customer needs with regulatory requirements. The

Energy*Forward* Resource Package identifies an optimized combination of wind, solar, and combined-cycle generation, furthering Minnesota Power's objective to reduce CO_2 emissions in its power supply.

3.1.4 Refinements from 2015 Plan

With Minnesota Power's small coal fleet (THEC and BEC1&2) operational decisions executed, the Company's analysis for this filing focuses on the integration and balance of renewable, natural gas, and customer-side programs to cost-effectively serve customers. The outlook for ongoing low natural gas prices, as well as advancements in natural gas generation technology and declining costs, support the selection of natural gas as part of the Company's Energy*Forward* Resource Package.

In addition, Minnesota Power's refined analysis continues to consider enhancements to the Company's longstanding distributed generation, demand response, and DSM programs. The partnerships forged with customers have served northeast Minnesota well as energy infrastructure has been added at customer sites. There are 550 MW of customer-sited distributed generation with combined heat and power, solar, and demand response programs that allow customer load to be interrupted to protect the power supply system and for economics. There is approximately 150 MW of interruptible capability assumed to be available long-term. Additionally, energy savings from the Power of One® conservation program have reduced the need to generate electricity by 624 GWh over the last 10 years.

In conducting an evaluation of the Company's power supply requirements and resource alternatives, several items were updated and refined from the Company's 2015 Plan for purposes of determining how best to meet customer energy and capacity needs between 2025 and 2031. These items include:

1. The analysis of existing power supply was updated to reflect the most recent additions and transitions that have occurred since the 2015 Plan. This information is provided in Appendix K: Existing Power Supply. Minnesota Power incorporated its Camp Ripley Solar Project (10 MW) and idled THEC1&2 (consisting of 142 MW; these units each operate with a gross generation capability of 75 MW with 4 MW of existing station service to operate auxiliary equipment), along with the planned retirement of BEC1&2 (135 MW) by the end of 2018.

2. Minnesota Power included the midpoint of Commission's approved CO_2 regulation penalty range[50] in one of the base case ("Futures") scenarios. The start of the CO_2 regulation penalty is 2022 to align with the proposed timing of the withdrawn EPA CPP. Another base case scenario assumes no CO_2 regulation penalty. Because the final carbon regulation mechanism has not been determined for the electric industry or the state, and the timing of a regulation penalty may be beyond the 2022 timeframe, Minnesota Power included both outcomes in its analysis. Impacts of key assumptions on power supply decisions are carefully considered to ensure actions that increase costs for customers are recommended only when the timing is appropriate.

3. Generation revenue requirements were updated with the latest information for ongoing capital and operating expenses at each facility and the generation book lives (i.e., depreciation lives) were updated consistent with the Company's 2016 general rate case filing in Docket No. E015/GR-16-664 ("2016 Rate Case").

4. Minnesota Power's capacity resources were updated to include the latest in near-term bilateral contract and accredited capacity values. MISO's UCAP value for accredited capacity was used in the refined analysis, as well as Minnesota Power's coincident peak demand forecast and the associated planning reserve margin.

5. Minnesota Power utilized the latest industry data, including costs, for DSM programs, generation technology, storage, natural gas, coal, and other key power supply drivers and trends to ensure an up-to-date set of assumption data was available. This updated information is reflected in the analysis set forth in this Section of the Petition and Appendix J: Detailed Resource Planning Analysis.

6. In accordance with order point 4.A of the Commission's September 19, 2017 Order for Hearing in this docket, Minnesota Power's energy demand outlook was updated based on the 2017 AFR submitted on June 29, 2017, in Docket No. E999/PR-17-11. The updated forecast addresses the comments and concerns raised in the Company's 2015 IRP proceeding and the findings and conclusions from the Commission's July 2016 IRP Order.[51]

7. The existing thermal generation fleet assumes that each unit is shutdown or retired at the end of its useful depreciable life, except for units where Minnesota Power has received approval to retire prior to the end of their life (i.e., BEC1&2 retire by 2019). This is consistent with the 2015 Plan, where thermal generation was assumed to shut

[50] The CO_2 regulation value for the mid-CO_2 regulation penalty are from the 2014 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06, in Docket No. E999/CI-07-1199.

[51] *See In the Matter of Minn. Power's 2015-2029 Integrated Res. Plan*, Docket No. E015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 14 (July 18, 2016) ("Minnesota Power's range of load forecasting used for its 2015 IRP is reasonable for planning purposes; however, in light of updated information, Minnesota Power's load forecast scenarios used in its 2015 IRP may overstate the size or timing of future needs.").

down at the end of its useful accounting life. This is also consistent with the Company's depreciation end of life used to determine revenue requirements in the 2016 Rate Case.

8. Minnesota Power's first step in its solar strategy of adding 11 MW of solar generation in 2016-2017 to comply with the Solar Energy Standard ("SES") is included in the base case (Camp Ripley Solar Project and Minnesota Power's solar garden pilot project).

9. Pursuant to order point 4.B of the Commission's Order for Hearing dated September 19, 2017, Minnesota Power updated the environmental externality costs with the most recent environmental externality values established by the Commission in Docket No. E999/CI-14-643.[52]

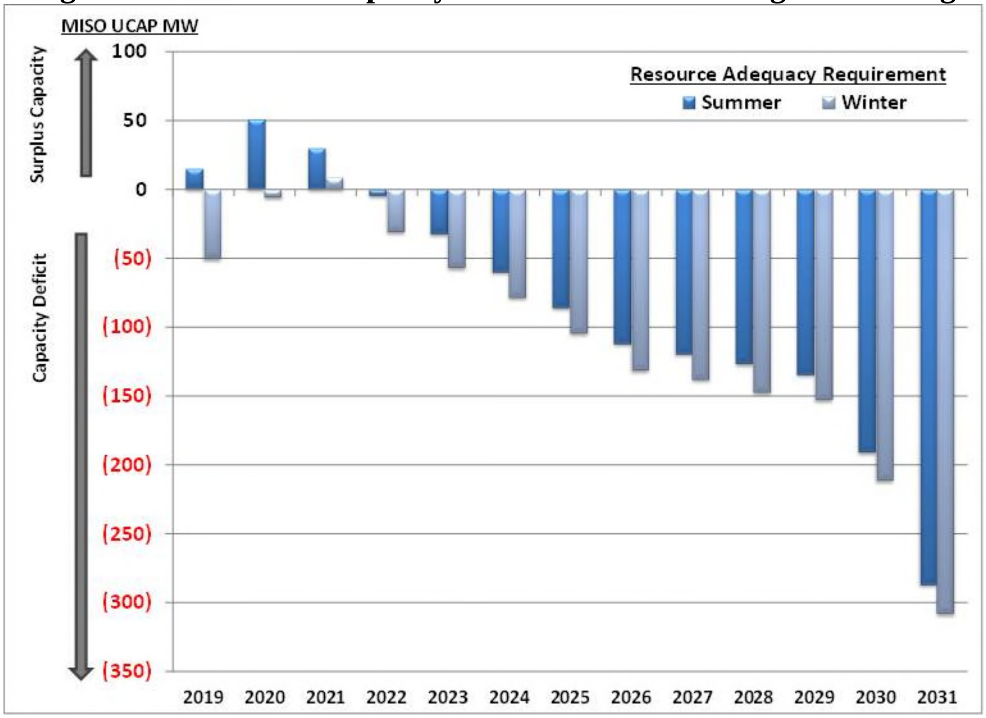
10. Incremental energy efficiency assumptions were developed using the same methodology included within the 2015 Plan. Minnesota Power has included 150 MW of large industrial interruptible demand in its capacity position used in the analysis. The industrial interruptible demand is not currently under contract for the entire study period, but Minnesota Power has a record of procuring this capacity in the short term. The Strategist model included 150 MW in the base case analysis.

Figure 11 below shows Minnesota Power's capacity position for summer and winter seasons when the 150 MW of large industrial interruptible demand, incremental energy efficiency, and the renewable projects from the Energy*Forward* Resource Package[53] are included. This is the summer and winter capacity position used in the expansion plan analysis performed with Strategist.

[52] *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs under Minn. Stat. § 216B.2422, Subd. 3*, MPUC Docket No. E999/CI-14-643 ("Environmental Externalities Docket"). As of the date of this submittal (October 24, 2017), the Commission has not issued a written Order in the Environmental Externalities Docket. Minnesota Power's discussion and analysis of the updated environmental externality values is based on the Company's understanding of the Commission's decisions based on motions and oral discussion at the July 21, and July 27, 2017 Agenda Meetings of that matter. All analysis is subject to update once a written order is issued.

[53] Minnesota Power's recommended Energy*Forward* Resource Package includes 250 MW of wind generation starting in 2020 (Nobles 2 wind farm) and 10 MW of solar starting in 2020 (Blanchard Solar). Although these resource acquisitions have not been approved by the Commission, given the order points on wind and solar for compliance, the Solar Energy Standard, Commission discussion at the September 7 procedural hearing, and the Commission's September 19, 2017 Order for Hearing in this Docket, Minnesota Power concluded it is appropriate to include these resources in the base case.

Figure 11: Base Case Capacity Position Used in Strategist Modeling



Together, these updates and modifications ensure the Company's analysis incorporates the most up-to-date and reasonable assumptions and information, and is consistent with the Commission's Order in Docket No. E015/RP-15-690 and the recent Commission Order issued on September 19, 2017 in Docket Nos. E015/RP-15-690 and E015/AI-17-568. Further, these items were considered in this evaluation to establish an appropriate overall power supply strategy.

3.2 ANALYSIS PROCESS

A two-step planning evaluation was used to find the best resource alternatives to augment the Company's power supply for long-term customer requirements, consistent with the refined need forecast presented in Section 2 of this Petition, the Commission's directives in the July 2016 IRP Order, and the September 19, 2017 Order for Hearing in this Docket. The NTEC 250 MW purchase was ultimately selected as the most reasonable and prudent alternative by comparing it to other technologies available in the mid-2020's using the Strategist model. The results showed the Company's proposal best served customer needs during this period and reinforced the benefits of including natural gas in the Energy*Forward* Resource Package. Minnesota Power assumed the 57 GWh conservation levels approved in the Company's Triennial filing, with additional sensitivities as described later in this Section. Generic resource technologies were also evaluated to serve customer needs later in the planning period. The two sequential steps in the Company's evaluation of resource alternatives included:

> *Step 1: "Detailed Resource Analysis"* – This step involved identifying a resource expansion plan that will best meet customer requirements starting in 2025. With Minnesota Power showing a capacity and energy need starting to grow in 2025, the analysis focuses on which alternatives best meet this need during this period. The NTEC combined-cycle, wind, and solar, updated with the latest data from the RFPs, other gas generation, battery storage, and demand response programs were available to fulfill capacity requirements starting in 2025. This step includes a series of eight Futures, each with over 34 sensitivities that stress key power supply cost drivers such as delivered fuel, CO_2 penalties, capital costs, revised environmental externality values, and additional customer load outlooks. Appendix J: Detailed Resource Planning Analysis, provides details regarding this analysis and results. The results of this step support selection of the Energy*Forward* Resource Package, including the proposed NTEC 250 MW purchase.

> *Step 2: "Swim Lane Comparative Analysis"* – This step involves comparing and stress-testing the proposed NTEC 250 MW purchase against three other viable power supply portfolio alternatives in a swim lane[54] analysis. The purchase of the NTEC 250 MW and the comparative swim lanes each included 250 MW of wind and 10 MW of solar identified in the Energy*Forward* Resource Package. The results of this step support Minnesota Power's conclusion that the NTEC 250 MW purchase best complements the other renewable resources in the Energy*Forward* Resource Package by being selected across 92 percent of cases and sensitivities. The four swim lane alternatives include these action plans:

1. 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 (required to meet capacity needs post 2030).[55]

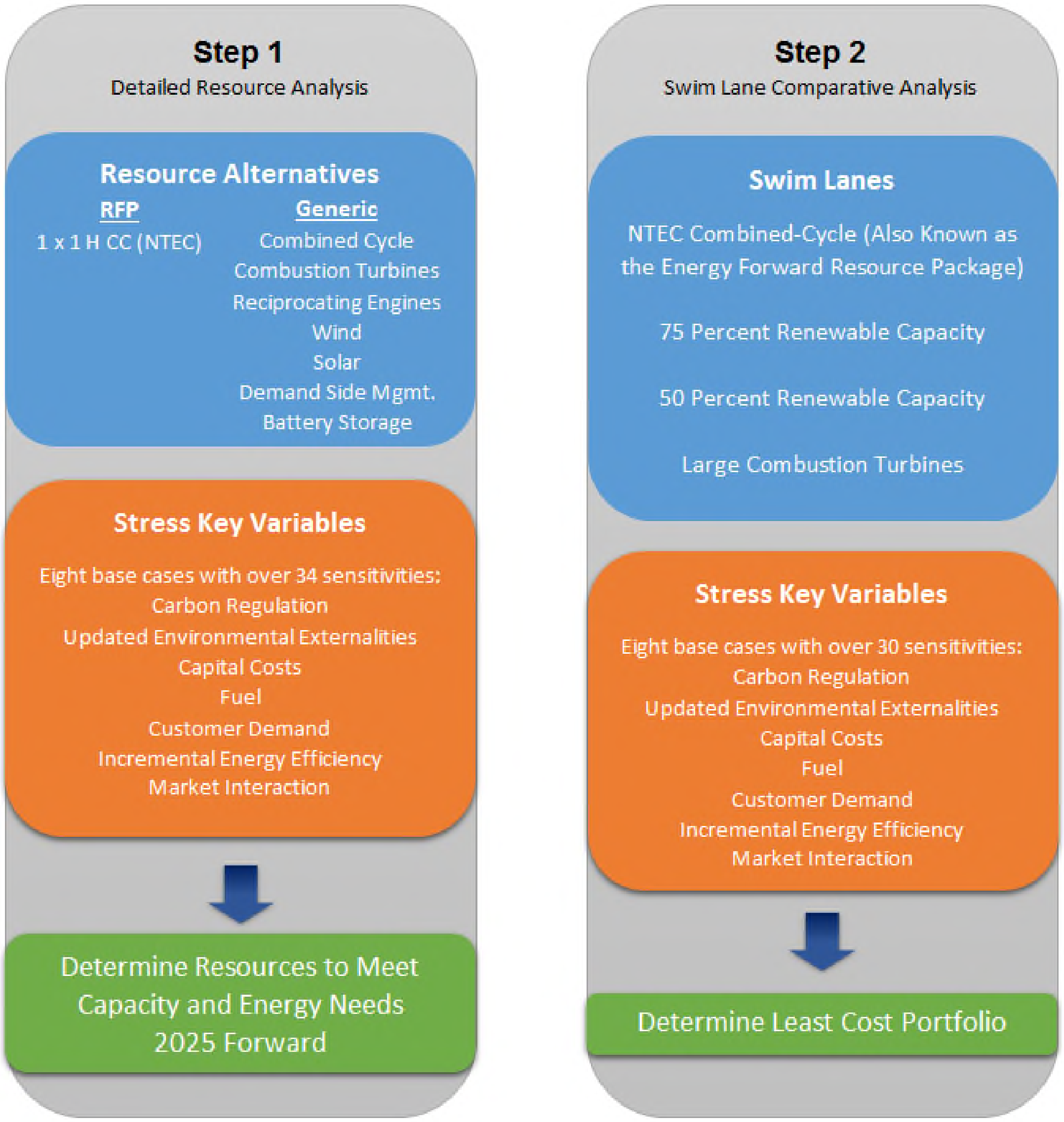
[54] A swim lane is a mechanism to evaluate alternative packages by considering them in a side-by-side "lane." For the Energy*Forward* Resource Package, each lane contains an alternative path for Minnesota Power's supply options.

[55] With this filing, Minnesota Power is seeking Commission approval of the NTEC 250 MW purchase.

2. 75 percent renewable capacity portfolio – 1950 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.
3. 50 percent renewable capacity portfolio – 1350 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.
4. Large combustion turbine portfolio – 456 MW of gas peakers with the first 228 MW added in 2025 and the second in 2031, and 250 MW of wind in 2020.

The comparison of the four swim lane alternatives includes a series of eight Futures, each with over 30 sensitivities that stress key power supply cost drivers such as delivered fuel, CO_2 penalties, capital costs, revised externality values, and additional customer load outlooks to identify how robust each lane is under the numerous variable changes. An overview of the evaluation processes is shown in Figure 12 for Step 1 and Step 2:

Figure 12: Plan Development Process - Step 1 and Step 2



See Appendix J: Detailed Resource Planning Analysis for more details on the analysis used to screen resource alternatives, storage, and demand-side resources to select the resources to meet capacity and energy needs from 2025 forward. Additional details regarding the swim lane analysis are also provided in Appendix J: Detailed Resource Planning Analysis.

Section 3.4 of this Petition, "Alternatives Evaluated," describes the results from Step 1 that determined which resource or resources are least cost for customers and should be included to meet Minnesota Power's growing energy and capacity requirements. The detailed results from Step 1 are included in Appendix J: Detailed Resource Planning Analysis. The comparison of the four swim lane alternatives, Step 2, is discussed in Section 3.6, "Analysis and Insights." This comparison demonstrates how the NTEC 250 MW purchase, plus the renewables included in the Energy*Forward* Resource Package, is least cost while also continuing to diversify Minnesota Power's power supply and bring environmental benefits to customers. First, however, Section 3.3 discusses uncertainties factored into the analysis process.

3.3 KEY CONTINGENCIES

Utilities plan in an uncertain business environment, and must recognize that not all assumptions will become reality. Resource planning in Minnesota is dynamic and allows additional information to be gathered and applied to adjust resource strategies for the best interests of customers on an ongoing basis.

Building on the analysis completed in Minnesota Power's 2015 Plan, the Company has carefully evaluated possible contingencies and alternative scenarios in an effort to identify a set of resource additions that positions customers for the industry transformation ahead while shielding them from unnecessary risk. The Company's planning process evaluated and compared various outcomes with a series of sensitivity impacts prior to finalizing the recommendation to procure the NTEC 250 MW. The key areas of uncertainty in the Company's refined evaluation were future load projections and potential future CO_2 regulation.

3.3.1 Future Load Projections

Minnesota Power's unique customer mix and its forecast of load growth during a period where other utilities are experiencing stagnant demand place it in a very different planning position than most of the electric industry. There are several large-scale mining projects that are feasible during the early 2020s, such that Minnesota Power's conservative forecast includes load growth during this period.

Minnesota Power is using a conservative outlook for customer demand. It assumes that the taconite processing facilities that are currently idled remain in this status and that only one of the several large-scale mining projects on the horizon starts operations,[56] even though there are several projects that are feasible and the potential exists for idled customers to resume operations as these facilities find new owners or markets improve. This load growth base case is described in Section 2 of this Petition. Including a conservative outlook in the base case ensures that Minnesota Power does not over-commit to adding energy resources, and maintains the flexibility for future capacity additions if several new industrial customers begin operations. The Company also considered higher and lower outlooks in this planning analysis to reflect the potential for changing large industrial customer profiles. As discussed in greater detail below, the proposed NTEC combined-cycle purchase was identified as least cost under both the base case and the majority of the low and high growth scenarios. Thus, while a conservative base case growth projection provides protection against the risk of over-building, the proposed NTEC combined-cycle purchase is supported even if growth is lower than the conservative base case.

3.3.2 CO_2 Regulation

Minnesota has a history of forward-looking power supply policy that positions the State well for a future of less carbon-intensive resources. The Greenhouse Gas Emissions Reduction Goal, set forth in Minn. Stat. § 216H.02, identifies significant target reductions of 15 percent for 2015, 30 percent for 2025, and 80 percent for 2050. Minnesota Power's Energy*Forward* Resource Package, which includes the NTEC 250 MW purchase, exceeds the 2025 goal by achieving a 42 percent reduction by 2025. The EPA final CPP Rule was released August 3, 2015. And while the EPA announced withdrawal of the CPP Rule in October 2017, Minnesota Power continues to assess the CPP and other future federal CO_2 regulation as it relates to the State of Minnesota and its potential impacts on the Company. [57]

Each power supply action step was considered under a range of potential carbon futures. By evaluating several outcomes, the Company clearly identified which resource or resources performed best, as well as which resource alternative decisions are based on higher CO_2

[56] In particular, potential mining projects include Essar, PolyMet, and Twin Metals.

[57] Minnesota Power notes that the federal government is taking steps to repeal the CPP rule; however, Minnesota Power continues to include CO_2 reductions in its analysis to show the impact on the Company and the State of Minnesota.

regulation penalties versus ongoing power supply needs. The approach to evaluating the impact of potential future carbon regulation includes:

- Utilizing a \$21.50/ton CO_2 regulation penalty as a base case assumption across four Futures considered.
- Utilizing a \$0/ton CO_2 regulation penalty as a base case assumption across four Futures considered.
- Comparing the expansion plans and alternative "swim lanes" with other plausible carbon alternatives, including \$9/ton and \$34/ton carbon regulation penalties, and the recently revised externality value for carbon.
- Evaluating the resource selections and the resulting annual customer costs.
- Determining how Minnesota Power would be positioned to implement resource alternatives for customers in the future should a carbon regulation penalty or target be implemented.

Given the uncertainty of a CO_2 regulation penalty, and the uncertainty of timing for implementation, Minnesota Power included Futures with and without CO_2 regulation penalties. Having these base cases — one that includes and one that excludes a CO_2 regulation penalty — allows the Company to understand how a carbon penalty can change the timing and technology type of new resource additions, and when to begin transition of existing resources. Analyses for Minnesota Power's past resource plans, as well as the refined analysis discussed in this filing, indicate that the timing and value of a CO_2 regulation penalty can influence resource decisions both with respect to technology and timing. As a result, these factors were taken into consideration when determining the need for the proposed NTEC 250 MW purchase.

Finally, the Company has an ongoing strategy to reduce CO_2 emissions in its power supply as part of its overall Energy*Forward* strategy. Based on a comprehensive analysis of various scenarios, contingencies, and alternatives, the Company has identified the NTEC 250 MW purchase plus the proposed additions in 2020 of 250 MW of wind and 10 MW of solar as the next step to achieve further reduction in CO_2 emissions and further position Minnesota Power for future regulation. Implementation of the Energy*Forward* Resource Package as a whole will place the Company in good position to comply with future CO_2 regulations.

3.4 ALTERNATIVES EVALUATED

Minnesota Power issued an RFP for a natural gas combined-cycle resource in 2015. The RFP process concluded that the NTEC 250 MW purchase was the least cost resource from the RFP. Minnesota Power also issued RFPs for wind, solar, and demand response in 2016 and used the information gained from RFP results to model updated costs for these alternatives. The NTEC combined-cycle proposal, updated wind and solar alternatives based on the RFP, and updated data for natural gas peaking and battery storage, was used to determine what least-cost generation resource or mix of resources are available to meet capacity and energy requirements starting in 2025 and further the Company's Energy*Forward* strategy. Details on the natural gas RFP processes and results are included in Section 4 of this filing. This Section introduces alternatives that were available to the Company and discusses the Company's evaluation of those options.

Given the customer requirements and power supply needs discussed above, Minnesota Power's planning principles call for a diversified and flexible power supply to meet customers' needs cost effectively in an environmentally-responsible manner. Minnesota Power considered the costs and characteristics of the proposals received and analyzed whether they are beneficial resource additions for customers.

The least-cost alternatives were evaluated across multiple sensitivities to determine the optimal and prudent resource or mix of resources for customers. Strategist was used to evaluate various alternative expansion plans based on the latest data for alternatives. Strategist allows a utility to offer many resource types into a production cost evaluation and optimize the technologies that best meet the projected customer needs over a defined study period. The resource alternatives modeled in Strategist included the least-cost offer from the RFP for combined-cycle, updated wind and solar data from recent RFPs, as well as generic generation resources, battery storage, and demand response. For Step 1, the Company allowed Strategist to select from the following supply and demand side resource options:[58]

RFP Alternatives

- 250 MW share of a natural gas-fired 1x1 combined-cycle gas turbine (NTEC)

Generic Alternatives[59]

- 525 MW of natural gas-fired 1x1 combined-cycle gas turbine
- 228 MW natural gas-fired combustion turbine
- 112 MW natural gas-fired aeroderivative turbine
- 50 MW lithium-ion battery storage
- 55 MW natural gas-fired reciprocating engines
- 100 MW wind farm located in Minnesota
- 10 MW solar farm located in central Minnesota
- 100 MW solar farm located in central Minnesota
- 50 MW bilateral bridge transactions (used to bridge to natural gas generation)
- Air conditioning load control and hot water load control

Minnesota Power uses the Strategist software to compare the new resource technologies that are available to meet long-term customer demand for electricity. The software is a capacity expansion model used in resource planning by many electric utilities. The Strategist model can take into consideration many factors that impact resource decisions, such as energy demand, fuel cost, environmental regulation(s), and capital cost. Strategist compares the costs of various resource expansion plans, evaluates the impacts of different power supply mixes, and helps identify cost impacts when various factors are stressed. The outcome is multiple least-cost expansion plans and Minnesota Power uses these results to identify the resource mix that is most robust across many contingencies.

The expansion plan optimization was conducted for both a $21.50 per ton carbon regulation penalty and a no carbon penalty outlook. The CO_2 regulation penalty is added to the costs to

[58] Appendix J: Detailed Resource Planning Analysis includes a complete list of resource alternatives considered in the analysis. This list was screened to remove higher cost alternatives due to limitations on the number of resource alternatives that can be evaluated in Strategist.

[59] Note that more than one of each resource option can be chosen during the optimization process. Also, the capacity listed is the installed capacity value for each resource.

generate energy at existing and new generating sources starting in 2022. As described above, Minnesota Power included both of these CO_2 penalty levels to clearly identify what expansion plan resource decisions are due to greenhouse gas regulation penalties versus customer load requirements. Expansion plan optimization also included a combination of seasonal resource adequacy (summer versus winter) and eliminating market energy sales across the eight Futures. As reflected in Table 1: Eight Futures Considered in the NTEC Combined-Cycle Analysis below, in total, there were eight Futures evaluated over 30 sensitivities. The insights gathered from the expansion plan evaluation assisted in the Company's selection of the resource or resources that best meet growing customer needs starting in 2025.

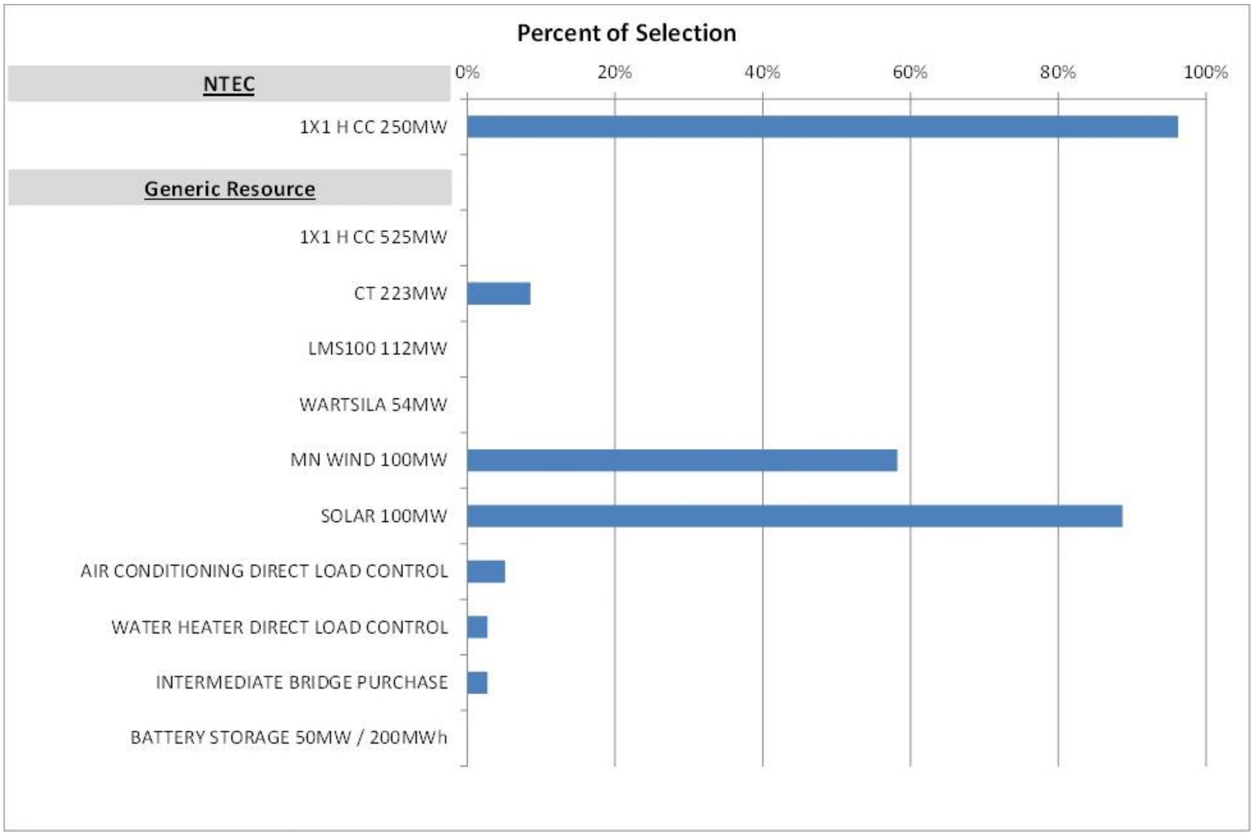
Table 1: Eight Futures Considered in the NTEC Combined-Cycle Analysis

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

Expansion plans were then created for the eight Futures and all sensitivities, including the required CO_2 regulation penalty ranges, delivered fuel costs, and other key variables. For a complete list of sensitivities, see Appendix I: Assumptions and Outlooks.

The proposed NTEC 250 MW purchase was identified as least cost across several optimal expansion plans using 292 sensitivities, including CO_2 regulation penalties, high and low market prices, revised high and low environmental externality values, and variable customer outlooks. Figure 13: Detailed Resource Analysis Expansion Plans shows the various generation technologies Minnesota Power considered in the expansion plan evaluation and the percentage of time they were included in the optimal expansion plan. By itself, the NTEC 250 MW proposal was selected in 96 percent of 292 expansion plans evaluated, clearly demonstrating the synergy between variable renewable generation and the need for efficient gas-fired generation. In compliance with Order Point 9 of the July 2016 IRP Order, the Strategist model included in the base case 250 MW of wind (Nobles 2) from the RFP.[60] Consistent with Order Point 11 from the July 2016 IRP Order, Minnesota Power also evaluated adding solar in 10 and 100 MW block sizes based on data, including pricing, received in the RFP.[61] Large scale solar was selected at a higher frequency in the longer term planning period with it being selected most often post-2030.

Figure 13: Detailed Resource Analysis Expansion Plans



The next sections of this Petition discuss these options in more detail.

[60] July 2016 IRP Order at 15 ("By the end of 2017, Minnesota Power shall initiate a competitive-bidding process to procure 100–300 MW of installed wind capacity.").

[61] *See* July 2016 IRP Order at 15 ("The Commission finds that up to 100 MW of solar by 2022 is likely an economic resource for Minnesota Power's system; the Company shall account for this finding in its request for proposals in any competitive acquisition process.").

3.4.1 Natural Gas Generation (NTEC)

Natural gas generation has been on the horizon for Minnesota Power for some time. Analyses performed for Minnesota Power's Baseload Diversification Study,[62] 2013 Plan, 2015 Plan, and this most recent refined evaluation consistently show that combined-cycle natural gas generation has an important place in the long-term power supply. The benefits for long-term power supply diversification are clear. The Step 1 expansion planning evaluation identified 250 MW of natural gas additions in the 2025 and beyond time period to augment a growing customer base and renewable power supply. The results of the natural gas RFP, which are discussed in greater detail in Section 4 of this Petition, presented Minnesota Power with a unique opportunity to procure an approximately 250 MW share of a modern and efficient combined-cycle unit through a joint ownership between Minnesota Power's affiliate, South Shore, and Dairyland. The results of the Company's updated expansion planning evaluation and Strategist modeling support executing on this opportunity to add the combined-cycle generation into the power supply. This is further supported with the modeling results showing a need for a gas resource with a capacity factor of 45 percent, which is best met with an efficient combined-cycle plant.

The proposed NTEC 250 MW purchase fits well with variable generation like wind and solar, especially for Minnesota Power's high load factor system. Natural gas is a flexible, fast-acting resource that can be present to deliver energy when needed. As Minnesota Power has already incorporated significant wind resources into its portfolio (over 600 MW currently, with another 250 MW addition planned for 2020, totaling over 850 MW) and is growing its solar portfolio, the addition of this more flexible technology is sensible and timely. This flexible generation gives customers a resource that can turn off during times of high wind generation and respond quickly by providing energy when there is no wind or solar generation available. Unlike baseload generation that has the capability to increase or decrease generation to set levels but cannot stop energy production rapidly, a combined-cycle resource provides efficient energy near baseload energy prices and provides the flexible operations required for a changing power supply.

[62] *In the Matter of Minn. Power's 2010-2024 Integrated Res. Plan,* Docket No. E015/RP-09-1088, MINNESOTA POWER'S BASELOAD DIVERSIFICATION STUDY COMPLIANCE REPORT (Feb. 6, 2012).

In 2015, Minnesota Power issued an RFP for up to 400 MW of dispatchable natural gas-fired capacity. The Company determined it was necessary to begin its natural gas investigation at that time to ensure the option to access a combined-cycle facility by 2024 would be available. Proposals on the RFP were due by January 7, 2016. And as noted above, the Step 1 expansion planning evaluation analyzed the best available alternatives to meet the growing capacity and energy needs starting in 2025. The expansion planning evaluation identified that an efficient and low-cost natural gas resource, such as owning a portion of a 1x1 combined-cycle generating unit, should be considered over a gas-fired peaking generation, battery storage, or other renewable options.

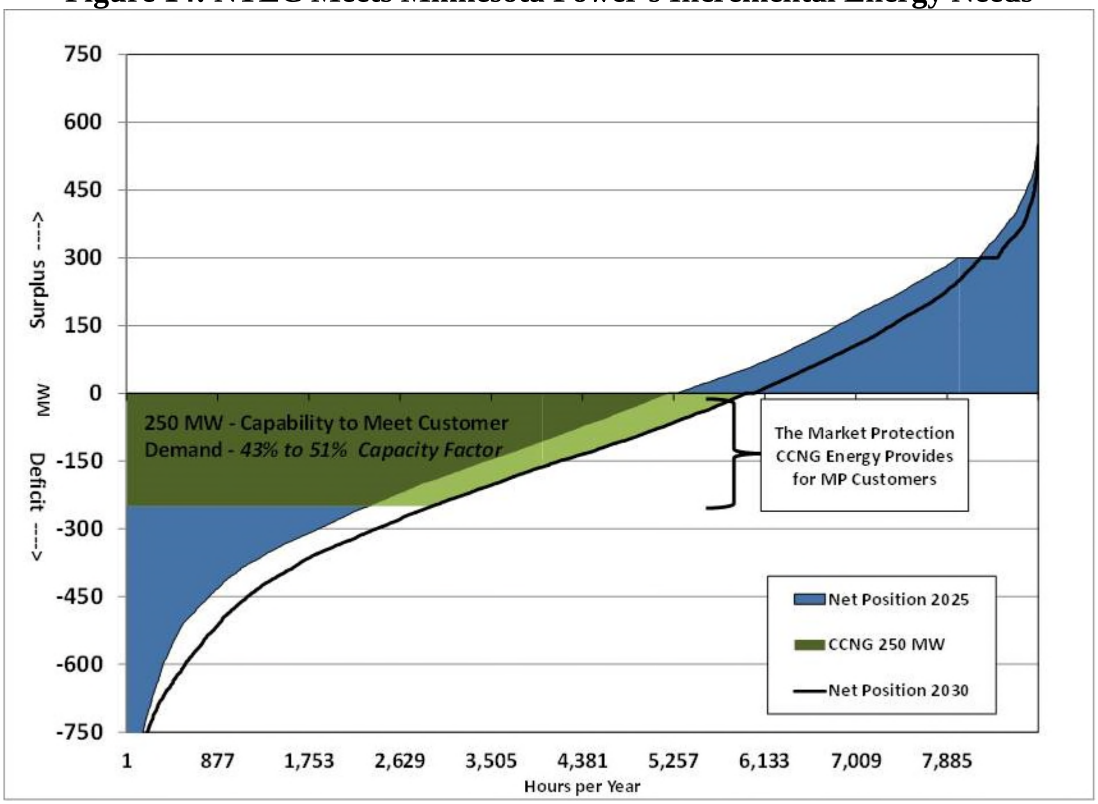
Through a thorough evaluation of RFP proposals, short listing, and independent evaluation, the NTEC 250 MW purchase was selected as least cost and best suited to serve customer needs. Hundreds of expansion plans developed over multiple sensitivities concluded that a share of NTEC should be selected for inclusion in 2025 96 percent of the time.[63] Minnesota Power's high load factor and energy intensive customers gain value from generating resources that can produce efficient, low-cost energy. With the addition of a new wind resource as part of the Energy*Forward* Resource Package, Minnesota Power's hourly energy position variation range will increase to over 850 MW, creating additional need for flexible energy to be available to mitigate and balance the exposure to energy markets. Economic energy from the new natural gas resource would be used to meet customer needs during periods of energy deficits, which is correlated to periods of low wind generation.

The need for a dispatchable capacity resource is further supported by Minnesota Power's hourly energy need shown in Figure 14. As demonstrated in the figure, the utilization of a natural gas addition is between 43 percent and 51 percent, aligning with Minnesota Power's selection of an efficient combined-cycle facility as part of the Energy*Forward* Resource Package. This is also supported by Minnesota Power's modeling in the analysis where NTEC is operating at around a 45 percent capacity factor in base case assumptions, and the capacity factor doubles under a carbon regulation penalty, demonstrating the benefits of the lower carbon emitting energy from a

[63] *See* Appendix J: Detailed Resource Planning Analysis.

combined-cycle unit. Independent forecasts, such as the IHS outlook purchased by Minnesota Power, show combined-cycle generation located in MISO North operating at a 60 percent capacity factor during this same period. The expectation, which is supported by Minnesota Power's own need and Strategist modeling, along with the independent forecast, is that the system will need efficient combined-cycle generation to meet customer needs as the power supply transitions away from higher emitting baseload carbon resources.

Figure 14: NTEC Meets Minnesota Power's Incremental Energy Needs



The proposed NTEC 250 MW purchase a matchless opportunity, giving customers access to an efficient combined-cycle resource, where typically a utility with a 250 MW capacity need would have to use a more inefficient large combustion turbine. The larger combustion turbines are typically 200 to 250 MW, which could be a nice fit for meeting Minnesota Power's capacity needs, although a combustion turbine consumes approximately 55 percent more fuel to produce 1 MWh of energy than a combined-cycle. With Minnesota Power's customers having a high load factor, and supported by the expansion plan analysis in Step 1, an efficient combined-cycle with lower fuel cost than other gas options is the wise resource addition for customers.

A new and efficient natural gas addition also positions Minnesota Power for future carbon regulations or State greenhouse gas targets. The Strategist results for the expansion plan analysis in Step 1 clearly identify a 250 MW share of a 1x1 combined-cycle gas generating facility is needed.

3.4.2 Wind Generation

Minnesota Power currently has over 600 MW of wind generation in its power supply. In its July 2016 IRP Order, the Commission directed Minnesota Power to initiate a competitive-bidding process by the end of 2017 to procure 100–300 MW of installed wind capacity.[64] In compliance with the Commission's Order, Minnesota Power issued an RFP in 2016 for new wind capacity. In compliance with Order Point 9 of the Commission's July 2016 IRP Order, Minnesota Power included the least cost wind project from the RFP in the base case. The wind project comprises 250 MW of new nameplate wind generation (Nobles 2) located in southwest Minnesota and is expected to be operational by 2020 (subject to separate Commission consideration and approval). The 250 MW of new wind is in southwestern Minnesota and is physically separate from the Company's North Dakota wind facilities. This helps diversify Minnesota Power's wind generation between southwestern Minnesota and North Dakota.

With the addition of the 250 MW Nobles 2 wind project, Minnesota Power will have over 850 MW of high capacity factor wind generation in its power supply. Similar to the results seen in the 2015 IRP, absent any carbon regulation penalty, the analysis shows the lowest cost plan for customers does not include new wind generation at projected post-PTC costs. The analysis identified two primary factors that influence the economics of adding wind to the Company's power supply: inclusion and timing of a CO_2 regulation penalty and projected cost continuing at PTC levels. As demonstrated in the expansion planning analysis, wind was shown to be most

[64] July 2016 IRP Order at 11, 15 ("The Commission concludes that Minnesota Power should begin a competitive acquisition process, by the end of 2017, to procure 100–300 MW of installed wind capacity. This range reflects the positions of both parties; the final amount can be resolved in a future resource-acquisition proceeding with the benefit of specific proposals.").

economical for customers starting at the mid CO_2 regulation penalty level or greater. Regardless of CO_2 regulation, wind was shown to be cost effective for customers when prices remain in the [**TRADE SECRET BEGINS** **TRADE SECRET ENDS]** range post-2025.

Wind does not provide the same level of resiliency as a dispatchable combined-cycle plant because there is a high probability that the wind generation will not be available at all hours when it is needed for reliability. This is reflected with the significantly lower capacity credit wind receives, approximately 85 percent less than the capacity value of a combined-cycle. Furthermore, as more wind is added in the MISO footprint, the capacity value it receives will decrease due to the high penetration of intermittent generation within the local region. Wind alone cannot meet Minnesota Power's growing capacity and energy needs, and this is reflected in the analysis results, which show a combined-cycle being the preferred alternative to meet capacity needs and energy needs when wind generation is unavailable.

In this proceeding, Minnesota Power is not recommending the addition of new wind beyond the 250 MW of wind already being recommended for 2020 as part of the Energy*Forward* Resource Package. Until there is more certainty on the timing and structure of a carbon regulation, or future wind cost in the post-2025 time period, the Company will remain flexible when considering additional wind through the resource planning process. With Minnesota Power approaching an 850 MW wind portfolio and a power supply made up of 45 percent renewable generation, locking into additional renewable resources at this time would not be prudent for customers as the Company evaluates and optimizes the existing power supply with high penetration of renewable and intermittent generation. Minnesota Power's Energy*Forward* strategy is positioning its power supply for a less carbon-intense future, and the Company does not need to take additional action at this time beyond what is being recommended in the Energy*Forward* Resource Package.

3.4.3 Solar Generation

In its initial 2015 Plan filing,[65] Minnesota Power identified a broad solar strategy to meet the estimated SES requirement in 2025. In 2016, Minnesota Power learned through its competitive process that the price of solar is declining and efficiency is increasing. However, solar is still substantially more expensive than wind and does not provide the same capacity benefits for customers due to Minnesota Power's system peaking in the winter evening hours. For these reasons, Minnesota Power's solar strategy remains to add solar as needed to meet, rather than substantially exceed, the Minnesota SES. Utilizing its customer, community, and utility focus, as discussed in Minnesota Power's June 1, 2015, SES Report,[66] the Company will leverage multiple sizes and types of solar energy to meet the projected requirements. In 2016, Minnesota Power implemented the 10 MW Camp Ripley Solar Project.[67] Additionally, the Company's first Community Solar Garden Pilot Program was approved in 2016 and is expected to be producing solar energy for participating customers in 2017 from two solar garden facilities totaling 1.04 MW.[68]

In the Energy*Forward* Resource Package, Minnesota Power is proposing to add an additional 10 MW of solar energy in 2020 through a PPA selected from the Company's solar RFP process. This 10 MW of solar generation was included in the base case for the analysis. In total, Minnesota Power anticipates 33 MW of solar resource additions as part of its strategy to meet

[65] *In the Matter of Minn. Power's Application for Approval of its 2015-2029 Res. Plan*, Docket No. E015/RP-15-690, 2015 INTEGRATED RESOURCE PLAN, APPENDIX H: RENEWABLE ENERGY (Sept. 1, 2015).

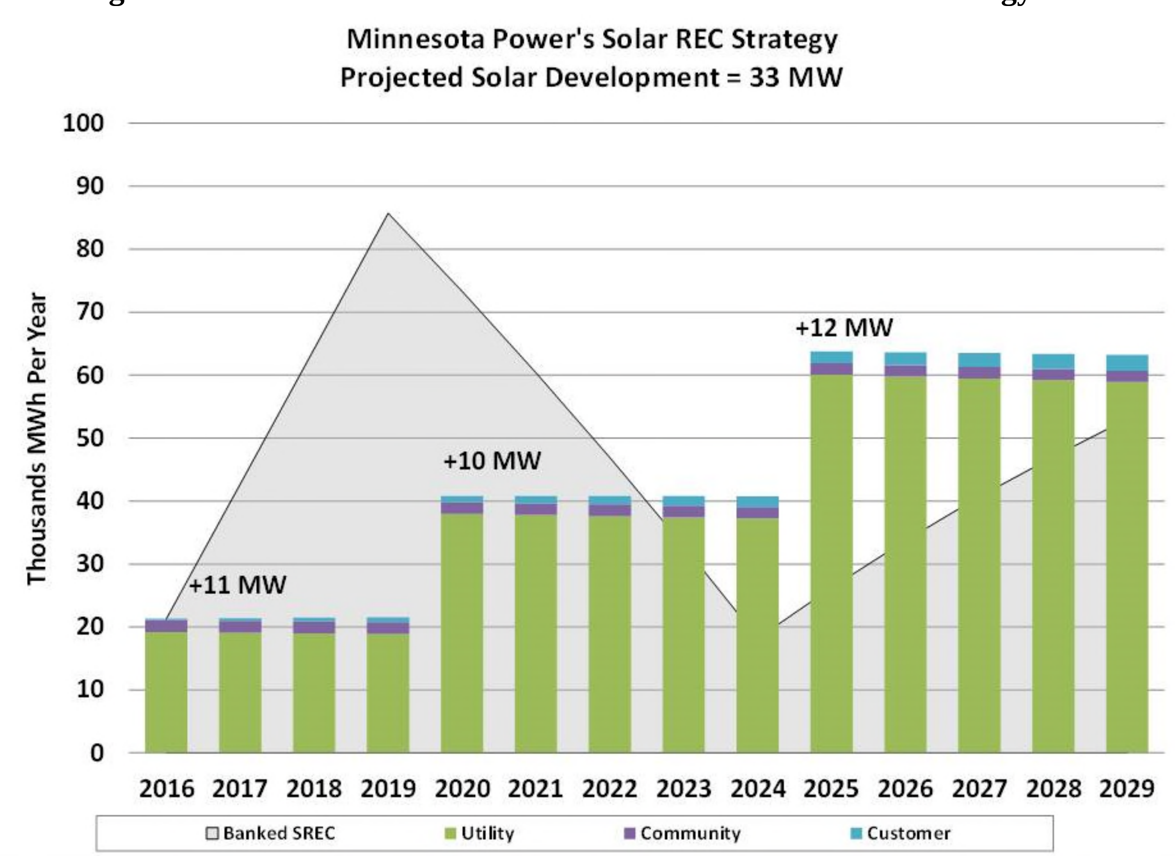
[66] *In the Matter of Utilities' Annual Reports on Progress in Achieving the Solar Energy Standard*, Docket No. E999/M-15-462, MINNESOTA POWER'S 2014 SOLAR ENERGY STANDARD PROGRESS REPORT at 1 (June 1, 2015) ("1) Customer – maintaining relationships and providing thoughtful incentive and education programs, 2) Community – enabling customer access to solar energy options and promoting community development, and 3) Utility – implementing efficient resources into the customer power supply.").

[67] *In the Matter of the Petition of Minn. Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minn. Power's Renewable Res. Rider Under Minn. Stat. §216B.1645 and Related Tariff Modifications,* Docket No. E015/M-15-773, ORDER GRANTING PETITION IN PART AND REQUIRING REEVALUATION OF SOLAR ENERGY ADJUSTMENT RIDER (Feb. 24, 2016).

[68] *In the Matter of a Petition by Minn. Power for Approval of a Community Solar Garden Program, Eligibility of the Energy for Small Scale Solar Energy Standard Compliance, and a Recovery Method for Program Cost Recovery*, Docket No. E015/M-15-825, ORDER APPROVING PILOT PROGRAM WITH MODIFICATIONS (July 27, 2016).

and sustain the 2025 SES requirement.[69] The Company continues its longstanding support of customer-sited solar systems with its SolarSense rebate program, which has been in place for over a decade. In 2016, Minnesota Power proposed to expand the SolarSense program by nearly tripling the amount of incentives available for customer-sited solar installations. This newly-proposed program expansion was approved in early 2017.[70] With proactive action in each pillar of the Company's solar strategy — Utility, Community, and Customer — Minnesota Power is well positioned for compliance with SES requirements in 2025. Figure 15 below illustrates Minnesota Power's anticipated plan for compliance with the SES requirement.

Figure 15: Minnesota Power's Solar Resources to Fulfill Solar Energy Standard



[69] The solar strategy of incorporating 33 MW of new solar resource for the SES requirement is included in the Energy*Forward* Resource Package and the three alternative swim lanes.

[70] *In the Matter of the Petition for Approval of Minn. Power's New SolarSense Customer Solar Program*, Docket No. E015/M-16-485, ORDER APPROVING PROGRAM CHANGES, DENYING COST RECOVERY IN PART, REQUIRING ANNUAL REPORT, AND REQUIRING COMPLIANCE FILING (Feb. 10, 2017).

Adding an additional 100 MW of new solar generation beyond Minnesota Power's current strategy was selected around 80 percent of the time post-2030 in the Step 1 expansion planning evaluation. Although solar generation was selected post-2030 at a high frequency, Minnesota Power does not recommend procuring additional solar generation at this time for the post-2030 time period. Minnesota Power has time to address the energy and capacity needs post-2030 in subsequent resource plans. Additionally, solar generation characteristics do not align well with the current energy needs of the Company's customers, because Minnesota Power has a high load factor due to the high concentration of industrial load on the system and the requirement for energy supply around the clock. Additionally, the Company has a winter peak that normally occurs during the evening when the sun is not available. This limits the peak-following benefit of solar to the summer months, when Minnesota peak demand is more aligned with neighboring utilities.

In addition to the load-following concerns with solar, Minnesota Power is also concerned with the capacity value solar would receive in a winter season resource adequacy requirement. 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.[71]

Minnesota Power realizes that the current MISO resource adequacy construct focuses on the capacity requirements for the summer peak. However, one of the 2017 goals for MISO's Resource Adequacy Subcommittee is to discuss seasonal resource adequacy requirements, a possible outcome of which is to separate capacity requirements for both summer and winter seasons. Given that resource decisions are often being made for assets with long operating lives to meet customer needs over a 20 to 40-year period, and in light of the uncertainty surrounding future resource adequacy requirements, Minnesota Power concludes it is most prudent to select

[71] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-16-664, REBUTTAL TESTIMONY AND SCHEDULES OF JULIE PIERCE at 13-17 (June 29, 2017) (discussing the Company's calculation of solar capacity value).

capacity resources that are available during both winter and summer seasons. This does not preclude Minnesota Power from considering the addition of large scale solar generation to the power supply; it just changes the lens through which solar generation is evaluated — as an energy-only resource with limited capacity value.

Minnesota Power recognizes that solar technology is continuing to become more efficient, and that costs are declining. At the right cost level, solar could begin to show a benefit to customers in the expansion planning process. To understand at what cost level solar is selected in the expansion plans for customers (above the 33 MW of solar included in the base case), a sensitivity was included that varied the cost of solar in $10/MWh increments from $35/MWh to $75/MWh. 100 MW of solar across these price ranges started to show economic benefit for customers in the early-2030s. Given that at certain cost ranges, solar starts to show a benefit for customers during the study period, Minnesota Power will continue to evaluate new solar technology trends in future resource plans to identify when it will augment the power supply with additional solar.

3.4.4 Battery Storage

Over the last several resource plans, battery storage was considered as a resource alternative to meet customer demand. Battery storage has been and continues to be higher cost than other resource options available for customers, but Minnesota Power expects the cost of the technology to continue declining in the future. Minnesota Power's planning process includes updating the project cost for viable technologies, and typically during the study period project cost are escalated to take into consideration general inflation rates on materials and labor. For battery storage a different approach was taken, in which Minnesota Power assumed the cost of battery storage continues to decline through 2024 and then remains constant for the remainder of the planning period. The rate at which battery storage declines was based on a 2017 study published by the International Finance Corporation called "Energy Storage Trends and Opportunities in Emerging Markets". The study assumed that the maturation of the battery industry and, improving capabilities, along with the financial community becoming more comfortable with this industry, will result in decreasing cost for battery storage. Minnesota

Power is of the view that the rate at which the cost of battery storage may decrease is uncertain. This uncertainty is common to many variables considered in resource decisions, such as fuel cost and production of intermittent generation; nevertheless Minnesota Power believed it was reasonable to apply a declining cost curve to an emerging technology like battery storage.

Battery storage has a unique set of attributes that has the potential to provide multiple value streams for customers. The transmission and distribution system could benefit from battery storage because deployment of battery storage could delay the need for investment, especially in regions experiencing load growth.[72] The customer experience could be improved with batteries because they could provide back-up power, micro grid development opportunities support, and usage profile management by shifting load to off-peak hours. From a system-wide perspective, batteries could be used to shift larger volumes of load to align with periods of excess renewable generation or provide ancillary services similar to what is provided by traditional dispatchable generation today. Currently, though, the up-front capital cost of battery storage is prohibitive compared to other resource alternatives and transmission solutions. This is supported by the Step 1 analysis results where 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.

Minnesota Power is unique because it has a large concentration of industrial customers that require a reliable electric system and power supply to meet their specific energy needs, including load factors in the 80 percent range. Battery storage and intermittent renewable resources, singly or in combination, is not a viable solution for meeting the needs of large industrial customers due to their 24 hour energy requirements. Supplemental dispatchable energy, such as a combined cycle resource, is required to provide dispatchable and reliable generation when wind or solar is not available or battery storage hours have been depleted. Minnesota Power continues to evaluate

[72] As mentioned earlier, batteries have the potential to provide multiple values streams for customers, but these value streams cannot be provided by just one battery system. Battery systems are typically designed for two purposes, either high energy output (capacity resource) or high power output (frequency regulation). Battery systems are typically designed to meet a specific need, capacity resource and/or frequency regulation. In this analysis Minnesota Power modeled in Strategist a high energy output type battery that can provide energy over short periods of time (4 hours) and capacity as this is the resource need being evaluated.

applications where the attributes of battery storage would be beneficial, however serving high levels of energy and capacity demand as our current outlook identifies it not currently a prudent utilization for customers.

One other barrier to battery storage is the current energy and capacity markets, in particular MISO, which do not have products that assign reliable value streams to battery storage. In fact, battery storage as an energy and capacity resource is in the early development phase of integration of the technology into the MISO market. Minnesota Power continues to follow developments in the MISO market relating to battery storage.

Minnesota Power recognizes that battery storage is continuing to become more efficient, and costs are declining. At the current projected cost levels and declining trends, and as shown in this evaluation, battery storage is not showing a benefit to customers in the expansion planning process. Minnesota Power does not recommend adding battery storage to meet capacity and energy needs starting in 2025 as a replacement for the natural gas alternative. But the Company will continue to evaluate new battery storage technology trends and evolving market value stream mechanisms in future resource plans to identify when it could be economical to augment the Company's power supply resources or the transmission or distribution system with battery solutions.

3.4.5 Bilateral Transactions

An important component of a utility's power supply is contracted purchases and sales, conducted to optimize the power surpluses and deficits that occur due to load and supply changes. These agreements are called bilateral transactions, and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources.

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms. Day-ahead markets operate in the 24 to 48-hour time frame with spot market prices. See Appendix I: Assumptions and Outlooks for additional details. Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in the best interest of its customers. Based on the refined analysis conducted for the planning period, a short-term bilateral bridge purchase will allow the Company to delay further investment in new capacity resources until 2025, when a natural gas combined-cycle resource is recommended. An unidentified 50 MW bilateral bridge transaction for energy and capacity was included in the Strategist model as a resource alternative in 2024 for both the summer and winter resource adequacy cases. The bilateral bridge transactions provide significant savings to customers when compared to procuring a large share of a capacity resource when only a minimal amount of capacity is required to bridge to a period when the capacity need is greater. These purchases also provide near-term stability in power supply costs for customers.

However, unidentified bilateral purchases for large volumes of energy are not a satisfactory approach to supplying customers over the long-term because of the price risk associated with contracting for energy and capacity at an assumed price level five to fifteen years in the future. Rather, they are distinct opportunities for very economical, shorter-term (typically one to five year) additions to the power supply. The bilateral bridge strategy of using stable-priced bilateral purchases with strong counterparties helps meet electricity requirements and allows for flexibility as large new customer loads are introduced on Minnesota Power's system. Consequently, using unidentified bilateral contracts is a shorter-term stability option but not a solution for capacity and energy needs in 2025 and beyond.

3.4.6 Large Industrial Demand Response

Minnesota Power currently has 250 MW of Large Industrial Interruptible demand response capability on its system that it utilizes for emergency operations and is accredited in MISO's resource adequacy program. Typically, the term for Large Industrial Interruptible capacity is one year and the amount of capacity made available by Large Industrial customers can vary from year to year. Over the past five MISO Planning Years, the capacity made available to Minnesota Power ranged from approximately 100 MW up to 260 MW, averaging slightly over 150 MW during that period. Minnesota Power has other existing demand response programs that provide benefits to customers, such as the dual fuel rate programs with residential and commercial/industrial customers. These existing programs are a valuable component of Minnesota Power's least-cost supply strategy, and help to ensure the reliability of the regional power supply portfolio.

In its July 2016 IRP Order, the Commission directed the Company to propose a demand response competitive-bidding process within six months of the Commission's Order.[73] In compliance with the Commission's July 2016 IRP Order, Minnesota Power issued an RFP for up to 300 MW of Large Customer Demand Response Resources on August 5, 2016.[74] The Company's RFP requested cost-effective demand response resources that utilize the capability of Minnesota Power's Large Industrial customers to curtail their load for electric system emergencies or market economics and provide capacity that is accreditable under current MISO resource adequacy rules, to be considered for optimizing within its power supply portfolio.[75] Proposals were due by September 26, 2016. Minnesota Power received only one response to its RFP, offering 96 MW of system capacity demand response available for energy curtailment events during MISO system emergencies or Minnesota Power local system emergencies starting in 2019 for a 10 year period, and at a price of **[TRADE SECRET DATA BEGINS…**

… TRADE SECRET DATA ENDS]. This RFP bid was not incorporated in the Step 1 expansion planning evaluation because the Strategist modeling already assumes 150 MW of Large Industrial Interruptible demand is available long-term in the base case. In other words, a portion of the 96 MW offered in the RFP is already assumed in the base case. Minnesota Power continues to work to identify reasonable additions to its demand response programs that would benefit customers. One possible approach is including curtailable energy for economics associated with the 150 MW of Large Industrial Interruptible demand, which is assumed in the

[73] July 2016 IRP Order at 15.

[74] *In the Matter of Minn. Power's 2015-2029 Res. Plan*, Docket No. E015/RP-15-690, MINNESOTA POWER COMPLIANCE FILING (Jan. 18, 2017). The Large Customer Demand Response Resources RFP is also included as Appendix L to this Petition.

[75] The Large Customer Demand Response Resources RFP is included as Appendix L to this Petition. The RFP requested two types of demand response products: (1) Minnesota Power System Capacity, demand response available for energy curtailment events during MISO system emergencies or Minnesota Power local system emergencies and (2) Scheduled Economic Curtailment Energy, demand response available for economic energy curtailment events determined by market energy prices in the discretion of the Company.

base case. The current product curtails Large Industrial demand during system emergency events.

Minnesota Power does not have the 150 MW of interruptible capacity procured via contracts throughout the study period, but does expect it will be available because the Company has a long track record of procuring this quantity of capacity through short-term contracts with Large Industrial customers and given the interest shown in the RFP process.

3.4.7 Demand Response Peak Shaving

The Company continues to investigate additional demand response opportunities to augment power supply needs starting in 2025 through the evaluation of two peak-shaving programs for central air conditioning ("CAC") customers and electric hot water ("HW") customers. Minnesota Power's load forecast process identified an increasing trend in air conditioning saturation for its customers. As a winter peaking utility, the Company previously focused its residential and commercial demand response programs on the electric heating characteristics of its load. However, with the emerging air conditioning trend, a CAC interruption program could provide benefit to the power supply. The HW demand on Minnesota Power's system has also been increasing over the past several years and was explored further in the analysis. Through a preliminary design process, Minnesota Power created a CAC cycling and HW cycling program for consideration in its expansion planning:

- Based on the CAC cycling program design and the current projection of CAC saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program starting in 2025. The net present value of the sample CAC cycling program's costs is estimated to be **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**.

- Based on the HW cycling program design and the current projection of HW saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program starting in 2025. The net present value of the sample HW cycling program's costs is estimated to be **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**.

The CAC and the HW peak-shaving programs were selected infrequently by Strategist; therefore, no peak-shaving programs are recommended to augment energy and capacity needs starting in 2025. However, as energy markets begin to rise again and program costs become more economical, this type of program could become more beneficial and will be monitored for implementation in future plans.

The initial design and investigation of CAC and HW cycling programs is a good example of how Minnesota Power is working to identify beneficial demand response options for its customers. Along with a strong dedication to conservation, the Company has a significant amount of demand response capabilities developed through longstanding commitment and relationships with its customer base. Minnesota Power will continue to work to identify reasonable additions to its demand response programs that benefit customers and provide power supply efficiencies.

3.4.8 Distributed Generation

Minnesota Power currently has approximately 280 MW of distributed generation interconnected to its system. The technologies include wind, solar, and combined heat and power. Consistent with the Commission's July 2016 IRP Order, Minnesota Power has proposed a distributed generation program in its pending rate case, Docket No. E015/GR-16-664, that utilizes customer sited backup generation to provide up to 10 MW of nameplate capacity and emergency energy for the power supply. This program concept gives customers the option to add backup generation technology on-site for a monthly demand fee to provide sustainable energy during distribution outages. Because the new backup generation will provide capacity and emergency energy to the larger power supply (when the distribution system is intact), part of the program cost will be funded by Minnesota Power customers. The customer receives the benefit of having a generator located on site to serve their energy needs when and if the utility is unable to serve them. The capital cost customers would pay is comparable to adding a small peaking unit to the power supply. To be conservative, the backup generation program was modeled as a base case assumption at 10 MW, in-service in 2018.

Minnesota Power also issued an RFP for up to 300 MW of Capacity and Energy from Customer Co-Generation on August 5, 2016. Proposals were due by September 26, 2016.[76] Minnesota Power received no response to this RFP. As such, no additional customer co-generation was modeled.

3.4.9 Energy Efficiency and Demand-Side Management

Minnesota Power is a state leader when it comes to meeting the 1.5 percent savings goal implemented in 2010 as part of the Next Generation Energy Act of 2007. Since 2010, the Company achieved first-year savings that ranged between 60,000 MWh to 86,000 MWh, with an average first year cost of $0.09 per kWh. The Company remains dedicated to continuous program improvement and views ongoing energy efficiency initiatives through its utility-sponsored CIP as a strong component of its broader Energy*Forward* strategy. Minnesota Power has evaluated past CIP program performance, related success factors, and potential future opportunities to determine scenarios that would help meet the Company's resource planning goals, while continuing to comply with the State's CIP-specific requirements related to the 1.5 percent energy-savings policy goal.

As part of the 2015 Plan, the Company developed scenarios for increased levels of planned energy efficiency based on analysis and research, which provided insight into historical performance, future opportunities, and the changing energy efficiency environment in which the Company operates. As identified in the 2015 Plan in Appendix B, three scenarios of incremental energy and capacity savings to the existing plan were developed in addition to evaluating the existing level of energy savings: 11 GWh, 15 GWh, or 30 GWh per year, resulting in aggregate capacity savings by 2025 of approximately 15 MW, 20 MW, and 40 MW, respectively.

In the 2015 IRP proceeding, the Company opposed the recommendation to establish a long-term planning assumption of 2.5 percent energy savings. While the Company acknowledged it had achieved comparable savings in prior years and supports ongoing efficiency efforts, it concluded that savings should normalize before being relied on in resource planning. Ultimately, the

[76] The Capacity and Energy from Customer Co-Generation RFP is provided as Appendix M of this Petition.

Commission determined that the Company's average annual energy savings goal should be set at 76.5 GWh for resource planning purposes (equivalent to the 30 GWh incremental energy efficiency scenario), acknowledging that the level of energy savings selected would not impact the recommended supply-side resources identified in that proceeding.

The Strategist base cases in this evaluation included 11 GWh per year of incremental energy efficiency above the current State goal of 1.5 percent. The 15 GWh and 30 GWh incremental energy efficiency scenarios were both included as sensitivities. The proposed 48 percent share of the NTEC combined-cycle plant remained the least-cost alternative across the 15 GWh and 30 GWh scenarios included as sensitivities.

There is a high degree of risk associated with assuming historical performance of energy efficiency programs are sustainable, and that significant new savings can be found each year to accumulate high levels of aggregate capacity in the long-term expansion plan. Relying on significant levels of energy and capacity savings to defer large long-term resource decisions could put supply reliability and affordability for customers at risk. In the event that the energy efficiency programs do not perform as projected, additional power supply would be required, and large resource additions take years to implement. Minnesota Power included multiple levels of increased energy efficiency in the analysis to understand how expansion plans might be impacted under high and lower energy efficiency targets. The expansion plan results showed that even under the highest level of energy efficiency, the Company's proposed natural gas purchase was selected at the same frequency as under lower energy efficiency targets.

Minnesota Power continues to support energy efficiency to promote customer energy savings. Minnesota Power is also investigating the potential for a competitive bidding process for additional energy efficiency opportunities from CIP-exempt and non-exempt customers and will be providing a summary of the investigation and report findings in the next resource plan.[77] However, the Company will proceed cautiously as it incorporates the concept of new programs as a replacement for supply-side resources. As part of its current short-term action plan from the

[77] The investigation into a competitive bidding process for additional energy efficiency opportunities is in response to Order Point 14 from the Commission's July 2016 IRP Order in Docket No. E015/RP-15-690.

2015 IRP, Minnesota Power included additional support of energy efficiency programs for customers to augment its already high-performing programs currently in place.

3.4.10 Step 1 Detailed Resource Analysis with Load Sensitivities

The RFP generation resources and generic generation alternatives were evaluated in the detailed resource analysis under the different load sensitivities described in Section 2. The Strategist software was used to determine the lowest cost expansion plan with varying load sensitivities. The results show under both lower and higher load sensitivities, the proposed NTEC 250 MW combined-cycle plant was selected at the highest frequency for the growing capacity and energy need starting in 2025. In the low load sensitivity, NTEC was selected in 50 percent of the cases, with it being selected in all the Winter Season resource adequacy cases to meet Minnesota Power's higher winter demand, but it was not selected in the Summer Season resource adequacy case. This is demonstrated in Figure 16 and Figure 17, where the expansion plan results from the low and high load sensitivity (respectively) across the eight Futures are shown. Note the high load and low load (Summer Season only) sensitivity selected a 223 MW combustion turbine at a high frequency to meet future capacity needs around 2030, and this was in addition to the NTEC 250 MW combined-cycle being selected in 2025.

Figure 16: Detailed Resource Analysis Expansion Plans with Low Load Sensitivity

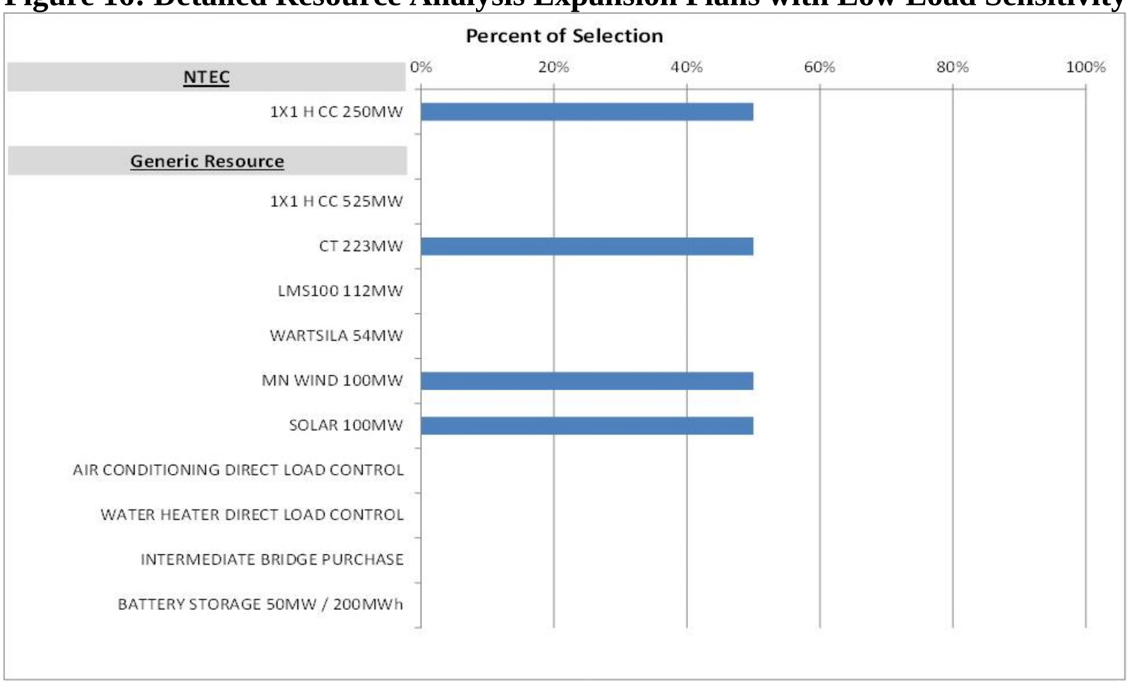
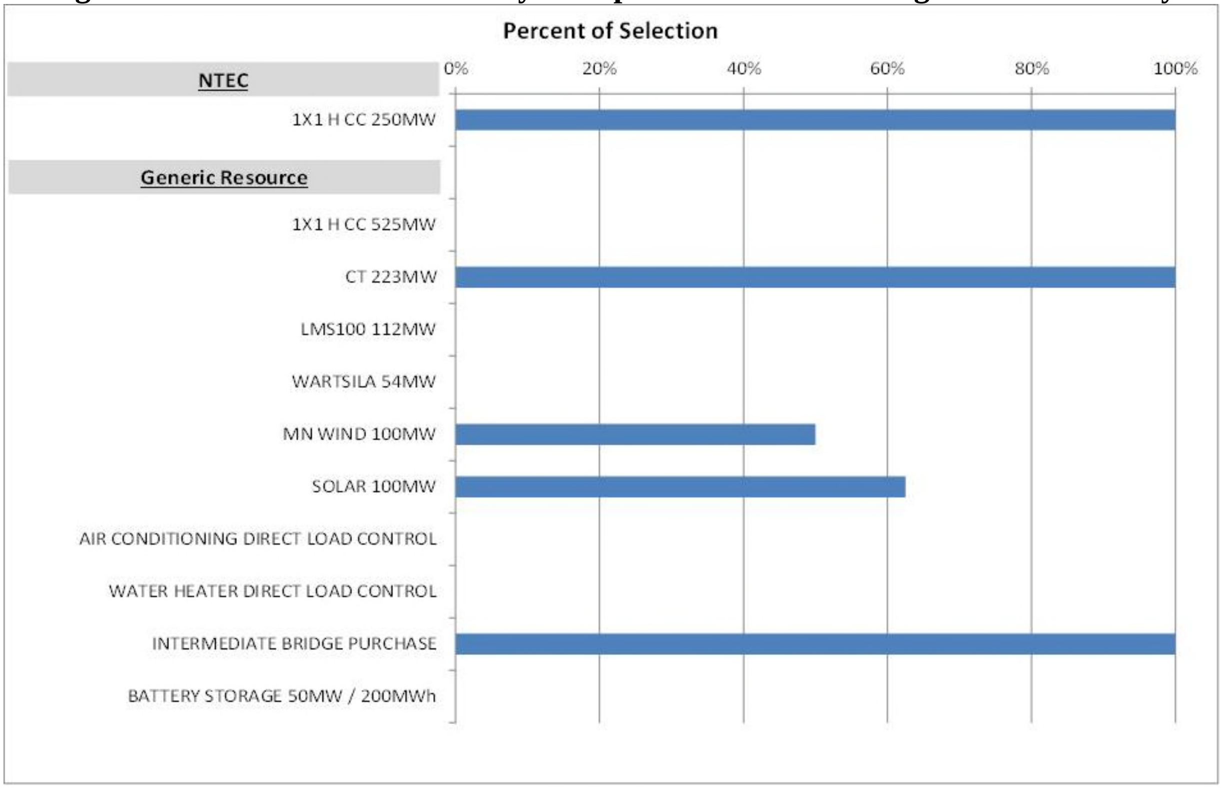


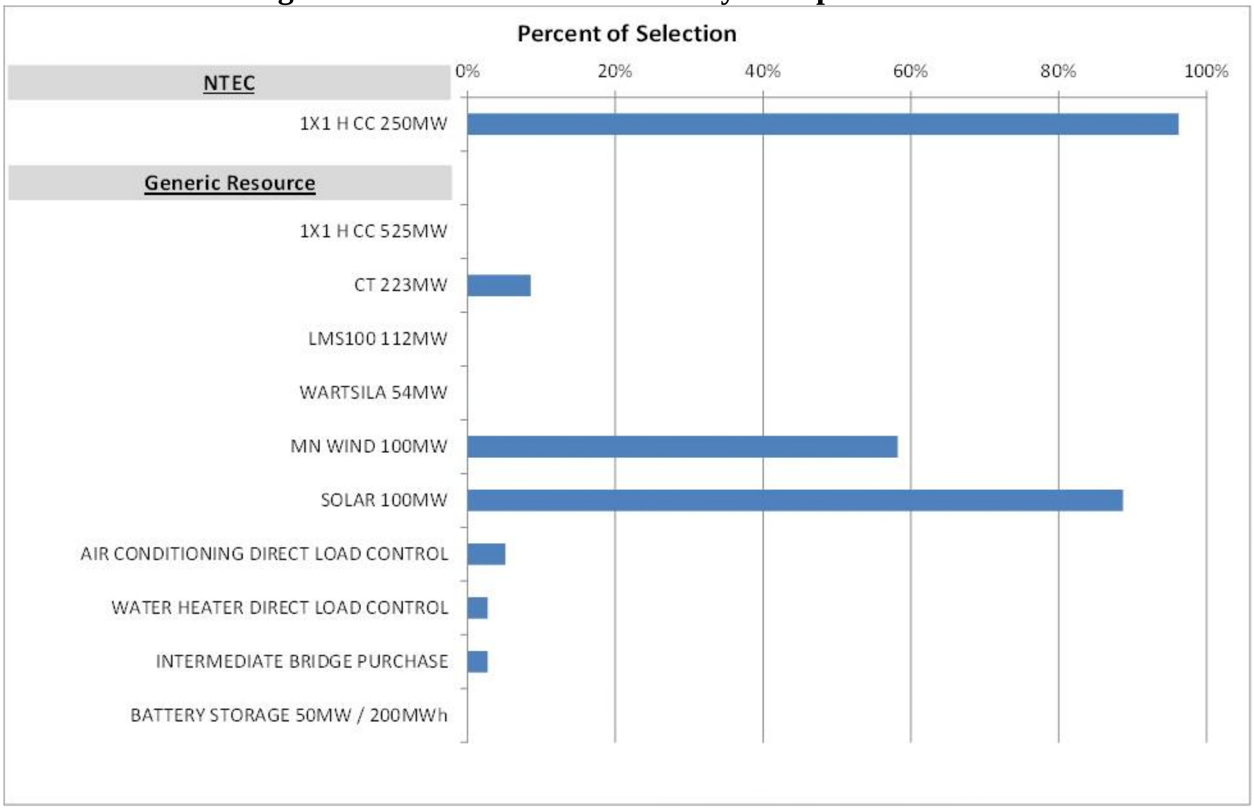
Figure 17: Detailed Resource Analysis Expansion Plans with High Load Sensitivity



3.4.11 Conclusions from Expansion Planning Analysis

The expansion planning analysis provided key insights to the Company as it developed its resource package and crafted its recommended resource mix. Based on the results of the analysis shown in Figure 18 below, the proposed addition of the NTEC 250 purchase provides a prudent and flexible resource to meet stakeholder requirements, and works to support Company values of maintaining a balanced and affordable power supply portfolio. The results support Minnesota Power's conclusion that the proposed offtake from the NTEC combined-cycle plant is the optimal resource to support the additional wind and solar energy proposed as part of the Energy*Forward* Resource Package.

Figure 18: Detailed Resource Analysis Expansion Plans



While a number of additional alternatives were explored, as described in the foregoing portions of this Section 3, the proposed NTEC 250 MW purchase emerged as the best resource in 2025 to support customer energy, capacity, and affordability needs. When combined with the proposed solar and wind projects from the RFPs, the entire Energy*Forward* Resource Package meets state policy goals and fulfills determinations from the Company's 2015 Plan. Additionally, the identified resources continue the Company's efforts to transform its power supply in a cost-effective way. Notably, the complete Energy*Forward* Resource Package:

- Increases combined wind and solar capacity by 260 MW (40 percent increase) from today;
- Results in over 45 percent renewable penetration (including hydro) overall;
- Meets growing needs during a period of declining planning reserve margins in MISO;
- Replaces coal plants with clean-burning dispatchable natural gas generation;
- Contributes to material decreases in CO_2 emissions;

- Ensures a flexible power supply for Minnesota Power customers;
- Positions the system for future renewable development; and
- Delivers the least-cost portfolio across hundreds of sensitivities.

This is a unique opportunity to bring a combination of resources into Minnesota Power's supply portfolio that aligns cost and non-cost interests. After vetting numerous resource options for meeting growing customer needs, changing energy supply requirements, and future environmental regulations, the Energy*Forward* Resource Package, including NTEC, is in the best interest of customers.

3.5 CHARACTERISTICS OF NTEC AND THE ENERGY*FORWARD* RESOURCE PACKAGE

The Energy*Forward* Resource Package, including dispatchable combined-cycle capacity, continues the transition of Minnesota Power's fleet to be more diverse, flexible, and lower emitting. To accomplish this, the Company is taking prudent steps that address a changing energy industry environment. The NTEC combined-cycle capacity purchase implements a capacity addition necessary as a result of previously-announced coal retirements and a large power demand side management product, and will provide a more balanced supply portfolio at least cost for customers. The Energy*Forward* Resource Package, which includes NTEC, will move Minnesota Power toward its Energy*Forward* vision and a power supply that is made up of two-thirds renewables and renewable-enabling natural gas and one-third coal over the long term. The Energy*Forward* Resource Package protects affordability, preserves reliability of power supply, and sustains environmental stewardship.

Figure 19 and Figure 20 demonstrate the resulting summer and winter capacity including the proposed NTEC 250 MW purchase. Building on the removal of nearly 700 MW of coal-fired generation by the end of 2026, combined with expected load growth, there is an identified need for additional capacity resources. Looking at the Energy*Forward* Resource Package as a whole, the NTEC 250 MW purchase represents nearly 95 percent of the accredited capacity in the Package that is meeting growing customer needs. With renewables having a low accredited capacity value, NTEC is replacing the capacity displaced with the removal of coal generation in the power supply and is a resource that can be relied on to operate when the system requires it. Incorporating the proposed NTEC combined-cycle plant brings the Company's capacity position into compliance with future resource adequacy requirements.

Figure 19: Summer Season Capacity Outlook with NTEC

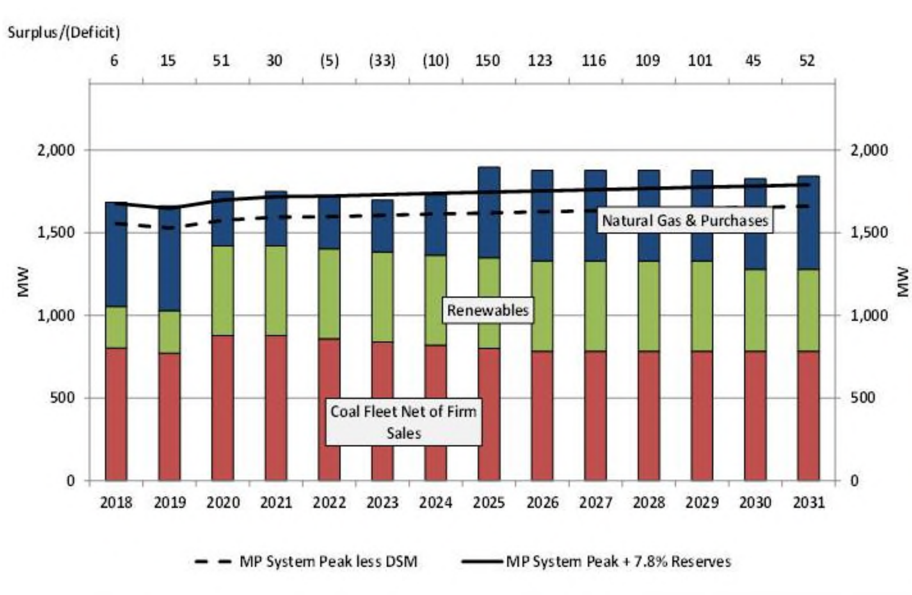


Figure 20: Winter Season Capacity Outlook with NTEC

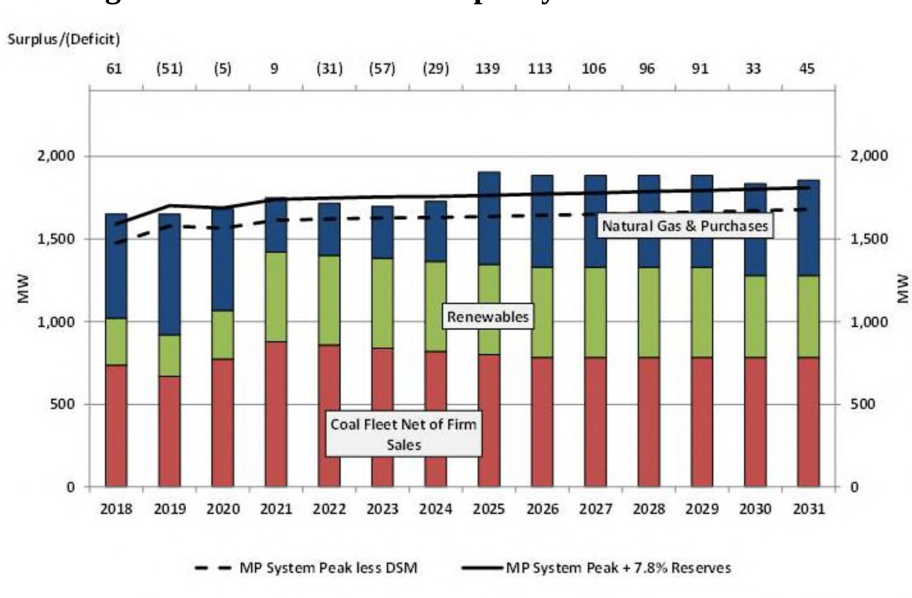


Figure 21 provides a long-term look at Minnesota Power's expected energy position. The proposed NTEC 250 MW purchase provides sufficient energy to serve customer requirements when wind and solar is unavailable, resulting in minimal market reliance risk while abiding by the Company's planning principles.

Figure 21: Energy Position Outlook with NTEC[78]

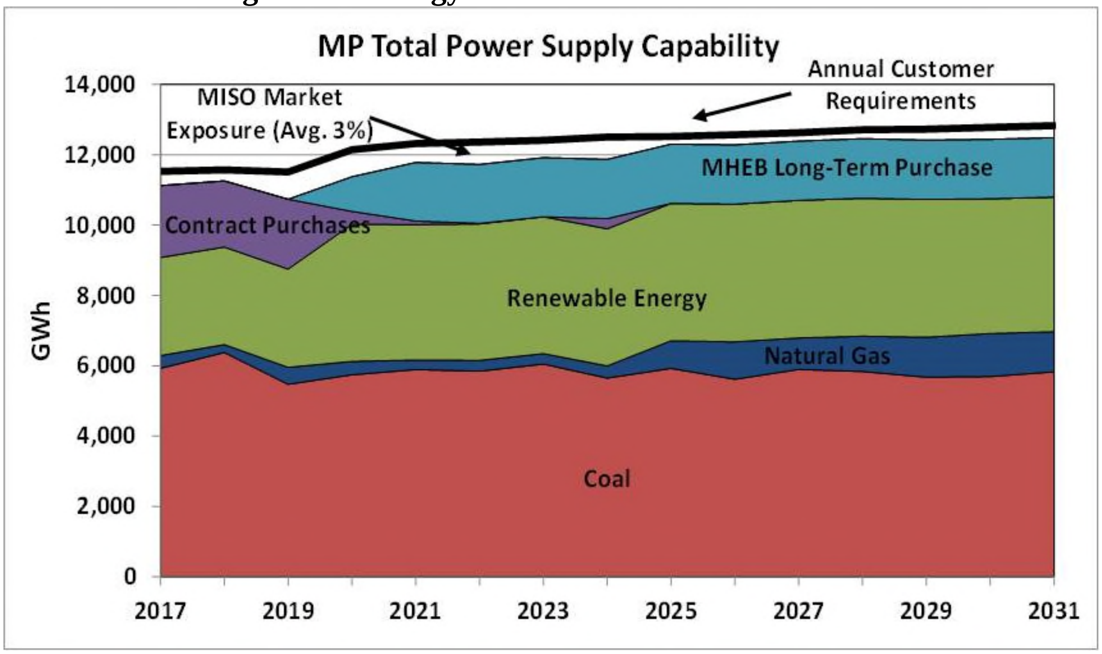
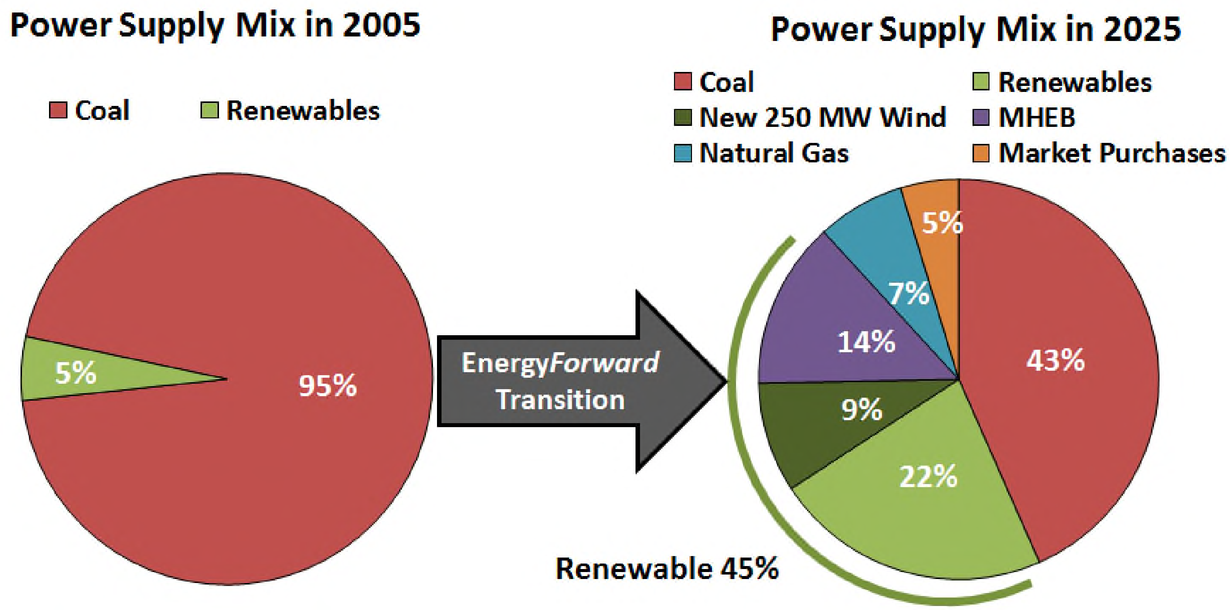


Figure 22 shows NTEC plus the proposed additional wind and solar included in the Energy*Forward* Resource Package brings additional diversity to Minnesota Power's power supply mix, reducing coal below 45 percent and augmenting both the renewable and natural gas components. Even with the addition of the 48 percent share of the NTEC combined-cycle plant, Minnesota Power's reliance on gas generation remains small relative to the larger reliance on intermittent renewable generation to meet customer requirements. The new power supply mix brings the Company one step closer to its vision for two-thirds renewables and renewable-enabling natural gas and purchases, and one-third coal. This represents a dramatic shift from a 95 percent coal-fired generation portfolio as of 2005.

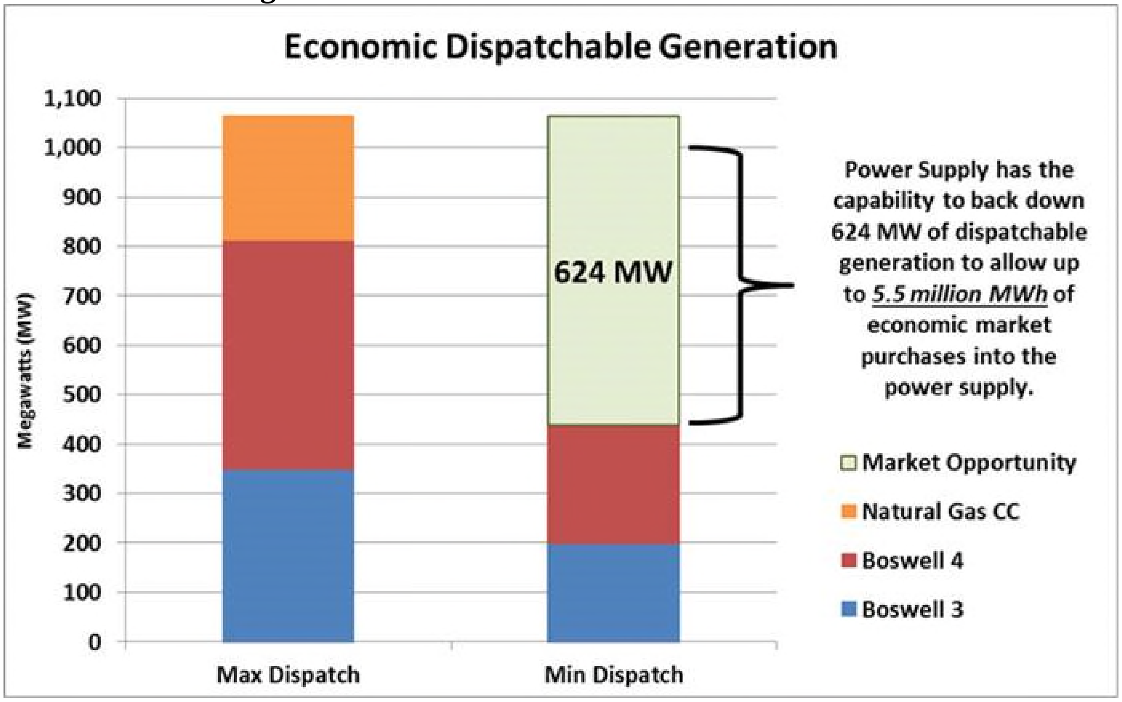
[78] This energy position represents the full capability of energy sources in Minnesota Power's Energy*Forward* Resource Plan. Actual dispatch will vary in real time operations.

Figure 22: Power Supply Mix Transformation by 2025



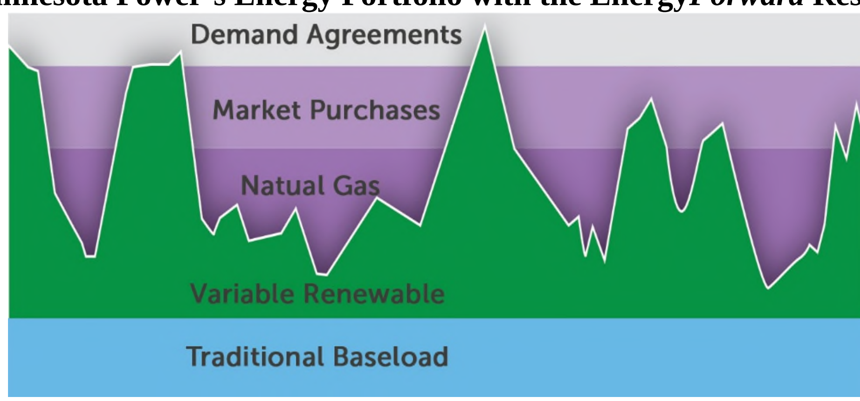
The addition of the NTEC 250 MW purchase to the power supply positions Minnesota Power to take advantage of up to 5.5 million MWh of economical market purchases annually while maintaining a natural price hedge with installed units. Figure 23 below illustrates the magnitude of potential dispatch during periods of low wholesale market prices. When the market energy prices are lower than the dispatch costs of the units, Minnesota Power can reduce generation to minimum levels and purchase replacement power from the market while retaining the ability to increase generation when prices rise, effectively hedging the price of power for its customers.

Figure 23: Economic Market Access with NTEC



The addition of NTEC to the power supply results in a balanced and diverse energy mix that will serve customer needs 24-hours a day without undue exposure to potentially volatile energy markets. Figure 24 shows how the overall Energy*Forward* Resource Package fits in with the Company's overall energy portfolio.

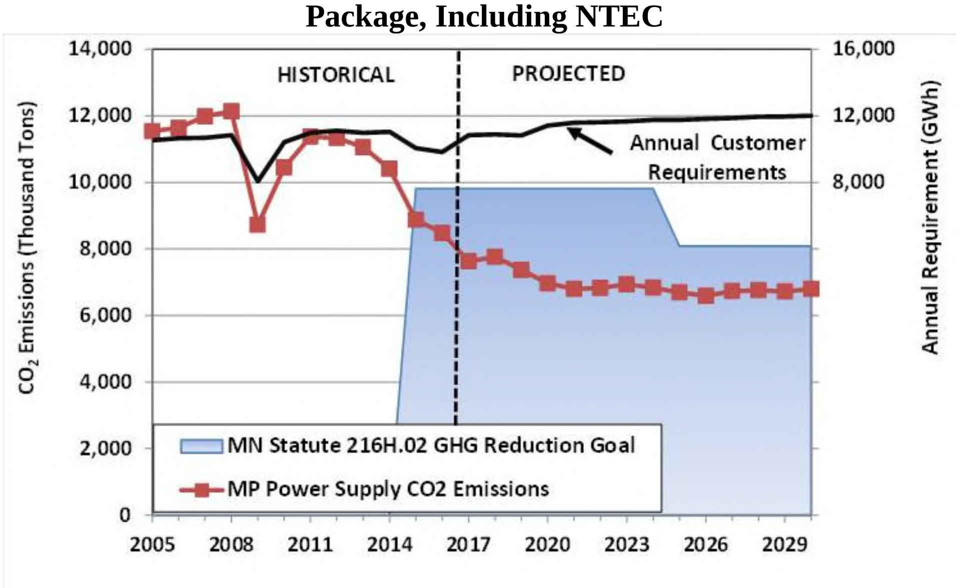
Figure 24: Minnesota Power's Energy Portfolio with the Energy*Forward* Resource Package



Environmental benefits are inherent in this transformation and help position the power supply for future regulations. Since 2005, the Company has committed to adding carbon-minimizing resources to its generation fleet. As load continues to grow, Minnesota Power has kept to this strategy and is continually reducing the carbon emissions in its power supply. With NTEC plus the proposed wind and solar, Minnesota Power will continue reshaping nearly 2,200 MW of generation in the Company's supply portfolio by 2025 and will continue to replace the energy and capacity lost due to removing nearly 700 MW of coal-fired generation from the power supply. This transition includes the addition or build of renewable energy generation, including over 850 MW of wind, 33 MW of solar, 250 MW from the MHEB PPA, and 70 MW from Thomson Hydro Station rebuild; the reduction to coal-fired generation, including the phasing out of power purchases from Young 2 (227 MW), refueling LEC with natural gas (110 MW); ceasing coal operations at THEC by 2020 (225 MW), and retiring BEC1&2 (135 MW) by the end of 2018; and adding 250 MW of combined-cycle natural gas (NTEC) by 2025.

These actions represent a significant transformation to less carbon-intensive resources for a utility with a current peak demand of nearly 1,800 MW. Minnesota Power is well positioned to demonstrate its carbon reduction impact. Specifically, the Company is projecting full compliance with the Minnesota state goals for greenhouse gas reduction. The Company has exceeded the 2015 goal of a 15 percent reduction from 2005 levels, and will exceed the 2025 goal of a 30 percent reduction from 2005 levels, as illustrated in Figure 25.

Figure 25: Greenhouse Emission Reductions Achieved with Energy*Forward* Resource Package, Including NTEC



While executing these reductions, Minnesota Power has the potential for its largest growth in industrial customer load since the late 1970s although the full load growth potential was not fully captured in the AFR17 base. Minnesota Power remains committed to its planning principle of adding less carbon intensive resources. The Company's proposed NTEC combined-cycle plant, coupled with recently-announced generation retirements and the proposed addition of 250 MW of wind and 10 MW of solar, will result in a reduction of approximately 18.3 million tons of CO_2 from 2020 through 2031, which translates into a reduction of approximately 18 percent annually, when compared to the 2015 Plan. These resource changes and additions position the Company well as environmental regulations continue to evolve.

3.6 ANALYSIS AND INSIGHTS – COMPARISON OF ENERGY*FORWARD* RESOURCE PACKAGE TO "SWIM LANE" ALTERNATIVES AND SENSITIVITY ANALYSIS

3.6.1 Overview of Swim Lane Analysis

In the second step of the evaluation process, Minnesota Power considered the proposed NTEC 250 MW purchase plus three swim lane alternative paths that vary the type of natural gas-fired generation and the quantity of renewable generation to comply with 50 percent and 75 percent renewable requirements under Minn. Stat. § 216B.2422, subd. 2. The assumptions for the NTEC and other three alternative swim lanes all included 250 MW of wind in 2020 and 10 MW of solar in 2020 as part of the Energy*Forward* Resource Package, 12 MW of solar in 2025 added to comply with SES, 150 MW Large Industrial demand response, and 11 GWh of energy efficiency. The four swim lane alternatives include these action plans:

1. NTEC Combined-Cycle Portfolio – Approximately 250 MW share of the NTEC combined-cycle gas turbine in 2025. The analysis also assumes a 100 MW combustion turbine in 2031 (required to meet capacity needs post 2030) for general planning purposes; however, the Company is not seeking approval at this time for this resource.[79] The Company will revisit need levels in future IRPs and present specific proposals for these time periods at that time.

[79] With this filing, Minnesota Power is seeking Commission approval of the NTEC 250 MW purchase. The additional 12 MW of solar in 2025 is included in modeling to address compliance with the SES and the combustion turbine is included later in the study period. These additional resources will be addressed for implementation in future IRP filings.

2. 75 Percent Renewable Capacity Portfolio – 1700 MW of wind added from 2025 through 2031 in 300 MW to 550 MW blocks depending on capacity need and 108 MW of gas peakers to meet capacity needs. This scenario was developed to comply with Minn. Stat. § 216B.2422, subd. 2.

3. 50 Percent Renewable Capacity Portfolio – 1100 MW of wind added from 2025 through 2031 in 300 MW to 450 MW blocks of wind and 198 MW of gas peakers to meet capacity needs. This scenario was developed to comply with Minn. Stat. § 216B.2422, subd. 2.

4. Large Combustion Turbine Portfolio – 456 MW of gas peakers with the first 228 MW added in 2025 and the second in 2031.

The Minnesota Legislature amended Minn. Stat. § 216B.2422, subd. 2 effective July 1, 2017, to require that in formal resource plan filings, a utility include the least-cost plan for meeting 50 and 75 percent of all *energy needs* from both new and refurbished generating facilities through a combination of conservation and renewable energy resources. For purposes of the analysis in this proceeding, Minnesota Power's Strategist swim lane alternatives were developed based on 50 and 75 percent renewable *capacity* additions (as was the case in the 2015 IRP). This will provide continuity and consistency in the analysis and will allow the Commission to review the proposed resource package on the same basis as contemplated in the 2015 IRP Order. For informational purposes, Minnesota Power is providing the percent of the open energy need that is met with renewable generation in Figure 26 and Table 2 below.

NTEC, along with the proposed wind and solar additions in 2020, meets the open energy requirement for customers with 51 percent renewables on average, with the renewable percentage in some years increasing to nearly 60 percent. It is important to note that adding one additional MWh of renewable energy does not equate to meeting one MWh of open energy need. Due to the intermittent nature of wind generation and the high concentration of it in Minnesota Power's supply portfolio, a large share of the wind generation is displacing existing thermal generation and not meeting new energy requirements because the wind or solar energy is not available during certain periods in a given year. For example, in 2020, Minnesota Power's open energy requirement is approximately 1.3 million MWh. The proposed Energy*Forward* Resource Package will add 1.1 million MWh of new renewable generation; however, after the

Energy*Forward* Resource Package has been implemented, Minnesota Power's open energy position is still 600,000 MWh. This means approximately 45 percent of the new renewable energy is meeting new energy requirements and the remaining renewable generation is displacing existing coal generation.

Minnesota Power believes that the Energy*Forward* Resource Package, which includes the NTEC 250 MW purchase, and the alternative renewable swim lanes are a good proxy for comparing the impact of meeting new energy requirements with different levels of renewable generation in accordance with Minn. Stat. § 216B.2422, subd. 2. When planning a power supply, especially when planning to meet new energy requirements with non-dispatchable renewable generation, the percentage of renewable generation meeting customer demand is more of a proxy than an exact science or calculation. The dynamics of the power supply result in various percentages throughout the study period as the power supply mix and other factors, such as carbon regulation and fuel costs, change as demonstrated in Figure 26 below.

Figure 26: Comparing Annual Percent of Open Energy Need Met With New Renewable Generation

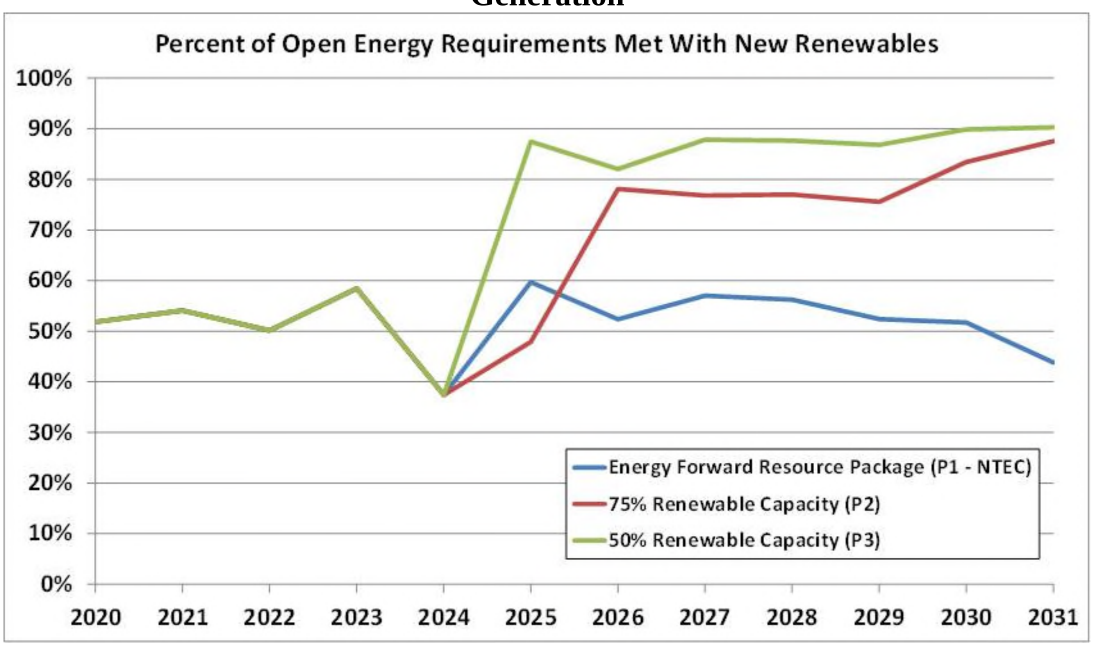


Table 2: Average Percentage of Minnesota Power's Open Energy Need Met With New Renewable Generation from 2020 through 2031

	Average Percentage of Open Energy Requirement Met With New Renewables, DSM and EE from 2020 through 2031
NTEC + Renewables from Energy*Forward* Resource Package (P1)	51%
75% Renewable Capacity (P2)	76%
50% Renewable Capacity (P3)	69%

The most prominent comparison of the swim lanes is between the NTEC Combined-Cycle and the Large Combustion Turbine scenarios from a power supply cost comparison. Due to the high penetration of renewable generation in the 50 percent and 75 percent renewable scenarios, the cost associated with procuring this level of renewables, and the impacts on Minnesota Power's power supply, these scenarios (#2 and #3) have higher power supply costs than the NTEC Combined-Cycle and the Large Combustion Turbine scenarios.

The inclusion of a CO_2 regulation penalty had a minimal impact on which portfolio was least cost. In both the no CO_2 penalty and CO_2 penalty scenarios, the proposed NTEC Combined-Cycle Portfolio was least cost in over 90 percent of cases. This demonstrates that combining NTEC with the proposed 250 MW of wind and 10 MW of solar making up the Energy*Forward* Resource Package, protects customers from additional cost risks in a future where CO_2 is regulated.

Along with the cost-protection benefit, the NTEC 250 MW purchase is in the best interest of customers for the following reasons:

- Efficiently meets growing energy and capacity need during a period where MISO planning reserve margins are shown to decline starting in 2022;[80]
- Enables synergy between flexible combined-cycle and variable renewable resources;
- Provides a unique opportunity to access a 250 MW share of an efficient combined-cycle facility. Typically, 250 MW of capacity need would be met with a much less efficient combustion turbine due to size constraints for a combined-cycle unit. As a result, customers effectively receive combustion turbine-sized generation with the benefits and costs of combined-cycle generation;
- Delivers least-cost portfolio across hundreds of sensitivities;
- Continues to exceed Minnesota greenhouse gas goals, while minimizing power supply cost impacts in a future where CO_2 is regulated;
- Provides balance to a portfolio with over 45 percent renewable penetration and increased dispatchable generation; and
- Adds resiliency to the power supply by being able to operate when needed by the system.

3.6.2 Details of Swim Lane Comparisons

Minnesota Power's swim lane analysis was designed to verify whether or not the alternative swim lane paths were in the best interests of customers compared to the proposed purchase from the NTEC combined-cycle plant, and to further assess the benefits of the dispatchable capacity purchase for customers. The three swim lane alternatives were developed to compare the proposed NTEC Combined-Cycle Portfolio to portfolios with higher renewable builds in accordance with resource planning requirements (Minn. Stat. § 216B.2422, subd. 2) and to evaluate replacing NTEC with a large combustion turbine. More detail on the resource alternatives and timing of when they were added in a swim lane is included in Appendix J: Detailed Resource Planning Analysis.

[80] Based on observations from the 2017 OMS MISO Survey results where by 2022 the planning reserve margin is trending down towards 16.3 percent (the target is 15.8 percent). If the declining trend in planning reserve margins continues by the time NTEC starts in 2025 the planning reserve margins could be below the 15.8 percent target.

Each swim lane alternative and the proposed approximately 250 MW purchase from the NTEC combined-cycle plant was put through a series of more than 30 sensitivities over eight Future scenarios that stressed the main drivers for resource decisions. These drivers include fuel, capital, additional potential for EPA regulation, carbon sensitivities, and additional energy efficiency programs. The series of swim lanes were put through both scenarios with and without the Commission-approved mid-CO_2 regulation penalty and with and without an energy market to sell surplus energy into, resulting in 260 unique sensitivities. The base case scenarios without an energy market to sell surplus energy into were created to delineate which resource decisions rely on revenue from the MISO market to be economical for customers. Relying on revenue from the market to make a resource decision exposes customers to market volatility, which could result in a resource decision costing customers more if sale revenues do not materialize as expected. The sensitivities help determine which resource actions available today would be in the best interest of customers.

Across this wide range of sensitivities, the proposed NTEC Combined-Cycle Portfolio was selected is providing low-cost power supply in over 90 percent of the sensitivities considered and reflects affordable and balanced resource additions. Table 3 through Table 5 provide a summary of the outcome of the swim lane and sensitivity analyses, demonstrating the strength of the Company's proposed participation in NTEC.

Table 3: Step 2 Sensitivity Analysis: Least-Cost Portfolio across all sensitivities

	NTEC Combined-Cycle (P1)	75% Renewable Capacity (P2)	50% Renewable Capacity (P3)	Large Combustion Turbine (P4)
Least Cost Count	238	8	0	0
Percent of Cases Least Cost	92%	8%	0%	0%

Table 4: Step 2 Sensitivity Analysis: Least-Cost Portfolio across sensitivities with Base Cases with No CO_2 Regulation Penalty[81]

	NTEC Combined-Cycle (P1)	75% Renewable Capacity (P2)	50% Renewable Capacity (P3)	Large Combustion Turbine (P4)
Least Cost Count	126	10	0	0
Percent of Cases Least Cost	93%	7%	0%	0%

Table 5: Step 2 Sensitivity Analysis: Least-Cost Portfolio Across sensitivities with Base Cases with CO_2 Regulation Penalty

	NTEC Combined-Cycle (P1)	75% Renewable Capacity (P2)	50% Renewable Capacity (P3)	Large Combustion Turbine (P4)
Least Cost Count	112	12	0	0
Percent of Cases Least Cost	90%	10%	0%	0%

Given these outcomes, the proposed NTEC combined-cycle plant represents the best alternative for customers and the most reasonable next step in Minnesota Power's Energy*Forward* strategy, resulting in a diverse generation portfolio fuel mix that allows flexibility for the Company to take advantage of changing fuel costs, energy prices, and future carbon regulation trends. Minnesota Power does find the CO_2 regulation penalty useful in understanding how a penalty mechanism can change resource planning decisions and inform decision making. As illustrated in these

[81] The detail results from the Step 2 sensitivity analysis are included in Appendix J: Detailed Resource Planning Analysis.

tables, the proposed purchase effectively protects customers against a future CO_2 regulation penalty if one was to be implemented, while simultaneously providing the capability of operating when needed.

3.6.3 Cost Impact

The sensitivities and consideration of the swim lane alternatives help solidify that the proposed NTEC 250 MW purchase will meet Minnesota Power's objective to balance improving environmental performance, preserving reliability, and protecting affordability for customers. The current proposal is expected to provide a reduction in rates, all other things being equal, when compared to the swim lane alternatives or if all energy and capacity needs are met by the market ("No Action" scenario). Figure 27 and Table 6 below compare the annual power supply cost[82] on a dollar per MWh basis of the proposed share of the NTEC combined-cycle plant and the three swim lanes to a "No Action" scenario where the open energy and capacity needs are met with only the market. When comparing the cost impact of the proposal to the other alternative swim lanes, the Strategist model includes all known costs associated with the generation resources and models those costs in the alternative swim lanes. The Strategist modeling balances the cost impact to customers of adding more low-cost intermittent generation (i.e., wind) relative to slightly higher cost dispatchable generation (i.e., combined-cycle). When looking at the NTEC scenario, which includes the proposed 250 MW of wind and 10 MW of solar in 2020, compared to the alternative renewable swim lanes that rely on more intermittent resources to meet energy needs, having a small portfolio of dispatchable gas generation is lower cost for customers than inundating the power supply with a large portfolio of intermittent renewable generation.

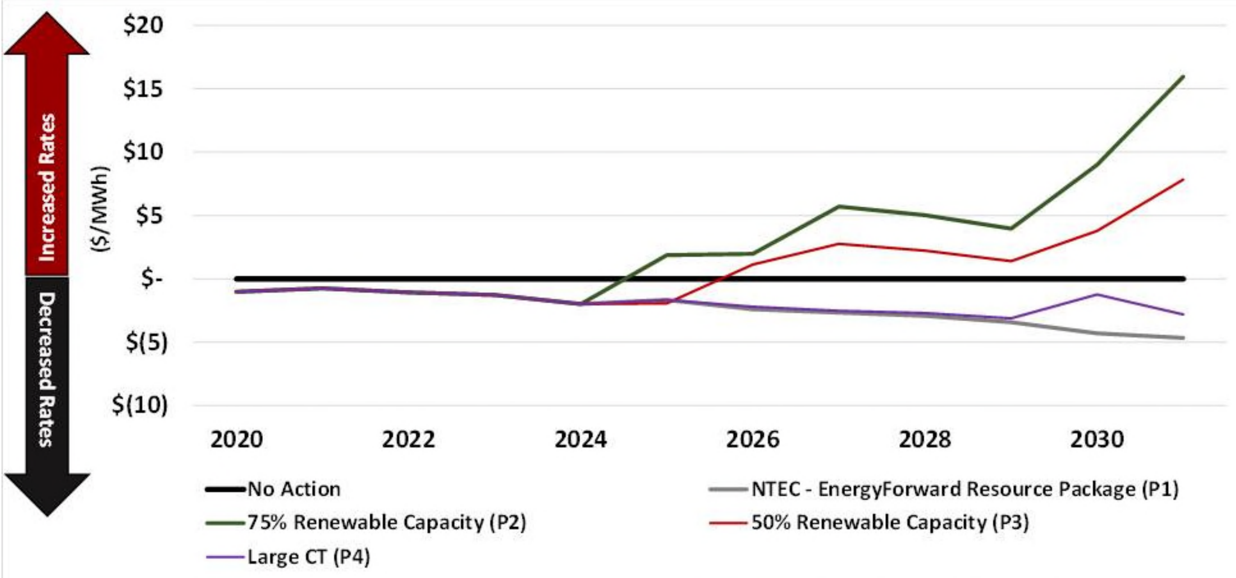
[82] The annual power supply costs are from the Strategist model output and only include costs modeled in Strategist.

Table 6: Change in Annual Power Supply Cost between NTEC-EnergyForward Resource Package/Swim Lane Alternatives with Base Case Assumption not Including a CO_2 Regulation Penalty and State Externalities

$/MWh	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
No Action	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NTEC - Energy*Forward* Resource Package (P1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($3)	($3)	($4)	($5)
75% Renewable Capacity (P2)	($1)	($1)	($1)	($1)	($2)	$2	$2	$6	$5	$4	$9	$16
50% Renewable Capacity (P3)	($1)	($1)	($1)	($1)	($2)	($2)	$1	$3	$2	$1	$4	$8
Large CT (P4)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($3)	($3)	($1)	($3)

Figure 27 demonstrates the proposed share of the NTEC combined-cycle plant is superior to the other swim lanes and it reduces cost for customers compared to taking no action to meet growing customer demand and replace coal generation. Minnesota Power realizes that this is not a complete rate analysis by customer class; however, using the Strategist modeling results in a reasonable indicator that the recommended NTEC purchase will likely result in lower rates for customers compared to alternative resource scenarios. Combining NTEC with the proposed wind and solar, the Energy*Forward* Resource Package will help to keep costs lower for customers as Minnesota Power adds a balanced mix of renewables and gas generation to meet growing customer demand and replace small coal generation that has been recently shutdown.

Figure 27: Change in Annual Power Supply Cost between NTEC-Energy*Forward* Resource Package/Swim Lane Alternatives with Base Case Assumption not Including a CO_2 Regulation Penalty and State Externalities



The proposed NTEC 250 MW addition as part of the overall Energy*Forward* Resource Package represents a balanced approach to delivering safe, reliable service at a reasonable cost to customers, while protecting and improving the region and state's quality of life through continued environmental stewardship. Since its 2013 Plan, Minnesota Power has refined and updated its outlook on major factors driving power supply decisions. The Company has identified options that further transform its power supply to align with its Energy*Forward* strategy. When the proposal to purchase the NTEC 250 MW is combined with the proposed 250 MW of wind and 10 MW of solar, it continues Minnesota Power on the path toward reducing emissions, protecting reliability of supplies, and ensuring competitive, cost-effective rates for customers, while complying with state and federal environmental regulations and goals. Based on this comprehensive analysis and evaluation of various alternatives and sensitivities, the proposed share of NTEC was identified as in the best interest for customers and the least-cost capacity resource to be the counterpart to the proposed wind and solar in 2020.

3.7 INDEPENDENT THIRD-PARTY EVALUATION AND ANALYSIS (PACE GLOBAL)

In light of the significant investment involved and in order to validate the results of Minnesota Power's resource planning evaluation and proposed Energy*Forward* Resource Package (including the NTEC 250 MW purchase), the Company engaged Pace Global as a third-party evaluator to conduct an independent analysis of available alternatives. Although each RFP process and selection was evaluated by a third-party independent evaluator, the Company believes it is critical to implement a package of resources that serve together to achieve multiple goals on an integrated basis. Minnesota Power therefore engaged Pace Global to test these overall analyses and conclusions.

The results of Pace Global's independent evaluation are presented in Appendix N. As reflected in their report, Pace Global conducted a risk-based resource analysis to evaluate the merits of the Energy*Forward* Resource Package relative to other resource options. The proposed 250 MW of wind and 10 MW of solar in 2020 was included in all portfolios evaluated. Pace Global's analysis effectively evaluated which resource or resource mix best complements the proposed wind and solar in 2020. Pace Global's "Risk Integrated Resource Planning" approach uses several steps to determine the resource portfolio that best balances various and often competing resource planning goals over a broad range of various future conditions.

Based on their detailed analysis and evaluation, Pace Global reached the conclusion that the Energy*Forward* Resource Package, which includes NTEC, is the preferred resource portfolio for Minnesota Power and its customers. Pace Global concluded the Energy*Forward* Resource Package to be the lowest cost portfolio under both expected market conditions and worst case market conditions. On average, the Energy*Forward* Resource Package performed better than other alternatives evaluated across the 200 simulations that were conducted. Specifically, Pace Global's analysis concluded that NTEC is the optimal resource to complement the proposed wind and solar by demonstrating the Energy*Forward* Resource Package has lower costs, more diverse technologies, is less reliant on market sales, and is less capital intensive than other alternatives. Compared to one natural gas combustion turbine alternative evaluated, the

EnergyForward Resource Package had similar costs, but lower reliance on market purchases and less environmental costs.

Table **7** below, from Appendix N: Pace Global 2017 Independent Resource Analysis, Exhibit 2, summarizes how each of the portfolios evaluated by Pace Global performed with respect to key metrics.

Table 7: Pace Global Scorecard of Risk Based Portfolio Analysis

Portfolios	Cost	Risk/ Rate Stability			Market Exposure		Cost Exposure		All-in
Study Period: 2018-2034	Mean Portfolio Cost NPV ($B)	High Cost Exposure 95th Percentile NPV ($B)	Diversity (#technologies supplying >5% generation)	Envt. Regulatory Risk ($M)	Reliance on Market Sales (GWh)	% Hours Must Take Energy Exceeds Load (%)	Capital Share of Total Portfolio Cost (%)	Fuel Share of Total Portfolio Cost (%)	Overall Ranking
EFRP	$5.66	$5.97	5	$106.7	0.44	0.4%	42%	20%	
P-1 – 75% Wind	$5.97	$6.20	3	$106.2	21.0	71%	51%	18%	
P-2 – 50% Wind	$5.84	$6.08	4	$106.4	7.7	46%	48%	18%	
P-3 – Battery	$5.89	$6.14	4	$106.4	7.2	47%	48%	18%	
P-4 – Gas Peaking	$5.66	$5.98	4	$106.9	0.11	0.4%	42%	19%	

Note: Cost rankings reflect green for optimal condition and those within 1 percent, yellow for 1% to 5%, and red for conditions more than 5 percent from the optimal condition.

Source: Pace Global

SECTION 4 GAS PLANT PROPOSAL

By this Petition, Minnesota Power seeks approval to acquire the output from a 48 percent share in the approximately 525 MW NTEC 1x1 combined-cycle natural gas power plant to be located in Superior, Wisconsin and placed in service by the end of 2024. This approximately 250 MW purchase (the "NTEC 250 MW" purchase)[83] of reliable and dispatchable natural gas capacity and economical combined-cycle energy was selected, first and foremost, because it was the least-cost resource presented through the RFP process to meet the Company's identified need. Second and importantly, this resource provides additional benefits for customers by (1) supporting the overall Energy*Forward* Resource Package by facilitating the assumed additions of 250 MW of wind and 10 MW of solar arising out of the July 2016 IRP Order, (2) promoting a reliable system that supports Minnesota Power's expanding portfolio of variable renewable energy production, (3) facilitating the Company's ongoing effort to transform its fleet by retiring coal generation and generally reducing greenhouse gas and other power plant emissions, and (4) ensuring adequate reliable capacity is in place to serve all customer requirements, particularly in light of the Company's heavily-industrial load and unusually high demand factors.

Consistent with the Commission's July 2016 IRP Order and September 19, 2017 Order for Hearing, the Company undertook a full analysis of options to meet its energy and capacity needs with the retirement of BEC1&2 and THEC1&2 based on the Commission's determinations in its July 2016 IRP Order and the Company's updated demand projections discussed in Section 2 of this Petition. In particular, the July 2016 IRP Order required that Minnesota Power idle THEC1&2 in 2016, retain the ability to restart them to address reliability or emergency needs on the transmission system, and cease coal-fired operation of those units by the end of 2020. Additionally, the July 2016 IRP Order required the Company retire BEC1&2 when sufficient

[83] 48 percent of the capacity of NTEC is being dedicated to Minnesota Power. The final capacity amount associated with Minnesota Power's 48 percent share will be determined when the final choice for turbines is made. The economic analyses supporting this Petition assume Minnesota Power's share is 250 MW. However, a slightly larger-sized turbine may be available on similar economic terms, making a larger selection potentially more cost effective. Thus, Minnesota Power recognizes that NTEC could range from 525-550 MW and the Company's 48 percent share of the plant's capacity could range from approximately 250-264 MW. Minnesota Power acknowledges that the soft cost cap described elsewhere in this Petition will apply to the purchased 48 percent share regardless of the final size of NTEC. In other words, customers may be able to obtain the benefit of the additional MW associated with the 48 percent share of a slightly larger unit without incurring incremental cost risk.

energy and capacity are available, but no later than 2022.[84] Adding the NTEC 250 MW purchase in 2024 is an important system addition that helps ensure that the retirement of the coal units can proceed as contemplated and that potential capacity shortages will not lead to adverse changed circumstances. Further, this proposed system addition is supported by the Company's forecasted need and resource planning analysis across the vast majority of future scenarios.

The Company sought proposals and fully investigated options available to fill its identified capacity need, including additional renewables, distributed generation, energy efficiency, storage, and demand response. While additional renewable generation in the form of wind and solar are part of Minnesota Power's current overall plan to meet projected need, the transition toward higher variable renewable penetration impacts the amount of dispatchable generation needed to reliably serve customers' requirements. When coupled with the significant reduction in coal generation (nearly 700 MW) and the overall projected wind portfolio of 850 MW, adding dispatchable natural gas capacity helps balance the overall system.

Without question, renewable energy will continue to be a significant part of Minnesota Power's ongoing fleet transition from a predominantly coal-based resource mix toward more diversity and flexibility and with fewer emissions and less carbon intensity. As noted throughout this Petition, the Company plans to deploy 250 MW of wind and 10 MW of solar generation arising out of the July 2016 IRP Order as part of the overall Energy*Forward* Resource Package. These additional renewable increments are assumed to be in place by 2024 when NTEC is scheduled to be deployed. As a result, the addition of a natural gas resource at this time is an efficient, low-cost, less carbon-intensive way to replace the energy and capacity that cannot be provided by renewable sources or conservation alone.

Further, the Company recognized the economies of scale available from taking a share of a larger plant and configuring NTEC as an efficient combined-cycle unit, rather than proceeding with a smaller and solely-owned, but less efficient, combustion turbine plant. Minnesota Power recognized that partnering with Dairyland Power Cooperative ("Dairyland") allows the Company

[84] July 2016 IRP Order at 14-15.

to obtain sufficient capacity to serve its needs in a much more cost-effective manner than if Minnesota Power had pursued its own generation addition without a partner.[85]

The proposed NTEC 250 MW purchase provides significant customer benefits including:

- Meeting the Company's projected capacity and energy requirements in a cost-effective way;
- Replacing retiring baseload coal-fired generation with an economic, reliable resource that emits approximately 65 percent less carbon;
- Providing necessary support for Minnesota Power's growing variable renewable generation fleet (such as the assumed wind and solar generation in the Energy*Forward* Resource Package);
- Achieving economies of scale by sharing the overall plant costs with a partner (Dairyland);
- Taking advantage of a shovel-ready site and excellent natural gas transportation and supply options;
- Providing socioeconomic benefits in the region surrounding the Twin Ports of Duluth and Superior; and
- Taking advantage of projected low natural gas prices.

Overall, adding this increment of dispatchable capacity will facilitate contemplated wind and solar additions and will stage the Company's system for future additions of renewable generation while optimizing market opportunities.

This Section of the Petition addresses Minnesota Power's need for dispatchable capacity, how Minnesota Power's proposed NTEC 250 MW purchase meets the identified need, and how the NTEC purchase compares to available alternatives. This Section also describes NTEC ownership, location, schedule for completion, and project costs. Ultimately, it supports why

[85] Dairyland had identified a capacity need in the same timeframe as Minnesota Power, and Dairyland similarly recognized the benefits of taking a share of a larger and more efficient plant. Working together, Dairyland and ALLETE were able to put together a transaction that serves customers of both utilities in a cost-effective and efficient manner. The combined transaction is much more cost-effective than would have been the case if each of the utilities had proposed separate smaller projects, particularly since those separate smaller projects could not have supported using the more efficient combined-cycle configuration.

NTEC is in the public interest. Finally, this filing requests a variance and associated tariff amendments to the Company's FPE Rider to ensure that fuel costs related to Minnesota Power's share of NTEC are recovered and that all of the revenues received by Minnesota Power from its share of MISO market sales of energy from NTEC flow back to customers.

4.1 THE NEED FOR DISPATCHABLE CAPACITY

Minnesota Power's 2012 Baseload Diversification Study,[86] 2013 Plan, 2015 Plan, and most recently-refined analysis consistently demonstrate that natural gas generation has an important place in the Company's long-term power supply. The benefits of diversifying the Company's power supply with a combined-cycle natural gas unit include the ability to replace some of the capacity lost by retiring coal units on a timely basis and avoiding the risk of needing to recommence operations at idled plants in the event that additional reliable capacity is needed. The benefits further include the ability to follow the variability of renewable generation with increased flexibility; the low cost of natural gas; the natural synergies between combined-cycle natural gas generation and Minnesota Power's wind and solar portfolio; and the continued reduction in CO_2 emission levels, as discussed in more detail below.

4.1.1 *Evolving System Calls for Reliable Replacement Capacity*

As previously discussed, Minnesota Power ceased coal-fired operations at THEC3 in 2015, refueled LEC with natural gas in 2015, idled THEC1&2 in 2016, has announced plans to close the coal-fired BEC1&2 by 2019, and is reducing purchases of capacity from the Young 2 lignite plant in North Dakota to zero by 2026 — an aggregate removal of nearly 700 MW of coal-fired generation. In addition, by 2024, when the NTEC plant is scheduled to go into service, Minnesota Power will have constructed or contracted to purchase more than 850 MW of wind generation (including 250 MW that is separately being proposed as part of the Energy*Forward* Resource Package); will be purchasing 250 MW of hydroelectric generation from MHEB beginning in 2020; and will have added solar power to its generation fleet with the 10 MW Camp Ripley Solar Project, 1 MW Community Solar Garden Pilot Program, and the 10 MW of solar as

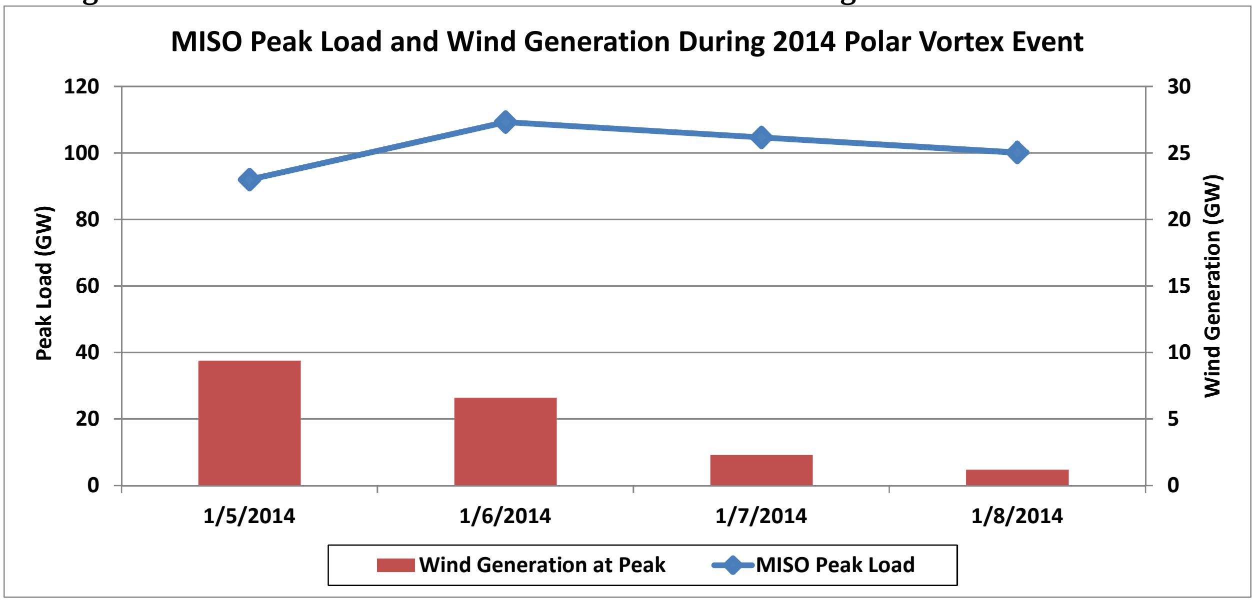
[86] *In the Matter of Minn. Power's 2010-2024 Integrated Res. Plan,* Docket No. E015/RP-09-1088, MINNESOTA POWER'S BASELOAD DIVERSIFICATION STUDY COMPLIANCE REPORT (Feb. 6, 2012).

part of the Energy*Forward* Resource Package. The net result is a power supply that includes significant new variable renewable generation and increasingly less baseload generation.

Minnesota Power recognizes the importance of these initiatives, but also notes that it must have sufficient dispatchable capacity resources to serve its unique customer needs. With load factors approaching 80 percent and many customers operating 24/7 for long stretches, the Company cannot rely on variable resources alone. The addition of a combined-cycle generation resource increases Minnesota Power's capability to bring generation on- and off-line quickly in order to manage energy imbalance, while providing regulation and load following, and to serve as an economic hedge for customers when the wind is not blowing and market prices are high.

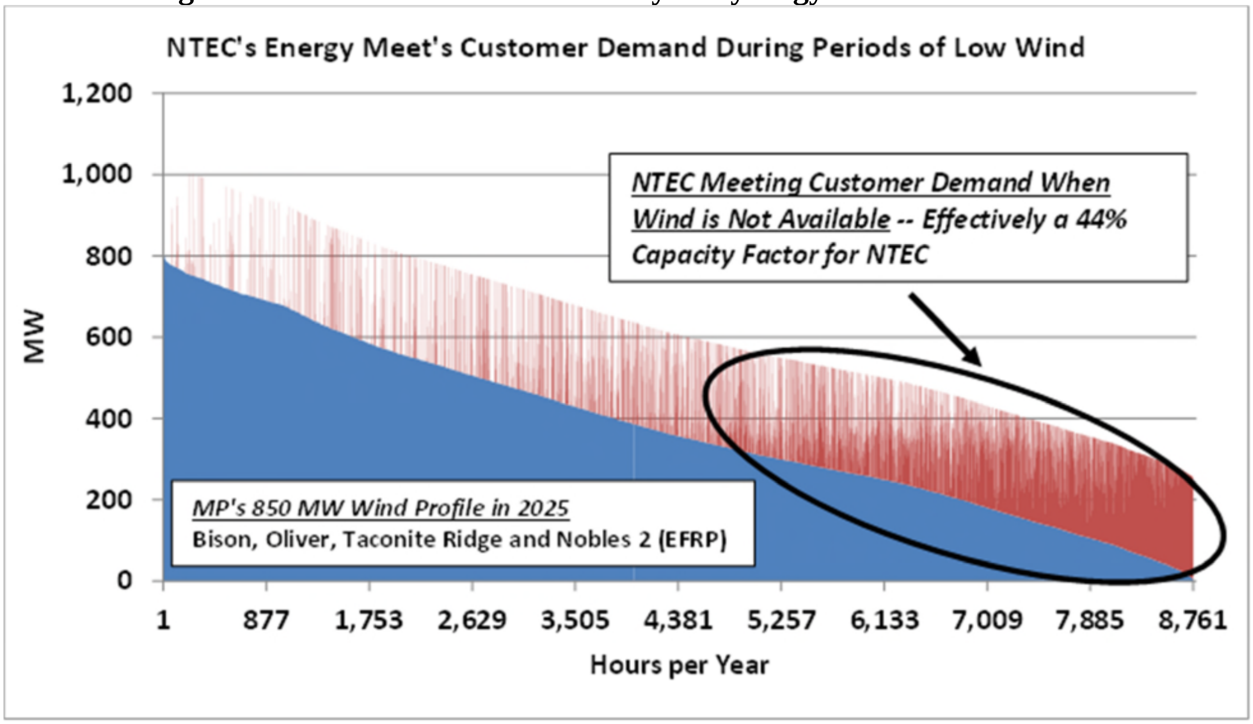
As noted in Section 2 of this Petition, by the time the NTEC plant is proposed to be in service, Minnesota Power's energy position will have the potential to vary by over 850 MW per hour, including the addition of 250 MW of wind and 10 MW of solar that are assumed to be deployed as part of the Energy*Forward* Resource Package. This change in energy position is significant as it amounts to over one-third of the Company's total generation in one hour. At the same time, periods of energy deficits are generally correlated to periods of low wind generation. As shown in Figure 28 below and discussed in Section 2, above, wind generation is often not available during system peak, as was the case with the Polar Vortex in 2014.

Figure 28: MISO Peak Load and Wind Generation During 2014 Polar Vortex Event



Currently missing from Minnesota Power's portfolio is dispatchable capacity that can readily follow demand and variable wind generation throughout the day, either generating or coming off-line, depending on system requirements. Combined-cycle natural gas generation supports variable renewable generation by providing the capability to quickly start up, ramp up and down, and go off-line more often than traditional baseload generation. Figure 29, below, demonstrates, from a modeling perspective, how a combined-cycle natural gas resource dispatches most frequently during periods of lower wind generation. The blue area of Figure 29 represents a duration curve of Minnesota Power's wind portfolio. As wind generation decreases, combined-cycle natural gas generation is available and dispatched more often. The decrease in wind generation simultaneous with the increased dispatch of natural gas generation demonstrates the synergy between wind and a natural gas resource.

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



Without an additional dispatchable resource, Minnesota Power's energy mix would be made up of a substantially reduced amount of baseload generation, variable renewables, on-peak "must-take" PPAs, and reliability/emergency-only energy resources. The addition of a combined-cycle natural gas resource starts to fill this gap by better balancing the characteristics of the energy resources available to serve customer requirements. It also positions Minnesota Power for additional variable renewable generation by adding a generation facility that is able to operate as a baseload resource to serve the high capacity factor needs of the Company's large industrial customers.

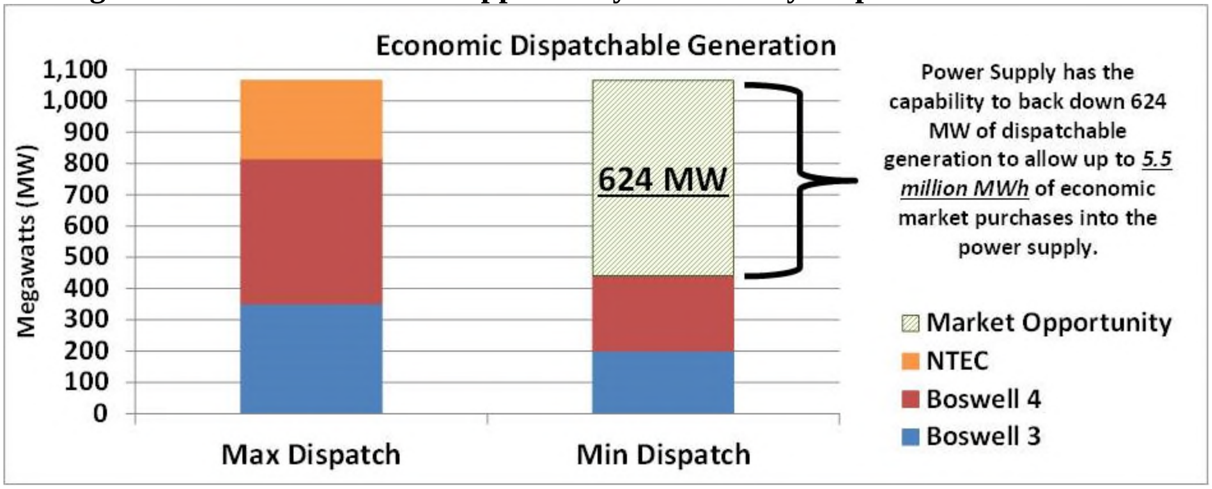
Not only does a combined-cycle natural gas resource offer dispatchable energy, flexibility, diversity, and capacity to balance variable generation, it does so at a lower cost than potential alternatives, including a combustion turbine natural gas generation facility, other types of generation, a no-build option, or demand response. Natural gas prices are currently ranging between \$2.50/MMBtu and \$3.00/MMBtu and are likely to remain lower than historical values for the foreseeable future.[87] Moreover, while renewable energy lowers wholesale electricity prices during hours in which it operates, ramping natural gas capacity can keep wholesale prices stable when solar and wind are not producing at full output. A combustion turbine natural gas resource would provide these same benefits, but would do so less efficiently and would therefore have higher energy costs.[88]

A natural gas resource also removes the need to rely on the availability of capacity and energy in the short-term market. Unlike "must-take" energy from wind and typical bilateral contracts, dispatchable generation provides Minnesota Power with the flexibility to optimize generation available when market prices are high and the opportunity to purchase from the market when energy prices are low. Figure 30 below, demonstrates that Minnesota Power has over 1,000 MW of dispatchable generation that has the capability to reduce generation by 624 MW or over 50 percent. When all of the Company's dispatchable generation is reduced, this creates the opportunity to purchase up to 5.5 million MWh per year from the MISO market when it is economical for customers. And NTEC provides the necessary dispatchable capacity to support variable generation while also delivering the other benefits to the Company's customers and power supply described in this Petition.

[87] As discussed in Section 3, the NTEC facility is projected to be economical even under high gas price sensitivities.

[88] As discussed in Section 3, a combustion turbine generation facility consumes approximately 55 percent more fuel than a combined-cycle generation facility.

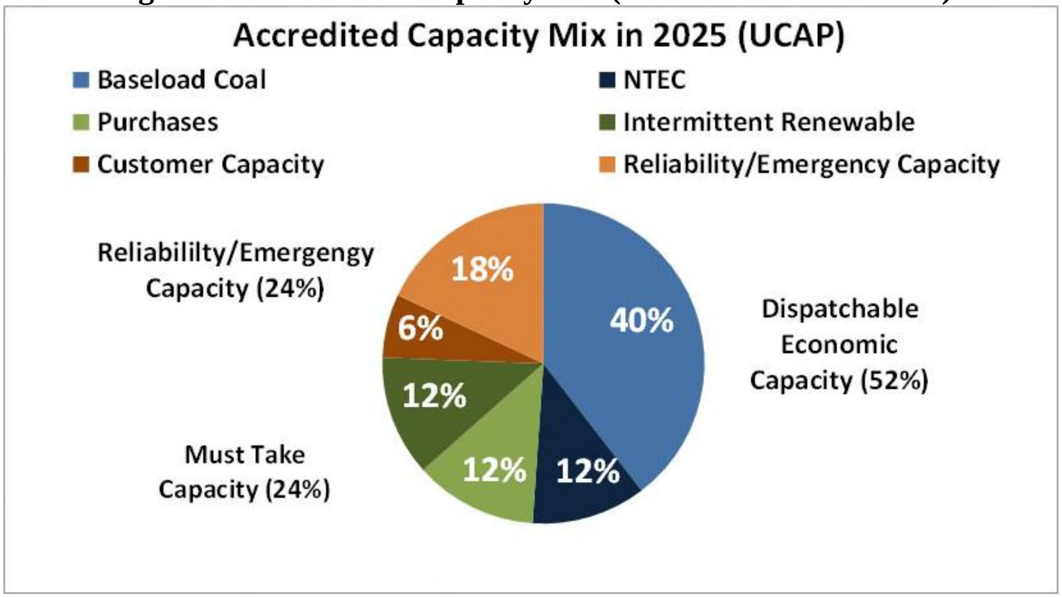
Figure 30: Market Purchase Opportunity Provided by Dispatchable Generation



Moreover, NTEC's emission profile is significantly less than other dispatchable resources in Minnesota Power's energy supply. NTEC, as compared to Minnesota Power's coal-fired generation, has approximately 65 percent lower CO_2 emissions. NTEC's other air emissions, such as NOx, CO, SO_2, VOCs, and PM_{10} are even lower, at a collective 97 percent less than traditional baseload coal resources, and NTEC will not have mercury emissions. NTEC allows Minnesota Power to successfully integrate the additional wind and solar from the Energy*Forward* Resource Package into its power supply without increasing CO_2 emissions.

Finally, Figure 31, below, demonstrates that the addition of 250 MW of combined-cycle generation brings the capacity of Minnesota Power dispatchable resources to around 50 percent. The remaining capacity mix is split between "must-take" energy from variable renewable resources, the MHEB 250 MW PPA, and capacity typically used during reliability or extreme weather events (i.e., large industrial interruptible demand and LEC).

Figure 31: Accredited Capacity Mix (Based on UCAP Values)



4.1.2 *Alternatives Considered*

Minnesota Power's analysis included consideration of a range of alternatives to serve the identified customer needs. These alternatives included renewable energy alternatives and a no-build alternative. In addition, the Company considered alternatives that were suggested by the Strategist modeling effort, such as constructing smaller combustion turbine generators instead of the larger and more efficient combined-cycle technology proposed in this filing. Finally, the Company considered the alternative of additional demand response as a potential way to mitigate and potentially delay the need to add generation.

As described more fully in Section 3 of this Petition, Minnesota Power's analysis concludes that the proposed NTEC 250 MW purchase is the most cost-effective way for the Company to satisfy customers' needs. The proposed NTEC capacity purchase is more cost-effective than any of the alternatives considered.

Notably, the addition of approximately 250 MW of combined-cycle natural gas generation will not meet all of Minnesota Power's projected energy needs and the Company's renewable energy portfolio is available to supply substantial amounts of energy into the system. Further, the benefit of participating in a reserve sharing pool, like MISO's Resource Adequacy Program, ensures sufficient capacity is available to meet customer needs throughout the year. This prevents utilities from building capacity to meet 100 percent of their energy needs, avoiding significant capital investments. The additional need beyond what is met with the NTEC 250 MW purchase can be met with MISO market purchases or other Minnesota Power emergency capacity resources.

Minnesota Power's Energy*Forward* vision includes a balanced energy mix moving towards approximately two-thirds renewables and renewable-enabling natural gas and purchases, and one-third coal over the long term. Based on this roadmap, Minnesota Power identified the potential natural gas generation and began assessing options and other considerations. Based on its analyses, Minnesota Power concludes that now is the right time to pursue a specific natural gas combined-cycle facility for its customers as part of its overall system transformation, and that the proposed NTEC 250 MW purchase presents an excellent opportunity to meet the Company's identified need. The Company's planning schedules have been developed to accommodate the long lead times needed to investigate, plan, develop, and implement a natural gas facility of this scale.

As discussed in detail in Section 3 of this Petition, Strategist was used to conduct an evaluation of available resource alternatives in order to determine the least-cost alternatives to meet the identified need. Strategist allows a utility to offer many resource types into a production cost evaluation, and optimize the technologies that best fit to meet projected customer needs over a defined study period. Strategist inputs for the detailed resource analysis included the data collected through the RFP processes conducted for wind, solar, natural gas, and demand response over the past two years.

The detailed resource analysis selected the proposed NTEC 250 MW purchase 96 percent of the time across 292 different scenarios. This additional natural gas generation also positions Minnesota Power for future carbon regulations or state greenhouse gas targets. The Strategist results clearly identify an approximately 250 MW share of a 1x1 combined-cycle resource as the best fit to meet identified need in the mid-2020 timeframe.

Notably, in light of the identified capacity deficit in 2024 and the fact that the proposed NTEC 250 MW purchase does not cover the entire projected deficit, the "no-build" and demand response alternatives are not feasible. In order to ensure that Minnesota Power can serve all of its customer needs reliably over the coming decades, a substantial increment of new dispatchable capacity is needed. Without adding new dispatchable capacity in this timeframe, the Company's ability to serve its customer needs without the legacy coal generation that it has committed to retire in the coming years would be called into question.

Further, the various renewable options that were considered do not provide the same quality of dispatchable capacity associated with the natural gas plant. The amount of variable generation that would be required to replicate the accreditable capacity being sought would result in significant additional costs and in Minnesota Power's system being overly weighted to variable generation. This is a particular problem in light of its heavily industrial customer base including a significant amount of load that operates with high load factors that approach 80 percent.

4.2 SELECTION OF THE NTEC 250 MW PURCHASE

In its July 2016 IRP Order, the Commission concluded that "Minnesota Power may pursue an RFP to investigate the possible procurement of combined-cycle natural gas generation to meet its energy and capacity needs in the absence of Boswell Units 1 and 2 and Taconite Harbor Units 1 and 2, with no presumption that any or all of the generation identified in that bidding process will be approved by the Commission."[89] Earlier in this Petition, the Company presented its analysis indicating the NTEC 250 MW purchase will best serve customer needs in the mid-2020s. In this Section of the Petition, the Company discusses the process by which it investigated and developed a potential combined-cycle natural gas RFP and the basis for selection of NTEC in particular, in light of all of the circumstances, including substantially increased renewable generation on the system.

[89] July 2016 IRP Order at 15 (Order Point 7).

4.2.1 Dispatchable Capacity RFP

On October 15, 2015, Minnesota Power issued an RFP for 200 to 400 MW of dispatchable natural gas-fired capacity and associated unit-contingent energy (the "Gas RFP").[90] Proposals were due by January 7, 2016, and entailed the bidder's development, ownership, and operation of an eligible project, with all or a share of the facility's generation to be sold to Minnesota Power over a long-term agreement.

To ensure fair and consistent treatment of all bidders, and because the Company anticipated that it would receive a proposal from an affiliate, Minnesota Power retained Sedway Consulting to oversee the RFP process and provide an independent evaluation of all bids.

Sedway Consulting had oversight of the entire Gas RFP process, including the design, administration, and evaluation, to ensure the Gas RFP process was transparent and defined, and that evaluation criteria were applied equally for all bidders. See Sections 4.2.3 and 4.2.4 for additional detail on the RFP evaluation process and Appendix S for Sedway Consulting's Independent Evaluation Report for Minnesota Power's 2015 Gas-Fired Resource Solicitation.

4.2.2 Approach to Dispatchable Capacity RFP

Minnesota Power sought to conduct a competitive, impartial, and balanced bidding process, consistent with industry best practices. These practices included:

- *Transparency*. The solicitation process was open to all interested parties and all parties were provided with the same information. To ensure equal-footing, Minnesota Power did not discuss the Gas RFP with interested parties prior to the submission deadline.[91] To publicize the Gas RFP to potential bidders, Minnesota Power posted the RFP on the Minnesota Power website, used developer vendor lists, posted in Platt's Megawatt Daily, and posted a notice with the North American Energy Markets Association. An updated version of the RFP was posted on December 15, 2015.

[90] The Gas RFP is provided as Appendix R to the Petition.

[91] *See* Appendix R: Request for Proposals for Up to 400 MW of Capacity and Energy, Section 3.

- *Defined*. With the oversight of Sedway Consulting acting as an independent evaluator, Minnesota Power developed the Gas RFP bid specifications, identifying Minnesota Power's capacity, fuel type, plant technology, power delivery, and fuel transportation requirements.[92] The Gas RFP sought power supply offers for 200 to 400 MW of gas-fired capacity and dispatchable energy to be placed in service between 2022 and 2024. Eligible power supply proposals were required to provide MISO accredited or accreditable capacity, operated by a MISO market participant, and delivered to the Minnesota Power load zone (Zone 1). In addition, the Gas RFP specified that the power supply proposals should be for a natural gas-fired, non-variable, firm resource with an availability guarantee of no less than 96 percent for the summer (June through August) and winter (December through February) months, and 75 percent for the remaining shoulder months. The Gas RFP specified consideration of PPAs, tolling agreements, asset purchases, and self-build generation. Proposals were expected to be served through firm natural gas transportation service by at least one major natural gas pipeline. Proposal contract terms specified a 20-year minimum.

- *Evaluation*. All proposals were due by January 7, 2016, and all submitted proposals were reviewed consistent with the evaluation criteria and evaluation process described in the Gas RFP.[93]

4.2.3 RFP Review Process

Minnesota Power divided the Gas RFP review into the following four stages:

- *Initial Review*. During the initial review, Sedway Consulting reviewed the seventeen proposals from seven bidders that were received for completeness. Sedway Consulting, as independent evaluator, was permitted to contact respondents for additional data or clarifications. Proposals that did not meet the Gas RFP requirements were either notified and given an opportunity to correct the deficiencies

[92] *See* Appendix R: Request for Proposals for Up to 400 MW of Capacity and Energy, Section 2.

[93] *See* Appendix R: Request for Proposals for Up to 400 MW of Capacity and Energy, Section 5.

or eliminated from consideration. Two proposals were eliminated from further consideration at this stage, one because it was for a wind resource and the other because it did not specify a site, as required by the Gas RFP.

- *Quantitative Evaluation*. After the initial review, Sedway Consulting performed a comprehensive quantitative evaluation of all conforming proposals' ability to meet the identified capacity and energy needs and the corresponding costs of the proposals. Again, Sedway Consulting was permitted to contact respondents for additional data or clarification. Sedway Consulting used the metrics from the quantitative evaluation to prepare a ranked list of all qualified proposals. The rankings were based on each proposal's $/kW per month net cost under four scenarios — with and without transmission costs and with and without CO_2 regulation costs. The results of the detailed quantitative analysis are provided in Appendix S.

- *Qualitative Evaluation*. After the independent evaluator completed its quantitative evaluation, Minnesota Power evaluated the results of the quantitative evaluation and evaluated qualitative aspects of the conforming proposals for selection of proposals for contract negotiation discussions. Qualitative criteria included, for example, price certainty; site control; the engineering, procurement, and construction contractor's experience; transmission interconnection risks; natural gas supply and firm transportation arrangements; and overall completeness, clarity, and quality of the proposal. The qualitative criteria were described in Section 5 of the Gas RFP. During the qualitative evaluation, Minnesota Power eliminated two bids from further consideration because the bids were for resources outside Minnesota Power's MISO Local Resource Zone (Zone 1). The Federal Energy Regulatory Commission has indicated that there are resource adequacy limitations associated with resources located outside of an entity's zone, such that Minnesota Power cannot include more than approximately 200 MW of resources from outside of Zone 1 in meeting resource adequacy. Consequently, Minnesota Power did not further consider the two proposals that would be located outside of Zone 1.

- *Preliminary Negotiations*. The ranked proposals list indicated that of the Zone 1 proposals, South Shore provided the most cost-effective proposals. In early March 2016, Minnesota Power narrowed the list of proposals to those submitted by the two most cost-effective bidders, South Shore and **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**, and began preliminary negotiations with both bidders. The preliminary negotiations were monitored by Sedway Consulting to ensure consistent treatment of both bidders.

In the preliminary contract negotiations stage of the Gas RFP, Minnesota Power negotiated and further clarified the proposals from the two most cost-effective bidders. Originally, South Shore provided bids for a new combined-cycle facility in Superior, Wisconsin and provided proposals for two turbine technologies. Ultimately, on May 27, 2016, South Shore notified Minnesota Power that it had settled on the chosen technology to support its bid.

Minnesota Power analyzed the final proposals for South Shore and the other bidder selected for negotiations under both base conditions and a higher stress under which all costs and heat rates for the South Shore proposals were assumed to be 10 percent higher than currently estimated, and concluded both the South Shore proposals, even under the stress-case scenario, were more cost-effective than either of the other bidder's proposals under its base conditions. Consequently, the South Shore initial proposal for the 2x1 combined-cycle for 300 MW of capacity and energy from a new facility in Superior, Wisconsin was selected as the successful bidder.

Negotiations between Minnesota Power and South Shore proceeded through the remainder of 2016. During that time, Minnesota Power worked with South Shore to refine the proposed NTEC project, including adjustments to the in-service date from 2022 to 2024 and adjustment to Minnesota Power's share of the project to approximately 250 MW, based on the Company's most updated analysis of the optimal level of natural gas capacity to meet customer needs. Further, South Shore advised that it was modifying the technology to build a 1x1 configuration to better match the desired purchases of the NTEC Owners. Based on review of the negotiated modifications, Sedway Consulting concluded that the capacity pricing, though modestly increased from the initial bid, was economically superior to the other shortlisted offers.[94] Minnesota Power therefore selected the approximately 250 MW capacity proposal with an in-service date of December 1, 2024, ultimately, NTEC.

4.2.4 Independent Analysis of RFP and Results

Sedway Consulting, acting as an independent evaluator, analyzed responses received to the Gas RFP and concluded NTEC represented the best resource option for Minnesota Power customers. Sedway Consulting also concluded that Minnesota Power's RFP process was conducted fairly.

Sedway Consulting's independent analysis of the Gas RFP is attached to this Petition as Appendix S. In conducting its review of the Gas RFP, Sedway Consulting,

- Reviewed and commented on the RFP document before the solicitation was launched;
- Discussed with Minnesota Power the separation of bidding and evaluation functions at Minnesota Power;
- Reviewed and assisted with developing answers to bidder questions that were submitted after the release of the RFP and ultimately posted for all bidders to see;
- Participated in Minnesota Power planning calls and meetings to establish the procedures and evaluation methodologies that would be employed by Sedway Consulting in its review and evaluation of all proposals;
- Acquired and archived all important evaluation parameters and market price assumptions prior to bid opening, for use in Sedway Consulting's proprietary evaluation models;
- Conducted the bid opening process and retained a hard copy and an electronic copy of each submitted proposal;
- Independently reviewed and evaluated all proposals;
- Assisted in developing and issuing clarification questions and transaction parameters to bidders to ensure that all proposals were clear, complete, and based on consistent PPA assumptions;
- Monitored all RFP-related email communications with bidders;

[94] Sedway Consulting considered whether Minnesota Power should rebid the RFP based on the changes but concluded that a rebid was not necessary under the circumstances. The updated proposals from South Shore continued to be superior to the other short-listed bids received in response to the RFP. Based on evaluation of the refined South Shore proposal, Sedway Consulting concluded that the proposed NTEC 250 MW purchase was the best and least-cost alternative to meet Minnesota Power's needs.

- Reviewed and incorporated where appropriate additional cost information (e.g., firm gas transportation costs, transmission costs) developed by Minnesota Power's subject matter experts or other outside consultants;
- Participated in the decision process for developing a short list of projects and counterparties with whom Minnesota Power should commence preliminary negotiations;
- Participated in debriefing calls with bidders who were not shortlisted;
- Monitored preliminary negotiation calls with shortlisted bidders; and
- Participated in the final selection decision-making process.

As noted in Appendix S: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation, Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own evaluation of all proposals. Sedway Consulting reviewed the Company's RFP, internal assumptions, and communications with bidders. Sedway Consulting also performed its own evaluation of proposals and participated in periodic calls to discuss proposal clarification, disqualification, and evaluation decisions.

As further set forth in Appendix S, Sedway Consulting concluded that South Shore's proposal was more cost-effective than any of the other proposals received in response to the Gas RFP, that the Company made the appropriate selection and rejection decisions, and that Minnesota Power made an appropriate decision to move ahead with final negotiations with South Shore. The other proposals received in the solicitation had prices that were too high to be competitive with the South Shore project. In addition, as previously noted, Sedway Consulting evaluated the revised South Shore offers and concluded that, although the capacity pricing had been increased as a result of the smaller sized project, they still were economically superior to the other shortlisted bidder's offers. As such, the final revised offer from South Shore represented the best option for meeting Minnesota Power's revised needs.

4.3 NTEC Project

4.3.1 Overview of Proposed Project

The NTEC project will be jointly owned and developed by South Shore and Dairyland. Each owner will have the rights to 50 percent of NTEC capacity (approximately 262.5 MW of an assumed 525 MW plant). As part of the affiliated interest transaction that is the subject of this proceeding, South Shore has agreed to dedicate 48 percent of the capacity of NTEC (approximately 250 MW) to Minnesota Power. NTEC is to be located in Superior, Wisconsin, at a site identified as part of a broad-range site selection study performed by Burns & McDonnell, on behalf of Minnesota Power in its evaluation of potential joint development of a combined-cycle power plant, completed in 2014 (the "Combined-Cycle Site Selection Study").[95] Minnesota Power's consultant is working on an update of this evaluation that will be submitted into the record of this proceeding upon its completion.

NTEC will consist of one 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. The total facility output is estimated at 525 MW.

The NTEC project will include the installation of a new 345 kV collector bus to interconnect the output from the generating plant to a new offsite 345 kV substation near the NTEC site. Existing transmission lines that traverse the site will also be relocated elsewhere on the site.

NTEC will be designed to operate as a dispatchable, variable load power plant and have the capability of operating up to the level of the GTG at full load with inlet evaporative coolers plus supplemental duct firing of the HRSG ("Maximum Load"). 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.

[95] *See* Appendix T: Combined-Cycle Site Selection Study.

4.3.2 Viable Location

The NTEC site is located in Superior, Wisconsin. This location was first assessed as part of the Combined-Cycle Site Selection Study completed in 2014 by Burns & McDonnell. The Combined-Cycle Site Selection Study area included the MISO region as it extends through the states of North Dakota, Minnesota, and Wisconsin. Preliminary site alternatives were identified by overlaying maps of infrastructure critical to economic combined-cycle generation power plant development. This infrastructure included major surface water sources, municipal waste water treatment plants, electric transmission lines and substations rated at or exceeding 230 kV, and natural gas pipelines having a diameter of 16 inches or greater. Line taps and substations were identified as potential development sites; however, existing power plants were not considered for expansion. Substations had to be in close proximity to a natural gas pipeline and both substations and line taps had to be within five miles of a significant source of water. Based on these criteria, 115 sites were identified. The number of sites was further refined through analyses discussed in the Combined-Cycle Site Selection Study.[96]

The NTEC site was identified by the Combined-Cycle Site Selection Study as providing advantages over other sites studied. The study of the Superior, Wisconsin site provided a strong foundation for future development potential. Burns & McDonnell subsequently developed an addendum to the Combined-Cycle Site Selection Study to consider additional sites that might be viable if a potential interstate pipeline in North Dakota was developed. The results of this supplemental analysis continued to identify the NTEC site as advantageous for development of a natural gas combined-cycle plant.

4.3.3 Gas Infrastructure

Availability of gas infrastructure presents one of the key benefits of the NTEC site location. The NTEC site is located less than ten miles from two interstate pipelines: Great Lakes Gas Transmission (“Great Lakes”) and Northern Natural Gas Company (“Northern Natural Gas”).

[96] The objective of the Combined-Cycle Site Selection Study was to identify a minimum of three potential plant sites and provide the information necessary to concentrate subsequent site acquisition and permitting efforts, should Minnesota Power decide to proceed with the project. Appendix T: Combined-Cycle Site Selection Study (Executive Summary).

Each pipeline transports gas from wholly different gas supply basins, providing optionality for gas supply in the future. This site location's proximity to multiple interstate pipelines also affords fuel transportation optionality and associated competitive pricing opportunities. Finally, the Company has developed a strategy for lateral connection to the pipeline ultimately selected for firm transportation to the NTEC site. As such, the NTEC site presents superior gas supply options and cost protections for customers.

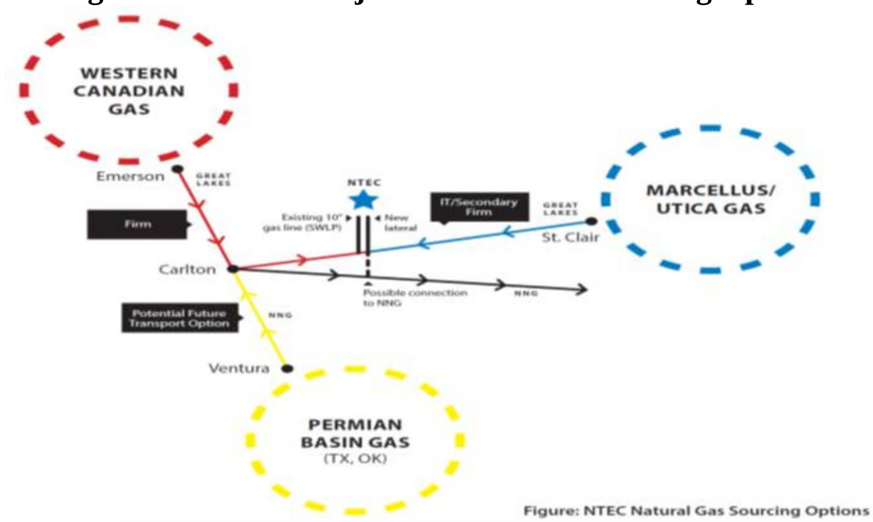
4.3.3.1 Fuel Supply and Transportation Options

The NTEC site is located in close proximity to both the Great Lakes interstate pipeline and the Northern Natural Gas pipeline. Great Lakes transports gas originating from western Canada, as well as backhauls from the Marcellus/Utica shale plays in the eastern United States. In contrast, Northern Natural Gas transports gas from the southern shale plays in Texas and Oklahoma.

By potentially utilizing both of these pipelines in the future, NTEC will have access to gas from multiple supply basins. Natural gas pricing across the country is dynamic, depending on variables such as supply and demand, pipeline expansions, liquefied natural gas ("LNG") exports, and new shale gas discoveries. Production costs could increase absent access to multiple options for procuring competitively priced gas. Consequently, access to multiple supply basins is critical over the years the combined-cycle plant is intended to be in operation, in order to ensure gas can be purchased at competitive prices throughout the plant's operating life. In the instance of NTEC, locating the plant near two different interstate pipelines will provide access to low price gas to keep the power supply cost as low as possible for customers.

Ultimately, the location of the NTEC site provides access to multiple fuel transportation and sourcing options, as indicated in Figure 32, below.

Figure 32: NTEC Project Natural Gas Sourcing Options



As Figure 32 illustrates, the anticipated configuration and sourcing optionality offered by the NTEC site provides flexibility and cost management opportunities for customers.

As part of the development of NTEC, an RFP for natural gas transportation service ("Transport RFP") was issued on April 16, 2015, with proposal submissions due May 15, 2015.[97] The Transport RFP was developed and evaluated by an independent evaluator, L.E. Peabody & Associates, Inc. ("Peabody"). The Transport RFP asked for proposals for maximum daily quantity of up to 106,000 MMBtu per day, maximum hourly quantity of 4,400 MMBtu per hour with a pressure at delivery point of a minimum of 535 psig. The quantity sought in the RFP was intended to address either a 1x1 or 2x1 natural gas combined-cycle plant. Originally, the Transport RFP sought proposals for two potential delivery sites, one in Superior, Wisconsin and the other in Edgerton, Wisconsin.

[TRADE SECRET DATA BEGINS…

…TRADE SECRET DATA ENDS]. After the sites were narrowed to just the Superior, Wisconsin site, Peabody ran quantitative and qualitative analyses on the remaining submission

[97] The Transport RFP is provided as Appendix U of this Petition.

proposals and various transportation scenarios. The Peabody quantitative analysis indicated that for all scenarios, the **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** options were least cost. Peabody also considered a number of qualitative factors. The qualitative factors indicated no significant difference in balancing, trading, and storage opportunities that would offset the economic benefits of going with the less costly **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** options.

Based on the RFP outcomes, Peabody ultimately recommended **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS].**

Negotiations with **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** were initiated **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]. [TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** in which NTEC is located. The NTEC Owners entered into a **[TRADE SECRET DATA BEGINS.. ..TRADE SECRET DATA ENDS]** Ultimately, the **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** however, because the rates remain highly competitive regionally and are fixed for **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** years, the NTEC Owners remain confident that the costs of gas transportation remain reasonable and adequately balance near- and long-term risks. Minnesota Power will update the Commission regarding the fuel transportation contracting process as the process moves forward.

[98] **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS].**

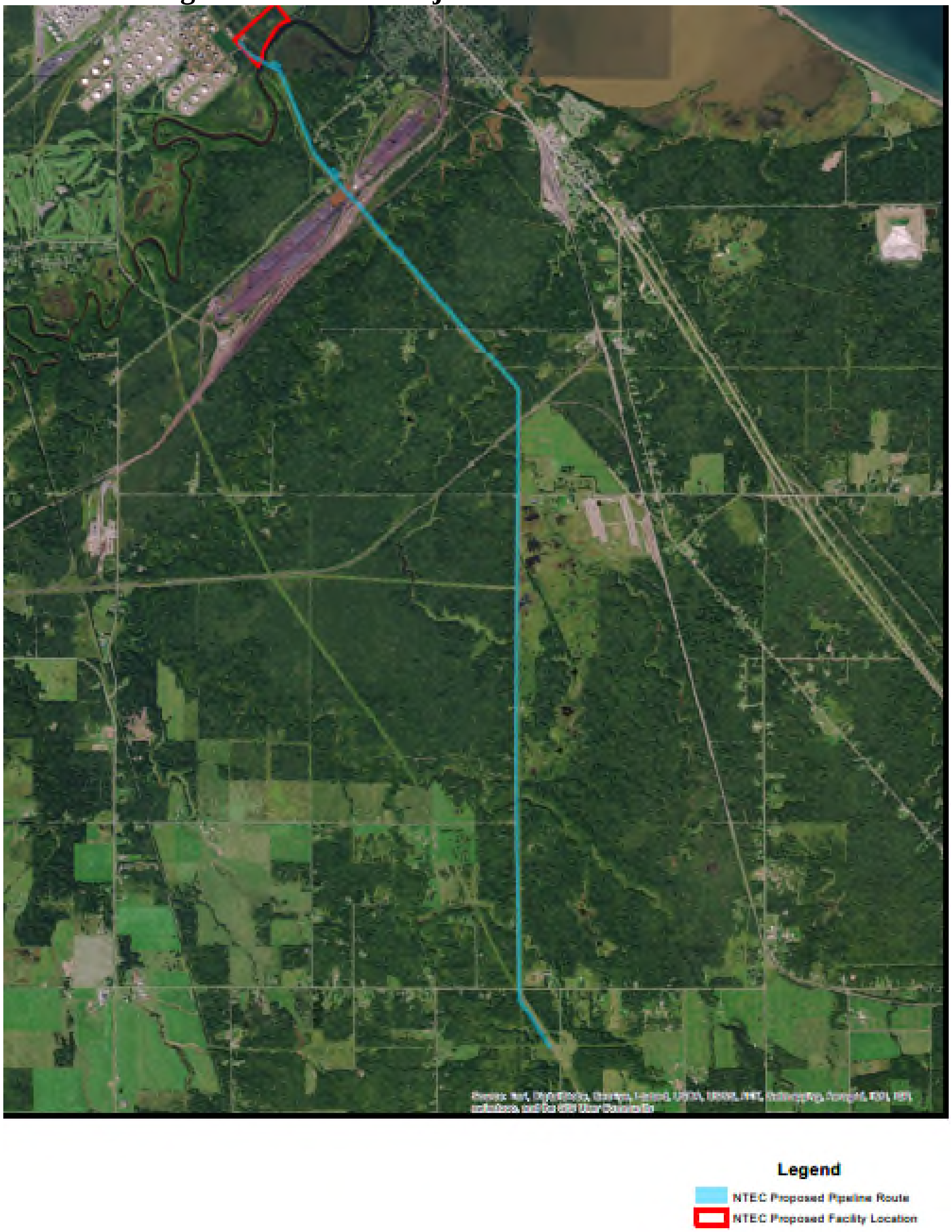
4.3.3.2 Lateral Connection to Interstate Pipeline

Apart from the negotiations for fuel transportation, it was necessary to assess the options for lateral connection to the available interstate pipelines. The NTEC site is located approximately **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** from **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** interstate pipeline from which the natural gas for the project will be transported. Three options for lateral pipeline ownership were identified:

- Superior Water Light and Power ("SWL&P"), a Minnesota Power affiliate, owned and operated;
- NTEC owned and operated; or
- **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** owned and operated.

Based on an evaluation of available alternatives, SWL&P ownership was identified as the best available alternative as SWL&P owns an existing 50-foot right of way ("ROW") from **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** through the Project site and has the knowledge to own and operate such a pipeline connection. The location of the anticipated SWL&P lateral connecting to the **[TRADE SECRET DATA BEGINS…. …TRADE SECRET DATA ENDS]** transmission pipeline is depicted in Figure 33 below.

Figure 33: NTEC Project Natural Gas Connection



Comparing the **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** and SWL&P options, **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS].** Further, selecting the **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS]. In contrast, SWL&P's ownership of an existing ROW smooths the permitting process, avoids creation of new ROWs, and reduces risk to the Project. Consequently, the NTEC Owners ultimately selected the SWL&P option.

The NTEC Owners and SWL&P have finalized a Term Sheet regarding the lateral gas pipeline.[99] In order to utilize the existing ROW, SWL&P will own and operate the pipeline. SWL&P proposes to invest **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** which will be recovered from the NTEC Owners through tariffed rates to be approved for the lateral project and on which SWL&P will earn its return on investment. The NTEC Owners will pay the remaining capital costs in addition to project development costs for the lateral pipeline.

4.3.4 Socioeconomic and Environmental Impacts

In its September 19, 2017 Order for Hearing, the Commission asked the Company to specifically address the socioeconomic and environmental impacts of the proposed NTEC 250 MW purchase. As described throughout this Petition, there are a variety of important reasons why the proposed site is advantageous to customers, including good natural gas access and availability, electric transmission infrastructure, and a shovel-ready site. In addition to those benefits, the development of the NTEC plant will provide significant beneficial impacts to the region surrounding Duluth, Minnesota. The Company has included Appendix O to this filing which provides the economic analysis that was conducted to assess the socioeconomic impacts of the proposed plant.

NTEC represents a sizable economic development project for the region in which it is located. According to the City of Superior, it is one of the largest investments in that community in history. With its headquarters in Duluth, Minnesota Power is part of a regional economy that

[99] The execution of the Term Sheet is between the NTEC Owners (South Shore and Dairyland) and SWL&P, not Minnesota Power; therefore, it is not an agreement between Minnesota Power and an affiliate.

includes the entire Twin Ports area of Duluth, Minnesota, and Superior, Wisconsin, as well as the its broader northeastern Minnesota service territory. Because of their proximity, the economies of the Twin Ports are inextricably linked – for example, many residents of Duluth work in Superior and many residents of Superior work in Duluth. According to Minnesota Power's economic analysis, of the 130 new, permanent jobs that NTEC is expected to create in the region, about 60 percent will be in the Twin Ports. Regional economic impacts are expected to exceed $1 billion over NTEC's first twenty years of operation.

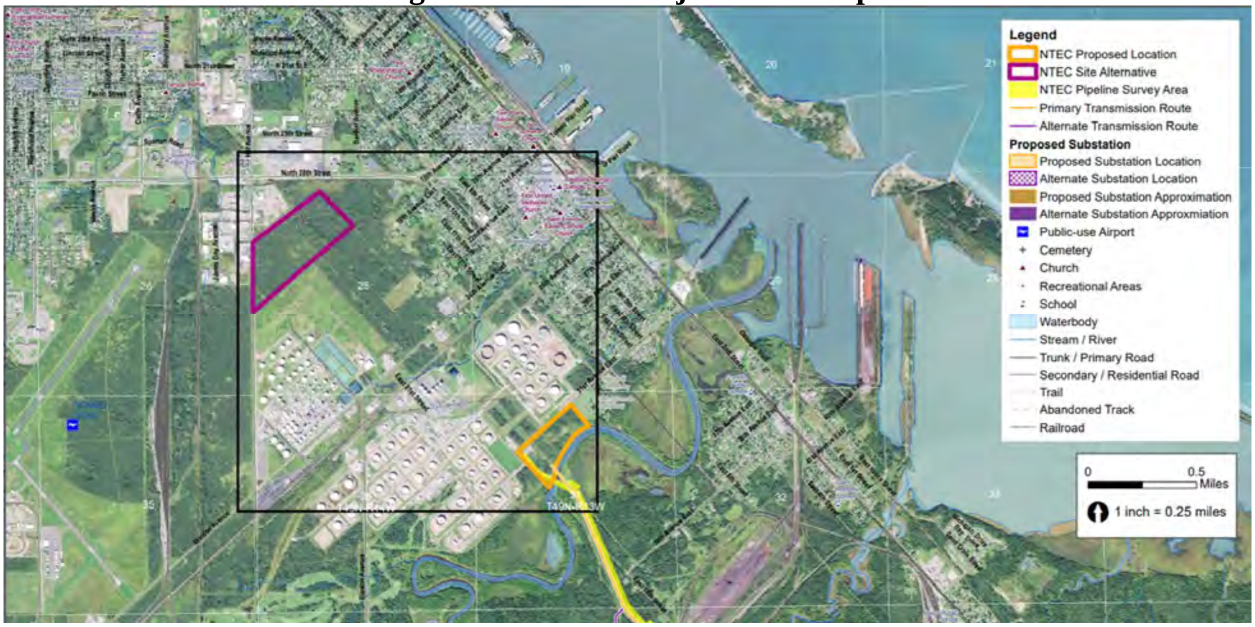
As explained elsewhere in this Petition, NTEC is a less carbon-intense resource than Minnesota Power's existing baseload generating resources – emitting about 65 percent less carbon dioxide than a coal unit. NTEC's other air emissions, such as NOx, CO, SO_2, VOCs, and PM_{10} are even lower, at a collective 97 percent less than traditional baseload coal resources, and NTEC will not have mercury emissions. NTEC will be constructed with the best available control technology for air emissions, as approved as part of the Wisconsin regulatory process.

NTEC's use of water will also be subject to Wisconsin regulation. Although the project is still working on detailed design, current estimates are that the water needed to operate NTEC will be available from on-site wells, such that surface water will not need to be disturbed. The majority of the water used will be lost through evaporation, thereby remaining in the hydrologic cycle. The remaining wastewater is expected to be able to be discharged to the local wastewater system.[100]

Although a greenfield site, the preferred 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 below.

[100] Additional information regarding environmental considerations related to NTEC can be found at http://nemadjitrailenergycenter.com.

Figure 34: NTEC Project Area Map



4.4 Wisconsin Facility Ownership

In order to take advantage of the location of the NTEC site near Superior, Wisconsin, it is necessary to also address Wisconsin requirements for generation facility ownership. In particular, Wisconsin Statutes only permit Wisconsin entities to obtain a Wisconsin license, permit, or franchise to own or operate a generation facility. That requirement is not applicable to Dairyland as an electric cooperative, but regardless, Dairyland is incorporated in Wisconsin. Minnesota Power is not a Wisconsin corporation. As previously noted, Minnesota Power's subsidiary, South Shore, submitted the proposals for what is currently named NTEC into Minnesota Power's Gas RFP. 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.

More specifically, Wisconsin Statutes require any person or entity that wishes to own a generation facility designed for nominal operation at a capacity of 100 MW or more to obtain a

Certificate of Public Convenience and Necessity ("CPCN") in Wisconsin.[101] In turn, Wisconsin Statutes § 196.53 states that:

> No license, permit, or franchise to own, operate, manage, or control any plant or equipment for the production, transmission, delivery or furnishing of heat, light, water or power may be granted or transferred to a foreign corporation. This section does not apply to an independent system operator, as defined in s. 196.485(1)(d) or an independent transmission owner, as defined in s. 196.485(1)(dm)….[102]

Minnesota Power is a "foreign corporation" under this statute, as it is a Minnesota corporation with its center of business located in Minnesota rather than Wisconsin.

There are two exceptions to the Wisconsin ownership requirements. Foreign corporations that are either an independent system operator or an independent transmission owner may obtain a license, permit, or franchise to own or operate plant or equipment in Wisconsin. However, Minnesota Power is neither an independent system operator nor an independent transmission owner under Wisconsin law and therefore, is not exempt from the Wisconsin ownership requirements under Wisconsin Statute § 196.53. Wisconsin defines an independent system operator as "an independent system operator that requires the approval of a federal agency to operate transmission facilities in this state or a region,"[103] i.e., MISO. Wisconsin defines an independent transmission owner as an entity that does not own electric generation facilities or does not sell electric generation capacity or energy in the MISO transmission system.[104] Minnesota Power does not meet the definition of an independent system operator and is thus not exempt under that provision of Wisconsin law. Further, Minnesota Power is not an independent transmission owner because it does own and sell the output of generation facilities within the specified geographic footprint. As such, Minnesota Power is considered a "foreign corporation"

[101] Wis. Stat. § 196.491(3). This requirement and other Wisconsin requirements for permitting and construction are discussed in more detail later in this Petition.

[102] Wis. Stat. § 196.53. The legality of this state statutory restriction was upheld in *Alliant Energy Corp. v. Bie*, 330 F.3d 904 (7th Cir. 2003).

[103] Wis. Stat. § 196.485(1)(d).

[104] Wis. Stat. § 196.485(1)(dm).

that does not fall within one of the exceptions to Wis. Stat. § 196.53, and therefore cannot obtain a Wisconsin license, permit, or franchise (including a CPCN) to own, operate, manage, or control the NTEC facility located in Wisconsin.

Consistent with the United States Seventh Circuit Court of Appeals determination in *Alliant Energy Corp. v. Bie*,[105] that "a foreign company that wants to get involved in Wisconsin utility provision need only create a subsidiary and incorporate it in Wisconsin," Wisconsin entity South Shore will maintain the permits for the ownership and operation of the NTEC facility. This corporate affiliation addresses the requirements of Wis. Stat. § 196.53. Other Wisconsin permitting requirements specific to South Shore are discussed later in this Petition.

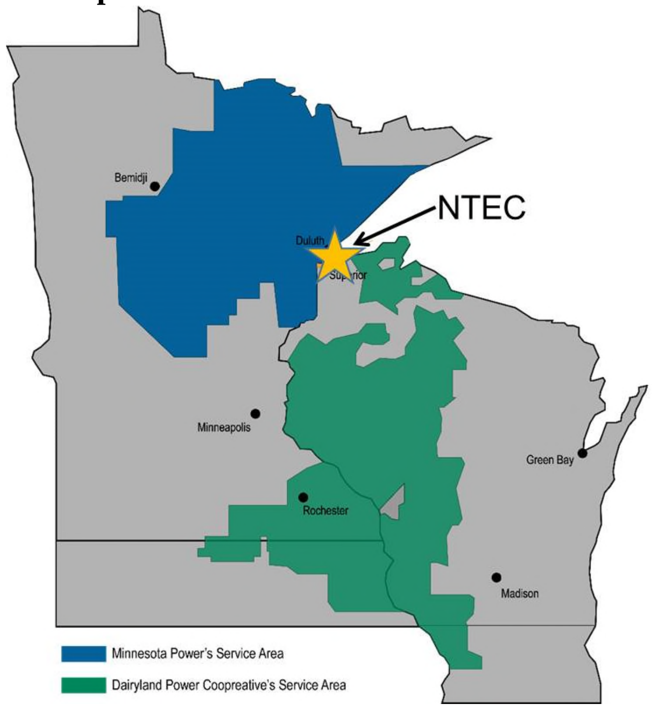
4.4.1 Joint Ownership Structure

Through the joint ownership of NTEC by South Shore and Dairyland, each owner will own an equal share of NTEC. Joint ownership by South Shore and Dairyland allows South Shore to take advantage of economies of scale and efficient operation associated with larger generation facilities, and meets both entities' goals.

Dairyland is a generation and transmission cooperative that provides wholesale electric service to twenty-five member distribution cooperatives that provide retail electric sales to their members. Dairyland has member distribution cooperatives in four states — Minnesota, Wisconsin, Iowa, and Illinois. In addition to providing service to its member distribution cooperatives, Dairyland provides wholesale service to seventeen municipal utilities. Figure 35 below is a map showing Minnesota Power and Dairyland's respective service territories and the location of NTEC.

[105] 330 F.3d 904 (7th Cir. 2003).

Figure 35: Map of NTEC Location and Joint Owner Service Areas



On June 30, 2017, Dairyland filed an Optional Resource Plan Compliance Report with the Commission in Docket No. ET6125/RP-17-525 ("Dairyland's O-IRP"). In Dairyland's O-IRP, Dairyland outlined its plan to add natural gas generation, in the form of a new combined-cycle natural gas plant.[106] Joint ownership by South Shore and Dairyland allows each party to participate in a single facility, achieving economies of scale and efficient operations. Finally, working with an upper Midwest-based utility with similar values and priorities, like Dairyland, provides benefits in the form of a stable, collaborative, and customer-focused partnership.

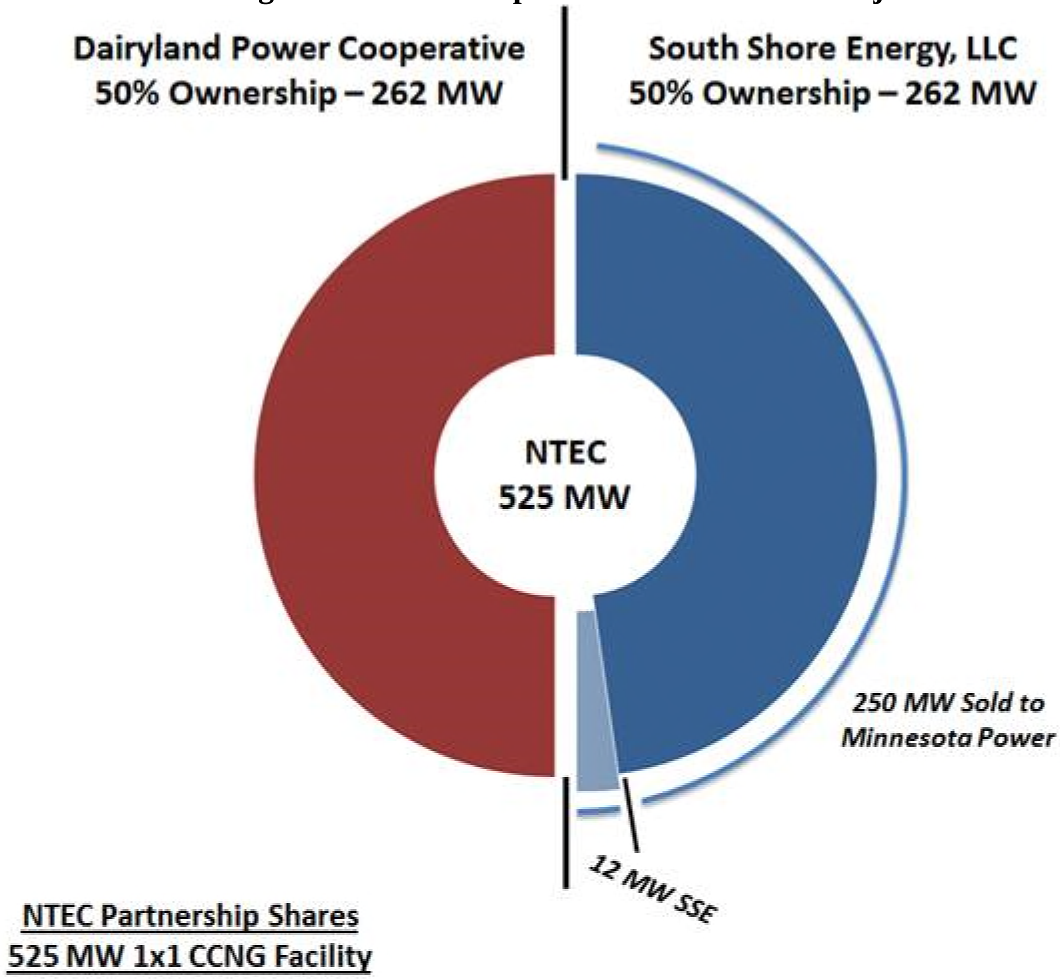
Specifically, joint ownership by South Shore and Dairyland allows South Shore to take advantage of the benefits of a larger power plant. The dedication of a substantial amount of South Shore's portion of the plant to Minnesota Power allows the Company to pass those savings on to its customers. Larger plant sizes typically benefit from economies of scale (lower initial cost per kilowatt) and improved efficiencies. These savings include construction, operating and maintenance ("O&M"), and fuel cost savings. Larger plants are also generally able to offer lower

[106] *In the Matter of Dairyland Power Coop.'s Optional Integrated Res. Plan,* Docket No. ET6125/RP-17-525, OPTIONAL INTEGRATED RESOURCE PLAN at 10 (June 30, 2017).

capacity prices and have lower heat rates than otherwise analogous smaller facilities. In this case, NTEC was the selected project in the Gas RFP, which underscores the value of a larger, shared resource.

As illustrated in Figure 36 below, Dairyland and South Shore will each own an equal share of the 525 MW NTEC plant. The NTEC Owner rights and responsibilities, as governed by the NTEC Agreements, are discussed in detail in Section 4.5 of this filing.

Figure 36: Ownership Structure for NTEC Project



4.4.2 Interconnection and Delivery

4.4.2.1 MISO GIP and GIA Overview

To ensure that NTEC can deliver the needed capacity to the Minnesota Power system, NTEC must interconnect with nearby transmission facilities following the MISO Generator Interconnection Procedures ("GIP") contained in Appendix X of the MISO Open Access Transmission Tariff ("MISO Tariff"). The MISO GIP outlines a Definitive Planning Phase ("DPP") process that is largely subdivided into four segments, DPP Studies 1 through 3 and the Generator Interconnection Agreement ("GIA") phase. To move into a new phase, an applicant must pay certain financial milestone payments. A more detailed description of the MISO GIP and the studies conducted during each phase is provided in Appendix Q.

South Shore, on behalf of the NTEC Owners, applied for interconnection with MISO for NTEC on June 7, 2017. NTEC will interconnect to American Transmission Company's ("ATC") Arrowhead-Weston 345 kV transmission line. The project is part of MISO's August 2017 DPP study group. The need for any transmission network upgrades will be determined through MISO's DPP study process, which is described in more detail below.

4.4.3 Project Schedule

NTEC is planned to be in service in 2024. Broadly speaking, there are four phases of the NTEC project: (1) development; (2) detailed design; (3) construction; and (4) testing and commissioning. Additional detail on each phase is discussed below.

4.4.3.1 Project Development

NTEC is currently in the development phase. This phase began in 2014 with identification of the anticipated need for additional capacity and identification of Minnesota Power customers' future needs through the 2015 Plan and updates, and resulted in identification of NTEC as the best option to meet these needs through the Gas RFP. Now that the specific project has been identified, Minnesota Power must obtain the necessary regulatory approvals and permits, enter into the necessary agreements with South Shore, and obtain authorization to interconnect to the transmission system through the MISO interconnection process. Minnesota Power and its affiliate, South Shore, executed the CDA in July 2017. That contract will govern the relationship between the parties, subject to Commission approval of the necessary affiliated interest agreements. The affiliated interest agreements were executed on July 28, 2017. Once the affiliated interest agreements are approved, Minnesota Power will take over responsibility as the Construction Agent for NTEC. The NTEC Owners intend to select the gas turbine vendor by the end of 2017.

NTEC entered the MISO DPP of the generator interconnection process on June 7, 2017. At that time, an initial milestone payment was made. It is anticipated that the MISO interconnection process will take at least two years. In order to continue the MISO interconnection study process, the NTEC Owners will need to make additional milestone payments. For NTEC, the initial milestone payment ("M2") required for entry into the MISO DPP study process was made at the time the project was submitted into the queue. Based on MISO's anticipated schedule for the August 2017 DPP cycle, the next milestone payment ("M3") is anticipated to be required at the end of July or early August 2018. Upon payment of the M3 milestone payment, the M2 milestone payment will become non-refundable. The last milestone payment ("M4") is presently anticipated to be required in third quarter 2018. Upon payment of the M4 milestone payment, all milestone payments (M2, M3, and M4) will become non-refundable. By planning this Petition for completion prior to all of the milestone payments, Minnesota Power has sought to mitigate the risk of having to forfeit milestone payments.[107]

Minnesota Power will continue to work to obtain the necessary regulatory approvals through 2020. The NTEC Owners intend to file for necessary Wisconsin approvals and Rural Utilities Services approvals in early 2018.

4.4.3.2 Detailed Design

Once the necessary approvals and agreements are in place, NTEC will enter into the detailed design phase. Detailed design work takes the previous high-level designs and converts them into detailed construction or production drawings and a plan for implementing the final project.

[107] The MISO DPP study schedule is current as of the time of filing, but subject to change.

Detailed design work generally follows multidisciplinary plant design and engineering processes to convert high-level specifications, data sheets, process calculations, and concepts into detailed design documentation. This enables final procurement, fabrication, installation, testing and commissioning. Minnesota Power plans to begin detailed design work by December 2020 and continue through November 2021. This phase will include some minimal construction activities as well.

4.4.3.3 Construction

Minnesota Power plans to complete the majority of construction activities between April 2022 and December 2023. Preliminary planning anticipates that the GTG will be delivered in September or October of 2022, the HRSG in late 2022 or early 2023, and the STG in early 2023. Minnesota Power anticipates that NTEC will reach a point of substantial completion by June 2024.

4.4.3.4 Testing and Commissioning

Between May 2023 and June 2024, NTEC will go through start-up and commissioning to reach a point of substantial completion by June 2024. Following substantial completion, NTEC will go through performance testing and reliability runs. NTEC is expected to be in commercial operation by November 2024.

4.5 NTEC Project Agreements and Affiliated Interest Agreements

This Section provides information on the terms of the two NTEC project agreements and the three affiliated interest agreements that are the subject of the Company's request for approval in this Petition. The two project agreements entered into between South Shore and Dairyland are the *Ownership and Operating Agreement* ("O&O Agreement"), dated June 1, 2017, between Dairyland and South Shore as Owners and South Shore as Operating Agent and the *Development and Construction Management Agreement* ("D&C Agreement"), dated June 1, 2017, between Dairyland and South Shore as Owners and South Shore as Construction Agent (together referred to as "NTEC Project Agreements"). The NTEC Project Agreements define the NTEC Owners' respective rights and obligations related to development, construction, ownership, and operation of NTEC. The O&O Agreement and D&C Agreement between South Shore and Dairyland designate South Shore as the responsible agent on behalf of the NTEC Owners to take those actions necessary to complete development and construction of NTEC and to operate and maintain the plant on behalf of the owners.

Finally, the O&O Agreement and the D&C Agreement both contemplate that South Shore's obligations as responsible agent on behalf of the NTEC Owners will be assigned to Minnesota Power upon Commission approval of the affiliated interest agreements. This structure will make Minnesota Power the responsible party to undertake the development, construction, operation, and maintenance of the plant. This structure was chosen to facilitate Minnesota Power taking on the role as experienced construction and operations manager for the project while still complying with the Wisconsin law that requires the plant to be owned or operated by a Wisconsin entity. The D&C Agreement is provided in Appendix F of this Petition. The O&O Agreement is provided in Appendix G of this Petition.

Between South Shore and Minnesota Power, there are three proposed affiliated interest agreements, subject to Commission approval as requested in this filing. These affiliated interest agreements are:

1. *Unit Contingent Capacity Dedication Agreement ("CDA")*, dated July 28, 2017, between South Shore and Minnesota Power, under which South Shore dedicates 48 percent of the total NTEC capacity (approximately 250 MW) to Minnesota Power and its customers (Appendix H);

2. *Assignment of Rights Agreement (Construction Agent)* dated July 28, 2017, between South Shore and Minnesota Power, under which South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 3.7.5 of the D&C Agreement (Appendix D).

3. *Assignment of Rights Agreement (Operating Agent)* dated July 28, 2017, between South Shore and Minnesota Power, under which South Shore assigns to

Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 4.7.5 of the O&O Agreement (Appendix E).

The CDA is provided in Appendix H. The Assignment of Rights Agreement (Construction Agent) and Assignment of Rights Agreement (Operating Agent) (collectively the "Assignment Agreements") are provided as Appendices D and E, respectively. Each of the NTEC Project Agreements, the CDA, and the Assignment Agreements are summarized below.

4.5.1 Development and Construction Management Agreement

On June 1, 2017, South Shore and Dairyland executed the D&C Agreement to govern the development and construction responsibilities for NTEC through the in-service date of NTEC. The D&C Agreement is provided as Appendix F. Under the D&C Agreement, South Shore is initially designated as the Construction Agent for NTEC. Section 3.7.5 of the D&C Agreement acknowledges that South Shore intends to assign all of its rights and obligations as Construction Agent to Minnesota Power as soon as reasonably practicable after receipt of Commission approval.

4.5.1.1 Term of the Agreement

The D&C Agreement is effective as of June 1, 2017, and continues until NTEC is commercially operational.

4.5.1.2 Services Provided under the Agreement

Under the D&C Agreement, the Construction Agent has primary responsibility and authority to manage the planning, permitting, design, construction, acquisition and procurement, completion, startup, and commissioning of NTEC, subject to the terms of the D&C Agreement and the direction of the NTEC Management Committee.

The Management Committee will be composed of a primary and alternate representative of each NTEC Owner. The Management Committee is responsible for providing oversight of the planning, permitting, design, construction, acquisition and procurement, completion, renewal, addition, replacement, modification, operation, maintenance, repair and decommission of NTEC. The Construction Agent is tasked with acting on behalf of the NTEC Owners.

4.5.1.3 Cost Allocation

The Construction Agent is entitled to reimbursement for actual costs incurred in connection with its performance of the construction services. The NTEC Owners will each pay a pro rata share of the project costs incurred by the Construction Agent. Project costs are defined in Schedule 1.2 of the O&O Agreement and payment of project costs is covered under Article V of the D&C Agreement.

4.5.1.4 Risk Allocation

There are certain inherent risks associated with any generation construction over which the parties have little direct control. The D&C Agreement addresses transmission interconnection project risks and regulatory approval risks by inclusion of provisions to reevaluate the viability of NTEC at certain key points. If the MISO network upgrades estimated costs exceed **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS], then the NTEC Owners may reevaluate the economic viability of the project. Lastly, there is a right to terminate if the parties fail to receive necessary regulatory approvals.

4.5.1.5 Other Provisions of the D&C Agreement

The following is a list of standard provisions within the D&C Agreement:

- Article IV governs ownership rights, such as access rights.
- Article VII addresses indemnification and limitations of liability.
- Article IX contains terms related to default and remedies.
- Article X contains general terms and conditions standard in a contracts related to representations, warranties, and covenants.

These provisions are consistent with standard development and construction contracts.

4.5.2 Ownership and Operation Agreement

On June 1, 2017, South Shore and Dairyland executed the O&O Agreement, which establishes their respective ownership interests in NTEC; establishes their respective rights and obligations with respect to the planning, permitting, design, construction, acquisition and procurement, completion, renewal, addition, replacement, modification, operation, maintenance, repair, and decommissioning of NTEC; and establishes the standards, policies, and procedures governing the project. The O&O Agreement is provided as Appendix G. Under the O&O Agreement, South Shore is initially designated as the Operating Agent for NTEC. The O&O Agreement acknowledges that South Shore intends to assign all of its rights and obligations as Operating Agent to Minnesota Power as soon as reasonably practicable after receipt of Commission approval.

4.5.2.1 Term of the Agreement

The O&O Agreement is effective as of June 1, 2017 and continues through decommissioning of NTEC.

4.5.2.2 Services Provided under the Agreement

The O&O Agreement governs the terms of ownership of NTEC between South Shore and Dairyland; defines the scope of the NTEC project; and governs the NTEC Owners' O&M responsibilities once NTEC is placed into service. Under the O&O Agreement, the Operating Agent has primary responsibility for the operation and maintenance of NTEC; the planning, permitting, design, construction, acquisition and procurement, and completion of any capital improvements; the scheduling, dispatch, sale, or other disposition of energy and ancillary services; decommissioning of NTEC; and any other matters set forth in the project agreements or otherwise determined by the Management Committee. The Operating Agent's authority is subject to the terms of the O&O Agreement and the direction of the NTEC Management Committee. The Operating Agent is tasked with acting on behalf of the NTEC facility as a whole on behalf of the NTEC Owners.

The Operating Agent is responsible to take all actions on behalf of the NTEC Owners to operate and maintain NTEC for the joint benefit of the NTEC Owners. These actions include, operating the plant, procuring fuel for the plant, submitting bids into the MISO market for the sale of energy from the plant, conducting routine and unscheduled maintenance on the plant, and taking all other actions necessary for the operation of the plant. The Operating Agent is authorized (within preset limits and subject to Management Committee approval) to enter into and perform contracts on behalf of the NTEC Owners and to generally act on behalf of the NTEC Owners. The O&O Agreement specifies a standard of performance, requiring the Operating Agent to comply with all applicable laws, act consistent with prudent utility practice, and follow the requirements and recommendations of major equipment manufacturers. This sets up a standard of performance that ensures that the Operating Agent will treat NTEC on the same basis as a reasonable power plant owner would.

4.5.2.3 Cost Allocation

The Operating Agent is entitled to reimbursement for actual costs incurred in connection with its performance of actions under the O&O Agreement. The NTEC Owners will each pay a proportional share of the costs incurred by the Operating Agent. Costs subject to reimbursement are defined in Section 4.3 and payment of costs is covered under Article V of the O&O Agreement.

4.5.2.4 Other Provisions of the O&O Agreement

The following is a list of standard provisions within the O&O Agreement:

- Article II defines the scope of the NTEC project.
- Article VII governs transfer of ownership interests.
- Article IX addresses indemnification and limitations of liability.
- Article X defines events of owner default and remedies.
- Article XI governs dispute resolution.

- Article XIV contains general terms and conditions standard in a contracts related to representations, warranties, and covenants.

All the terms outlined in this Section of the Petition are generally standard provisions in ownership and operating contracts.

4.5.3 Proposed Assignment Agreements

On July 28, 2017, South Shore and Minnesota Power executed two assignment agreements, effective pending Commission approval. Under the first assignment agreement, South Shore assigns its rights and obligations as the Operating Agent under the O&O Agreement to Minnesota Power. This assignment agreement is permitted pursuant to Section 4.7.5 of the O&O Agreement. Under the second assignment agreement, South Shore assigns its rights and obligations as the Construction Agent under the D&C Agreement to Minnesota Power. This assignment agreement is permitted under Section 3.7.5 of the D&C Agreement. Minnesota Power's acceptance of the Construction Agent and Operating Agent responsibilities is contingent on receiving approval from the Commission as requested by this filing.

4.5.4 Capacity Dedication Agreement

The CDA is the mechanism by which South Shore conveys the rights to a portion of NTEC to Minnesota Power. Under the CDA, Minnesota Power is procuring all of the NTEC 250 MW purchase on the same basis as if Minnesota Power owned the asset in its own name.

As described elsewhere in this Petition, Minnesota Power would prefer to develop and own its share of the plant in its own name, but this is infeasible in light of the Wisconsin statute described earlier. Further, Minnesota Power would be willing to have the CDA itself treated as the equivalent of a rate based asset even though it is owned by a subsidiary, but also recognizes that this would be unusual. Nevertheless, Minnesota Power is fully willing to provide the Commission with expansive regulatory authority over the CDA and Minnesota Power's relationship with South Shore to ensure that the Commission can address NTEC on the same basis as if Minnesota Power owned the asset in its own name and the asset was held in rate base.

Minnesota Power and South Shore designed the CDA to substantially replicate the treatment of Minnesota Power's 48 percent share of NTEC as the functional equivalent of a rate-based asset. In this way, the CDA operates in a manner substantially similar to Minnesota Power's offtake agreement with Square Butte Electric Cooperative for the purchase of a portion of the capacity and associated energy from Young 2. Under that agreement, Minnesota Power is obligated to make payments for its proportional share of Young 2 on the same basis as if it was an owner of the plant and all of those costs are recovered from customers as if Minnesota Power owned the asset directly to the full extent of its capacity purchase.

4.5.4.1 Term of the Agreement

The CDA has a 40-year term and dedicates the NTEC 250 MW capacity and associated energy production to Minnesota Power and its customers. Because the CDA is between South Shore and Minnesota Power, this agreement is an affiliated interest agreement as defined by Minn. Stat. § 216B.48, subd. 3. In exchange, Minnesota Power receives 48 percent of the MISO accreditable capacity and associated energy, along with the equivalent share of ancillary services and other attributes.

As noted previously, upon final turbine selection, the final baseline capacity of NTEC will be set and is expected to be about 525–550 MW. Minnesota Power's 48 percent share will therefore likely be between 250 and 264 MW. The CDA is provided in Appendix H. Affiliated interest filing information in compliance with Minn. Stat. § 216B.48, Minn. R. 7825.2200, and the Commission's September 14, 1998, Order Initiating Repeal of Rule, Granting Generic Variance, and Clarifying Internal Operating Procedures in Docket No. E,G999/CI-98-651, are detailed in Appendix B. A verification of filing is included as Appendix W.

4.5.4.2 Services Provided under the Agreement

The CDA provides for the dedication of 48 percent of the total NTEC baseline capacity and associated energy production to Minnesota Power on the same basis as if Minnesota Power owned the dedicated capacity directly. This gives Minnesota Power rights to 48 percent of the plant on the same basis as if Minnesota Power owned the asset in its own name and held it in rate base.

Further, this agreement specifically provides that Minnesota Power is giving the Commission complete authority over the contract and the relationship on the same basis as if Minnesota Power owned the plant in its own name as a rate based asset. If the CDA and the two Assignment Agreements discussed below are approved, Minnesota Power will assume the role of Construction Agent, consistent with the terms of the D&C Agreement and the role of Operating Agent, consistent with the terms of the O&O Agreement.

Development of NTEC is described in Article III of the CDA. Transmission interconnection requirements are discussed in Article IV. Sale and purchase obligations are outlined in Article V and O&M procedures are contained in Article VIII.

4.5.4.3 CDA Pricing

Under the CDA, Minnesota Power will pay a $/kW per month charge for the installed costs of its 48 percent interest in the total NTEC baseline capacity on the same basis as if Minnesota Power was the owner of that capacity, as well as its proportional share of the MISO network upgrade costs. This “capacity pricing” concept is contained in Section 6.1 of the CDA and includes separate components for the cost of the plant and the cost of the network upgrades.

This pricing essentially converts the installed cost of NTEC into a revenue requirement based on assumed construction costs, assumed cost of capital, and other inputs and applies those values to 48 percent of the overall plant. The costs are then translated into a payment stream on a $/kW per month basis for each of the plant costs and the network upgrade costs. Because this pricing stream is designed to replicate a revenue requirement, the key inputs of cost of capital are designed after the first contract year to be based on Minnesota Power’s authorized rate of return, capital structure, depreciation schedule, and the like. In addition, Minnesota Power has designed the pricing to replicate a revenue requirement on a rate based asset, meaning that the per-unit cost decreases over time as the asset depreciates.

A comparable formula is utilized for the network upgrade costs, where the Company has stated a specified amount of potential network upgrades and designed a $/kW per month payment to reflect recovery of that cost.

Most notably, the CDA capacity pricing formula gives ratepayers the benefit of cost savings and assumes a soft cap on the overall cost of the project. Essentially, Minnesota Power has assumed that the entire NTEC project, including network upgrades will cost approximately $700 million (of which Minnesota Power will be responsible for 48 percent). If the actual cost of the plant and associated network upgrades exceeds the target aggregate amount, the pricing formula is designed to flow Minnesota Power's proportional share of those savings directly through to ratepayers. This is the way it would work if the asset was owned by Minnesota Power and included in rate base; therefore, Minnesota Power determined it was appropriate to design the CDA to replicate that ratepayer benefit.

Conversely, if the aggregated cost of the plant and network upgrades exceeds the target aggregate amount, Minnesota Power is at risk of not recovering its pro rata share of those excess costs. This type of aggregate cap puts rigor on the construction process and protects Minnesota Power's customers from the risk of unbounded cost increases. That said, Minnesota Power recognizes that sometimes unforeseen or otherwise legitimate cost increases can occur. As a result, the CDA implements a "soft cap" on costs whereby aggregate costs in excess of the overall cap are only recoverable if Minnesota Power obtains specific Commission approval of the increased costs. And Minnesota Power acknowledges that it bears the burden of proving the reasonableness of those increased costs. Essentially, the CDA designs a pricing stream that ensures customers are fully protected in all scenarios. Customers realize cost savings for construction while they only risk cost increases that are specifically approved by the Commission.

Operations and maintenance costs (including MISO market costs, fuel costs, and associated MISO market revenues) will be directly assessed on a weekly basis and are proposed to be recovered through Minnesota Power's FPE Rider. The CDA pricing details are contained in Article VI of the CDA. Billing and payment procedures are in Article VII.

Under Section 6.1 of the CDA, the fixed payments are the sum of a monthly capacity payment plus a monthly network upgrade payment, adjusted (up or down) by a true-up payment (if any).

The monthly capacity payment calculated as set forth in Exhibit C to the CDA and is based on the estimated total investment in NTEC (including capitalized interest) in 2025 of about $700 million. The capacity payments under the CDA represent 48 percent of this amount based on the amount of capacity being dedicated to Minnesota Power through the CDA. For the first year of the CDA, the monthly capacity payment is derived by calculating the first year Cost of Capital using the assumptions contained in Exhibit C to the CDA. There is a similar formula based on similar inputs for the cost of network upgrades needed for the project which is shown in Exhibit D to the CDA.

Because Minnesota Power is treating its investment in NTEC as the equivalent of a utility-owned and rate-based asset, customers receive the benefit of pricing that reflects the Company's regulated cost of capital and a 40-year depreciation schedule. On that basis, the CDA results in a first-year capacity price of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** based on Minnesota Power's 48 percent share of the overall plant and the assumption that the overall cost of the overall plant equals **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** including financing costs. The net result is a capacity payment of about **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** in the first year for the plant. This amount will reduce over time as a result of depreciation of the investment.

In addition, the pricing includes an additional amount for MISO network upgrades[108] of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA**

[108] Network upgrades are defined under the MISO Tariff as: "the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System or Distribution System, as applicable, to accommodate the interconnection of the Generating Facility(ies) to the Transmission System. Network Upgrades shall not include any [high-voltage, direct current] Facility Upgrades." Attachment X of the MISO Tariff. Note that these network upgrades are separate and apart from the direct costs of interconnecting NTEC to the Point of Interconnection. Those direct interconnection costs are included in the calculation of the total investment cost for NTEC and are charged separately.

ENDS] based on Minnesota Power's 48 percent share of the network upgrades and the assumption that the overall cost of network upgrades for NTEC equal **[TRADE SECRET DATA BEGINS… ...TRADE SECRET DATA ENDS]** including financing costs. The net result is approximately [**TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** for network upgrades in the first year.

At the end of the first year, the Company will revise the exhibits to represent actual values and other assumptions that are consistent with the levels authorized by the Commission for treatment of Minnesota Power's other assets. The payments will be further subject to periodic true up adjustment to ensure that customers are responsible only for their 48 percent share of NTEC.

The proposed CDA pricing is advantageous to customers particularly because the revenue requirement design means that costs decrease over time.

Similarly, energy from this unit will result in customer benefits. This highly-efficient combined-cycle resource produces energy more economically than a combustion turbine. Energy from this unit will be bid into MISO on the same basis as other Minnesota Power units and will be dispatched into the MISO market when market prices are greater than the cost of production. The Company anticipates a much greater ability to dispatch and market energy from this plant than would be the case from a combustion turbine, which would be expected to operate only as a peaking facility.

The costs incurred by Minnesota Power under the CDA are reimbursed through a variety of mechanisms that are designed to replicate standard rate recovery for utility infrastructure. Articles VI and VII of the CDA set forth the pricing of the various components of the costs Minnesota Power will incur. Charges for variable costs incurred to operate NTEC that are associated with Minnesota Power's share of capacity will be payable by the Company on the same basis as those costs are charged through the O&O Agreement between the NTEC Owners. Payment of charges on this basis ensure that actual costs and revenues are reflected and that Minnesota Power's customers are charged the appropriate amount and receive appropriate credit for revenues received. Essentially, Minnesota Power will be responsible to pay 48 percent of all project costs and market operations costs and will be entitled to 48 percent of all market operations revenues, consistent with the O&O Agreement.

Project costs include all costs incurred by the Construction Agent or Operating Agent as agent for the NTEC Owners in connection with the planning, permitting, design, construction, acquisition and procurement, completion, renewal, addition, replacement, modification, operation, maintenance, repair, or decommissioning of NTEC under the terms of the D&C Agreement and O&O Agreement. Market operations revenues and costs are the costs and revenues related to fuel commodity, fuel transportation, MISO market costs, and MISO market revenues.

As described in Article VI of the O&O Agreement, the Operating Agent is responsible for all fuel commodity, transportation costs, and charges imposed by MISO arising from the sales participation in the MISO markets (the “Market Operations Costs”). Assuming the Commission approves the requested assignment of obligations from South Shore to Minnesota Power as requested in this Petition, the Market Operations Costs will be incurred by Minnesota Power on behalf of the NTEC Owners.

This means that 48 percent of the fuel commodity and transportation costs, MISO market costs, and MISO revenues will be the responsibility of Minnesota Power’s customers by operation of the CDA. These costs and revenues are intended to be allocated to customers on the same basis as if Minnesota Power’s share of NTEC is owned directly as a rate-based asset.

4.5.4.4 Conditions Precedent Risk Mitigation Provisions

The CDA includes numerous provisions to address risk and protect Minnesota Power’s customers. Article I of the CDA provides conditions precedents, which if not satisfied, will permit Minnesota Power to terminate without any further financial or other obligation to South Shore. These conditions precedent include Commission approval of the CDA, approval by the Public Service Commission of Wisconsin (“PSCW”) of a CPCN, obtaining an air permit, executing the interconnection agreement, and confirmation that the aggregate cost of the required network upgrades will not exceed the agreed-upon cap.

4.5.4.5 Other Provisions of the CDA

The following is a listing of standard provisions within the CDA:

- Article VIII addresses security for performance.
- Article IX contains terms related to default and remedies.
- Article XIII addresses indemnification.
- Article XIV provides for dispute resolution.
- Article VIII contains terms related to default and remedies.

In summary, the CDA is an innovative agreement structure that is intended to replicate cost treatment that is the equivalent of a rate-based utility asset. Under the CDA, customers get the benefit of potential cost savings and are at risk of cost increases (over the overall cap) that are specifically approved by the Commission. Customers also reap the benefit of the declining revenue requirement pricing stream, which has the effect of passing on to customers the time value of this long-term investment as the cost to customers declines, while the plant itself remains a valuable system addition. Finally, customers benefit from the innovative energy pricing and ultimately, the production profile of this combined-cycle plant, which will provide cost effective energy at a net benefit to customers.

4.6 THE NTEC PROJECT AGREEMENTS AND AFFILIATED INTEREST AGREEMENTS ARE IN THE PUBLIC INTEREST

4.6.1 NTEC Project Benefits

Pursuant to the NTEC Project Agreements and affiliated interest agreements, Minnesota Power and its customers will receive the benefit of the NTEC 250 MW purchase from a plant that is competitively-priced, while retaining the economies of scale arising from this capacity being a small piece of a larger plant. This transaction includes the ability to offer cost-competitive combined-cycle energy into the MISO Day-Ahead and Real-Time markets while ensuring that the benefits of those energy sales are realized by customers.

The NTEC 1x1 combined-cycle facility presents many additional benefits, including:

- The project meets the Company's currently anticipated capacity needs.
- Pricing is more competitive than other bids received in response to the Gas RFP, providing capacity and energy at highly competitive prices;
- The property itself is owned by ALLETE, reducing site acquisition costs;
- The project provides important socioeconomic benefits to the region surrounding Duluth;
- The site is located near the city of Duluth — within reasonably close proximity to the Minnesota Power service territory;
- The site is located near Lake Superior, providing ideal weather conditions for combined-cycle operations;
- The Arrowhead-Weston 345 kV electric transmission line, owned by ATC, is within a few miles of the site;
- The site is situated with access to water supply;
- Much of the surrounding area has been appropriated for industrial use;
- The site is located less than half of a mile from a branch of the BNSF rail line, making heavy haul equipment deliveries by rail possible;
- The site is less than ten miles from two interstate pipelines and has direct access to backup fuel alternatives. Firm transportation capacity is planned on one of the interstate pipelines, which will ensure reliable fuel supply; and
- ALLETE subsidiary SWL&P owns an existing natural gas pipeline ROW that would permit connection of a new lateral pipeline to the interstate pipeline.

4.6.2 NTEC Project Risk Factors

As with any project of this scale, certain risks are involved. These risks, and the steps taken by Minnesota Power to mitigate them, are discussed below.

4.6.2.1 Construction Cost Risk

Risk exists with any generation construction project that actual costs may be higher than estimated as a result of various factors. Minnesota Power recognizes that cost is an important factor in determining the reasonableness of any proposal. NTEC has the lowest total system costs of the alternatives considered. In addition, the costs for the Project are more certain and involve less risk than other alternatives. Further, because Minnesota Power will act as Construction Agent for NTEC, with responsibility for planning, permitting, design, construction, acquisition and procurement, startup, and commissioning of NTEC, the Company will be in a position to ensure project costs remain on budget and are reasonable and prudently incurred. Minnesota Power has experience acting as construction manager and the ability to manage project costs.

As discussed in greater detail in Section 4.5.4.3 above, the pricing for Minnesota Power's share of NTEC under the CDA is based on anticipated total investment of about $700 million for the combined plant and network upgrades. This estimate of total investment in NTEC is reasonable and accurately reflects anticipated costs of NTEC. Further, Minnesota Power, as Construction Agent, will be able to manage the construction to mitigate cost increases to the extent practicable.

Additionally, the Company would agree that its estimated costs be established as a "soft cap" on overall cost recovery in the event actual costs exceed the aggregate approximately $700 million. In the event actual costs to construct NTEC exceed the Company's estimated costs, Minnesota Power would retain the burden of proving that costs in excess of the estimate 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 provision ensures Minnesota Power's customers are fully protected from the risk that costs exceed estimated costs.

4.6.2.2 Project Timing

The Company's planning and schedule for NTEC have been developed to accommodate the long lead times needed to investigate, plan, develop, and implement a natural gas facility of this scale. Like with any large construction project, there are a number of risk factors that could delay construction and, potentially, the in-service date of NTEC. The NTEC project schedule, presented in Section 4.4.3 of this filing, includes some schedule allowance so that delays are less likely to impact the in-service date.

4.6.2.3 Wisconsin Permitting and Construction

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 require over a year or more to obtain agency approval: (1) CPCN approval from the PSCW for construction of a large electric generating facility;[109] (2) certificate of authority from the PSCW for construction of the SWL&P lateral pipeline;[110] and (3) the WDNR permit for construction and operation of new source of air emissions.[111] These three permits must be obtained prior to construction and a significant delay in review and approval from the PSCW or WDNR could delay construction of NTEC. The schedule 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, which will allow ample time for approval prior to construction and provide the PSCW with the benefit of having both approvals simultaneously.

4.6.2.4 Natural Gas Pricing and Reliability

Because the NTEC facility is a natural gas generation plant, risk also exists with respect to the pricing and reliability of natural gas transportation service and the pricing of natural gas commodity. In light of the location of the NTEC plant, however, these risks have been significantly mitigated. As noted above, NTEC is to be located less than ten miles from two interstate natural gas pipelines (Northern Natural Gas and Great Lakes). Each of these natural gas pipelines transports natural gas from different supply basins, providing for access to multiple transportation alternatives as well as multiple commodity supply alternatives. Firm transportation service from an interstate pipeline will ensure reliability of the fuel supply. With natural gas prices currently ranging between \$2.50/MMBtu and \$3.00/MMBtu and likely to remain lower than historical values for the foreseeable future, and given the availability of diverse natural gas

[109] Wis. Stat. § 196.491(3).

[110] Wis. Stat. § 196.49.

[111] Wis. Admin. Code Chs. Natural Resources (NR) 405 through 408; 40 C.F.R. Part 52.21.

supply options, the risks related to natural gas pricing and reliability with respect to NTEC are low.

4.6.2.5 Transmission Risk

It is difficult to precisely predict the interconnection costs that may be identified through the MISO study process for any given interconnection request. Recent queue sizes have been significantly larger than prior queues, which has led to complexities in MISO's study work and delays in the study schedules. MISO is working closely with its stakeholders to navigate these issues, but there is a considerable amount of uncertainty regarding the cost of network upgrades and schedule for completion of studies for any given interconnection customer.

As discussed previously and summarized below, Minnesota Power has addressed these transmission-related risks effectively in the NTEC Project Agreements.

4.6.2.5.1 Transmission Cost Risk and Mitigation

The primary cost risk is the uncertainty of the network upgrade costs. To protect Minnesota Power's customers from excessive network upgrade costs, the NTEC Project Agreements include provisions to reevaluate the viability of NTEC if network upgrades costs are projected to exceed the agreed-upon level.

Appendix Q: Summary of MISO's Generator Interconnection Process describes the required milestone payments associated with each phase of the interconnection process, and the points at which those milestone payments become non-refundable. There are three major milestone payments required to progress the NTEC project through the interconnection process. Each milestone payment corresponds to a decision point at which the project may either choose to withdraw from the queue or continue with the next phase of the interconnection process. If the project chooses to continue, the previous milestone payment becomes non-refundable, unless the penalty-free criteria discussed in Appendix Q are met. For NTEC, the initial milestone payment ("M2") required for entry into the MISO DPP study process was made at the time the project was submitted into the queue. Based on MISO's anticipated schedule for the August 2017 DPP cycle, the next milestone payment ("M3") is anticipated to be required at the end of July or early

August 2018. Upon payment of the M3 milestone payment, the M2 milestone payment will become non-refundable. The last milestone payment ("M4") is presently anticipated to be required in third quarter 2018. Upon payment of the M4 milestone payment, all milestone payments (M2, M3, and M4) will become non-refundable. By planning this Petition for completion prior to all of the required milestone payments, Minnesota Power has sought to mitigate the risk of having to forfeit milestone payments.

4.6.2.5.2 Transmission Timeline Risk and Mitigation

There are two main timeline-related risks associated with the MISO interconnection process: (1) the uncertainty of DPP timelines and (2) the uncertainty of time necessary to complete required network upgrades. The Company is mitigating the risk of a longer MISO interconnection process timeline impacting NTEC by filing for interconnection now instead of waiting until the project is further developed and closer to the in-service date of 2024.

The second time delay risk is the time necessary to build required network upgrades. If the MISO generator interconnection study process identifies that one or more large new transmission projects are needed in order for the August 2017 DPP group (of which NTEC is a part) to interconnect, then the time required to build the necessary network upgrades could extend past 2024. Similarly, if one or more large new transmission projects are required to facilitate the interconnection of previous DPP study groups there is a risk that construction of those projects — assumed to be in service for the NTEC study group — could also extend past 2024. In either of those situations, NTEC would need to enter into a Conditional GIA. A Conditional GIA permits a generating facility to interconnect to the transmission system on an as-available basis until the necessary network upgrades are complete. Conditional GIA's are discussed in further detail in Appendix Q. The availability of a Conditional GIA helps manage the risk of network upgrade construction extending past the 2024 in-service date for NTEC. Minnesota Power is further managing this risk by filing for interconnection now instead of waiting until the project is further developed and closer to the in-service date of 2024.

In short, while there are certain risks associated with purchasing a share of NTEC, Minnesota Power and South Shore have taken reasonable steps to mitigate such risks.

4.7 REQUEST FOR APPROVAL TO FLOW THE COSTS, CHARGES, AND REVENUES THROUGH THE FUEL AND PURCHASED ENERGY RIDER

In addition to obtaining Commission approval of the CDA and the Assignment Agreements related to the NTEC project, described above, Minnesota Power also requests authorization to modify the Company's currently-approved FPE Rider tariff[112] and approval of necessary variances to the Commission's automatic adjustment rules, Minn. R. 7825.2390 through 7825.2920, to structure the flow of costs, charges, and revenues related to the Company's share of NTEC in a manner that replicates utility generation ownership for the benefit of Minnesota Power customers.

To take advantage of the beneficial location of the NTEC plant and the benefits of significant economies of scale associated with joint ownership of the larger combined-cycle unit, it is not possible for Minnesota Power to directly own and dispatch a share of the NTEC plant. As a result, the Company has structured the CDA with South Shore so that the capacity and associated energy production from Minnesota Power's share of the NTEC plant are dedicated to Minnesota Power on the same basis as if Minnesota Power owned the generation asset directly in its own name. Minnesota Power, in its role as Operating Agent, will manage the fuel supply, be the market participant for the entire plant, and be responsible for offering energy from the entire plant into the MISO Day-Ahead and Real-Time markets. Minnesota Power's customers will receive a pro rata share of all of the benefits associated with the dispatch of its share of energy production associated with the capacity dedicated to Minnesota Power in these transactions.

To achieve these outcomes and to ensure ratepayers obtain the same benefits they would achieve if the NTEC 250 MW purchase was held as a rate-based asset, Minnesota Power requests that the Commission approve modification of the Company's FPE Rider, along with all necessary rule variances, so that the costs of and revenues from MISO purchases and sales as well as the fuel costs associated with the generation of energy from NTEC flow back to Minnesota Power customers. Minnesota Power's current FPE Rider operates pursuant to Minnesota rules and the

[112] Minnesota Power Electric Rate Book, Vol. 1, Section V, Page 50-50.1. Clean and redline versions of the proposed tariff amendments are included as Appendix V to this Petition. Because Minnesota Power currently has proposed amendments to this tariff sheet pending in Docket No. E015/GR-16-664, the attached clean and redline revisions are incorporated with those proposed pending amendments.

tariff on file with the Commission to account for any over- or under-recovery associated with providing energy to customers and is an integral part of the Company's current cost recovery. Under the currently-approved FPE Rider, fuel costs are recovered for Company-owned generating facilities and for associated energy purchases. Net energy costs (costs offset by revenues) are recovered for energy purchased on an economic dispatch basis. Under the structure of the CDA with South Shore, no actual energy will flow to Minnesota Power. Instead, the Company would receive the benefit of needed capacity and would continue to purchase needed energy from the MISO market as it does currently.

To structure the flow of costs, charges, and revenues to replicate utility ownership for the benefit of Minnesota Power customers, the Company proposes that the fuel costs associated with the generation of energy from NTEC would flow into the FPE Rider just as if it were Minnesota Power-owned generation but with no energy attached. The cost to procure energy (and related MWhs) from the MISO market would also flow through the FPE Rider, just as it does now. However, through the CDA, the credits and charges related to the NTEC generation would also flow to the benefit of Minnesota Power ratepayers and through the FPE Rider, offsetting the cost of the MISO purchases. The result is a netting of the costs of energy purchases against the revenue from the sales of NTEC energy into the MISO market, such that only the fuel costs associated with Minnesota Power's share of the generation of energy from the NTEC plant remain to be paid for by customers.

4.7.1 The Proposed Modifications to the Fuel and Purchased Energy Rider are in the Public Interest

The proposal to amend the currently-approved FPE Rider tariffs is consistent with Minn. Stat. § 216B.16, subd. 7(3), which permits an electric utility to utilize an automatic adjustment clause to recover the "federally regulated wholesale rates for energy delivered through interstate facilities" and "costs for fuel used in generation of electricity." In addition to ensuring that Minnesota Power's customers receive the benefit of the NTEC facility to the same extent as a utility-owned generation unit, the Company's proposal to modify the FPE Rider will ensure that any additional revenue from the sale of ancillary services related to the NTEC plant sold to MISO would flow through the FPE, providing additional benefits to Minnesota Power customers. Further, by allowing the costs, credits, and revenues related to Minnesota Power's share of the NTEC plant to flow through the FPE Rider, the Commission and other interested parties are ensured an opportunity to review the reasonableness and prudence of the costs.

While Minnesota Power believes its proposal for treatment of the costs, charges, and revenues related to its share of the NTEC plant are consistent with the purpose of the automatic adjustment rules outlined in Minn. R. 7825.2390 through 7825.2920, the proposed treatment is different than the treatment of other costs and revenues in the FPE Rider. The language of the Commission's automatic adjustment rules does not anticipate inclusion of revenues related to energy sales or other costs and revenues related to other MISO services. Therefore, Minnesota Power is requesting approval for modification of its FPE Rider tariffs and for approval of any and all variances to applicable rules to effectuate the proposed modification. Specifically, Minnesota Power requests variances to the following rules, as well as any other applicable rules the Commission determines necessary to implement the proposed treatment of costs with respect to the Company's FPE Rider:

- Minn. R. 7825.2400, subp. 8, which defines the "cost of fossil fuel" as "the current period withdrawals from account 151 as defined by the Minnesota uniform system of accounts." A variance to this rule would allow Minnesota Power to flow fuel costs that are related to a generating plant that is not a Minnesota Power owned asset.
- Minn. R. 7825.2500, which provides that an automatic adjustment must encompass "changes in cost resulting from changes in the federally regulated wholesale rate for energy purchased and changes in the cost of fuel consumed in the generation of electricity." A variance to this rule would allow for automatic adjustment for revenues generated from the sale of energy related to Minnesota Power's share of NTEC and to the extent the Commission determines a variance is required for Minnesota Power's proposal to recover its share of fuel costs for NTEC where those fuel costs are not specifically tied to energy.
- Minn. R. 7825.2600, which establishes the computation for the automatic adjustment of charges as "the sum of the current period cost of energy purchased and cost of fuel

> consumed per Kwh less the base electric cost per Kwh." A variance to this rule would allow Minnesota Power to adjust the definition of the cost of energy purchased and cost of fuel consumed with respect to NTEC where those costs are not specifically tied to units of energy generated from NTEC.

Minnesota Rule 7829.3200 allows the Commission to vary Minnesota rules provided that the following criteria are satisfied:

> (a) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
>
> (b) granting the variance would not adversely affect the public interest; and
>
> (c) granting the variance would not conflict with standards imposed by law.

Given that Minnesota Power is proposing modifications to the current FPE Rider to include the costs, charges, and revenues associated with serving Minnesota Power's retail customers and to facilitate passing back benefits from the sales of energy and ancillary services that result from the CDA to customers, the three factors for a variance have all been satisfied, as discussed below. The proposed modifications are reasonable, consistent with the public interest, and will ensure opportunities for the Commission to evaluate the costs, charges, and revenues to be recovered through the FPE Rider for prudence and reasonableness.

4.7.2 Denial of the Requested Modifications Would Impose An Excessive Burden

As a result of applicable Wisconsin law prohibiting direct Minnesota Power ownership and the joint ownership structure of NTEC, the Company is not able to structure recovery of NTEC fuel costs except as proposed. Denial of the requested modifications to the Company's FPE Rider as proposed would result in significant burden to Minnesota Power customers in not being able to take advantage of the benefits of NTEC, as described above.

Minnesota Power's proposed modifications to the FPE Rider are necessary to allow the costs and revenues linked to the Company's load serving obligations to be recovered through the FPE

Rider. Further, these modifications are necessary to ensure that the benefit of revenues generated from the sales of energy and ancillary services related to Minnesota Power's share of NTEC flow to the benefit of customers. Denial of the requested modifications would impose an excessive burden on both the Company, because an alternative mechanism for the recovery of energy and fuel costs related to serving Minnesota retail customers is not available; and to customers, who would not otherwise receive the full benefit of revenues generated for MISO sales.

4.7.3 Approval of the Proposed Modifications Would Not Adversely Affect the Public Interest

The public interest will be served by adopting the proposed modifications to the FPE Rider, which will effectively achieve the current balance between Minnesota Power and its customers provided under the existing FPE Rider. These variances ensure the NTEC project can be undertaken for the benefit of Minnesota Power customers, as described earlier. Moreover, ensuring the revenues from the sale of energy and ancillary services related to the Company's share of the NTEC plant are transferred through the FPE Rider for the benefit of Minnesota Power's customers will provide an offset to the associated costs for Minnesota Power to acquire needed energy from the MISO market to serve customer needs. The proposed transaction also allows Minnesota Power to net the costs and revenues of Locational Marginal Pricing ("LMP") purchases and sales associated with serving native load requirements in order to direct the value of its lowest cost generation available to retail customers; therefore, the modified FPE Rider allows customers to benefit from Minnesota Power's low-cost generation when less than the LMP and benefit from the LMP when lower than Minnesota Power's generation fuel cost. The FPE Rider, as modified, would continue to protect customers from market volatility.

Additionally, recovery of the cost of fuel related to the operation of Minnesota Power's pro rata share of the NTEC plant through the FPE Rider ensures Minnesota Power is able to recover for changes in fuel costs related to the generation of energy to meet customer needs. Further, approval of the requested modifications ensures the Department and Commission will have an opportunity to review these costs and revenues for reasonableness and prudence. Overall, approval of the proposed modifications will ensure the Company recovers its reasonable costs to procure energy to serve its customers while also providing benefits to customers, and does not adversely affect the public interest.

To better exemplify how the Company-owned generation costs will flow through the FPE Rider and how this transaction compares to Minnesota Power's current FPE Rider methodology, Table 8, below, illustrates a comparison between the traditional FPE Rider approach used by the Company and the proposed treatment of the FPE Rider with the inclusion of NTEC.

Table 8: Comparison of Current and Proposed FPE Rider Methodologies

Line	COST OF FUEL	April 2017	April 2017
1	All Stations - Total Burned for Generation	9,771,781	9,021,781
2	Plus : Fuel Component of Purchased & Interchange (Excl. Young 2)	13,515,871	14,415,871
2a	Less: Deferred Schedule 16 & 17 and other nonrecoverable MISO charges	9,585	9,585
	Plus: NTEC fuel costs		750,000
	Less: MISO credits from NTEC		900,000
3	Plus: Young 2 Purchases	2,888,147	2,888,147
4	Plus : Purchased Steam	0	0
5	Less : Fuel Cost recovered thru Inter-System Sales	8,457,954	8,457,954
6	Less : Fuel Cost recovered thru Large Power Excess Energy Sales	0	0
7	Less: Fuel Cost recovered thru Interruptible Power	0	0
8	Less: Fuel Costs Recovered thru Incr. Prod. Service	201,260	201,260
9	Total Monthly Fuel Cost	17,507,000	17,507,000
10			
	KWH SALES		
11	Total Sales of Electricity	1,187,323,562	1,187,323,562
12	Less: Inter-System Sales	357,378,808	357,378,808
13	Less: Large Power Excess Energy Sales	0	0
14	Less: Interruptible Power	0	0
15	Less: Incremental Production Sales	6,816,286	6,816,286
16	Total Monthly KWH Sales	823,128,468	823,128,468
18	**One Month Fuel Cost - cents/kWh**	**2.127**	**2.127**
		(1)	(2)

(1) This example assumes that NTEC is an MP asset and generates 30,000 MWh at a fuel cost of $25 and is included in line 1- total burned for generation. This would also decrease purchases by 30,000 MWh at an assumed cost of $30 which is inlcuded on line 2.

(2) This example includes the purchase of 30,000 MWh from the market at $30, the payment to NTEC for fuel-related costs, and the credit from NTEC for MISO charges/credits for the sale of NTEC energy to the market at $30 - all of these costs are included in line 2.

Column 1 assumes that NTEC is included as a Minnesota Power-owned asset and includes fuel costs (i.e., the current treatment of Company-owned generation costs that flow through the FPE

Rider). Column 2 assumes NTEC as proposed in this petition, including the purchase of energy from the market, payment to NTEC for fuel-related costs, and the credit from NTEC for MISO charges and credits for the sale of NTEC's energy into the market. The above example illustrates that whether Minnesota Power's share of NTEC is treated as a company owned asset (illustrated in column (1)) or treated as proposed (illustrated in column (2)), Minnesota Power's customers are unaffected.

Two assumptions were made in creating Table 8: (1) the 30,000 MW of generation from NTEC is a one for one offset of purchases that the Company would have made from the market; and (2) the LMP at MP.MP and at NTEC would be the same or very similar. With respect to the second assumption, the Company does not anticipate price separation due to the proximity of NTEC to the MP.MP load. If, however, price separation were to occur, due to the way the MISO market functions, the impact to customers would still be insignificant as the total costs and credits from MISO would not change due to the MISO settlement function.

While the figures used in Table 8 are meant to be illustrative, the table shows the similarities between the traditional and revised FPE Rider methodologies. Under the Company's proposed treatment of the FPE Rider, customers are not taking on any additional risk in comparison to the current treatment of FPE Rider costs today. As demonstrated in Table 8, above, the total monthly cost of fuel, total monthly kWh sales, and one month fuel costs are identical as between the current and proposed scenarios. Customers are, therefore, indifferent with respect to the Company's proposed treatment of the FPE Rider in this case, as the impact would be equivalent to the Company treating the FPE Rider in its current form.

This illustration further demonstrates that the public interest will not be adversely affected by the proposed modifications to the FPE Rider, as these modifications will not result in Minnesota Power's customers incurring additional expense; rather, customers will receive the benefits of the revenue generated from dispatch of the NTEC plant and the Commission will be ensured regulatory oversight consistent with a Company-owned generation asset.

4.7.4 Approval of the Proposed Modifications Would Not Conflict with Applicable Legal Standards

The proposed modification to Minnesota Power's FPE Rider would not conflict with applicable law. All of the costs and revenues sought to be included in the FPE Rider are properly classified as "federal regulated wholesale rates for energy delivered through interstate facilities" and "costs for fuel used in generation of electricity," consistent with Minn. Stat. § 216B.16, subd. 7. The Commission is authorized by Minn. Stat. § 216B.16, subd. 7 to allow for the automatic adjustment of charges for the expenses described in the filing. This statute does not limit the Commission's authority over how to best design such automatic adjustment mechanisms. Minnesota Power is not aware of any conflict with any other laws.

Accordingly, Minnesota Power respectfully requests that the Commission approve the Company's proposal to modify its existing FPE Rider methodology, as well as all variances to applicable rules as required to effectuate such changes. The proposed revisions to the FPE Rider will not result in an expansion of the FPE Rider recovery; rather, the revised FPE Rider would continue to reflect the costs and revenues supporting the cost of fuel and energy delivered to Minnesota Power's retail customers. The proposal to amend the FPE Rider will result in rate recovery of the overall costs for fuel and energy comparable to the costs contemplated to be recovered by the automatic adjustment statute and rules, and satisfies the requisite criteria under Minn. R. 7829.3200 for the Commission to vary any rules necessary to effectuate the Company's proposed modifications to its FPE Rider methodology.

4.8 COMMUNICATION AND FILING

Minnesota Power recognizes the importance of on-going communication with the Commission, the Department, and other stakeholders during the period following approval of the CDA up through commercial operation of NTEC. Minnesota Power has identified three primary milestones where it would be important to communicate project updates, first, when Minnesota Power, on behalf of the NTEC Owners, MISO, and ATC sign the GIA; second, when Minnesota Power, on behalf of the NTEC Owners, receives the required CPCN authorization from the PSCW; and third, when NTEC is operational. Minnesota Power commits to informing the

Commission, the Department, and other stakeholders in a timely manner about the achievement of these milestones.

Once commercially operational, Minnesota Power commits to file an annual compliance filing that provides the amount of actual delivered energy and actual accredited capacity for NTEC.

4.9 Conclusion

NTEC was selected based on thorough resource planning analysis and consideration of available alternatives and sensitivities and identified in a robust RFP process as the least-cost bid to meet Minnesota Power's identified need for dispatchable capacity. The proposed affiliated CDA and Assignment Agreements for the dedication of 48 percent of NTEC to Minnesota Power and its customers are consistent with the public interest and all required affiliated interest information to support approval of these agreements is provided in Appendix B.

Based on the foregoing, Minnesota Power respectfully requests that the Commission approve the Company's purchase of the output of a 48 percent share of the NTEC plant as proposed in this filing. Specifically, Minnesota Power respectfully requests that the Commission grant the following requests:

- Approval of the affiliated Assignment of Rights Agreements authorizing Minnesota Power to act as Construction Agent and Operating Agent under the NTEC Agreements;
- Approval of the affiliated CDA, dedicating 48 percent of NTEC to Minnesota Power and energy cost recovery through the FPE Rider; and
- Granting a variance and approval of associated tariff amendments to the FPE Rider to ensure that fuel costs related to Minnesota Power's share of NTEC are recovered and that MISO revenues realized under the CDA flow back to customers.

Timing is an important consideration as the Company has important project deadlines in the third and fourth quarters of 2018. Minnesota Power respectfully requests that the Commission make a final determination on this Petition in the third quarter of 2018, as contemplated by the Commission's September 19, 2017 Order for Hearing. This will ensure a robust discussion of all of the relevant issues while also providing certainty in accordance with project deadlines.

This next step in Minnesota Power's overall Energy*Forward* plan to diversify its resource mix will result in renewable resources providing 45 percent of the Company's energy supply by 2025 at the same time reducing carbon emissions by 42 percent. Minnesota Power is already meeting or exceeding state standards for renewable power, energy conservation, and carbon emission reduction through fleet transition of smaller coal units and the addition of renewable energy. The 48 percent share of NTEC coupled with the wind and solar elements of the Energy*Forward* Resource Package provides Minnesota Power's customers with safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, and adding substantial renewable resources to the system. This new set of resources will allow the Company to continue serving its customers for the long term and will ensure continued cost-effective flexibility for the benefit of Minnesota Power's customers.

Dated: October 24, 2017

Respectfully submitted,

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Attachment B

EAW for the Mankato Energy Center II Project near Mankato, MN

Environmental Assessment
Mankato Energy Center Expansion Project

In the Matter of Mankato Energy Center II, LLC's Application for a Site Permit for the 345 MW Expansion of the Mankato Energy Center

Docket No. IP6949/GS-15-620

Minnesota Department of Commerce
Energy Environmental Review and Analysis
February 2016

Responsible Government Unit

Department of Commerce
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Abstract

On August 5, 2015, Mankato Energy Center II, LLC (applicant) filed a site permit application with the Minnesota Public Utilities Commission (Commission) for the Mankato Energy Center expansion project. The applicant proposes to add a combustion turbine generator, a heat recovery steam generator, and associated equipment to the existing Mankato Energy Center (MEC) in Blue Earth County. This expansion of the MEC will allow for the production of an additional 345 megawatts of electrical power.

The applicant's proposed project requires a site permit from the Commission. Department of Commerce, Energy Environmental Review and Analysis (EERA) staff is responsible for conducting environmental review for site permit applications submitted to the Commission. Accordingly, EERA staff has prepared this environmental assessment (EA) for the project. This EA addresses the issues required in Minnesota Rule 7850.3700 and those identified in the Department's scoping decision of November 3, 2015.

Following release of this EA, a public hearing will be held in the project area. The hearing will be presided over by an administrative law judge from the Office of Administrative Hearings. Upon completion of the environmental review and hearing process, the record compiled on the site permit application will be presented to the Commission for a final decision. A Commission decision on the site permit application is anticipated in early 2016.

Persons interested in this project can place their names on the project mailing list by contacting Tracy Smetana, the Commission's public advisor, by email: consumer.puc@state.mn.us, or by phone: 651-296-0406 (toll free: 1-800-657-3782).

Documents of interest for this project can be found on the State of Minnesota's eDockets system: https://www.edockets.state.mn.us/EFiling/search.jsp. Enter the year "15" and the number "620." Documents of interest can also be found on the Department's website at: www.mn.gov/commerce/energyfacilities/ Docket.html?Id=34238.

List of Preparers
Ray Kirsch, Environmental Review Manager
Minnesota Department of Commerce

Acronyms, Abbreviations, and Definitions

AERA	Air Emissions Risk Analysis
ALJ	Administrative Law Judge
BACT	Best Available Control Technologies
Commission	Minnesota Public Utilities Commission
CN	Certificate of Need
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
CTG	Combustion Turbine Generator
dB	Decibels
dBA	A-weighted Sound Level Recorded in Decibels
DNR	Minnesota Department of Natural Resources
Department	Minnesota Department of Commerce
EA	Environmental Assessment
EERA	Department of Commerce Energy Environmental Review and Analysis
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
kV	Kilovolt
MEC	Mankato Energy Center
MGD	Million Gallons per Day
MnDOT	Minnesota Department of Transportation
MPCA	Minnesota Pollution Control Agency
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NAC	Noise Area Classification
NERC	North American Electric Reliability Corporation
NLEB	Northern Long-Eared Bat
NESC	National Electrical Safety Code
NO_X	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
PSD	Prevention of Significant Deterioration
SCR	Selective Catalytic Reduction
SPCC	Spill Prevention, Contingency, and Counter Measures
USFWS	United States Fish and Wildlife Service
VOC	Volatile Organic Compounds
WWTP	City of Mankato Wastewater Treatment Plant

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Summary

Mankato Energy Center II, LLC (applicant) proposes to expand the existing Mankato Energy Center (MEC) by adding a combustion turbine generator, a heat recovery steam generator, and associated equipment. This expansion of the MEC will allow for the production of an additional 345 megawatts of electrical power. The MEC was designed and constructed to accommodate this expansion.

In order to construct the proposed project, the applicant must obtain a site permit from the Minnesota Public Utilities Commission (Commission). The Commission's docket number for the site permit application is IP6949/GS-15-620. In addition to a site permit from the Commission, the project will require approvals (e.g., permits, licenses) from other state agencies, federal agencies, and local units of government.

Department of Commerce, Energy Environmental Review and Analysis (EERA) staff is responsible for conducting environmental review for site permit applications submitted to the Commission. The intent of this review is to ensure that citizens, local governments, agencies, and the Commission are aware of the potential human and environmental impacts of the project and possible mitigation measures. The Commission considers these impacts and mitigation measures when determining whether to issue a site permit for the project.

State Review Process

EERA staff has prepared this environmental assessment (EA) for the Commission and for other agencies and entities that have permitting authority related to the project. This EA is also intended to assist citizens in providing guidance to the Commission and other decision-makers regarding the project. This EA evaluates the potential human and environmental impacts of the applicant's proposed project and possible mitigation measures.

The EA does not advocate or state a preference for the proposed project. The EA analyzes potential impacts and mitigation measures so that citizens, local governments, agencies, and the Commission can work from a common set of facts.

EERA staff initiated work on this EA by soliciting comments on: (1) the issues and impacts that should be evaluated in the EA, and (2) the mitigation measures to study in the EA. This process of soliciting comments on the contents of the EA is known as "scoping." EERA solicited comments through a public meeting on October 13, 2015, and a public comment period that ended October 27, 2015.

Based on the scoping comments received, the Department issued the scoping decision for this EA on November 3, 2015. The scoping decision details the impacts and mitigation measures that are analyzed in the EA. Once completed and issued, the EA is entered into the record for the site permit proceedings, so that it can be used by the Commission in making decisions about the project.

Upon completion of the EA, a public hearing will be held in the project area. The hearing will be presided over by an administrative law judge (ALJ) from the Office of Administrative Hearings. Members of the public will have an opportunity to speak at the hearing, present evidence, ask questions, and submit comments. The ALJ will provide a report to the Commission that summarizes the hearing proceedings and comments.

Upon completion of the environmental review and hearing process, the record will be presented to the Commission for a final decision. A decision by the Commission on a site permit for the project is anticipated in summer 2016.

Potential Impacts of Proposed Project

Impacts to human settlements are anticipated to be minimal. Aesthetic impacts are unavoidable but are anticipated to be incremental and minimal. Impacts to public health and safety are anticipated to be minimal. Air emissions are anticipated to be within all state and federal guidelines. Though the project will increase greenhouse gas emissions at the MEC, it is anticipated to reduce greenhouse gas emissions in Minnesota overall.

Impacts to land-based economies are anticipated to be minimal. Impacts to archaeological and historic resources are anticipated to be minimal. Impacts to the natural environment, including air resources, water resources, flora, and fauna are anticipated to be minimal. Impacts to rare and unique natural resources are anticipated to be minimal.

Application of Siting Factors to Proposed Project

The Commission is charged with locating large electric power generating plants in a manner that is "compatible with environmental preservation and the efficient use of resources" and that minimizes "adverse human and environmental impact[s]" while ensuring electric power reliability.[1] Minnesota Rule 7850.4100 lists 14 factors for the Commission to consider in its site permitting decisions.

The potential human and environmental impacts of the project, relative to the siting factors of Minnesota Rule 7850.4100, are anticipated to be minimal and mitigated by (1) the proposed location of the project, (2) the general conditions in section 4.0 of the Commission's generic site permit template, and (3) the requirements of downstream permits.

[1] Minnesota Statute 216E.02.

1.0 Introduction

This document is an environmental assessment (EA) that has been prepared for the Mankato Energy Center expansion project proposed by Mankato Energy Center II, LLC (applicant). This EA evaluates the potential human and environmental impacts of the applicant's proposed project and possible mitigation measures.

The EA is intended to facilitate informed decision-making by state agencies, particularly with respect to the goals of the Minnesota Environmental Policy Act – "to create and maintain conditions under which human beings and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of the state's people."[2]

1.1 Proposed Project

The applicant proposes to expand the existing Mankato Energy Center (MEC) by adding a combustion turbine generator (CTG), a heat recovery steam generator (HRSG), and associated equipment. This expansion of the MEC will allow for the production of an additional 345 megawatts of electrical power. The MEC was designed and constructed to accommodate this expansion.

The project will use natural gas as a fuel source. Existing infrastructure installed for the MEC (e.g., electrical transmission, gas pipeline, water service) will be used for the project. The project is anticipated to be operational by July 1, 2018. The estimated project cost is between $220 million and $300 million dollars.

Project Location
The proposed project is located within the existing MEC, in the city of Mankato, in Blue Earth County (**Figure 1**). The MEC was designed and constructed to accommodate the project.

Project Need
The proposed project is needed to provide electrical power to meet the projected needs of Xcel Energy's electric power customers. The project was selected by the Minnesota Public Utilities Commission (Commission) to provide this power in a competitive resource acquisition process.

1.2 State of Minnesota Review Process

In order to construct the proposed project, the applicant must obtain a site permit from the Commission. The applicant submitted a site permit application to the Commission on August 5, 2015.[3] The Commission's docket number for this application is IP6949/GS-15-620. In addition to a site permit from the Commission, the project will require approvals (e.g., permits, licenses) from other state agencies, federal agencies, and local units of government (see Section 2.3).

In considering the applicant's site permit application, the Commission must determine whether a site permit can be issued, and, if so, what conditions should be included in the permit to mitigate potential

[2] Minnesota Statute 116D.02.
[3] Mankato Energy Center II, LLC, Application for a Site Permit for the Proposed 345 MW Expansion of the Mankato Energy Center, August 5, 2015, eDockets Numbers 20158-113056-01, 20158-113056-02, 20158-113056-03, 20158-113056-04 [hereinafter Site Permit Application].

impacts of the project. To aid the Commission in these determinations, the Commission gets assistance from several state agencies, including the Department of Commerce (Department) and the Office of Administrative Hearings (OAH).

Department Energy Environmental Review and Analysis (EERA) staff is responsible for conducting environmental review for site permit applications submitted to the Commission. The intent of this review is to ensure that citizens, local governments, agencies, and the Commission are aware of the potential human and environmental impacts of a proposed project and possible mitigation measures. The Commission considers these impacts and mitigation measures when determining whether to issue a site permit.

The OAH, at the request of the Commission, provides an administrative law judge (ALJ) to conduct a public hearing for a proposed project. The ALJ facilitates the hearing to gather input on the project and mitigation measures appropriate for the project. The ALJ submits a report to the Commission which summarizes the input received during the hearing.

Environmental Review

EERA staff has prepared this EA for the Commission, which has before it the applicant's site permit application, and for other agencies and entities that have permitting authority related to the project. Additionally, this EA has been prepared to assist citizens in providing guidance to the Commission and other decision-makers regarding the project. The EA evaluates the potential human and environmental impacts of the project and possible mitigation measures.

The EA does not advocate for a project or a specific mitigation measure. Rather, the EA analyzes potential impacts and mitigation measures such that citizens, local governments, agencies, and the Commission can work from a common set of facts.

EERA staff initiated work on this EA by soliciting comments on: (1) the issues and impacts that should be evaluated in the EA, and (2) the mitigation measures to study in the EA. This process of soliciting comments on the contents of the EA is known as "scoping." EERA solicited comments through a public meeting on October 13, 2015, and a public comment period that ended October 27, 2015.

Based on the scoping comments received, the Department issued the scoping decision for this EA on November 3, 2015 (**Appendix A**). The scoping decision details the impacts and mitigation measures that are analyzed in the EA. Once completed and issued, the EA is entered into the record for the site permit proceedings so that it can be used by the Commission in making decisions about the project.

Public Hearing

After the EA is issued, an ALJ will conduct a public hearing for the project. The hearing will be held in the project area. Interested persons will have an opportunity at the hearing to ask questions, provide comments, and advocate for the mitigation measures that they believe are most appropriate for the project.

The ALJ will submit a report to the Commission which summarizes the input received during the public hearing. The Commission will use the ALJ report, the EA, and the entire record in deciding whether to issue a site permit for the project.

1.3 Organization of the Environmental Assessment

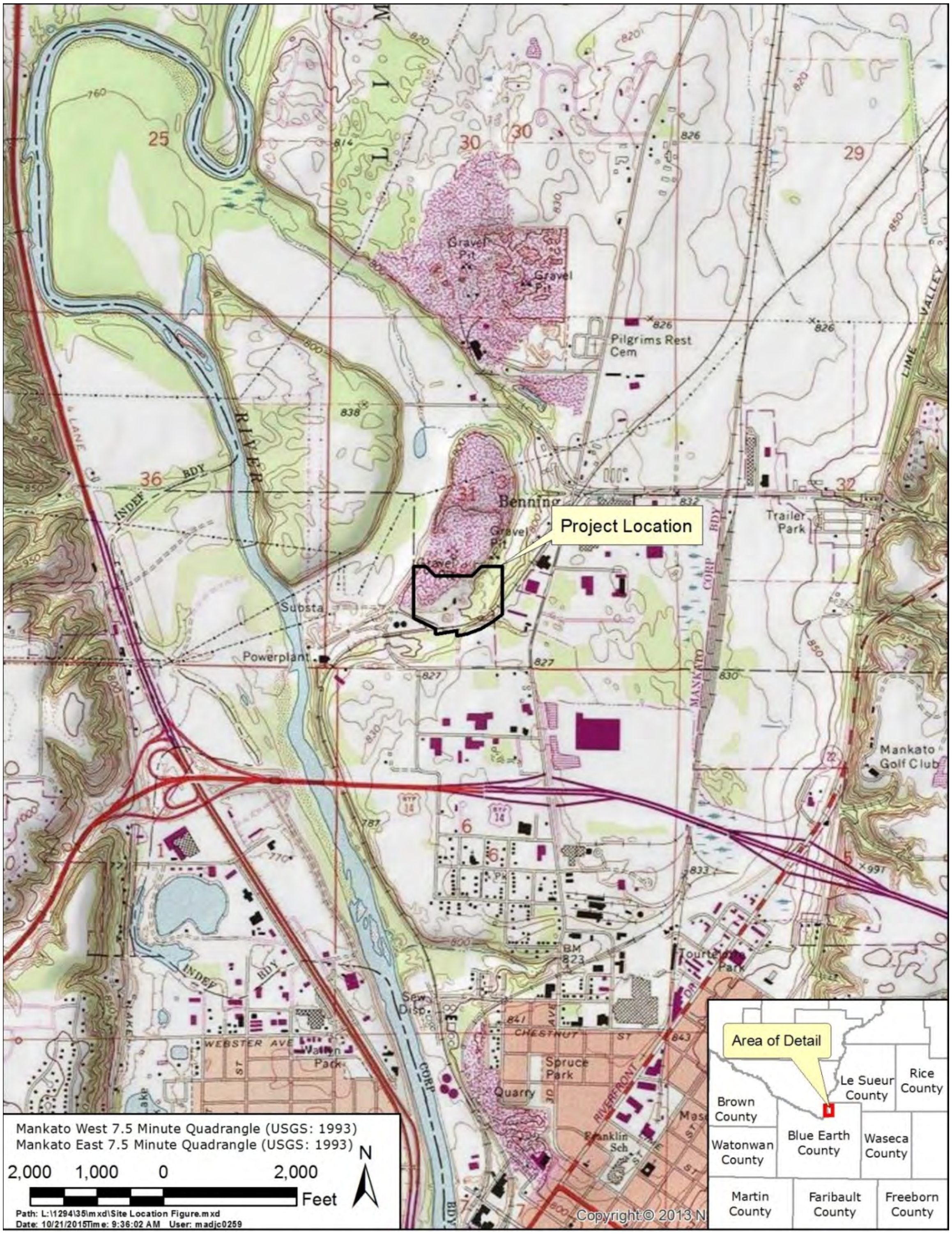
This EA addresses the issues required in Minnesota Rule 7850.3700 and those identified in the Department's scoping decision of November 3, 2015 (**Appendix A**), and is organized as follows:

Section 1.0	**Introduction**	The introduction provides an overview of the proposed project, the State of Minnesota's review process, and this EA.
Section 2.0	**Regulatory Framework**	Section 2.0 describes the regulatory framework associated with the project, including the Commission's site permitting process and other permits and approvals required for the project.
Section 3.0	**Proposed Project**	Section 3.0 describes the Mankato Energy Center expansion project as proposed by the applicant. It also describes the engineering and construction of the project
Section 4.0	**Potential Impacts of the Proposed Project**	Section 4.0 analyzes the potential impacts of the proposed project to human and natural resources and identifies measures that could be implemented to avoid, minimize, or mitigate these impacts.
Section 5.0	**Application of Siting Factors**	Section 5.0 discusses the proposed project relative to the siting factors of Minnesota Rule 7850.4100.

1.4 Sources of Information

The primary source of information for this EA is the site permit application submitted by Mankato Energy Center II, LLC. Additional sources of information are indicated in footnotes. New and additional information has been included from the applicant. Information from prior EERA environmental review documents and other state agencies is included. Information was also gathered by a site visit.

Figure 1. Project Overview Map



2.0 Regulatory Framework

The Mankato Energy Center (MEC) expansion project requires a site permit from the Minnesota Public Utilities Commission (Commission). Additionally, the project will require approvals from other state and federal agencies with permitting authority for actions related to the project.

2.1 Certificate of Need

No person may construct a large energy facility in Minnesota without a certificate of need (CN) from the Commission.[4] An electric power generating plant is a large energy facility if it has capacity to generate 50,000 kilowatts or more.[5] The proposed project will have the capacity to generate 345 MW and thus is a large energy facility. However, a CN is not required for a large energy facility if the facility is selected in a bidding process established by the Commission.[6] The proposed project was selected in such a process by the Commission.[7] As a result, the project does not require a CN.

2.2 Site Permit

In Minnesota, no person may construct a large electric power generating plant without a site permit from the Commission.[8] A large electric power generating plant is defined as electric power generating equipment and associated facilities designed for and capable of operation at a capacity of 50,000 kilowatts or more.[9] The proposed project will have the capacity to generate 345 MW and therefore requires a site permit from the Commission.

The applicant submitted a site permit application to the Commission on August 5, 2015. The application was accepted as complete by the Commission on October 14, 2015. The applicant has indicated its intention to utilize the Power Plant Siting Act's alternative review process for the project. Because the project will be fueled solely by natural gas, the project is eligible for this process.[10] The alternative review process includes environmental review and a public hearing, and typically takes six to nine months to complete.

Environmental Review

Applications to the Commission for site permits are subject to environmental review conducted by Department of Commerce, Energy Environmental Review and Analysis (EERA) staff.[11] Projects proceeding under the alternative review process require the preparation of an environmental assessment (EA).[12] An EA is a document which describes the potential human and environmental impacts of the proposed project and possible mitigation measures. The Department of Commerce determines the scope of the EA. The EA must be completed and made available prior to the public

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[4] Minnesota Statute 216B.243.
[5] Minnesota Statute 216B.2421.
[6] Minnesota Statute 216B.2422, Subd. 5(b).
[7] Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel, February 5, 2015, Docket No. E-002/CN-12-1240, eDockets Number 20152-107070-01.
[8] Minnesota Statute 216E.03.
[9] Minnesota Statute 216E.01.
[10] Minnesota Statute 216E.04, Subd. 1.
[11] Minnesota Statute 216E.04, Subd. 5.
[12] Id.

hearing for the project.

On October 13, 2015, Commission staff and EERA staff held a joint public information and EA scoping meeting in the city of Mankato. The purpose of the meeting was to provide information to the public about the proposed project, to answer questions, and to allow the public an opportunity to suggest impacts and mitigation measures that should be considered in the EA for the project. Three persons attended the meeting; these persons made no comments regarding the project.[13]

A comment period followed the public meeting and was open through October 27, 2015. Comments were received from one person and two state agencies.[14] These comments did not identify specific impacts or mitigation measures to study in the EA.

The Minnesota State Historic Preservation Office noted that, based on its review of the project, there were no archaeological or historic resources in the project area that would be impacted by the project.[15]

The Minnesota Department of Transportation (MnDOT) noted that the project did not appear to impact MnDOT right-of-way.[16] MnDOT indicated that consideration should be given to the movement of oversize/overweight equipment for the project, and that the applicant should coordinate with MnDOT if such equipment is transported on local highways.[17]

After consideration of the site permit application and public comments received during the scoping process, the deputy commissioner of the Department of Commerce issued a scoping decision on November 3, 2015 (**Appendix A**). The scoping decision identifies the resources, potential impacts, and mitigation measures that are evaluated in this EA. EERA staff provided notice of the scoping decision to those persons on the project mailing list.

Public Hearing

Upon completion of the EA, a public hearing will be held in the project area.[18] The hearing will be presided over by an administrative law judge (ALJ) from the Office of Administrative Hearings. Members of the public will have an opportunity to speak at the hearing, present evidence, ask questions, and submit comments. The ALJ will provide a report to the Commission that summarizes the hearing proceedings and comments.

Comments received during the hearing on the EA become part of the record in the proceeding. EERA staff will respond to comments on the EA during the hearing comment period, but staff is not required to revise or supplement the EA document.[19] Upon completion of the environmental review and hearing process, the record will be presented to the Commission for a final decision. A decision by the Commission on a site permit for the project is anticipated in summer 2016.

[13] Comments on Scope of Environmental Assessment, eDockets Number 201510-115183-01.
[14] Id.
[15] Id.
[16] Id.
[17] Id.
[18] Minnesota Statute 216E.04, Subd. 6.
[19] Minnesota Rule 7850.3800, Subp. 5.

Permit Decision

The Commission is charged with selecting sites for electric power generating plants that minimize adverse human and environmental impacts while ensuring electric power system reliability and integrity.[20] Site permits issued by the Commission may include conditions specifying construction and operation standards. The Commission's generic site permit template for large electric power generating plants is included in **Appendix B**.[21]

Minnesota Statute Section 216E.03, subdivision 7(b) identifies 12 considerations that the Commission must take into account when evaluating sites for electric power generating plants.[22] Minnesota Rule 7850.4100 lists 14 factors for the Commission to consider when making a decision on a site permit:[23]

A. Effects on human settlement, including, but not limited to, displacement, noise, aesthetics, cultural values, recreation, and public services;

B. Effects on public health and safety;

C. Effects on land-based economies, including, but not limited to, agriculture, forestry, tourism, and mining;

D. Effects on archaeological and historic resources

E. Effects on the natural environment, including effects on air and water quality resources and flora and fauna;

F. Effects on rare and unique natural resources;

G. Application of design options that maximize energy efficiencies, mitigate adverse environmental effects, and could accommodate expansion of transmission or generating capacity;

H. Use or paralleling of existing right-of-way, survey lines, natural divisions lines, and agricultural field boundaries;

I. Use of existing large electric power generating plant sites;

J. Use of existing transportation, pipeline, and electrical transmission systems or rights-of-way;

K. Electrical systems reliability;

L. Costs of constructing, operating, and maintaining the facility which are dependent on design and route;

M. Adverse human an natural environmental effects which cannot be avoided; and

N. Irreversible and irretrievable commitments of resources.

[20] Minnesota Statute 216E.02.
[21] Generic Site Permit Template for a Large Electric Power Generating Plant, Minnesota Public Utilities Commission, February 8, 2016, eDockets Number 20162-118074-02.
[22] Minnesota Statute 216E.03, Subd. 7.
[23] Minnesota Rule 7850.4100.

At the time the Commission makes a final decision on a site permit, the Commission must determine whether the EA and the record created at the public hearing address the issues identified in the scoping decision.[24]

The Commission is charged with making a final decision on a site permit within 60 days after receipt of the ALJ's report.[25] A final decision must be made within six months after the Commission's determination that an application is complete. The Commission may extend this time limit for up to three months for just cause or upon agreement of the applicant.[26]

If issued a site permit by the Commission, the applicant may exercise the power of eminent domain to acquire land for the project.[27]

2.3 Other Permits and Approvals

A site permit from the Commission is the only state permit required for the siting of the project. The Commission's site permit supersedes local planning and zoning and binds state agencies.[28] Thus, state agencies are required to participate in the Commission's permitting process to aid the Commission's decision-making and to indicate sites that are not permittable.[29]

This said, various federal, state, and local permits may be required for activities related to the construction and operation of the project. All permits subsequent to the Commission's issuance of a site permit and necessary for the project (commonly referred to as "downstream permits") must be obtained by a permittee. **Table 1** includes a list of downstream permits that may be required for the project.

Federal Approvals

The U.S. Environmental Protection Agency (EPA) regulates potential impacts to human health and the environment through a variety of permit and approvals.[30] The EPA's authority extends to multiple activities including emissions to air and water and the handling of hazardous wastes.

The U.S. Federal Energy Regulatory Commission (FERC) regulates the interstate transport of electricity, natural gas, and oil.[31] FERC regulates the wholesale sale of electricity in interstate commerce.

The U.S. Fish and Wildlife Service (USFWS) requires permits for the taking of threatened or endangered species.[32] The USFWS encourages consultation with project proposers to ascertain a project's potential to impact these species and to identify mitigation measures for the project generally.

[24] Minnesota Rule 7850.3900.
[25] Id.
[26] Id.
[27] Minnesota Statute 216E.12.
[28] Minnesota Statute 216E.10.
[29] Id.
[30] U.S. Environmental Protection Agency, Our Mission and What We Do, http://www2.epa.gov/aboutepa/our-mission-and-what-we-do.
[31] U.S. Federal Energy Regulatory Commission, What FERC Does, http://www.ferc.gov/about/ferc-does.asp.
[32] U.S. Fish and Wildlife Service, Endangered Species, http://www.fws.gov/ENDANGERED/permits/index.html.

Table 1. Potential Permits and Approvals[33]

Jurisdiction	Permit
Federal Approvals	
U.S. Environmental Protection Agency	Acid Rain Permit; Risk Management Plan; Hazardous Waste Generation
Federal Energy Regulatory Commission	Exempt Wholesale Generator Self-Certification; Market-Based Rate Authorization
U.S. Fish and Wildlife Service	Threatened and Endangered Species Consultation
State of Minnesota Approvals	
Department of Natural Resources	Threatened and Endangered Species Consultation
Minnesota Pollution Control Agency	NPDES/SDS Stormwater Permit; Air Emission Facility Permit; Hazardous Waste Generator License; Storage Tank Registration and Permitting
Minnesota Department of Transportation	Special Hauling Permit
Local Approvals	
County, City	Conditional Use Permit; Building Permit; Sewer Connections

State Approvals

The Minnesota Department of Natural Resource (DNR) regulates potential impacts to Minnesota's natural resources.[34] Similar to USFWS, DNR encourages consultation with project proposers to ascertain a project's potential to impact state-listed threatened and endangered species and possible mitigation measures.

The Minnesota Pollution Control Agency (MPCA) regulates potential impacts to public health and the environment.[35] A national pollutant discharge elimination system / sanitary disposal system (NPDES/SDS) stormwater permit is required for stormwater discharges from construction sites and industrial facilities. An air permit is required for regulated facilities to ensure compliance with a variety of state and federal air quality requirements. The MPCA also regulates generation, handling, and storage of hazardous wastes.

[33] Site Permit Application, Section 11.
[34] Minnesota Department of Natural Resources, About the DNR, http://www.dnr.state.mn.us/aboutdnr/index.html.
[35] Minnesota Pollution Control Agency, About MPCA, http://www.pca.state.mn.us/index.php/about-mpca/index.html.

A permit from the Minnesota Department of Transportation (MnDOT) is required for the transport and delivery of equipment that is oversize or overweight.[36]

Local Approvals

The Commission's site permit supersedes local planning and zoning regulations and ordinances.[37] However, permittees must obtain local approvals necessary for proper local government functioning – e.g., the safe use of local roads; the inclusion of infrastructure on local government maps.

2.4 Applicable Codes

The applicant's proposed project must meet the requirements of the National Electrical Safety Code (NESC).[38] The code is designed to protect human health and the environment. It also ensures that electrical generating equipment and associated facilities are built from materials that will withstand the operational stresses placed upon them over the expected lifespan of the equipment, provided that routine maintenance is performed.

The applicant must also comply with North American Electric Reliability Corporation (NERC) standards.[39] NERC standards define the reliability requirements for planning and operating the electrical transmission grid in North America.

2.5 Issues Outside the Scope of the Environmental Assessment

In accordance with the scoping decision for this EA (**Appendix A**), the following topics are not addressed in this document:

- No-build alternative.
- Issues related to project need, size, type, or timing.
- Any site alternative not specifically identified for study in the scoping decision.

[36] Minnesota Department of Transportation, Overdimension Permits, http://www.dot.state.mn.us/cvo/oversize.
[37] Minnesota Statute 216E.10.
[38] Minnesota Statute 326B.35 (requiring utilities to comply with the most recent edition of the NESC when constructing new facilities or reinvesting capital in existing facilities); see also Appendix B, Section 4.3.1, Generic Site Permit Template.
[39] Appendix B, Section 4.3.1, Generic Site Permit Template.

3.0 Proposed Project

The applicant proposes to expand the existing Mankato Energy Center (MEC) by adding a combustion turbine generator, a heat recovery steam generator, and associated equipment. This expansion of the MEC will allow for the production of an additional 345 megawatts of electrical power. This section describes the applicant's proposed project, project construction, and project costs.

3.1 Project Description

The applicant's proposed expansion of the Mankato Energy Center (MEC) includes a new combustion turbine generator (CTG), a new heat recovery steam generator (HRSG), and associated equipment. The CTG will use natural gas as a fuel. The HSRG will supply high pressure steam to the MEC's existing steam turbine. The project will use cooling water from the city of Mankato's wastewater treatment plant (WWTP). Electrical power produced by the project will be transmitted to the existing Wilmarth substation.

Mankato Energy Center Site

The MEC is located in the city of Mankato in Blue Earth County. The plant is located on a portion of an old limestone quarry which was converted to a landfill.[40] The landfill is now closed. Construction of the plant began in 2004, and the MEC became operational in May 2006.[41] The MEC site is approximately 25 acres in size (**Figure 2**).[42]

The MEC was permitted by the Minnesota Environmental Quality Board in 2004 as a combined cycle electric generating plant with two CTGs, two HSRGs, and one steam turbine.[43] The facilities for the plant were sized to accommodate these components.[44] However, only one CTG and one HSRG were ultimately constructed.[45] Thus, the MEC, as it currently exists, is a site specifically designed for the applicant's proposed expansion. The addition of a CTG and HSRG would complete the power plant and site as it was originally planned.

[40] Site Permit Application, Section 2.4
[41] Additional Project Information from Applicant, January 27, 2016, eDockets Number 20161-117736-01 [hereinafter Additional Project Information from Applicant].
[42] Site Permit Application, Section 2.4.
[43] Site Permit Application, Section 2.3.
[44] Id.
[45] Id.

Figure 2. Mankato Energy Center Site

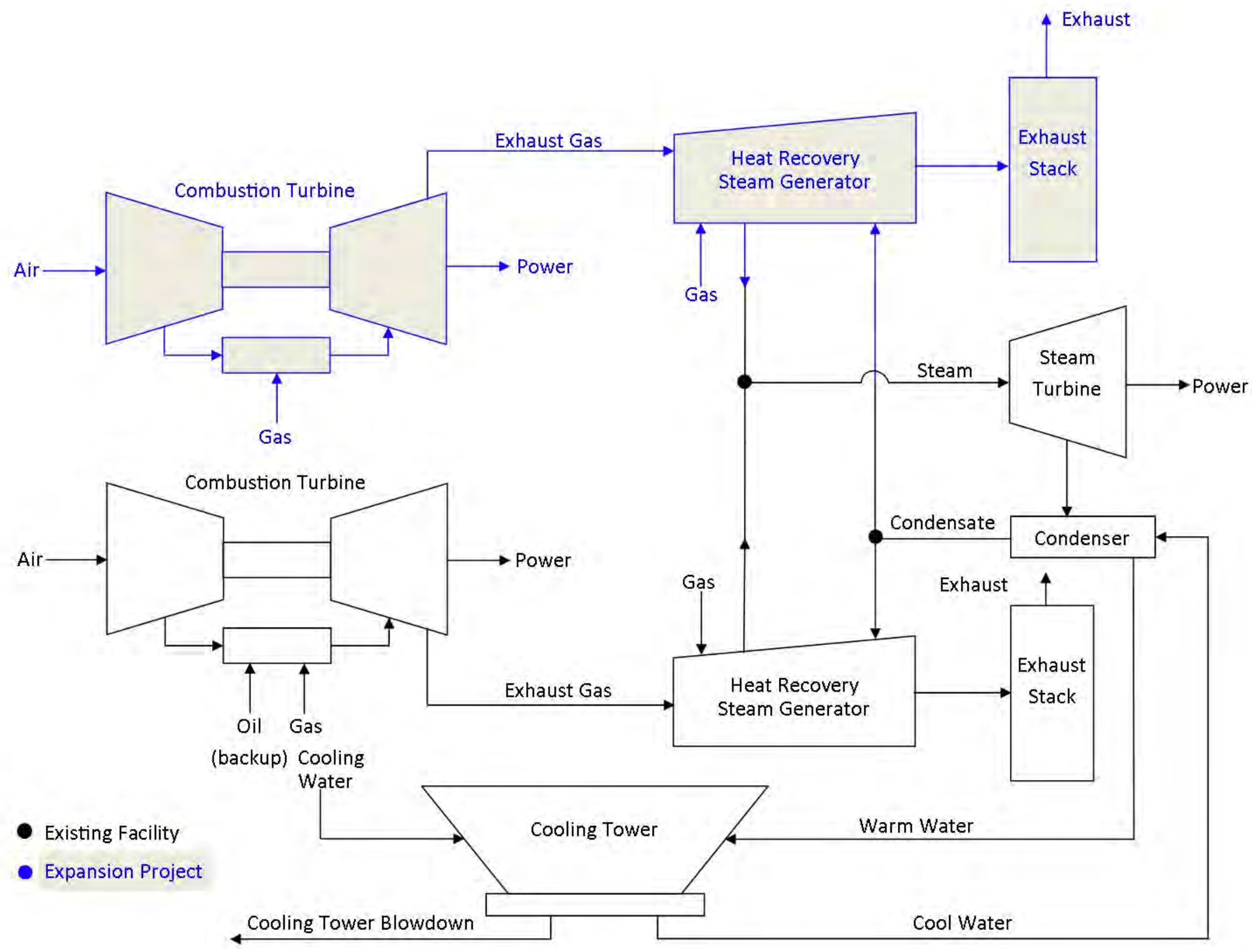
Power Generation Systems

Currently, the MEC is a combined cycle electric generating plant with one CTG, one HSRG, and a steam turbine (**Figure 3**).[46] The plant generates electrical power through the mechanical turning of the CTG and the steam turbine. This power generation configuration is known as a "1 X 1" combined cycle power plant – it has one CTG and one HSRG, with the steam from the HSRG driving one steam turbine. The applicant's proposed expansion would change the MEC into a 2 X 1 configuration.[47] The expanded plant would have two CTGs and two HSRGs, with steam from two HSRGs driving one steam turbine (**Figure 4**).

Figure 3. Mankato Energy Center[48]

[46] Site Permit Application, Section 2.7.
[47] Id.
[48] View looking south of combustion turbine generator, heat recover steam generator, and exhaust stack.

Figure 4. Power Generation Schematic for Mankato Energy Center



The applicant's proposed expansion of the MEC includes (**Figure 5, Appendix C**):[49]

- A natural-gas fired combustion turbine generator;
- A heat recover steam generator with natural gas-fired duct burners;
- Four new cooling tower cells;
- A step-up transformer and associated switchgear;
- An emergency diesel generator (if necessary); and
- Expansion of plant support systems, e.g., fire suppression, steam piping, electrical systems.

The CTG will be a natural-gas fired F-Class turbine with low nitrogen oxide (low-NO_X) combustors.[50] Electrical output of the CTG will be approximately 200 MW. Exhaust gas from the CTG will be directed

[49] Site Permit Application, Section 2.7.

to the new HSRG. The HSRG will be a triple-pressure, reheat type steam generator designed to supply high pressure stream appropriate for the existing steam turbine at the MEC.[51] The HSRG will have a selective catalytic reduction (SCR) system to reduce NO_X emissions.[52] The HSRG will also use an oxidation catalyst to reduce emissions of carbon monoxide (CO) and volatile organic compounds (VOC).[53] Exhaust gases from the CTG and HSRG will be directed to an exhaust stack, similar to the existing stack at the MEC.

Figure 5. Proposed Mankato Energy Center Expansion

The expansion project does not require a new steam turbine. The steam turbine at the MEC is sized to accommodate the additional steam from a 2 X 1 power plant configuration.[54] With steam from the new HSRG, the steam turbine will have the capacity to produce an additional 150 MW of electrical power.[55]

[50] Site Permit Application, Section 2.7.3.
[51] Id.
[52] Id.
[53] Id.
[54] Site Permit Application, Section 2.7.5.
[55] Id.

The MEC does not operate continuously and generates power only when needed by the electrical transmission grid.[56] As a result, the MEC generates approximately 15 percent of its maximum potential power production over the course of a year.[57] It is anticipated that the MEC will operate similarly with the expansion project.

Fuel Supply

The expansion project will be fueled solely with natural gas.[58] Natural gas is delivered to the MEC by a 20 inch pipeline, approximately four miles in length.[59] The pipeline is sized to support the natural gas requirements of the expanded MEC; thus, no new gas pipeline will be required for the expansion project.[60]

Water Supply and Use

The expansion project will use water for two primary purposes: (1) cooling water and (2) service water. Cooling water is required to dissipate the waste heat generated by the CTGs and HSRGs. This waste heat is first transferred to a condenser and then to a multi-cell evaporative cooling tower (**Figure 6**).[61] Cooling water is provided to the cooling tower through a pipeline from the Mankato wastewater treatment plant (WWTP).[62] This water is treated wastewater effluent from the WWTP. The cooling water will continue to be supplied by the Mankato WWTP for the expansion project.

There are currently eight cooling tower cells. The expansion project will require the addition of four more cells, resulting in a total of 12 cooling tower cells (**Figure 5**).[63] This addition will increase the tower's ability to dissipate heat and will increase water evaporation from the tower. The additional evaporative water loss will require approximately 74 percent more cooling water from the Mankato WWTP.[64] The applicant has indicated that they will work with the Mankato WWTP to upgrade existing pumps or install new pumps to supply additional cooling water needed for the expansion project.[65]

Service water is potable water from the Mankato municipal water system.[66] Service water is used for domestic purposes (e.g., drinking water, showers) and other plant related purposes.[67] Service water use is substantially less than cooling water use and is not anticipated to increase significantly with the expansion project.[68]

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[56] Site Permit Application, Section 2.3.
[57] Id.
[58] Site Permit Application, Section 2.7.1.
[59] Id.
[60] Id.
[61] Site Permit Application, Section 2.7.8.
[62] Site Permit Application, Section 2.7.6.
[63] Site Permit Application, Section 2.7.8.
[64] Site Permit Application, Section 2.7.6, Table 2-1.
[65] Site Permit Application, Section 2.7.6.
[66] Site Permit Application, Section 2.7.7.
[67] Id.
[68] Id.

Figure 6. Existing Cooling Tower at Mankato Energy Center[69]

Electrical Interconnection

Electricity currently generated at the MEC by the CTG and steam turbine proceeds through step-up transformers, to a switchyard, and then to the Wilmarth substation (**Figure 7**).[70] Electricity from the CTG is stepped up to 115 kV and transmitted at this voltage to the substation. Electricity from the steam turbine is stepped up 345 kV and transmitted to the substation.

For the expansion project, a new 115 kV step-up transformer will be installed to commute the power produced by the new CTG.[71] A breaker, disconnect, and dead end structure will be added to the switchyard.[72] A new 115 kV electrical line, approximately 300 feet in length, will be added to connect the switchyard to the Wilmarth substation (**Figure 7**).

The Wilmarth substation was constructed to accommodate electrical interconnections for the MEC as originally conceived – i.e., as a 2 X 1 power plant configuration. Thus, no substation upgrades will be needed to accommodate the power generated from the expansion project.[73]

[69] View looking northeast.
[70] Site Permit Application, Sections 2.7.11, 2.7.12, and 2.7.13.
[71] Id.
[72] Id.
[73] Id.

Figure 7. Electrical Interconnection at Mankato Energy Center

3.2 Project Construction

Construction of the project would not begin until all federal, state, and local approvals have been obtained. Construction is anticipated to begin in 2016; however, the construction timeline is dependent upon a number of factors including the receipt of all approvals, weather, and the availability of labor and materials.

The applicant will employ a contractor to design and construct the expansion project to meet all of the applicant's engineering requirements and all state, local, and federal requirements.[74] Construction of the project will involve foundation work, steel erection, and the delivery and installation of heavy equipment.[75] Improvements will be made to the existing cooling tower and gas delivery systems.[76] Existing water pumps at the Mankato WWTP will be upgraded for the project.[77]

The expansion project will, at various points in the construction process, be "tied in" to existing MEC systems – including the main steam system, hot and cold reheats, the low pressure steam system, and a

[74] Additional Project Information from Applicant.
[75] Site Permit Application, Section 4.3.
[76] Additional Project Information from Applicant.
[77] Site Permit Application, Section 2.7.6.

variety of water and instrumentation systems.[78] Cold commissioning will begin as project completeness allows.[79] Hot operational testing will follow to properly clean and operate all systems.[80] The final steps will be to interconnect the steam systems of the existing MEC with the expansion project and fine tune operation of a 2 x 1 combined cycle configuration.[81]

3.3 Project Costs

The estimated total cost for project construction is between $220 and $300 million dollars.[82] The applicant indicates that this cost range may fluctuate until the project's commercial operation date has been finalized.[83] Annual operating costs for the expansion project are anticipated to be between $3.5 and $5 million dollars.[84]

[78] Additional Project Information from Applicant.
[79] Id.
[80] Id.
[81] Id.
[82] Site Permit Application, Section 2.8.
[83] Id.
[84] Id.

4.0 Potential Impacts of the Proposed Project

This section discusses the resources, potential impacts, and possible mitigation measures associated with the proposed Mankato Energy Center expansion project. Impacts can be positive or negative, short or long term. Impacts can vary in duration and intensity, by resource and across geographies. Some impacts may be avoidable; some may be unavoidable but can be mitigated; others may be unavoidable and unable to be mitigated.

Potential Impacts and Mitigation

This section analyzes potential impacts of the expansion projects on various resources. Impacts are given context through discussion of their duration, size, intensity, and location. This context is used to determine an overall resource impact level. Impact levels are described in this section using qualitative descriptors. These descriptors are not intended as value judgments, but rather as a means to both ensure a common understanding among readers and compare resource impacts between alternatives.

- **Minimal**. Minimal impacts do not considerably alter an existing resource condition or function. Minimal impacts may, for some resources and at some locations, be noticeable to an average observer. These impacts generally affect common resources over the short-term.
- **Moderate**. Moderate impacts alter an existing resource condition or function, and are generally noticeable or predictable for the average observer. Effects may be spread out over a large area making them difficult to observe, but can be estimated by modeling or other means. Moderate impacts may be long-term or permanent to common resources, but are generally short- to long-term for rare and unique resources.
- **Significant**. Significant impacts alter an existing resource condition or function to the extent that the resource is severely impaired or cannot function. Significant impacts are likely noticeable or predictable for the average observer. Effects may be spread out over a large area making them difficult to observe, but can be estimated by modeling. Significant impacts can be of any duration, and may affect common and rare and unique resources.

This section also discusses possibilities to avoid, minimize, or mitigate specific impacts. These actions are collectively referred to as mitigation.

- **Avoid**. Avoiding an impact means it is eliminated altogether by moving or not undertaking parts or all of a project.
- **Minimize**. Minimizing an impact means to limit its intensity by reducing project size or moving a portion of the project from a given location.
- **Mitigate**. Impacts that cannot be avoided or minimized could be mitigated. Impacts can be mitigated by repairing, rehabilitating, or restoring the affected environment, or compensating for it by replacing or providing a substitute resource elsewhere.

Regions of Influence

Potential impacts to human and environmental resources are analyzed in this EA within specific spatial bounds or regions of influence (ROI). The ROI for each resource is the geographic area within which the project may exert some influence; it is used in this EA as the basis for assessing the potential impacts to each resource as a result of the project. Regions of influence vary with the resource being analyzed and the potential impact. The ROI for resources analyzed in this EA are summarized in **Table 2**.

The ROI for most human and environmental resources is the site of the Mankato Energy Center (MEC). Resources at the site could be impacted by the construction and operation of the expansion project. Other resources may be impacted at a greater distance from the project. In this EA, the following ROI will be used for these resources:

- **One thousand five hundred feet.** A distance of 1,500 ft. from the project will be used as the ROI for analyzing potential aesthetic, noise, and land use impacts as well as potential impacts to public safety from water vapor plumes. These impacts may extend outside of the 1,500 ft. distance, but are anticipated to diminish relatively quickly such that potential impacts outside of this distance would be minimal.

- **One mile**. A distance of one mile from the project will be used as the ROI for analyzing potential impacts to archaeological and historic resources and to rare and unique species.

  Direct impacts to archaeological and historic resources are anticipated to occur, if at all, within the MEC site. However, indirect impacts may extend beyond the site. For example, a historic resource may be impacted by power generating equipment near, but not directly next to, the resource. Direct impacts to rare and unique species are anticipated to occur, if they occur, within the MEC site. However, indirect impacts to rare and unique species may extend beyond the site, particularly for wildlife species. Wildlife may move throughout a project area and may be impacted by limitations on their movement and their ability to access cover, food, and water.

- **Project area.** The project area, defined generally as the city of Mankato and Blue Earth County, will be used as the ROI for analyzing potential impacts to cultural values, socioeconomics, public services, air quality, and tourism and recreation. These are resources for which impacts may extend throughout the project area.

Table 2. Regions of Influence for Human and Environmental Resources

Type of Resource	Specific Resource / Potential Impact to Resource	Region of Influence (ROI)
Human Settlements	Displacement	Site
	Aesthetics, Noise, Zoning and Land Use Compatibility	1,500 Feet
	Socioeconomics, Cultural Values, Public Services	Project Area
Public Health and Safety	Fire / Electrical	Site
	Water Vapor Plumes	1,500 Feet

Type of Resource	Specific Resource / Potential Impact to Resource	Region of Influence (ROI)
	Air Quality	Project Area
Land-Based Economies	Agriculture, Forestry, Mining	Site
	Tourism and Recreation	Project Area
Archaeological and Historic Resources	---	One Mile
Natural Environment	Water Resources, Soils, Flora, Fauna	Site
Rare and Unique Species	---	One Mile

Summary of Potential Impacts of the Proposed Project

Impacts to human settlements as a result of the project are anticipated to be minimal. Aesthetic impacts are unavoidable but are anticipated to be incremental and minimal. Impacts to public health and safety are anticipated to be minimal. Air emissions are anticipated to be within all state and federal guidelines. Though the project will increase greenhouse gas emissions at the MEC, it is anticipated to reduce greenhouse gas emissions in Minnesota overall by displacing more greenhouse gas intensive fuels (e.g., coal) and facilitating wind and solar power generation.

Impacts to land-based economies are anticipated to be minimal. Impacts to archaeological and historic resources are anticipated to be minimal. Impacts to the natural environment, including air resources, water resources, flora, and fauna are anticipated to be minimal. Impacts to rare and unique natural resources are anticipated to be minimal.

The Commission, if it issues a site permit for the project, can require the permittee to use specific mitigation measures or require that certain mitigation thresholds or standards be met through permit conditions (see **Appendix B**).

4.1 Environmental Setting

The MEC expansion project is proposed to be located within the MEC, in the city of Mankato, Blue Earth County. The MEC site is approximately 25 acres in size and is zoned for commercial / industrial / public use (**Figure 2**).[85] The MEC was permitted in 2004 as a 2 X 1 combined cycle electric generating plant. The facilities for the plant were sized to accommodate a 2 X 1 combined cycle plant. However, only a 1 X 1 combined cycle plant was constructed. Consequently, the MEC has a level, graveled area within the site that is undeveloped and would be used for the expansion project (**Figure 8**).

The MEC is located in an industrial area in the northern part of the city of Mankato. Adjacent properties are industrial and manufacturing facilities including Xcel Energy's Wilmarth electric generating plant and

[85] Site Permit Application, Section 4.1.

substation, scrap metal operations, and a U.S Postal Service mail processing facility.[86] The MEC site is just south of an old limestone quarry that was converted to a landfill. The landfill is now closed. The nearest residential area is approximately one-half mile to the south of the MEC, on the south side of U.S. Highway 14.[87]

Figure 8. Area within Mankato Energy Center for Expansion Project

The MEC is located on the northern edge of a large urban/suburban area that includes the city of Mankato – a city of approximately 40,000 residents – and the city of North Mankato. The project area includes multiple roads and highways including U.S. Highway 169 and U.S. Highway 14. Areas to the north and east of the MEC consist mainly of agricultural and conservation lands.[88]

The MEC is located approximately 1,800 feet east of the Minnesota River in the Minnesota River valley (**Figure 1**). The river and river bottoms provide wildlife habitat and recreational opportunities.[89]

4.2 Socioeconomic Setting

The project area has a median household income that is generally less than the median for the State of Minnesota (**Table 3**). The percentage of the population below the poverty level is generally higher in the project area than in the state as a whole (**Table 3**).

[86] Id.
[87] Id.
[88] Id.
[89] Id.

The economy in south central Minnesota, including the project area, is relatively diverse with the four largest industries, by employment, being professional and business services, manufacturing, trade, and health services.[90] In 2012, south central Minnesota produced approximately $24.7 billion dollars in goods and services, accounting for about four percent of Minnesota's $567.8 billion dollar economy.[91] The three largest industries, by economic output, are manufacturing, professional and businesses services, and agriculture.[92]

Table 3. Socioeconomic Characteristics of Project Area[93]

Location	Population	Median Household Income (dollars)	Population Below Poverty Level (percent)
Minnesota	5,457,173	$59,836	11.5
Blue Earth County	65,385	$49,935	19.2
City of Mankato	40,411	$41,171	27.0
City of North Mankato	13,432	$61,672	6.7

4.3 Human Settlements

Large electric power generating plants have the potential to negatively impact human settlements through a variety of means. A power plant could change the aesthetics of a project area, introduce new noise sources, or displace residences or businesses.

Impacts to human settlements resulting from the MEC expansion project are anticipated to be minimal. No residences or businesses will be displaced by the project; impacts to aesthetics are anticipated to be incremental and minimal. Noise levels are anticipated to increase as a result of the project, but are projected to remain within Minnesota state noise standards. Impacts to public services are anticipated to be minimal. The project is compatible with existing and future land uses. Impacts related to construction of the project are anticipated to be minimal and temporary.

Aesthetics

Aesthetic and visual resources include the physical features of a landscape such as land, water, vegetation, animals, and manmade structures. The relative value of these visual resources in a given area depends on what individuals perceive as being beautiful or aesthetically pleasing. Viewers'

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[90] Economic Composition of the South Central Region of Minnesota: Industries and Performance, http://www.extension.umn.edu/community/economic-impact-analysis/reports/docs/2014-South-Central-MN.pdf. For this report, south central Minnesota is defined as the 11 counties represented by the Region Nine Development Commission, including Blue Earth County.
[91] Id.
[92] Id.
[93] U.S. Census Bureau, State and County QuickFacts, http://quickfacts.census.gov/qfd/.

perceptions are based on their psychological connection to the viewing area and their physical relationship to the view, including distance to physical features, perspective, and duration of the view. Landscapes which are, for the average person, harmonious in form and use are generally perceived as having greater aesthetic value. Infrastructure which is not harmonious with a landscape or negatively impacts existing features of a landscape could negatively affect the aesthetics of an area.

The MEC expansion project is proposed to be built within the MEC site, which is itself within an industrial area of the city of Mankato.[94] The industrial area encompasses approximately 500 acres and includes industrial and manufacturing facilities including waste processing, scrap metal operations, a construction company, and a household hazardous waste collection site.[95] The MEC site is relatively lower than the surrounding topography with a landfill berm along the northern edge of the site.[96] U.S. Highway 14 is approximately one-half mile south of the MEC site. Immediately to the west is the Wilmarth electric generating station, an electric generating plant built in the 1940s and since converted to burn municipal solid waste.[97] Further west, approximately 1,800 feet from the MEC site, is the Minnesota River. The closest residential neighborhood is approximately two-thirds of a mile south of the MEC site, south of U.S. Highway 14.[98]

The existing MEC consists of buildings ranging in height from 30 to 120 feet.[99] The tallest existing structure at the site is the emissions stack, which is approximately 200 feet tall. The MEC expansion project will be a mirror image of the existing plant, and thus structures will be very similar in size. The tallest structure installed as a result of the expansion project will be a second emissions stack, approximately 200 feet in height.

Water vapor in emissions from the MEC stack, under certain meteorological conditions, can condense to form a plume that is visible in the project area (**Figure 9**).[100] Similarly, water vapor from the MEC cooling towers can result in a plume that is visible in the project area.[101] Plumes are most persistent and visible during cold and damp weather.[102] Generally plumes, if present, disperse and evaporate fairly quickly.[103]

Potential Impacts

Aesthetic impacts due to the MEC expansion project are anticipated to be minimal. The expansion project is harmonious with the existing landscape; it places like with like – it is the construction of an electric generating plant on the site of an existing electric generating plant. Further, any aesthetic impacts associated with the expansion will be incremental. The expansion project will introduce a new emissions stack; however the aesthetic impact of this second stack is anticipated to be incremental and minimal. Similarly, the expansion project will cause an increase in water vapor plumes, but the impact of these plumes is anticipated to be incremental and minimal. Because of the topography of the MEC site and screening by trees and other industrial facilities, the expansion project is anticipated to have limited visibility in the project area.

[94] Site Permit Application, Section 4.4.
[95] Id.
[96] Id.
[97] Id.
[98] Site Permit Application, Section 4.2.
[99] Site Permit Application, Section 4.4.
[100] Id.
[101] Id.
[102] Id.
[103] Id.

Figure 9. Water Vapor Plumes at Mankato Energy Center[104]

Mitigation
Aesthetic impacts as a result of the project are anticipated to be minimal; thus, no mitigation measures are proposed.

Noise

Noise can be defined as unwanted sound. Noise is measured in units of decibels (dB) on a logarithmic scale. The A weighted decibel scale (dBA) corresponds to the sensitivity range for human hearing. A noise level change of 3 dBA is barely perceptible to average human hearing while a 5 dBA change in noise level is noticeable.

All noises produced by the project must be within Minnesota noise standards (**Table 4**). These standards are promulgated by the Minnesota Pollution Control Agency (MPCA). The standards are organized by the type of environment where the noise is heard (Noise Area Classification, NAC) and the time of day. The noise standards are expressed as a range of permissible dBA within a 1-hour period; L_{50} is the dBA that may be exceeded 50 percent of the time within an hour, while L_{10} is the dBA that may be exceeded 10 percent of the time within 1 hour.

The primary noise receptors in the project area are neighboring industrial properties.[105] These industrial properties are in noise area classification three (NAC 3). The nearest residential area is approximately

[104] View looking east.

3,500 feet south of the MEC, south of U.S. Highway 14. Noise levels at the MEC site boundary are currently in the range of 63 to 67 dBA when the plant is operating.[106] These noise levels are within state noise standards for industrial properties.[107]

Table 4. Minnesota Noise Standards[108]

Noise Area Classification (NAC)	Daytime		Nighttime	
	L_{50}	L_{10}	L_{50}	L_{10}
1 – Residential	60	65	50	55
2 – Commercial	65	70	65	70
3 – Industrial	75	80	75	80

Potential Impacts

Potential noise impacts from the project fall into two categories: (1) noise impacts due to construction and (2) noise impacts due to operation of the expanded MEC. For both of these categories, noise impacts are anticipated to be minimal and within state noise standards.

Construction Noise

Construction noise sources are anticipated to include trucks, cranes, excavating equipment, pneumatic tools, and cleaning equipment.[109] Construction of the project will involve foundation work, steel erection, and the delivery and installation of heavy equipment.[110] Though construction noises are unavoidable, they are anticipated to be temporary in nature.[111] The applicant indicates that construction noise impacts will be mitigated by:[112]

- Controlling the extent and duration of significant noise generating activities during construction.
- Limiting the duration of the overall construction period by contracting for sufficient construction resources and through efficient scheduling of construction activities.

Commission site permits require that construction noise impacts be limited to daytime working hours (**Appendix B**). Based on the temporary nature of construction noises, the industrial setting of the MEC, the applicant's proposed mitigation measures, and the substantial distance to the nearest residential area, noise impacts due to construction of the project are anticipated to be minimal.

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[105] Site Permit Application, Section 4.3.
[106] Id.
[107] Id.
[108] Minnesota Rule 7030.0040. Standards expressed in dBA. Day time is 7:00 a.m. – 10:00 p.m.; night time is 10:00 p.m. – 7:00 a.m.
[109] Site Permit Application, Section 4.3.
[110] Id.
[111] Id.
[112] Id.

Operation Noise

The MEC's power generating equipment produces noise when in operation. This equipment includes the CTG, HSRG, steam turbine, cooling tower cells, and electrical transformers.[113] Noise levels at the MEC site boundary are currently in the range of 63 to 67 dBA when the plant is operating.[114] Noise levels at the MEC site when the plant is not in operation are generally in the range of 50 to 55 dBA.[115]

The applicant modeled and estimated operational noise levels for the MEC with the expansion project (**Appendix D**). This modeling indicates that noise levels at the MEC site boundary, with the expansion project, will be approximately 73 dBA. This noise level is within state noise standards for industrial properties. It is an incremental increase of approximately 6 to 10 dBA over current operational noise levels at the plant.

Mitigation

Noise impacts from the project are anticipated to be minimal and within Minnesota noise standards. Commission permits require compliance with these standards (**Appendix B**). However, this does not mean that noise impacts would not occur. Operation of the expanded MEC will increase noise levels in the project area. Even if noise levels are within state standards, persons near the plant – e.g., persons in or near the industrial near in which the MEC is located – would likely notice an increase in noise level. Operational noise impacts are mitigated, to a great extent, by the location of the MEC (away from persons and residential receptors) and by the fact that impacts will be incremental.

<u>Displacement</u>

Displacement is the removal of a residence or commercial building to facilitate the construction and operation of a power plant. There are no residences or commercial buildings within the MEC site that must be removed to construct the MEC expansion project. The only buildings within the site are those required for operation of the MEC.

No displacements are anticipated as a result of the project; no mitigation measures are proposed.

<u>Economics</u>

The MEC expansion project will take approximately 24 to 27 months to construct.[116] The project will employ up to 250 construction workers.[117] Once in operation, the applicant anticipates adding two employees, for a total of 19 full time employees at the plant.[118]

Potential Impacts

Economic impacts resulting from the project are anticipated to be positive. The project will provide construction jobs for persons in the project area – e.g., welders, pipefitters, carpenters.[119] The wages associated with these jobs will positively impact the regional economy. The project will result in increased purchasing of local goods and services during construction and, to some extent, during

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[113] Id.
[114] Id.
[115] Site Permit Application, Appendix A.
[116] Site Permit Application, Section 4.5.
[117] Id.
[118] Id.
[119] Id.

operation of the expanded plant.[120] Indirect positive impacts will accrue due to the improved load-serving capability of the electric transmission grid.

Potential negative economic impacts are anticipated to be minimal. Disruptions of local business due to construction of the project are anticipated to be minimal. Though the population below the poverty level in the project area, as a percentage of residents, is relatively greater than the state average (**Table 3**), no low-income or minority population is anticipated to be negatively and differentially impacted by the project.

Mitigation
Economic impacts resulting from the project are anticipated to be positive; thus, no mitigation measures are proposed.

Cultural Values

Cultural values are those community beliefs and attitudes which provide a framework for community unity and animate community actions. Cultural values are informed, in part, by history and heritage. The project area has been home to a variety of persons and cultures. In the early to mid-1800s, the area was populated primarily by Dakota Sioux. The city of Mankato was established in 1852 at the confluence of the Minnesota and Blue Earth Rivers.[121] North Mankato was established in 1898.[122] Settlers of these cities were of German, Welsh, Norwegian, Swedish, Irish, and Scottish heritage.[123]

Cultural values are also informed by the work and recreation of residents and by geographical features. The cities of Mankato and North Mankato have become a regional center for commerce, education, health care, and industry.[124] Persons in the project area have various recreational opportunities. The city of Mankato, and the project area generally, host multiple events each year, including the Deep Valley Homecoming, Mahkato Pow-Wow, and Minnesota River Ramble.[125]

Potential Impacts
No impacts to cultural values are anticipated as a result of the project. The project will not adversely impact the work or recreation of residents in the project area that underlie the area's cultural values. Nor will it adversely impact geographical features that inform these values.

Mitigation
No impacts to cultural values are anticipated as a result of the project; thus, no mitigation measures are proposed.

Public Services

Power plants are large infrastructure projects that have the potential to negatively impact public services, e.g., roads, utilities, emergency services. These impacts are typically temporary in nature, e.g., the inability to fully use a road or utility while construction is in process. However, impacts can be long term if they change the project area in such a way that public service options are foreclosed or limited.

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[120] Id.
[121] Mankato History, http://visitgreatermankato.com/mankato/explore/history/.
[122] Id.
[123] Blue Earth County History, http://www.bechshistory.com/museum/bec-history.
[124] Site Permit Application, Section 4.6.
[125] Annual Mankato Events, http://visitgreatermankato.com/mankato/visit/events/major-events/.

Temporary impacts to public services resulting from the MEC expansion project are anticipated to be minimal. Long-term impacts to public services are not anticipated.

Roads and Highways

The primary highways in the project area are U.S. Highway 169 and U.S. Highway 14. The MEC site is located approximately one-half mile north of U.S. Highway 14, off of the Summit Avenue exit.[126] The total distance from U.S. Highway 14 to the MEC entrance is approximately 0.75 miles.[127] No road or highway improvements are required for the project.[128]

Impact to roads and highways due to the project are anticipated to be minimal and temporary. Minor, temporary impacts to road or highway usage may occur during transportation of large equipment to the MEC site, e.g., traffic delays.[129] These impacts can be minimized through coordination with roadway authorities. No impacts to roads and highways are anticipated after the project has been constructed.

Airports

The Mankato Municipal Airport is located approximately 3.7 miles northeast of the MEC site in Lime Township, Blue Earth County.[130] The airport is one of the busiest municipal airports in the state with two runways that accommodate personal, business, and commercial flights.[131]

Tall structures can impact airport operations if they are within airport safety zones. Different classes of airports have different safety zones depending on several characteristics, including runway dimensions, classes of aircraft accommodated, and navigation systems. These characteristics determine the necessary takeoff and landing glide slopes, which in turn determine the safety zones.

No impacts to the Mankato Municipal Airport are anticipated as a result of the project. The orientation of the runways at the airport is such that the MEC is not within takeoff and landing glide slopes.[132] Further, the airport is located at an elevation (1,200 feet) that is higher than the elevation of the top of the emissions stack at the MEC (995 feet).[133] Because of the distance from the airport to the MEC, the orientation of the airport's glide slopes, and the elevation of the airport relative to the MEC, no impacts to the airport are anticipated as a result of the project.

Water Utilities

Water and sewer service are provided to the MEC by the city of Mankato.[134] Cooling water for the MEC is provided from the city's municipal wastewater treatment plant (WWTP).[135] Service water is provided through the city's municipal water supply.[136] The MEC expansion project will increase the use of wastewater for cooling (see Section 4.8). The applicant has indicated that they will work with the

[126] Site Permit Application, Section 3.1.
[127] Id.
[128] Id.
[129] Site Permit Application, Section 5.3.
[130] Site Permit Application, Section 5.4.
[131] Id.
[132] Id.
[133] Id.
[134] Site Permit Application, Section 4.8.2.
[135] Site Permit Application, Section 5.2.
[136] Id.

Mankato WWTP to upgrade existing pumps or install new pumps to supply the additional cooling water needed.[137] Increases in municipal water use are not anticipated.

No adverse impacts to water utilities in the project area are anticipated as a result of the project. The expansion project will not impact water supplies in the project area.[138] Pumping capacity at the Mankato WWTP will be upgraded as a result of the project.

Electric Utilities
Electrical service in the project area is provided by Xcel Energy and regional electric cooperatives.[139] The project will provide additional electrical generation in the project area. This electrical power may be used in the project area or distributed to other areas via the electric transmission system. No adverse impacts to electrical service are anticipated as a result of the project; no mitigation measures are proposed.

Natural Gas Utilities
Natural gas service in the project area is provided by CenterPoint Energy.[140] The project will utilize an existing, dedicated natural gas pipeline (see Section 3.1). The pipeline is sized to support the natural gas requirements of the expansion project. No new gas pipeline will be required for the expansion project.[141] No adverse impacts to natural gas service are anticipated as a result of the project; no mitigation measures are proposed.

Emergency Services
Emergency services are provided to the MEC and the project area by the city of Mankato.[142] Impacts to emergency services in the project area could result from (1) an inability to communicate that there is an emergency or (2) an inability to respond to an emergency.

No impacts to communication systems are anticipated as a result of the project; therefore, no impacts to the community's ability to communicate regarding an emergency are anticipated. During construction of the project, there may be temporary impacts to roads which could impede responses to an emergency, e.g., traffic delays. However, these impacts are anticipated to be minimal. No impacts to emergency services are anticipated once the project is operational; no mitigation measures are proposed.

Zoning and Land Use Compatibility
Electric power generating plants have the potential to adversely impact existing land uses and to be incompatible with future land uses. The MEC is located in an area zoned as commercial / industrial / public utility by the city of Mankato.[143] The MEC is a site specifically designed for the proposed expansion project. Accordingly, the project is consistent with existing and future land uses and no impacts to these land uses are anticipated as a result of the project.

[137] Site Permit Application, Section 2.7.6.
[138] Site Permit Application, Section 5.2.
[139] Electric Utility Service Areas, http://www.mngeo.state.mn.us/eusa/index.html.
[140] CenterPoint Energy, Where We Serve, http://www.centerpointenergy.com/en-us/corporate/about-us/company-overview/where-we-serve.
[141] Site Permit Application, Section 3.2.
[142] Site Permit Application, Section 4.8.4.
[143] Site Permit Application, Section 2.4.

4.4 Public Health and Safety

Electric power generating plants have the potential to negatively impact public health and safety – during construction and operation. As with any project involving heavy equipment, power generation systems, and high voltage transmission lines, there are safety issues to consider. Potential health and safety impacts related to construction of the project include injuries due to falls, equipment use, and electrocution. Potential health impacts related to the operation of the project include health impacts from air emissions, water emissions, fire, and electrocution.

Impacts to public health and safety resulting from the MEC expansion project are anticipated to be minimal. Potential construction related impacts are anticipated to be minimal. Potential impacts related to air and water emissions are anticipated to be minimal. Though the project will increase greenhouse gas emissions at the MEC, it is anticipated to reduce greenhouse gas emissions in Minnesota overall. Potential impacts due to water vapor plumes from the plant are anticipated to be minimal. Potential impacts due to fire or electrocution at the plant are anticipated to be minimal.

Air Emissions

Air emissions of many types – including those from the combustion of carbon-based fuels to produce electrical power – have the potential to impact public health. Health impacts can range from relatively minor annoyances such as coughing or itching eyes, to more severe impacts that require emergency-room visits and hospital admissions.[144] To avoid and minimize these impacts, the U.S. Environmental Protection Agency (EPA) has promulgated National Ambient Air Quality Standards (NAAQS).[145] These standards are designed to protect human health and the environment.[146] The responsibility for meeting these standards in Minnesota falls to the MPCA, which, through a state implementation plan, designs and implements means to control air pollutants.[147]

In order to ensure that NAAQS are met, the EPA requires major new stationary sources of air emissions to demonstrate that they will not cause a violation of the NAAQS.[148] In Minnesota, major new stationary sources must obtain a prevention of significant deterioration (PSD) permit from the MPCA. A PSD permit may allow certain air pollutants to increase in an area (referred to as the "PSD increment"), but must prevent air quality from deteriorating below the level set by the NAAQS.[149]

In addition to meeting NAAQS and PSD requirements, certain new facilities must also demonstrate, through an air emissions risk analysis (AERA), that the potential health risks associated with their air emissions are within state guidelines.[150]

[144] Air Quality in Minnesota – 2015 Report to the Legislature, Minnesota Pollution Control Agency, http://www.pca.state.mn.us/index.php/about-mpca/legislative-resources/legislative-reports/air-quality-in-minnesota-reports-to-the-legislature.html.
[145] National Ambient Air Quality Standards (NAAQS), http://www3.epa.gov/ttn/naaqs/criteria.html.
[146] Id.
[147] Minnesota State Implementation Plan (SIP), http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/state-implementation-plan/minnesota-state-implementation-plan-sip.html.
[148] Prevention of Significant Deterioration Basic Information, http://www.epa.gov/nsr/prevention-significant-deterioration-basic-information.
[149] Id.
[150] Air Emissions Risk Analysis (AERA), http://www.pca.state.mn.us/index.php/air/air-monitoring-and-reporting/air-emissions-modeling-and-monitoring/air-emission-risk-analysis-aera/air-emissions-risk-analysis-aera.html.

Air emissions may include greenhouse gases – gases that, upon release to the atmosphere, warm the atmosphere and surface of the plant, leading to alterations in the earth's climate.[151] Because warming of the planet and changes in the earth's climate result in adverse human and environmental impacts, the State of Minnesota has established goals to reduce greenhouse gas emissions.[152] The state has a goal of reducing greenhouse gas emissions to 15 percent below 2005 emission levels by 2015 and to 30 percent below 2005 emission levels by 2025.[153]

Potential Impacts

The MEC, as it exists now, is fueled by natural gas with fuel oil as a backup.[154] The MEC expansion project will be fueled solely with natural gas.[155] The combustion of these fuels will result in the emission of combustion by-products that have the potential for public health impacts.[156] With appropriate mitigation measures, these emissions are anticipated to be within all state and federal standards and guidelines. Additionally, though the project will increase greenhouse gas emissions at the MEC, it is anticipated to reduce greenhouse gas emissions in Minnesota overall. As a result, public health impacts due to air emissions from the project are anticipated to be minimal.

National Ambient Air Quality Standards and Prevention of Significant Deterioration

Estimated potential annual emissions of air pollutants from the MEC expansion project are shown in **Table 5**. Because a number of air pollutants have the potential to be emitted in amounts greater than their respective PSD thresholds, the project is subject to PSD review and permitting (**Table 5**).[157] The applicant has submitted an application to the MPCA for an amendment of the MEC's current air permit (**Appendix E**).

Air dispersion modeling conducted by the applicant indicates that emissions from the project will not cause a violation of NAAQS and will not increase air pollutants in the area beyond the allowable PSD increment.[158] A PSD permit cannot be issued by the MPCA until the applicant demonstrates that the project, with appropriate mitigation measures, complies with all state and federal standards.[159] Accordingly, impacts to public health resulting from the project's impact on ambient air quality are anticipated to be minimal and within all state and federal standards.

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[151] Greenhouse Gas Emissions Reduction, Biennial Report to the Minnesota Legislature, January 2015, https://www.pca.state.mn.us/sites/default/files/lraq-2sy15.pdf [hereinafter Greenhouse Gas Emissions Reduction Report].
[152] Id.
[153] Id.
[154] Site Permit Application, Section 5.1.
[155] Id.
[156] Id. Other emission sources at the MEC include auxiliary boilers, a diesel-fueled fire pump, a bath heater, and a proposed emergency generator.
[157] Site Permit Application, Section 5.1.2.
[158] Site Permit Application, Sections 5.1.3 and 5.1.4.
[159] Id.

Table 5. Estimated Potential Annual Air Emissions and PSD Thresholds[160]

Air Pollutant	Combined Facility Post-Project Potential Emissions (tons per year)	Expansion Project Potential Emissions (tons per year)	PSD Major Modification Threshold (tons per year)
Particulate Matter (PM)	192.91	58.71	25
PM Less Than 10 Microns (PM_{10})	175.08	52.76	15
PM Less Than 2.5 Microns ($PM_{2.5}$)	173.20	52.14	10
Sulfur Dioxide (SO_2)	98.58	30.46	40
Nitrogen Oxides (NO_x)	354.01	167.44	40
Volatile Organic Compounds (VOC)	647.02	382.58	40
Carbon Monoxide (CO)	1,266.03	768.64	100
Lead	0.52	0.01	0.6
Carbon Dioxide Equivalent (CO_2e)	3,094,401	1,576,725	75,000
Beryllium	3.91×10^{-4}	4.24×10^{-5}	0.004
Mercury	3.07×10^{-3}	9.20×10^{-4}	0.1
Sulfuric acid mist	14.88	4.58	7

Air Emissions Risk Analysis

In accordance with MPCA guidance, the applicant has conducted an air emissions risk analysis (AERA) to assess potential health impacts attributable to the project.[161] These are potential impacts to residents in the project area who could be affected directly by pollutants from the project (e.g., inhalation, deposition), as opposed to being affected by changes in ambient air quality generally. Using air dispersion modeling and several exposure scenarios, cancer and non-cancer health risks can be estimated and quantified using indices.[162] These indices are then compared to thresholds established by the MPCA and the Minnesota Department of Health.[163]

The applicant's AERA indicates that potential health risks to residents in the project area due to air emissions are within state guidelines (**Table 6).[164]** The greatest cancer risk is to a person in the project area who is outdoors continuously (modeled in the AERA as a "farmer"). The estimated risk to such persons is 0.9 additional lifetime cancers per 100,000 persons.[165] This risk is slightly less than the state

[160] Site Permit Application, Section 5.1.2, Table 5-1. Potential emissions based on continuous full power operation of the MEC (or expansion project). Actual emissions are anticipated to be substantially less; see Site Permit Application, Section 2.3 (discussing that the MEC operates only when needed by the electrical transmission grid and indicating actual power production at approximately 15 percent of potential production).
[161] Site Permit Application, Section 5.1.5.
[162] Id.
[163] Id.
[164] Id.
[165] Id.

risk guideline of one additional lifetime cancer in 100,000 persons.[166] The estimates in the AREA are conservative in that they assume maximum potential emissions from the MEC rather than estimated actual emissions.[167]

In sum, the MEC, with the expansion project, has the potential to impact the health of residents in the project area through air emissions; however, these impacts are anticipated to be within state guidelines and minimal.

Table 6. Air Emission Risk Analysis Results[168]

Screening Scenario	Risk Analysis Result	State Guideline / Threshold
Acute Hazard Index	0.8	1.0
Sub-chronic Hazard Index	0.02	1.0
Chronic Hazard Index	0.2	1.0
Cancer Risk	3×10^{-6}	1×10^{-5}
Farmer Non-cancer Hazard	0.6	1.0
Farmer Cancer Risk	9×10^{-6}	1×10^{-5}

Greenhouse Gases and Global Warming

The accumulation of greenhouse gases in the atmosphere and associated warming of the planet is leading to a variety of adverse human and environmental impacts – including more severe droughts and floods, more heat related illnesses, and a decrease in food security.[169] Though a variety of gases contribute to the greenhouse effect, the most prominent greenhouse gas is carbon dioxide.[170]

In 2012, approximately 154 million carbon dioxide equivalent (CO_2e) tons of greenhouse gases were emitted in Minnesota.[171] The electric utility sector was responsible for approximately 31 percent of this total, or about 48 million tons CO_2e.[172]

Between 2005 and 2012 Minnesota greenhouse gas emissions declined by 11 million tons CO_2e, or approximately seven percent.[173] During this period, emissions from the electric utility sector declined by approximately 17 percent (**Figure 10**). This decline was due to utilities switching to less greenhouse gas intensive fuels, such as natural gas, and the increased use of renewable energy sources (e.g., wind, solar).[174]

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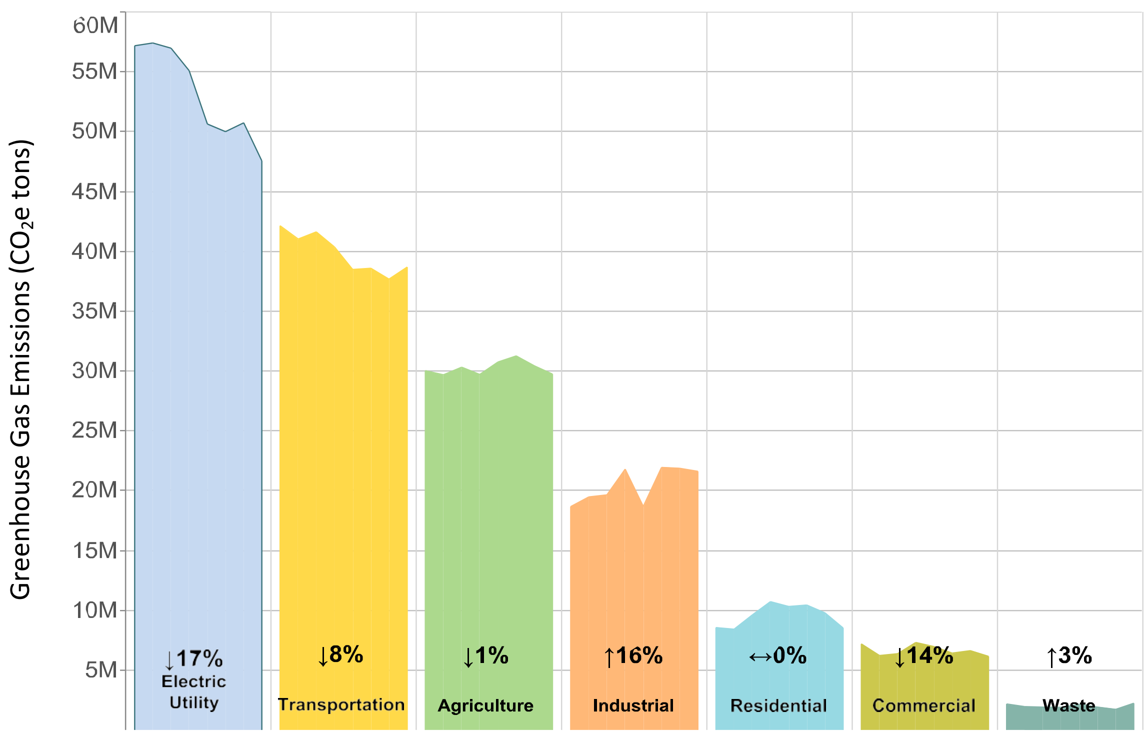
[166] Id.
[167] Id.
[168] Site Permit Application, Section 5.1.5, Table 5-4.
[169] Minnesota and Climate Change: Our Tomorrow Starts Today, Minnesota Environmental Quality Board, www.eqb.state.mn.us.
[170] Id.
[171] Greenhouse Gas Emissions Reduction Report.
[172] Id.
[173] Id.
[174] Id.

With the expansion project, the MEC will have the potential to emit approximately 3 million tons CO_2e per year.[175] Because the MEC operates only when needed by the electrical transmission grid, actual greenhouse gas emissions are anticipated to be approximately 15 percent of this potential, or about 450,000 tons CO_2e annually.[176]

Looking solely at the expansion project and emissions from the MEC, the project will increase greenhouse emissions at the MEC – approximately doubling current greenhouse gas emissions from the MEC.[177] Thus, the project would appear to contribute to global warming and associated human and environmental impacts. However, looking at the role of the MEC in the electric utility sector in Minnesota, the increased use of natural gas at the MEC and the displacement of more greenhouse gas intensive fuels (e.g., coal) combined with the ability of the MEC to facilitate additional wind and solar power generation is anticipated to reduce greenhouse gas emissions in Minnesota.[178] Though the displacement of more greenhouse gas intensive fuels and the addition of wind and solar power generation depend on a variety of actions by multiple actors, trends in electric utility emissions from 2005 to 2012 indicate that these activities will occur.[179] Thus, the project is anticipated to reduce greenhouse gas emissions in Minnesota overall and may reduce potential human and environmental impacts associated with global warming.

Figure 10. Minnesota Greenhouse Gas Emission Changes by Economic Sectors: 2005-2012[180]



[175] Site Permit Application, Section 5.1.2.
[176] Site Permit Application, Section 2.3 (discussing actual power production versus potential power production at the MEC).
[177] Site Permit Application, Section 5.1.2.
[178] Greenhouse Gas Emissions Reduction Report.
[179] Id. See also, Natural Gas, Renewables Projected to Provide Larger Shares of Electricity Generation, U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.cfm?id=21072.
[180] Greenhouse Gas Emissions Reduction Report.

Mitigation

Potential health impacts of air emissions can be mitigated by technologies and processes that minimize emissions of certain pollutants. MPCA's PSD permit will require that the MEC employ best available control technologies (BACT).[181] The applicant indicates that it will use several emission control strategies, including:[182]

- Using natural gas to fire the turbines to minimize NO_X, sulfur dioxide, and particulate emissions.
- Using dry low NO_X combustors to minimize the formation of nitrogen oxides in combustion turbines.
- Using select catalytic reduction to reduce nitrogen oxides in combustion turbine exhaust.
- Use of catalytic oxidation to reduce CO, VOC, and organic air pollutant emissions from combined cycle system exhaust gas.
- Limiting operation of the emergency generator and fire pump, as practicable, to less than 100 hours per year.
- Installing high efficiency mist eliminators to reduce cooling tower drift rates and minimize particulate matter emissions from cooling towers.
- Use of energy efficient designs, processes, and practices.

Through the PSD permitting process, the MPCA may require mitigation measures in order to ensure that the project meets all air emissions standards and guidelines.

Water Vapor Plumes

When exhaust gases are emitted from the stacks, the water vapor present in the exhaust gas can condense to form a visible plume.[183] Water vapor emitted from the cooling towers can also result in a visible plume (**Figure 9**).[184] The length and persistence of these plumes are influenced by prevailing weather conditions such as temperature, relative humidity, and wind speed.[185] The plumes are most persistent and visible during cold and damp weather.[186] The plumes, when present, disperse and evaporate fairly quickly and typically travel only short distances.[187]

Potential Impacts

Water vapor plumes from the MEC have the potential to impair visibility and/or create icy areas on nearby roadways. However, because plumes are anticipated to dissipate before reaching roadways, potential impacts to health and safety due to plumes are anticipated to be minimal.

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[181] Site Permit Application, Section 5.1.2.
[182] Id.
[183] Site Permit Application, Section 5.5.
[184] Id.
[185] Id.
[186] Id.
[187] Id.

Water vapor plumes from the HRSG stacks will form approximately 200 feet above ground level. When emitted at this height the plumes are anticipated to dissipate before reaching ground level.[188] The cooling towers are not as tall as the HRSG stacks; however, they utilize drift eliminators to minimize water vapor emissions that can cause fogging and icing.[189] Summit Avenue and 3rd Avenue, the nearest local roads, are approximately 800 feet from the MEC.[190] U.S. Highway 14 is approximately 0.75 miles from the MEC.[191] Based on these distances and the rate at which water vapor plumes typically evaporate and dissipate, impacts to these roadways are anticipated to be minimal. The applicants note that plumes from the MEC to date have not impacted visibility or roadway safety.[192] Water vapor plumes associated with the MEC expansion project will be incremental and impacts from the expanded MEC are anticipated to be minimal.

Mitigation

Impacts to public health and safety as a result of the MEC's water vapor plumes are anticipated to be minimal; thus, no mitigation measures are proposed.

<u>Water Emissions</u>

Water used at the MEC and rainfall at the site could become polluted with oils, chemicals, and other substances used for power production at the MEC. If polluted waters are not properly treated or handled, their discharge into the environment could result in impacts to public health. However, because waters at the MEC are treated and handled to minimize the discharge of pollutants, impacts to public health due to water emissions are anticipated to be minimal.

Potential Impacts

Process wastewater, i.e., wastewater from power systems, is collected and treated and then discharged to the Mankato WWTP.[193] The Mankato WWTP, after further treatment, discharges to the Minnesota River in accordance with its NPDES/SDS permit.[194] No changes in this process are anticipated as a result of the project. Discharges from the MEC – through the Mankato WWTP – are not anticipated to change as a result of the project and are not anticipated to adversely impact public health.

Domestic wastewater from the MEC is discharged to the city of Mankato sanitary sewer system.[195] This discharge is monitored by the city and subject to pollutant discharge limits. No changes are anticipated to this process and no impacts to the Mankato sanitary sewer system or to public health are anticipated.

Stormwater from the power production areas of the MEC is treated to separate oil and water – oil is shipped off-site for disposal; water is recycled as cooling water makeup.[196] Stormwater from non-power production areas is routed to an existing stormwater basin.[197] Stormwater flows from this basin through

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[188] Id.
[189] Id.
[190] Id.
[191] Site Permit Application, Section 3.1.
[192] Site Permit Application, Section 5.5 (noting that the MEC has received no complaints to date concerning water vapor plumes).
[193] Site Permit Application, Section 2.7.9.
[194] Site Permit Application, Section 8.3.6
[195] Id.
[196] Site Permit Application, Section 8.3.5.
[197] Id.

a drainage ditch to the Minnesota River.[198] Discharges from the basin are regulated by an NPDES/SDS permit.[199] No changes in the handling of stormwater are anticipated as a result of the project. No public health impacts are anticipated as a result of stormwater from the project.

Mitigation
Impacts to public health and safety as a result of water emissions from the MEC are anticipated to be minimal; thus, no mitigation measures are proposed.

Fire and Electrocution
The power generation equipment at the MEC and the equipment proposed for the expansion project combust natural gas at high pressure and temperature and convert this heat energy to electrical power. As a result, there is a risk of fire or explosion and a risk of electrocution. However, because of systems and controls in place at the MEC, because access to the MEC is controlled, and because the MEC is relatively distant from populated areas (approximately one-half mile), the risk to public health and safety from these potential accidents is anticipated to be minimal.

Potential impacts due to safety risks at the MEC are minimized by a number of controls at the MEC including training, personal protective equipment, and signage.[200] All employees participate in on-going safety training.[201] All employees, contractors, and visitors are required to use appropriate personal protection equipment, e.g., hard hats, safety glasses, safety harnesses.[202] Employees are trained in the proper use of this equipment.[203] The MEC utilizes signage to identify hazards at the facility and the locations of safety equipment.[204]

The MEC is equipped with a security system and a fire suppression system.[205] The fire suppression system includes a diesel-fueled fire pump.[206] The city of Mankato provides any fire, police, or rescue services needed at the MEC.[207] Accordingly, public health impacts from a potential fire at the MEC are anticipated to be minimal.

The MEC utilizes step-up transformers and electrical switchgear to commute the electrical power generated at the MEC to the Wilmarth substation (see Section 3.1). The switchgear includes circuit breakers and relays that de-energize electrical equipment should a structure or conductor fall to the ground or should electrical equipment otherwise fail. Accordingly, public health impacts resulting from electrocution at the MEC are anticipated to be minimal.

Mitigation
Impacts to public health and safety as a result of fire or electrocution accidents at the MEC are anticipated to be minimal; thus, no mitigation measures are proposed.

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[198] Id.
[199] Id.
[200] Additional Project Information from Applicant.
[201] Id.
[202] Id.
[203] Id.
[204] Id.
[205] Site Permit Application, Section 4.8.4.
[206] Site Permit Application, Section 2.7.10.
[207] Site Permit Application, Section 4.8.4.

4.5 Land-Based Economies

Electric power generating plants have the potential to impact land-based economies. Power plants require a dedicated physical area on the landscape to accommodate power generation equipment. The use of this area for power generation can prevent or otherwise limit use of the landscape for other purposes and can adversely impact land-based economies.

Impacts to land-based economies as a result of the project are anticipated to be minimal. The project will be located within the existing MEC.[208] No additional land is required for operation of the expanded MEC. The project will require the temporary use of approximately 15 acres outside of the MEC site for construction of the project.[209] The applicant anticipates securing land from a local property owner for this use.[210] Once the project is constructed, this land would be returned to its current use.

Agriculture

Impacts to agriculture as a result of the project are anticipated to be minimal. There is no agricultural land within the MEC site. The project will require the use of approximately 15 acres outside of the MEC site for construction of the project. This land will be agricultural land or vacant industrial land.[211] If agricultural land were used, it would be unavailable for cultivation for approximately two growing seasons (24-30 months).[212] After this time, the land would be returned to agricultural use. Impacts to agriculture as a result of the project are anticipated to be minimal; thus, no mitigation measures are proposed.

Forestry

No impacts to forestry are anticipated as a result of the project. There is no forested land within the MEC site. No forested land will be used for construction of the project. No mitigation measures are proposed.

Mining

No impacts to mining are anticipated as a result of the project. There are no mining operations or resources within the MEC site. There are mining operations and resources in the project area including limestone quarries and aggregate mines.[213] These operations and resources are at a distance from the MEC site and will not be impacted by the construction or operation of the project.[214] No mitigation measures are proposed.

Recreation and Tourism

No impacts to recreation and tourism are anticipated as a result of the project. The MEC is located in an industrial area away from recreational features and tourism attractions.[215] There are parks in the

[208] Site Permit Application, Section 6.0.
[209] Id.
[210] Id.
[211] Site Permit Application, Section 6.1.
[212] Id.
[213] Site Permit Application, Section 6.4.
[214] Id.
[215] Site Permit Application, Section 6.3.

project area used for recreation, but these parks are located at a distance from the MEC site and their use will not be impacted by the project.[216] No mitigation measures are proposed.

4.6 Archaeological and Historic Resources

Electric power generating plants have the potential to impact archaeological and historic resources. Archaeological resources can be impacted by the disruption or removal of such resources during the construction of a plant. Historic resources can be impacted by locating a plant in a manner that impairs or decreases the historic value of the resources.

Impacts to archaeological and historic resources resulting from the project are anticipated to be minimal. There are no archaeological or historic resources within the MEC site.[217] A review of records at the State Historic Preservation Office indicates that there are two historic farmsteads within the section where the MEC is located (Section 31, Lime Township).[218] No impacts to these farmsteads are anticipated as a result of the project. No mitigation measures are proposed.

4.7 Air Resources

Emissions from electric power generating plants can adversely impact air quality with concomitant impacts to persons, flora, and fauna. Potential impacts to air quality as a result of the project are discussed in Section 4.4. EPA air emission standards are protective of public health and public welfare, including the welfare of flora and fauna.[219] As the MEC must comply with these standards, impacts to air resources are anticipated to be minimal, and no impacts to flora or fauna are anticipated due to air emissions from the MEC. No mitigation measures beyond those discussed in Section 4.4 are proposed.

4.8 Water Resources

Electric power generating plants have the potential to impact water resources in several ways. Construction of the project will require the movement and removal of soils. This handling of soils can result in soil erosion and changes in water flow patterns such that water resources are adversely impacted. Operation of the MEC requires water for cooling (see Section 3.1). The use of water for cooling could remove water from the ecosystem. This removal could have adverse impacts on water resources, flora, and fauna. Operation of the MEC could result in the emission of pollutants to waterbodies; such emissions could adversely impact water quality and habitat for flora and fauna.

Impacts to water resources as a result of the project are anticipated to be minimal. Soil erosion and construction related impacts to water resources are anticipated to be minimal. The project will increase the MEC's use of cooling water; however, the water used for cooling is wastewater from the Mankato WWTP. Accordingly, the impact of increased cooling water use on water resources is anticipated to be minimal. Emissions of pollutants to waterbodies are anticipated to be minimal and within all applicable standards; thus, impacts to water resources due to potential pollutants are anticipated to be minimal.

[216] Parks, City of Mankato, http://www.mankatomn.gov/city-services-a-z/city-services-n-z/parks.
[217] Site Permit Application, Section 7.0.
[218] Id.
[219] Site Permit Application, Section 8.1.

Surface Waters
The MEC site contains no waterbodies or watercourses. There is a stormwater basin (detention pond) located in the northeast corner of the site (**Figure 11**).[220] The basin was designed and constructed to contain stormwater from the MEC as originally proposed, i.e., with the MEC expansion project.[221] The basin discharges to a drainage ditch on the east side of the site.[222] This drainage ditch is a tributary of the Minnesota River.[223] The river itself is located approximately 1,800 feet west of the MEC site.

Construction
Impacts to surface waters could occur due to construction activities. These activities could expose and disturb soils, increasing erosion and the potential for sediment to reach surface waters. Construction of the project will disturb approximately four acres.[224] Though there are no surface waters at the site, disturbed soils could move, via rainfall events, to the stormwater basin and through the drainage ditch.

Impacts to surface waters as a result of project construction are anticipated to be minimal and can be mitigated. Construction of the CTG and HSRG will impact approximately two acres of a paved, impervious surface and will not require substantial earth movement or grading (**Figure 8**).[225] Construction of new cooling tower cells will impact approximately one acre of a flat, gravel surface.[226] Substantial earth movement or grading will not be required for these cells.[227] The applicant indicates that it will employ several erosion and sediment control measures during construction of the project, including silt fences, hay bales, matting, and mulching.[228] The stormwater basin at the MEC will collect and filter stormwater during construction of the project.[229] The project will require an NPDES/SDS stormwater construction permit from the MPCA (see Section 2.3). This permit may require specific mitigation measures to minimize potential impacts to water resources resulting from construction of the project. Commission site permits require permittees to minimize soil erosion and associated impacts on surface waters (**Appendix B**).

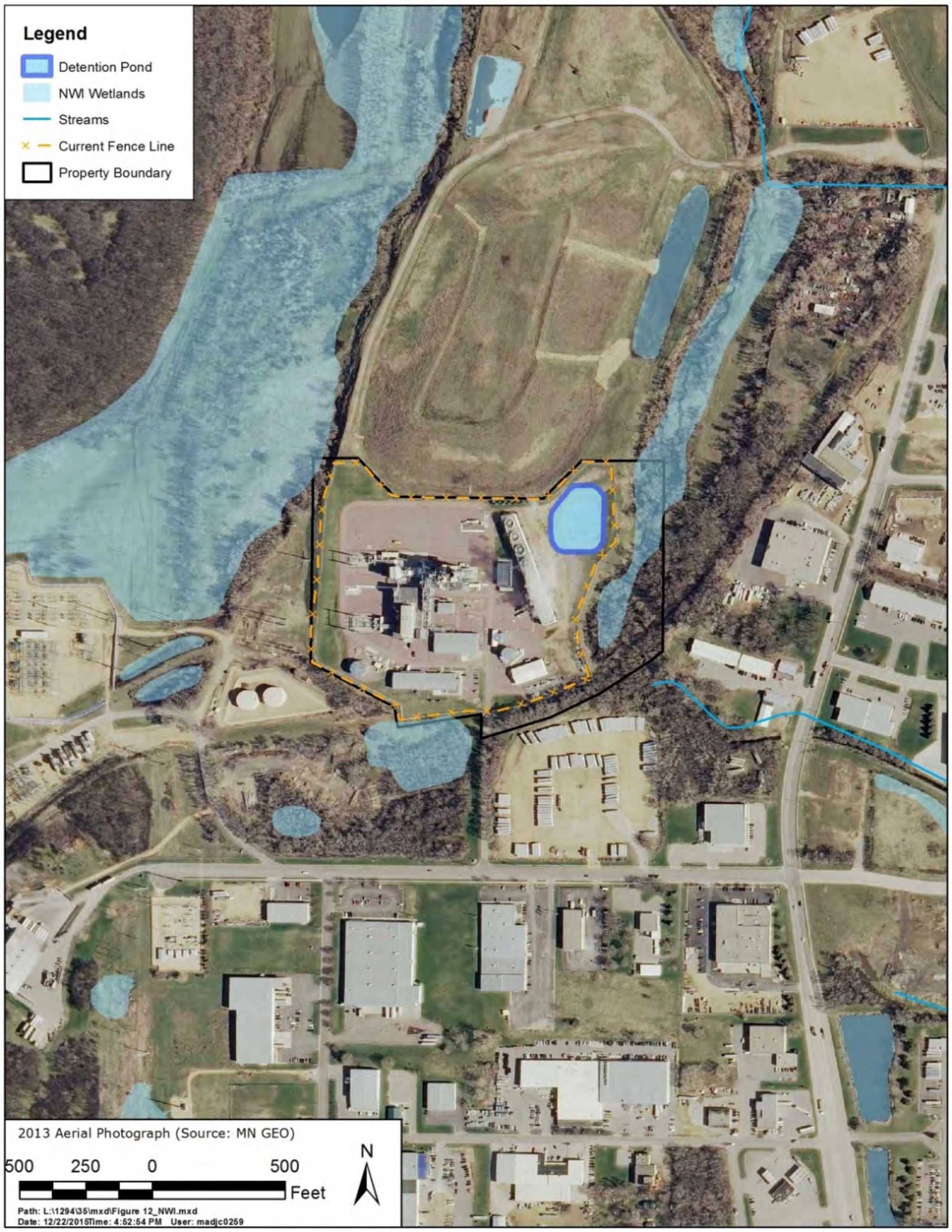
Operation
Impacts to surface waters could occur due to the use of water for cooling at the MEC and to emissions of pollutants from the MEC. These potential operational impacts are anticipated to be minimal.

Evaporative Loss of Cooling Water
There are currently eight cooling tower cells at the MEC. The expansion project will require the addition of four more cells, resulting in a total of 12 cooling tower cells (see Section 3.1). This addition will increase the tower's ability to dissipate heat and will increase water evaporation from the tower. When running at full power, the MEC currently has the potential to evaporate 3.48 million gallons per day (MGD).[230] With the expansion project, the MEC will have the potential to evaporate 6.04 MGD.[231]

[220] Site Permit Application, Section 8.3.
[221] Id.
[222] Id.
[223] Id.
[224] Id.
[225] Id.
[226] Id.
[227] Id.
[228] Id.
[229] Id.
[230] Site Permit Application, Section 2.7.6.

Because the MEC does not run continuously, its average daily water evaporation is considerably less – approximately one-tenth of its maximum potential evaporation.[232] On average, the MEC evaporates 0.34 MGD; with the expansion project, the MEC will evaporate, on average, approximately 0.47 MGD.[233]

Figure 11. Water Resources



[231] Id.
[232] Id.
[233] Id.

The wastewater used for cooling at the MEC, were it not lost to evaporation, would be discharged by the Mankato WWTP to the Minnesota River.[234] The Mankato WWTP treats and discharges, on average, approximately 7.0 MGD.[235] Thus, evaporation from the MEC, with the expansion project, will remove approximately 6.7 percent of the WWTP's average discharge to the Minnesota River.[236]

The evaporative loss of cooling water from the MEC could impact water resources and ecosystems by removing water otherwise available to ecosystems in the project area. However, the potential impacts of evaporative losses from the MEC are anticipated to be minimal. First, the cooling water used at the MEC is wastewater. Thus, it is water that has already provided ecosystem services to humans, flora, and fauna. Second, the evaporative loss from the MEC and resulting reduction in discharge from the Mankato WWTP is not anticipated to impact the Minnesota River or the habitat it provides for flora and fauna. The evaporative loss is insignificant compared with the flow volume of the Minnesota River.[237] Thus, though evaporation from cooling towers at the MEC will remove water from the water systems and ecosystems in the project area, the impacts of this removal are anticipated to be minimal.

Emissions to Surface Waters

Water used at the MEC and rainfall at the site could become polluted with oils, chemicals, and other substances used at the MEC. If these polluted waters are not properly treated or handled, their discharge could impact surface waters in the project area. However, because waters at the MEC are treated and handled to minimize the discharge of pollutants, impacts to surface waters are anticipated to be minimal.

Process wastewater, i.e., wastewater from power systems, is collected and treated and then discharged to the Mankato WWTP.[238] The Mankato WWTP, after further treatment, discharges to the Minnesota River.[239] No changes in this process are anticipated as a result of the project. Accordingly, the handling of process wastewater at the MEC is not anticipated to impact surface waters.

Stormwater from the power production areas of the MEC is treated to separate oil and water – oil is shipped off-site for disposal; water is recycled as cooling water makeup.[240] Stormwater from non-power production areas is routed to the stormwater basin.[241] Discharges from the basin are regulated by an NPDES/SDS permit.[242] No changes in the handling of stormwater are anticipated as a result of the project. The project will not increase the amount of impervious surface within the MEC site.[243] The applicant indicates that it will maintain the MEC site in good order and keep road surfaces clean to minimize potential pollutants in stormwater.[244] The applicant also indicates that it will maintain

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[234] Site Permit Application, Section 8.3.6.
[235] City of Mankato, Plant History, http://www.mankatomn.gov/city-services-a-z/city-services-n-z/wastewater-treatment/plant-history.
[236] (0.47 MGD / 7.0 MGD) = 0.067.
[237] A minimum flow for the Minnesota River at Mankato is approximately 3,000 cubic feet per second, or about 1,940 MGD (see National Weather Service, Advanced Hydrologic Prediction Service, http://water.weather.gov/ahps2/hydrograph.php?wfo=mpx&gage=MNKM5).
[238] Site Permit Application, Section 2.7.9.
[239] Site Permit Application, Section 8.3.6
[240] Id.
[241] Id.
[242] Id.
[243] Site Permit Application, Section 8.3.5.
[244] Id.

vegetation buffers along the perimeter of the MEC to minimize stormwater impacts on surface waters.[245]

The MEC utilizes and stores liquids (e.g., fuel, chemicals) that could, if released, mix with stormwater or otherwise flow to the stormwater basin. The applicant indicates that such liquids are stored within appropriate containment areas.[246] Handling and unloading areas are equipped with secondary containment.[247] The MEC has a spill prevention, contingency, and countermeasure (SPCC) plan.[248] The plan identifies staff responsible for maintenance and inspection of storage tanks, steps to take in the event of a release, locations of spill response supplies at the MEC, and notification and communication responsibilities.[249] The MEC has a risk management plan for the storage of ammonia at the MEC.[250] The plan is similar to the SPCC and includes details specific to the proper handling of ammonia.[251]

In sum, impacts to surface waters due to emissions of potential pollutants are anticipated to be minimal. Impacts are avoided and minimized by facilities and processes in place at the MEC.

Floodplains

The MEC site is located outside of the 100-year floodplain, as identified by the Federal Emergency Management Agency (**Figure 12**).[252] The 100-year floodplain elevation is approximately 25 feet below the base elevation of the MEC.[253] Thus, no impacts to the 100-year floodplain or to development near the floodplain are anticipated as a result of the project. No mitigation measures are proposed.

Groundwater

The MEC is located on a portion of an old limestone quarry which was converted to a landfill.[254] The landfill is now closed and the site was reworked to construct the MEC. The project does not require any groundwater wells.[255] Cooling water will continue to be supplied by the Mankato WWTP; service water will continue to be supplied by the city of Mankato's municipal water system.[256]

Potential Impacts

Impacts to groundwater as a result of the project are anticipated to be minimal. Potential impacts to groundwater from the project could occur through (1) surface water impacts and (2) impacts directly to groundwater resulting from concrete foundations.

Because surface waters are hydrologically connected to groundwater, impacts to surface waters can lead to impacts to groundwater. Soils underlying the MEC site are fairly permeable, and the MEC sits atop a former quarry.[257] Thus, any pollutants in surface waters are likely to percolate downward into

245 Id.
246 Site Permit Application, Section 8.3.4.
247 Id.
248 Additional Project Information from Applicant.
249 Id.
250 Id.
251 Id.
252 Site Permit Application, Section 8.3.1.
253 Id.
254 Site Permit Application, Section 2.4
255 Site Permit Application, Section 8.3.4.
256 Id.
257 Site Permit Application, Section 8.3.5.

groundwater. As discussed above, impacts to surface waters at the MEC are anticipated to be minimal. Accordingly, impacts to groundwater are anticipated to be minimal.

Figure 12. Floodplains

Direct impacts to groundwater could occur as a result of project construction and the placement of concrete foundations. Some portion of the soluble components of the concrete could leach into groundwater prior to the setting and hardening of the concrete. Because of the relatively low solubility of concrete components, direct impacts to groundwater are anticipated to be minimal.

Mitigation
Impacts to groundwater can be mitigated by measures to prevent impacts to surface waters (discussed above).

Wetlands
There are no wetlands within the MEC site (**Figure 11**).[258] There are wetlands in the project area, but these areas would not be impacted by the project. Accordingly, no impacts to wetlands are anticipated as a result of the project; no mitigation measures are proposed.

4.9 Flora

Electric power generating plants have the potential to impact flora through the removal or disturbance of vegetation during construction. Potential impacts to flora due to the project are anticipated to be minimal.

There is no flora within the MEC site.[259] There are treed areas to the south and east of the site (**Figure 2**). Construction within the MEC site will not impact flora. The applicant indicates that materials for construction of the project will be transported on existing roads.[260] The project will require temporary use of approximately 15 acres outside of the MEC site for construction laydown and parking.[261] This land will be agricultural land or vacant industrial land.[262] The applicant indicates that some clearing of flora may be necessary to create a walkway from the construction laydown area to the MEC site.[263] Commission site permits require that permittees minimize impacts to flora (**Appendix B**). In sum, impacts to flora as a result of the project are anticipated to be minimal; no mitigation measures are proposed.

4.10 Fauna

Electric power generating plants have the potential to impact fauna through a variety of means including displacement and habitat loss. Potential impacts to fauna due to the project are anticipated to be minimal.

The MEC site is an industrial property that does not include habitat for fauna.[264] Fencing around the site prevents many species from entering or crossing the site.[265] There are forest and wetland habitats to the east of the MEC site; there are forest, grassland, and wetland habitats northwest of the site along the Minnesota River.[266] These habitats are outside of the MEC site and away from possible, temporary construction laydown areas and will not be impacted by the project. Some species in the project area may be disturbed or displaced by construction noise. Any such impacts are anticipated to be temporary and are not anticipated to impact wildlife populations. On whole, impacts to fauna as a result of the project are anticipated to be minimal; no mitigation measures are proposed.

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[258] Site Permit Application, Section 8.3.3.
[259] Site Permit Application, Section 8.4.1.
[260] Id.
[261] Id.
[262] Site Permit Application, Section 6.1.
[263] Site Permit Application, Section 8.4.1.
[264] Site Permit Application, Section 8.4.2.
[265] Id.
[266] Id.

4.11 Rare and Unique Natural Resources

Impacts to rare and unique natural resources (flora and fauna) from the project could result from ecosystem changes, introduction of invasive species, and habitat loss. Potential impacts to rare and unique natural resources due to the project are anticipated to be minimal.

Flora
A review of natural resource databases indicates that there is one rare plant community in the project area – a mesic prairie (**Table 7**). In addition to this rare plant community, there are two rare plant species in the project area – *Berula erecta* and Hair-like Beak-rush (**Table 7**). The mesic prairie community and these rare plant species are distant from the MEC site; the two rare species are found in habitats along the Minnesota River.[267]

Fauna
A review of natural resource databases indicates that there is one animal assemblage area, eleven rare and unique animal species, and habitat for an additional species in the project area (**Table 7**). The majority of the rare and unique species are associated with the Minnesota River. The river contains the animal assemblage area – a freshwater mussel concentration area – as well as several fish (Paddlefish, Blue Sucker, Shovelnose Sturgeon) and mussel species (Rock Pocketbook, Yellow Sandshell, Monkeyface, Black Sandshell, Round Pigtoe, Hickorynut). The only animal species not confined to the Minnesota River are two snake species – the North American Racer and Western Foxsnake.

The Northern Long-Eared Bat (NLEB) is found throughout eastern and central North America.[268] The bats hibernate in caves and mines during winter months and roost in forested areas during summer months.[269] The NLEB was listed by the USFWS as a threatened species on April 2, 2015. The primary reason for the listing is the rapid decline in NLEB populations due to white nose syndrome, a fungal disease that has quickly spread throughout the species' range.[270] Because of this disease, other possible causes of NLEB mortality may now be important factors affecting the viability of NLEB populations in the United States.[271] One such cause is the loss or degradation of summer roosting habitat (trees).

Potential Impacts
Impacts to rare and unique species due to the project are anticipated to be minimal. The MEC site contains no habitat for rare and unique species and is located away from such habitat in the project area. Impacts to water resources as a result of the project are anticipated to be minimal (see Section 4.8). Thus, impacts to rare and unique species associated with the Minnesota River are anticipated to be minimal.

The two rare snake species in the project area could cross through the MEC site. In doing so, they could be impacted by construction activities. The applicant indicates that it will use exclusionary silt fencing to prevent movement of these species across the site and will use wildlife friendly erosion control practices to mitigate potential impacts to these species.[272] Impacts to trees as a result of the project are

[267] Site Permit Application, Section 9.0.
[268] USFWS Endangered Species, Northern Long-Eared Bat, http://www.fws.gov/midwest/endangered/mammals/nleb/.
[269] Id.
[270] Id.
[271] Id.
[272] Site Permit Application, Section 9.0.

anticipated to be minimal (see Section 4.9). Thus, impacts to potential roosting habitat for the NLEB are not anticipated.

Mitigation
Impacts to rare and unique species due to the project are anticipated to be minimal. Impacts to two rare snake species in the project area could be mitigated by exclusionary fencing and wildlife friendly erosion control practices.

Table 7. Rare and Unique Species in Project Area[273]

Type	Common Name	Scientific Name	Federal Status	State Status
Plant Community	Mesic Prairie	---	None	None
Plant	---	*Berula erecta*	None	Threatened
Plant	Hair-like Beak-rush	*Rhynchospora capillacea*	None	Threatened
Animal Assemblage	Freshwater Mussel Concentration Area	---	None	None
Fish	Paddlefish	*Polyodon spathula*	---	Threatened
Fish	Blue Sucker	*Cycleptus elongates*	---	Special Concern
Fish	Shovelnose Sturgeon	*Scaphirhynchus platorynchus*	---	Watchlist
Mussel	Rock Pocketbook	*Arcidens confragosus*	---	Endangered
Mussel	Yellow Sandshell	*Lampsilis teres*	---	Endangered
Mussel	Monkeyface	*Quadrula metanevra*	---	Threatened
Mussel	Black Sandshell	*Ligumia recta*	---	Special Concern
Mussel	Round Pigtoe	*Pleurobema sintoxia*	---	Special Concern
Mussel	Hickorynut	*Obovaria olivaria*	---	Watchlist
Reptile	North American Racer	*Coluber constrictor*	---	Special Concern
Reptile	Western Foxsnake	*Patherophis ramspotti*	---	Watchlist
Bat	Northern Long-Eared Bat	*Myotis septentrionalis*	Threatened	Special Concern

[273] Site Permit Application, Section 9.0, Table 9-1; USFWS Endangered Species, Northern Long-Eared Bat, http://www.fws.gov/midwest/endangered/mammals/nleb/.

5.0 Application of Siting Factors to the Proposed Project

The Power Plant Siting Act requires the Commission to locate electric power generating plants in a manner that is "compatible with environmental preservation and the efficient use of resources" and that minimizes "adverse human and environmental impact[s]" while ensuring electric power reliability.[274] Minnesota Statute Section 216E.03, subdivision 7(b) identifies considerations that the Commission must take into account when designating power plant sites.[275]

Minnesota Rule 7850.4100 lists 14 factors for the Commission to consider in its site permitting decisions, including effects on human settlements, effects on public health and safety, and effects on the natural environment (**Figure 13**).[276] In this section, the information gathered by EERA staff during the environmental review process, as presented in this EA, is applied to these factors.

The discussion here focuses first of the first 12 siting factors of Minnesota Rule 7850.4100 (factors A through L). Siting factors M and N – the unavoidable and irreversible impacts of the project – are discussed at the end of this section.

There are three siting factors which are not relevant to the project and are not discussed further here. These are:

- The use of existing rights-of-way, division lines, and boundaries (factor H);
- The use of existing infrastructure rights-of-way (factor J);
- Costs which are dependent on design and route (factor L).

Factors H and J are relevant solely to the routing of transmission lines. Factor L is relevant only when there is more than one design and/or route with costs that can be compared. The only design for the project is the applicant's proposed design.

5.1 Siting Factors and Elements

Some of the siting factors in Minnesota Rule 7850.4100 describe a resource in relatively succinct terms, e.g., effects on archaeological and historic resources. Other siting factors are more descriptive and include a list of factor elements, i.e., parts that make up the sum of the whole factor. For example, the factor "effects on human settlements" includes the factor elements displacement, noise, aesthetics, cultural values, recreation, and public services. Finally, there are siting factors that are relatively succinct, but for which elements have been identified through the scoping process and analyzed in this EA. For example, the factor "public health and safety" includes the elements air emissions, water vapor plumes, water emissions, and fire and electrocution.

[274] Minnesota Statute 216E.02.
[275] Minnesota Statute 216E.03, Subd. 7.
[276] Minnesota Rule 7850.4100.

Figure 13. Factors Considered by the Commission for Electric Power Generating Plant Site Permits

In determining whether to issue a site permit for a large electric power generating plant, the Commission shall consider the following factors of Minnesota Rule 7850.4100:

A. Effects on human settlement, including, but not limited to, displacement, noise, aesthetics, cultural values, recreation, and public services;

B. Effects on public health and safety;

C. Effects on land-based economies, including, but not limited to, agriculture, forestry, tourism, and mining;

D. Effects on archaeological and historic resources

E. Effects on the natural environment, including effects on air and water quality resources and flora and fauna;

F. Effects on rare and unique natural resources;

G. Application of design options that maximize energy efficiencies, mitigate adverse environmental effects, and could accommodate expansion of transmission or generating capacity;

H. Use or paralleling of existing right-of-way, survey lines, natural divisions lines, and agricultural field boundaries;

I. Use of existing large electric power generating plant sites;

J. Use of existing transportation, pipeline, and electrical transmission systems or rights-of-way;

K. Electrical systems reliability;

L. Costs of constructing, operating, and maintaining the facility which are dependent on design and route;

M. Adverse human an natural environmental effects which cannot be avoided; and

N. Irreversible and irretrievable commitments of resources.

5.2 Siting Factors for Which Impacts are Anticipated to be Minimal

There are several siting factors for which impacts are anticipated to be minimal with the general conditions in section 4.0 of the Commission's generic site permit template (**Appendix B**). These are:

- Effects on human settlements (factor A);
- Effects on public health and safety (factor B);
- Effects on land-based economies (factor C);

- Effects on archaeological and historic resources (factor D);
- Effects on the natural environment (factor E);
- Effects on rare and unique natural resources (factor F).

5.3 Siting Factors for Which Impacts are Anticipated to be Minimal to Moderate, and Which May Require Special Conditions to Mitigate

There are no siting factors for which impacts are anticipated to be minimal to moderate with the general conditions in section 4.0 of the Commission's generic site permit template (**Appendix B**). Thus, there are no impacts that require special conditions in a Commission site permit in order for the impacts to be mitigated. As discussed in this EA, impacts of the project are minimized and mitigated by its location, by processes already in place at the MEC, and by permits other than the Commission's site permit, e.g., MPCA air permit.

5.4 Siting Factors that are Well Met

There are several siting factors that do not describe a resource or impact but rather indicate the state's interest in efficient design and use of resources, particularly the state's limited land resources. For the applicants' proposed project, these factors are well met:

- Application of design options that maximize energy efficiencies, mitigate adverse environmental effects, and could accommodate expansion of transmission or generating capacity (factor G);
- Use of existing large electric power generating plant sites (factor I);
- Electrical system reliability (factor K).

The project utilizes an existing large electric power generating plant site, the MEC site (see Section 3.1). This location maximizes energy efficiencies and mitigates adverse environment effects (see Section 4). The project will ensure reliable electrical power for projected electrical needs within the state (see Section 1.1).

5.5 Unavoidable Impacts

Electric power generating plants are large infrastructure projects that have the potential for adverse human and environmental impacts. As discussed in this EA, the impacts associated with the MEC expansion project are anticipated to minimal. Despite being minimal, there are some impacts that cannot be avoided.

The project will utilize natural gas to create electrical energy. The use of natural gas – a limited, carbon feedstock – is unavoidable. Air emissions are unavoidable. Though public health risks associated with the project are anticipated to be within state guidelines, the emission of additional combustion by-products into the air will increase the risk of adverse public health impacts. Air emissions will include carbon dioxide, a greenhouse gas. Though the project will increase greenhouse gas emissions at the MEC, it is anticipated to lower greenhouse gas emissions in Minnesota overall.

Aesthetic impacts are unavoidable. The project will introduce a new emissions stack and additional water vapor plumes into the project area. Temporary construction-related impacts cannot be avoided. These include construction noise and increased traffic near the MEC site.

5.6 Irreversible and Irretrievable Commitments of Resources

The commitment of a resource is irreversible when it is impossible or very difficult to redirect that resource to a different future use. An irretrievable commitment refers to the use or consumption of a resource such that it is not recoverable for later us by future generations.

The commitment of land for the MEC expansion project is likely an irreversible commitment. In general, land utilized for electric power generating plants remains in use by these plants for a relatively long period of time. Repurposing the land for a different future use is possible; however, it would require substantial resources to do so.

There are few commitments of resources associated with the project that are irretrievable. These commitments include the steel, concrete, and carbon (e.g., natural gas) resources committed to the project, though it is possible that the steel could be recycled at some point in the future. Labor and fiscal resources required for the project are also irretrievable commitments.