AN ALLETE COMPANY

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July 28, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

VIA ELECTRONIC FILING

Re: In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan
Docket No. E015/RP-15-690 (Compliance Filing)

In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package
Docket No. E015/M/AI-17-568 (Petition for Approval)

Dear Mr. Wolf:

Enclosed for filing, please find Minnesota Power's (or the "Company's") Petition for Approval of the Energy*Forward* Resource Package and Compliance Filing ("Petition") to the Minnesota Public Utilities Commission ("Commission"). On July 18, 2016, the Commission issued its Order Approving Resource Plan with Modifications in Docket No. E015/RP-15-690, directing the Company to investigate and propose safe, affordable, and environmentally-appropriate power supplies, including replacement capacity and additional wind and solar energy. Since the issuance of that Order, Minnesota Power has spent a considerable amount of time evaluating various options and developing its Energy*Forward* Resource Package. The Company is excited about the proposed Energy*Forward* Resource Package in this filing, as the proposed set of cost-effective and sustainable resource additions are needed to ensure long-term reliable energy supply to meet existing customers' needs.

In furtherance of the Commission's directive, Minnesota Power presents for Commission approval its proposed Energy*Forward* Resource Package, a unique and synergistic combination of 250 MW of wind, 10 MW of solar, and approximately 250 MW of dispatchable natural gas capacity, all designed as an integrated package. In this filing, the Company respectfully requests that the Commission grant the following:

- Approval of the 250 MW Nobles 2 Wind Project Power Purchase Agreement ("PPA") and authorization of cost recovery;

- Approval of the 10 MW Blanchard Solar Project PPA and authorization of cost recovery;

- Approval of the affiliated interest agreements dedicating 48 percent of the Nemadji Trail Energy Center ("NTEC") 1x1 natural gas combined-cycle facility in Superior, Wisconsin to Minnesota Power and energy cost recovery through the Company's Fuel and Purchased Energy ("FPE") Rider; and

- 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 Midcontinent Independent System Operator, Inc. ("MISO") revenues realized under the Capacity Dedication Agreement proposed in this filing flow back to customers.

The Petition is organized into eight sections as presented in the Table of Contents. Supporting appendices provide supplementary information, including information related to compliance requirements and the various requests for proposals, PPAs, and other agreements affiliated with and needed to effectuate the Company's acquisition of the wind, solar, and natural gas components of the Energy*Forward* Resource Package. Further, while no formal certificate of need is required for this package, Minnesota Power provides the type of information considered in a certificate of need proceeding, as this criteria set forth in Minn. R. 7849.0120 is likely to be helpful in review of this filing.

As described further in the accompanying Petition, the best way to proceed to make decisions on the approvals requested in this Petition is to build a record through a contested case proceeding. Timing in this matter is an important consideration, as Minnesota Power has important deadlines in the third and fourth quarters of 2018 associated with the agreements addressed in this Petition. The Company respectfully requests that the Commission process result in final decisions on this Petition by the end of September 2018 to ensure a robust discussion of all of the relevant issues and to allow the proceeding to advance on regular and predictable timelines.

Certain portions of the Petition and accompanying appendices contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which procedures further the intent of Minn. Stat. § 13.37 and Minn. R. 7829.0500. As required by the Commission's Revised Procedures, a statement providing the justification for excising the trade secret data is attached to this letter.

As reflected in the attached Affidavit of Service, this Petition has been served on the general service list, as well as the service list for Docket No. E015/RP-15-690.

Thank you for your consideration of the Company's Energy*Forward* Resource Package Petition. If you have any questions regarding this filing, please contact me by email at dmoeller@allete.com or by phone at (218) 723-3963.

Respectfully submitted,

David R. Moeller

Enclosures
cc: Service Lists

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Commission's revised Procedures for Handling Trade Secret and Privileged Data in furtherance of the intent of Minn. Stat. § 13.37 and Minn. R. 7829.0500, Minnesota Power has designated portions of the attached Petition for Approval of the Energy*Forward* Resource Package ("Petition") and appendices as Trade Secret.

Minnesota Power's Energy*Forward* Resource Package filing includes commercially-sensitive information related to request for proposals bidder and selection information; power purchase agreement and other agreement terms; and cost and pricing information. Designated appendices to the Energy*Forward* Resource Package also contain confidential, contractual, and energy procurement information that is materially sensitive and commercially valuable to Minnesota Power. Minnesota Power follows strict internal procedures to maintain the secrecy of all of this information in order to capitalize on the economic value of the information. As a result of public availability, Minnesota Power and its customers would suffer severe competitive implications, including a detrimental effect on energy costs paid by Minnesota Power's customers.

Minnesota Power believes that this statement and the attached Index of Non-Public/Trade Secret Information Contained in Petition provides the justification as to why the information excised from the Petition and its appendices should remain trade secret under Minn. Stat. § 13.37. The attached Index of Non-Public/Trade Secret Information Contained in Petition summarizes the portions of the Petition and appendices that have been designated as non-public and/or trade secret and the justification for that designation. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

<u>**Index of Non-Public/Trade Secret Information Contained in Initial Filing**</u>

Item/Location	Justification
Petition	
Throughout document	The information designated as trade secret in the Petition includes information related to request for proposals bidder and selection information; power purchase agreement and other agreement terms; and cost and pricing information. Minnesota Power considers this information to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information derives independent economic value from not being generally known to, and not being readily ascertainable by, other persons who can obtain economic value from its disclosure or use, and Minnesota Power has taken reasonable precautions to maintain its confidentiality. Similarly, some of the designated information relates to contractually-negotiated terms. To maintain competitiveness in contract negotiations regarding these terms, Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendices	
Appendix D: Nobles 2 Wind PPA	Certain information in this appendix has been designated as non-public. Minnesota Power considers the marked information to be trade secret as it contains information about contractually-negotiated terms which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use. To maintain the Company's competitiveness in contract negotiations regarding these terms, Minnesota Power maintains the confidentiality of these data. Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret as defined by Minn. Stat. § 13.37, subd. 1(b).

Item/Location	Justification
Appendix E: Blanchard Solar PPA	Certain information in this appendix has been designated as non-public. Minnesota Power considers the marked information to be trade secret as it contains information about contractually-negotiated terms which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use. To maintain the Company's competitiveness in contract negotiations regarding these terms, Minnesota Power maintains the confidentiality of this information. Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendix F: Development and Construction Management Agreement between Dairyland and South Shore	The entirety of this appendix has been designated as non-public. Dairyland and South Shore consider the entirety of the document to be trade secret as it contains information about contractually-negotiated terms which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use. To maintain the third-parties' competitiveness in contract negotiations regarding these terms, Minnesota Power maintains the confidentiality of this document. Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendix G: Ownership and Operating Agreement between Dairyland and South Shore	The entirety of this appendix has been designated as non-public. Dairyland and South Shore consider the entirety of the document to be trade secret as it contains information about contractually-negotiated terms which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use. To maintain the third-parties' competitiveness in contract negotiations regarding these terms, Minnesota Power maintains the confidentiality of this document. Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret as defined by Minn. Stat. § 13.37, subd. 1(b).

Item/Location	Justification
Appendix H: Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power	Certain information in this appendix has been designated as non-public. Minnesota Power considers the marked information to be trade secret as it contains information about contractually-negotiated terms which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use. To maintain the Company's competitiveness in contract negotiations regarding these terms, Minnesota Power maintains the confidentiality of this information. Minnesota Power has taken reasonable precautions to maintain confidentiality and this information is, therefore, trade secret as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendix I: Assumptions and Outlooks	Certain information in this appendix constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has important economic value to Minnesota Power as a result of this information remaining not public, and Minnesota Power has taken reasonable precautions to maintain its confidentiality.
Appendix J: Detailed Resource Planning Analysis	Certain cost information is marked as trade secret in this appendix because it constitutes information the Company considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has important economic value to Minnesota Power as a result of this information remaining not public, and the Company has taken reasonable precautions to maintain its confidentiality.
Appendix O: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Wind Resource Solicitation	The entirety of Appendix A to Appendix O is marked as trade secret because the document describes each proposal made in response to Minnesota Power's RFP for wind projects. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendix R: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation	The entirety of Appendix A to Appendix R is marked as trade secret because the document describes each proposal made in response to Minnesota Power's RFP for solar projects. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).

Item/Location	Justification
Appendix T: Summary of MISO's Generator Interconnection Process	Certain information in this appendix constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has important economic value to Minnesota Power as a result of this information remaining not public, and Minnesota Power has taken reasonable precautions to maintain its confidentiality.
Appendix V: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation	The entirety of Appendix A to Appendix V is marked as trade secret because the document describes each proposal made in response to Minnesota Power's RFP for gas-fired projects. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).
Appendix W: Combined-Cycle Selection Study	Certain information in this appendix constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has important economic value to Minnesota Power as a result of this information remaining not public, and Minnesota Power has taken reasonable precautions to maintain its confidentiality.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan	Docket No. E-015/RP-15-690 COMPLIANCE FILING
In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package	Docket No. E-015/M/AI-17-568 PETITION FOR APPROVAL

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SUMMARY OF FILING

PLEASE TAKE NOTICE that on July 28, 2017, Minnesota Power ("Minnesota Power" or the "Company") filed a Compliance Filing and Petition for Approval with the Minnesota Public Utilities Commission ("Commission"), implementing the Commission's July 18, 2016, Order Approving Resource Plan with Modifications in Docket No. E015/RP-15-690 ("July 2016 IRP Order") with respect to the Company's 2015 Integrated Resource Plan ("2015 Plan"). Consistent with the Commission's July 2016 IRP Order, the Company requests approval of its Energy*Forward* Resource Package, a unique and synergistic combination of 250 MW of wind, 10 MW of solar, and approximately 250 MW of dispatchable natural gas capacity, all designed as an integrated package. Specifically, the Company requests approval of (i) Power Purchase Agreements ("PPAs") for 250 MW of wind and 10 MW of solar energy; (ii) affiliate interest agreements for approximately 250 MW of dispatchable natural gas capacity, and (iii) associated tariff changes and rule variances. The Energy*Forward* Resource Package provides customers low-cost and long-term solutions to meet the need identified in the 2015 Plan, which continues to be supported by Minnesota Power's updated analysis and outlooks. This portfolio was developed based on robust and competitive processes and provides economical and long-term capacity and energy at competitive costs.

In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan

Docket No. E015/RP-15-690
COMPLIANCE FILING

In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package

Docket No. E015/M/AI-17-568
PETITION FOR APPROVAL

CERTIFICATE OF SERVICE

I, Kristin M. Stastny, hereby certify that on the 28th of July, 2017, on behalf of Minnesota Power, I electronically filed a true and correct copy of the enclosed Petition for Approval/Compliance Filing and supporting appendices on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service lists.

Dated this 28th day of July, 2017.

/s/ Kristin M. Stastny
Kristin M. Stastny

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PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan	Docket No. E015/RP-15-690 COMPLIANCE FILING
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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 submits this Compliance Filing and Petition for Approval to the Minnesota Public Utilities Commission ("Commission"), implementing the Commission's July 18, 2016, Integrated Resource Plan Order ("July 2016 IRP Order") approving the Company's 2015 Integrated Resource Plan ("2015 Plan").[1] In that order, the Commission directed the Company to investigate and propose safe, affordable, and environmentally-appropriate power supplies, including replacement capacity and additional wind and solar energy to support long-term customer needs. In furtherance of that directive, the Company requests approval of its Energy*Forward* Resource Package, a unique and synergistic combination of 250 MW of wind, 10 MW of solar, and approximately 250 MW of dispatchable natural gas capacity, all designed as an integrated package.[2]

The Energy*Forward* Resource Package provides low-cost and long-term solutions to meet the need identified in the 2015 Plan, which continues to be supported by the Company's updated analysis and outlooks. This portfolio was developed based on robust and competitive Request for Proposal ("RFP") processes and is supported by independent evaluation. Modeling demonstrates that the proposed Energy*Forward* Resource Package is economical and serves long-term customer needs at competitive costs. The proposed package of resources also continues the Company's long-term fleet transformation toward an overall mix of two-third renewables plus renewable-enabling natural gas, and one-third compliant coal, that will reduce emissions and

[1] *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).

[2] Specifically, the Company requests approval of (1) Power Purchase Agreements ("PPAs") for 250 MW of wind and 10 MW of solar energy; (2) affiliated interest agreements for approximately 250 MW of dispatchable natural gas capacity; and (3) 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.

increase renewable penetration without sacrificing cost competitiveness and the reliability of Minnesota Power's power supply. [3]

This transformation calls for the strategic addition of resources to ensure adequate energy and capacity to meet existing and future customer needs, particularly considering Minnesota Power's unique customer load requirements serving some of the nation's largest industrial customers. Overall, implementation of the Energy*Forward* Resource Package results in a resource mix of 44 percent renewables (including hydroelectric) and a 40 percent reduction in greenhouse gas emissions by 2030 from 2005 levels, as detailed in Section 3.

The Energy*Forward* Resource Package is also consistent with the Company's customer requirements, including a heavily industrial customer base, with load factors approaching 80 percent and a critical need for reliable power around the clock. The combination of dispatchable capacity with low-cost renewable energy ensures reliable supply in all reasonable circumstances.

1.2 OVERVIEW OF ENERGY*FORWARD* RESOURCE PACKAGE

Three integrated elements make up the Energy*Forward* Resource Package. These components are summarized here and described in detail in Sections 4, 5, and 6 of this Petition. They are:

- A Power Purchase Agreement ("PPA") for the 250 MW Nobles 2 Wind Project in southwestern Minnesota,
- A PPA for the 10 MW Blanchard Solar Project in central Minnesota, on Minnesota Power's distribution system, and
- Affiliated interest agreements dedicating 48 percent of the Nemadji Trail Energy Center ("NTEC") 1x1 natural gas combined cycle facility in Superior, Wisconsin to Minnesota Power.

1.2.1 Wind

The Nobles 2 Wind Project is a 250 MW wind development, to be constructed in southwestern Minnesota by an affiliate of Tenaska, Inc. It was selected through an RFP consistent with the

[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). Further, by 2026, Minnesota Power will have removed almost 700 MW of older coal-fired generation from its 2,050 MW generation portfolio.

July 2016 IRP Order. Minnesota Power has executed a 20-year PPA (Appendix D) for the output of the facility, capacity, and renewable attributes, conditioned on Commission approvals in this proceeding.

[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS] adjusted for transmission network upgrade costs, but capped at **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. The Nobles 2 Wind Project PPA is expected to provide over 1 million MWh of energy each year and to be in operation in 2020. It provides system benefits and is consistent with the July 2016 IRP Order requirement that Minnesota Power procure 100–300 MW of installed wind capacity.

1.2.2 Solar

The Blanchard Solar Project is a 10 MW solar facility near Royalton in Morrison County, to be developed by an affiliate of Cypress Creek Renewables. It was a least-cost bid in the RFP process and helps meet the Company's Minnesota Solar Energy Standard ("SES") requirements. The Blanchard Solar Project will be interconnected to the Company's distribution system, avoiding cost and timing risks associated with transmission interconnection. Minnesota Power has executed a 25-year PPA (Appendix E) for the output of the facility, capacity, and renewable attributes, conditioned on Commission approval, at a fixed price of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** for the term of the PPA. The project is expected to begin operations by mid-2020.

While the price and efficiency of solar have improved, solar remains more expensive than wind and does not provide optimal capacity benefits for the Company due to Minnesota Power's system peaking in the evening hours of winter. For these reasons, Minnesota Power's strategy remains to add solar only as needed to meet the SES until resource economics change.

1.2.3 Natural Gas

Minnesota Power proposes a Capacity Dedication Agreement ("CDA") to procure the output of a 48 percent undivided share from NTEC, a nominal 525 MW combined-cycle natural gas plant in

Superior, Wisconsin, expected to be in service by the end of 2024.[4] NTEC will be jointly owned by a Wisconsin affiliate of Minnesota Power — South Shore Energy, LLC ("South Shore") — and Dairyland Power Cooperative ("Dairyland") (collectively the "NTEC Owners"). Jointly owning NTEC between South Shore and Dairyland allows Minnesota Power to procure this highly competitive resource that would not have been available without the economies of scale from a larger plant. Subject to Commission affiliated interest approvals in this proceeding,[5] Minnesota Power will take the lead to develop, construct, operate, and maintain NTEC[6] and will purchase 48 percent of its output for the entire useful life of the plant at prices and on terms and conditions that replicate utility ownership.[7] This structure provides the Commission with control over the prudence of costs associated with the asset.[8]

The 48 percent share of NTEC[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] NTEC adds flexible, efficient, and cleaner generation to replace retiring baseload coal-fired generation;

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

[5] As described in detail in Section 6 of this filing, 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, requires use of affiliated interest agreements that are subject to Commission approval.

[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 ("Square Butte"). Under the Square Butte 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 procure the entire position.

ensures reliable electric service; and complements the Company's expanding renewable portfolio.

Pricing under the CDA reflects regulated cost recovery. The price for Minnesota Power's 48 percent share in the first year is **[TRADE SECRET DATA BEGINS…**
…**TRADE SECRET DATA ENDS]** plus an additional amount assumed to be not more than **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** for network upgrade costs.[11]

Energy associated with Minnesota Power's share of NTEC 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 operate with a capacity factor ranging from 40 to 80 percent,[12] depending on fuel cost, demand, and carbon regulation.[13]

1.3 OVERVIEW OF LOAD FORECAST/NEED

The selection of the proposed Energy*Forward* Resource Package was based on an overall analysis of future customer needs, implementation of the July 2016 IRP Order, and evaluation of available alternatives to meet customers' long-term energy needs. As described in Section 2 of this Petition, the Company projects a capacity deficit beginning in 2018, increasing to approximately 500 MW in 2031. This deficit is in part because Minnesota Power is in the process of idling, removing, or refueling resources, including nearly 700 MW of older coal-fired capacity that have already been or are planned to be removed or idled. The net effect is to require that Minnesota Power deploy significant new resources by the mid-2020s.

[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 on the same basis as if the asset was owned directly by the utility.

The updated forecast developed to evaluate the proposed Energy*Forward* Resource Package reflects a reasonable overall outlook of customer demand and is not overly optimistic. The forecast 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.[14]

1.4 THE ENERGY*FORWARD RESOURCE* PACKAGE IS IN THE PUBLIC INTEREST

The Energy*Forward* Resource Package continues Minnesota Power's efforts to transform its generation portfolio without sacrificing reliability and affordability of service. The proposed package is in the public interest for a variety of reasons described in this filing. In particular, the proposed package of resources:

- Increases wind and solar energy 40 percent (260 MW increase) from current levels;
- Increases overall renewable penetration to approximately 44 percent (including hydroelectric);
- Meets growing needs during a period of declining planning reserve margins in MISO;
- Replaces older 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;
- Positions the system for future renewable development; and
- Delivers the least-cost portfolio across hundreds of sensitivities.

This is a unique opportunity to deploy resources that align cost and non-cost interests. 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 Energy*Forward* Resource Package is a cost-effective way to meet customer needs. It replaces high-cost legacy resources, benefiting all customers, and decreases overall customer

[14] The Company also considered higher and lower forecast sensitivities. The Energy*Forward* Resource Package is least cost under those scenarios as well, further supporting the reasonableness of the proposed packages.

costs by adding both low-cost wind generation with highly-efficient combined-cycle natural gas capacity. As described in Section 3 of this Petition, the proposed Energy*Forward* Resource Package is the least-cost alternative relative to no-action, a 75 percent renewable alternative, 50 percent renewable alternative, or large combustion turbine peaker alternative.

1.4.2 Strategist Analysis

The Company's Strategist Proview modeling ("Strategist") analysis confirms that the Energy*Forward* Resource Package is 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 Energy*Forward* Resource Package provides the most prudent and flexible set of resources to comply with the July 2016 IRP Order and meet customer requirements with an overall balanced, reliable, and affordable power supply portfolio.

1.4.3 Other Considerations

Beyond pure economics, the Energy*Forward* Resource Package provides additional benefits described in this filing:

- ***Reduces CO_2 Emissions***: It continues Minnesota Power's commitment to finding less carbon-intense resources to meet customer needs. The Company will substantially exceed compliance with the Minnesota CO_2 emissions goals by (1) replacing nearly 700 MW of older 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 meet 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) in an hour due to variable renewable generation. Adding dispatchable capacity will help mitigate and balance the exposure to potentially volatile energy markets for such variability.
- ***Replaces Coal-fired Generation***: Adding 260 MW of incremental renewable energy production with approximately 250 MW of dispatchable natural gas capacity 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 between by 2025. This combination gives customers flexible resources that can adjust during times of high wind generation and respond quickly to changes in wind production.
- ***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.
- ***Location Benefit***: Finally, the resources are beneficially located. The Nobles 2 Wind Project in southwestern Minnesota is geographically diverse from the Company's North Dakota wind generation, spreading weather and energy price risk. The Blanchard Solar Project directly interconnects to Minnesota Power's distribution system, simplifying and lowering the costs of the interconnection process. And NTEC is advantageously located to serve Minnesota Power's customers, is near a ready supply of available labor, and is close to electric transmission facilities and multiple interstate natural gas pipelines.

1.5 OVERVIEW OF PROCESS

Minnesota Power requests decisions on a number of specific but interdependent elements to enable implementation of the Energy*Forward* Resource Package. Specifically, the Company requests:

- Approval of the 250 MW Nobles 2 Wind Project PPA and authorization for Minnesota Power to recover the PPA costs through its Fuel and Purchased Energy ("FPE") Rider;

- Approval of the 10 MW Blanchard Solar Project PPA and authorization for Minnesota Power to recover the PPA costs through the Solar Energy Adjustment;
- Approval of the affiliated CDA, dedicating 48 percent of NTEC to Minnesota Power and energy cost recovery through the 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
- 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.

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 or PPA filing. Minnesota Power views this Petition to be an opportunity for the Commission and stakeholders to evaluate the proposed package and alternatives considered. Accordingly, while no formal certificate of need is required for this package, the Company provides the type of information considered in a certificate of need proceeding, as well as the information necessary to fully evaluate the agreements that effectuate Minnesota Power's acquisition of the wind, solar, and natural gas components of the Energy*Forward* Resource Package.[15]

As reflected in the Company's June 8, 2017, letter and subsequent July 12, 2017, Reply Comments submitted in Docket No. E015/RP-15-690, Minnesota Power supports referral of 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. Section 7 of this Petition provides a more detailed description of the Company's proposed process and schedule.

Timing is a significant consideration as the Company has important deadlines in the third and fourth quarters of 2018 and regulatory certainty by that time will be very helpful. The Nobles 2 Wind Project PPA, Blanchard Solar Project PPA, and NTEC CDA contain conditions precedent

[15] Appendix C provides a checklist 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.

calling for Commission approval by October 2018. Additionally, network upgrade study work associated with the NTEC component of the package calls for non-refundable milestone payments in the fourth quarter of 2018. A contested case process and 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 Energy*Forward* Resource Package as proposed 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 grant this Petition.

SECTION 2 ENERGY AND DEMAND FORECAST AND RESOURCE NEED

This Section provides the results of Minnesota Power's updated forecast for customer demand and peak demand (the "Energy*Forward* Resource Package Forecast") utilized in the Company's evaluation of resource options in selecting the Energy*Forward* Resource Package. 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 conclusions regarding the size and timing of proposed resource additions. Under several variations, this forecast fully supports the proposed size, type, and timing of Minnesota Power's resource additions.

While a certificate of need is not required for this Energy*Forward* Resource Package,[16] the criteria used to evaluate a certificate of need are likely to be helpful in review of this filing. Under applicable certificate of need rules, the Commission is to analyze the need for the proposed generation additions in comparison with reasonable alternatives and to determine whether "the probable result of denial 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."[17]

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 the Energy*Forward* Resource Package 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.

[16] None of the elements of the package require Minnesota Power to obtain a certificate of need. The size of the Blanchard Solar Project exempts it from a certificate of need under Minn. Stat. § 216B.243. The Nobles 2 Wind Project PPA does not require Minnesota Power to obtain a certificate of need, although the project developer, Tenaska, requires a certificate of need to proceed with the underlying project. NTEC is located in Wisconsin, and thus does not require a Minnesota certificate of need.

[17] Minn. R. 7855.0120.

Minnesota Power is committed to being responsive to Commission and stakeholder feedback on its forecasting, continuous forecast process improvement, forecasting transparency, forecast 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. In Minnesota Power's 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 capacity and energy, Minnesota Power would have a capacity deficit of approximately 300 MW by 2025, increasing to approximately 500 MW in 2031, and would need to source approximately 10 percent of its energy from the MISO market in the 2025 timeframe, increasing to approximately 20 percent by 2031, resulting in significant market exposure for its customers.

As outlined below, five major factors contribute to Minnesota Power's projected need for capacity and energy by the mid-2020s: (1) increases in customer load of about 180 MW, (2) the retirement of Boswell Energy Center Units 1 and 2 ("BEC1&2") in 2018, eliminating approximately 135 MW from Minnesota Power's system, (3) the expiration of a bilateral purchase contract for capacity from Square Butte's Milton R. Young 2 ("Young 2") generating station in North Dakota, eliminating the last 100 MW of generation from this long-standing lignite coal resource,[18] (4) the expiration of short-term contracts for 250 MW of Large Industrial Interruptible capacity; and (5) the idling of Taconite Harbor Energy Center Units 1 and 2

[18] In particular, as outlined in Minnesota Power's 2015 Plan, the Company reduced capacity from 227.5 MW to 100 MW in August 2014 and anticipates phasing out Young 2 entirely by 2026. *In the Matter of Minn. Power's 2015-2029 Integrated Res. Plan*, Docket No. E015/RP-15-690, 2015 INTEGRATED RESOURCE PLAN at 12 (Sept. 1, 2015); *see also In the Matter of Minn. Power's Petition to Purchase Square Butte Coop.'s Transmission Assets and Restructuring Power Purchase Agreements from Milton R. Young 2 Generating Station*, Docket No. E015/PA-09-526, ORDER GRANTING PETITION WITH CONDITIONS (Dec. 21, 2009).

(“THEC1&2”) in 2016 and termination of coal-fired operations at THEC1&2 by the end of 2020.[19]

In the remainder of this Section, Minnesota Power (1) details its forecast methodology for this Petition; (2) discusses its 2015 Plan forecast and outcomes of that proceeding by way of background; and (3) presents its updated forecast results, both in terms of its base case and high and low sensitivities.

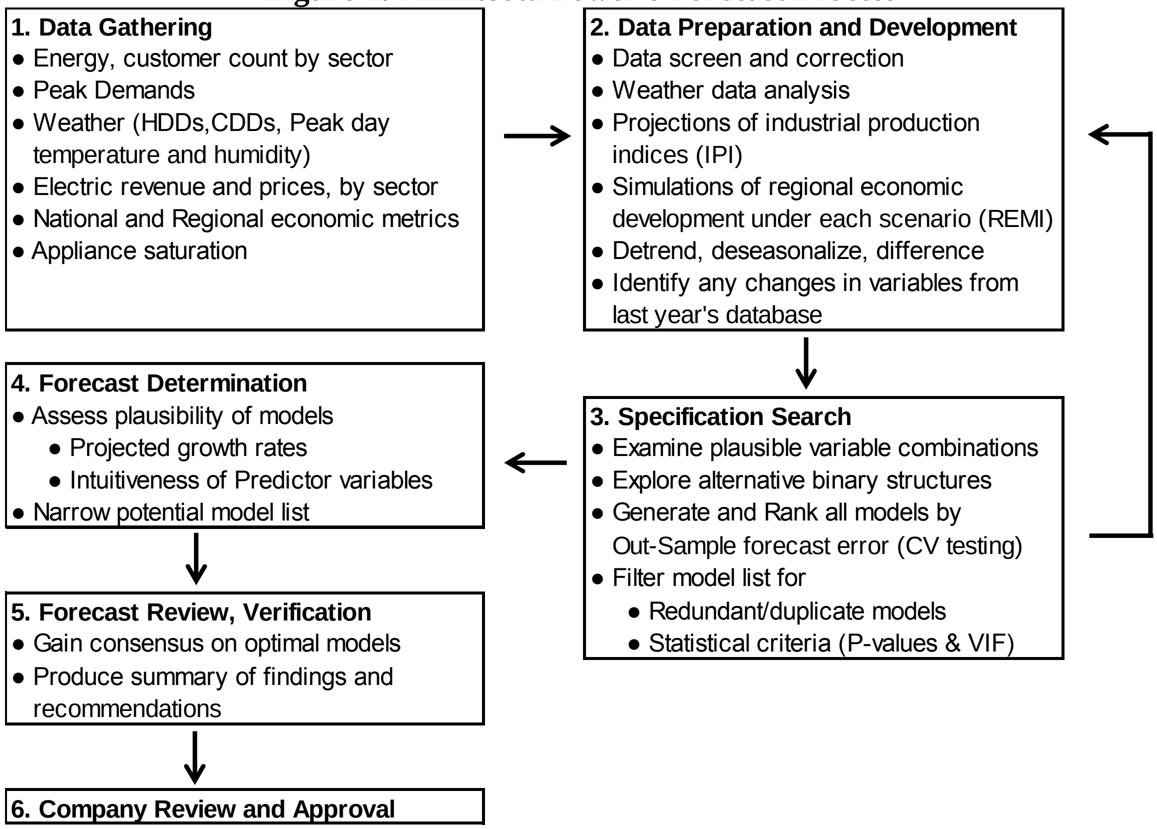
2.1 OVERVIEW OF FORECAST METHODOLOGY

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.

[19] 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 recommissioning alternatives in its analysis.

Figure 1: Minnesota Power's Forecast Process



In order to determine the amount of energy and capacity necessary to meet Minnesota Power's customer needs in the coming years, the Company prepared an updated sales and demand forecast based on the 2016 Annual Forecast Report ("2016 AFR").[20] The Company's annual forecast methodology, data sources, analytical techniques, results of statistical tests, and 2016 forecast scenario results are documented in Minnesota Power's 2016 AFR, which was filed in Docket No. E999/PR-16-11 on June 30, 2016.[21] The Company's 2016 AFR filing also discusses the methodology's inherent strengths and weaknesses and any process enhancements implemented in developing the 2016 AFR forecast, which built on the forecast results presented

[20] The methodology used to develop the 2016 AFR forecast of sales and demand, as well as other forecast details, are provided in Minnesota Power's initial 2016 Annual Electric Utility Forecast Report filed in Docket No. E999/PR-16-11 on June 30, 2016.

[21] Minnesota Power submits an Annual Electric Utility Forecast Report to the Department by July 1 each year. Minnesota Power began its analysis for this Energy*Forward* Resource Package 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.

in the Company's 2015 Plan, while addressing stakeholder feedback and updates for customer projections and additional historical data.[22]

As discussed in Minnesota Power's 2016 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.[23] Through its conservation program efforts, Minnesota Power achieved 64,117,319 kWh 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.[24]

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 utilized following the 2015 Plan proceeding, and discusses additional updates based on the most current outlooks for large industrial and resale customers that were

[22] *Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at 15 (June 30, 2016).

[23] *Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at 14 (June 30, 2016).

[24] *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).

applied to the 2016 AFR filed on June 30, 2016. This section also discusses the Company's recently-filed 2017 Annual Forecast Report ("2017 AFR").[25]

2.2.1 2015 Plan Forecast and Outcomes

On September 1, 2015, Minnesota Power filed its 2015 Plan for the period of 2015 through 2029.[26] 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 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 and reduced offtake from Young 2.[27]

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. The load forecast reflected a projected (summer) peak demand of 1,970 MW by 2020 and 2,030 MW by 2028,[28] with a winter peak between 20 and 30 MW higher. On average, energy sales and peak demand were projected to grow at about 1.1 percent per year from 2014 through 2028.

[25] *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017). The 2017 AFR was filed on June 29, 2017, in Docket No. E999/PR-17-11. A comparison of the Energy*Forward* Resource Package Forecast and the 2017 AFR forecast is provided in Section 2.3.1.3.

[26] *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).

[27] In its 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 recommissioning alternatives in its analysis.

[28] Minnesota Power's initial 2015 IRP filing contained typos, indicating a projected (summer) peak demand of 1,970 MW by 2026 and 2,070 MW by 2028. However, the analysis presented in the 2015 IRP was correct, and the correct numbers are utilized here.

The 2015 Plan also proposed retiring THEC1&2 by 2020; reducing sulfur-dioxide ("SO_2") emissions from BEC1&2 by routing the exhaust through BEC Unit 3's pollution-control equipment. The 2015 Plan indicated that the projected peak demand growth from the 2014 AFR combined with reducing Minnesota Power's reliance on coal-fired generation would lead to short-term capacity deficits until 2020. Minnesota Power planned to address the short-term capacity needs through bilateral contracts. In 2020, Minnesota Power will add 250 MW of hydroelectric power to its generation supply through the Manitoba Hydro-Electric Board ("MHEB") PPA, which will meet the Company's capacity needs until the mid-2020s. The 2015 Plan showed a capacity deficit again starting in the mid-2020s and, by 2028, that capacity deficit, absent resource additions, would grow to close to 300 MW.

During the 2015 IRP proceeding, the Clean Energy Organizations ("CEO")[29] argued that there were flaws in the Company's load forecast, causing it to overestimate future demand. In particular, the CEO 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 CEO's 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.

The Commission, in its July 18, 2016 Order Approving Resource Plan with Modifications, 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

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

> 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]

The Commission agreed with the Company's proposed coal-fired generation retirement plans, but determined that BEC1&2 should also be retired as soon as capacity and energy are available, no later than by the end of 2022.[31] Additionally, the Commission concluded that Minnesota Power could continue to pursue an RFP for the possible procurement of combined-cycle natural gas to meet its energy and capacity needs in the absence of BEC1&2 and THEC1&2.[32] The Commission also found that Minnesota Power should (1) initiate competitive bidding to procure 100–300 MW of installed wind capacity and (2) acquire solar generation to meet SES requirements and account for the Commission's finding that up to 100 MW of solar by 2022 is likely an economic resource for Minnesota Power's system in a competitive acquisition process.[33]

Minnesota Power took steps to address those inputs and Commission conclusions from its 2015 Plan proceeding in developing its refined forecast to ensure the Energy*Forward* Resource Package draws on both the Commission's forecasting findings as well as its determination that the Company should pursue wind and solar resource additions to its system. In particular, Minnesota Power made the following modifications from its 2015 Plan forecast approach in its subsequent annual forecast, the 2016 AFR filed June 30, 2016:

- 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;

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

[31] July 2016 IRP Order at 14-15 (Order Points 5-6).

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

[33] July 2016 IRP Order at 15 (Order Points 9-11).

- 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.

The overall effect of all forecast adjustments made since the 2015 Plan is an Energy*Forward* Resource Package energy sales outlook that is about 1,700,000 MWh per year lower than the 2015 Plan in the pre-2020 timeframe, and about 590,000 MWh per year lower by 2025. The majority of the decrease in the outlook is due to the reduced large customer assumptions. There are also some minor differences attributable to secondary economic impacts and methodological enhancements implemented in the 2016 AFR. Each of these modifications is discussed in greater detail below.

2.2.2 Updates From 2015 Plan Forecast

2.2.2.1 Large Industrial Customer Projections

As previously noted, the 2015 Plan's base load forecast (which was the 2014 AFR forecast) was developed in the first half of 2014. Since the 2014 AFR's filing on July 1, 2014, eight of Minnesota Power's ten mining and metals customers' facilities experienced some idling of production, and several remain indefinitely idled. The forecast used in this Energy*Forward* Resource Package filing has been updated to reflect the most current expectations for existing industrial customers. Other prospective new mining operations' start dates were deferred, in light of economic considerations, or were no longer deemed likely enough to be included in the outlook used in this Energy*Forward* Resource Package Forecast. Overall, the Energy*Forward* Resource Package Forecast assumptions for large customer sales are about 1,200,000 MWh lower in the pre-2020 timeframe and about 200,000 MWh lower by 2025.

2.2.2.2 Secondary Economic Impacts

Minnesota Power uses the Regional Economic Models, Inc.[34] model to quantify the indirect economic effects of known and expected changes in regional employment (e.g., expansions,

[34] Minnesota Power subscribes to the latest REMI Policy Insight version (PI+) for northeastern Minnesota. This input/output econometric simulation software combines a national economic outlook with specified regional

layoffs, and closures of large employers) to produce an expected economic outlook for the region. The Company also simulates alternative regional outlooks utilizing different employment scenarios where each employment scenario corresponds to a large industrial and resale customer outlook. The goal is to create forecasts that are internally consistent or have "consistency of assumption." In other words, these alternative outlooks are designed so that the residential and commercial energy sales forecasts are consistent with various economic scenarios. For example, the alternative outlooks can contemplate a scenario in which the mining sector adds 200 jobs and the paper sector adds 100 jobs.

The consistency of assumption in the outlook is accomplished by first applying direct, post-regression load adjustments to the econometric forecasts to account for large and sudden expansions or contractions by industrial and resale customers, and, second, through indirect, simulated economic impacts that shape the residential and commercial outlooks via their effect on the predictor variables (e.g., employment or population) used in econometric modeling.

The Energy*Forward* Resource Package Forecast contains a combined residential and commercial sales outlook that is lower than the 2015 Plan forecast by about 90,000 MWh each year of the forecast. A rough approximation of the secondary economic impacts in both the Energy*Forward* Resource Package outlook and 2014 AFR (2015 Plan outlook) suggests that about 14 percent of this 90,000 MWh per year decrease is due to the secondary economic impacts of a conservative industrial sector employment outlook. The remainder of the difference between the 2015 Plan forecast and Energy*Forward* Resource Package Forecast is due to econometric modeling enhancements and an additional two years of observed energy sales.

2.2.2.3 Forecast Process Enhancements

Finally, Minnesota Power has implemented several process and methodological enhancements designed to produce more accurate and more reasonable overall forecasts since the 2015 Plan.

economic conditions to produce a forecast for a 13 County Planning Area such as employment by sector, population, economic output by sector, and gross regional product. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at 18 (June 30, 2016).

First, the Company made a number of pre-regression adjustments to historical energy sales series to back-out recent load additions or volatile year-to-year energy use by customers that were not economically-driven. Adjusting the historical sales series prior to modeling ensures a consistent definition of the historical series. Inconsistently-defined historical data will produce an inconsistently-defined forecast. For example, it would be difficult to determine whether the load associated with a customer's recent expansion is fully, partially, or not accounted for in the forecast. Pre-regression adjustments help avoid potential for double-counting of load in the forecast timeframe — once (partially) embedded in the econometric projection, and again through a post-regression load adjustment.

Second, Minnesota Power has applied binary and trend variables during regression modeling in two new ways to hedge against over-forecasting. First, to recognize and account for the slow-down in residential and commercial customer and sales growth in the post-recession timeframe, and second, to account for recent and substantial changes in load that cannot be precisely quantified and therefore cannot be "backed-out" of the historical sales series prior to regression modeling.

Regarding the need to recognize the slow-down in customer growth, Minnesota Power has observed a divergence of economic indicators and energy sales. Although economic conditions have improved, employment has rebounded, and population growth in the region has resumed, there has been little to no growth in electricity use or customer count in several customer classes. Simple regression models that ignore recent trends and do not account for the inflection that occurred in the 2007-2009 timeframe are likely to result in an over-stated forecast. Minnesota Power recognized the need to account for the recent "slow-growth" trends and avoid projecting a sales or customer count series at implausible pre-recession rates of growth. The approach Minnesota Power considered was to include an additional binary and an additional trend series to denote a change in paradigm sometime after the slow-down in order to effectively shift the first forecast year to align with the last historical year and to change the underlying non-economically-driven growth rate of the series.

With respect to the need to account for recent and substantial changes in load that cannot be precisely quantified, Minnesota Power has observed some gradual and substantial load expansions in one industrial sector — the pipeline sector. The load addition is not metered independently, so it is not easily quantified and therefore it cannot be "backed-out" of the historical sales series without introducing some subjectivity and additional uncertainty to the estimate. Minnesota Power identified a more objective approach to accounting for these large load changes that cannot be precisely quantified. Trend and binary variables are applied in the same way as discussed above — they denote and account for a structural shift and inflection in the dependent variable. However, instead of being carried forward into the forecast timeframe, where they would continue to denote a changed paradigm, they are terminated at the end of the historical timeframe. This approach allows the regression model to estimate and subsequently "back out" this recent load addition from the forecast. An assumption for the expected load added due to the recent expansion can then be accurately quantified and applied to the econometric forecast.

Third, the Company has continued to improve its regression model specification search (Step 3 in the AFR Forecast Process) to ensure selection of optimal forecast models from the broader pool based on defined statistical criteria. Improvements in this process since the 2015 Plan forecast (2014 AFR) include enhanced model testing, filtering, and ranking capabilities that allow Minnesota Power to identify more plausible regression models. The 2014 AFR specification search step identified about three million plausible models, whereas — even with expanded testing and more stringent criteria — the 2016 AFR, which forms the basis for this Energy*Forward* Resource Package Forecast, still produced about four million more plausible models.

Expanded testing was made possible by the new, more-automated specification search step. Specifically, the Company was able to program and implement a Heteroscedasticity and Autocorrelation Consistent ("HAC") adjustment into the testing phase of the specification search step. The HAC adjustment process adjusts the standard errors of regression coefficients to correct t-statistics and P-values for biases resulting from autocorrelation and heteroscedasticity. Once unbiased, the program can disqualify or filter models with HAC-adjusted P-values greater than 10 percent to ensure only truly predictive variables are used in the final customer count and energy sales models.

The Company has worked diligently to address critiques of its forecasts, and has often worked directly with the Department to establish acceptable methodologies. These steps have further enhanced the forecasting process for Minnesota Power customers, especially with respect to those aspects of sales forecasting that are most susceptible to the modeling process — i.e., those areas other than large power load, which can be significantly and suddenly affected by shifts in the industry and unpredictable world events. Minnesota Power also continues to work closely with customers to gather information pertinent to its sales forecasting.

2.2.3 Summary of Forecasting Updates from Prior Filings

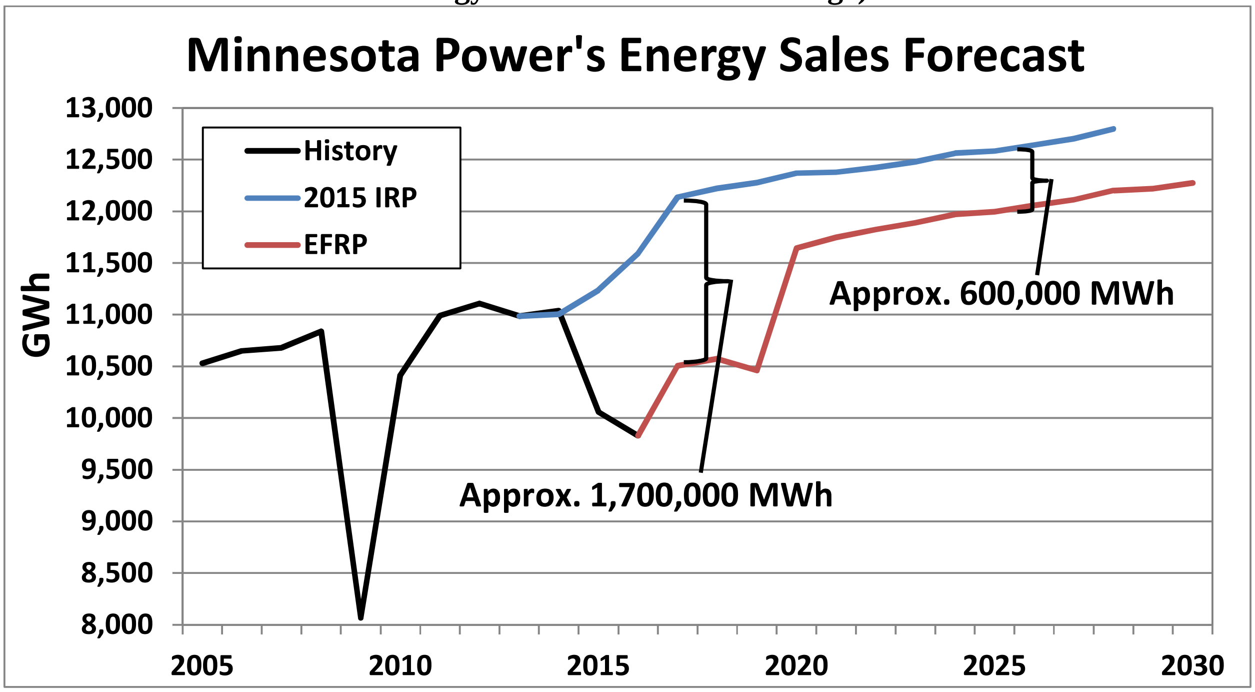
In light of these additional refinements, the Company's Energy*Forward* Resource Package Forecast reflects improvements in the Company's statistical analytic capabilities, continuous validation of forecast model inputs, and close cooperation with customers and other interested stakeholders. These efforts result in an overall reasonable and reliable forecast for Minnesota Power customers. The Energy*Forward* Resource Package Forecast also addresses feedback from the Commission, the Department, and the CEO 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 Energy*Forward* Resource Package Forecast are described in the next section.

2.3 FORECAST RESULTS AND NEED

2.3.1 Energy*Forward* Resource Package Forecast Results

Figure 2 below compares the current Energy*Forward* Resource Package energy sales outlook ("EFRP" in Red) to the 2015 Plan forecast (Blue).

Figure 2: Minnesota Power's Energy Sales Forecast (2015 Plan Compared to Energy*Forward* Resource Package)



In the short term (present through 2020), the Energy*Forward* Resource Package sales forecast is about 1,700,000 MWh per year lower than the 2015 Plan forecast due to more reasonable overall assumptions concerning Minnesota Power's large mining customers, specifically: Mesabi Metallics, Keewatin Taconite ("Keetac"),[35] PolyMet, and Magnetation Plants 2 and 4. The revisions to the forecast assumptions for these five customers reduce the short-term, pre-2020 outlook by about 1,600,000 MWh per year, and account for about 95 percent of the short-term (1,700,000 MWh per year) decrease from the 2015 Plan forecast.

In the long-term, post-2020 timeframe, both outlooks assume PolyMet and Keetac operate at full production, and by 2025 the majority (about 400,000 MWh) of the total 600,000 MWh per year decrease in sales from the 2015 Plan is attributable to the assumptions for Mesabi Metallics and Magnetation Plants 2 and 4 being removed from the forecast, and the addition of Silver Bay Power.

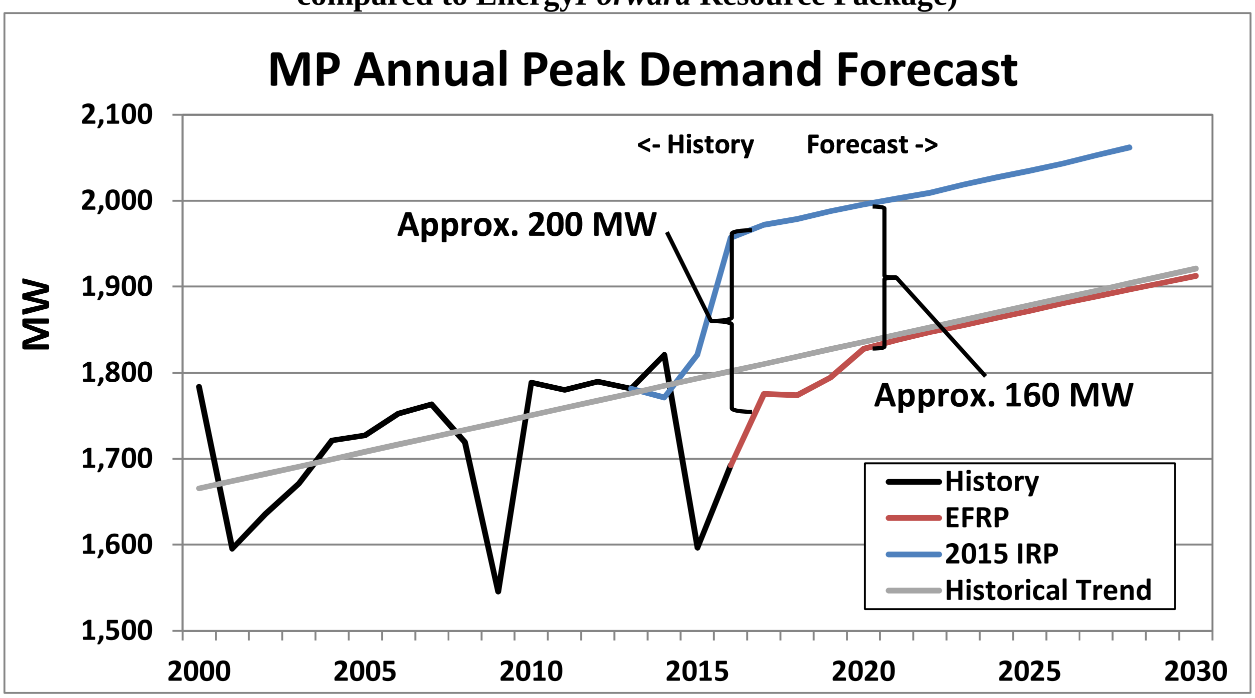
[35] In particular, since the 2016 AFR was filed in June 2016, production has resumed at Keetac. The Energy*Forward* Resource Package Forecast assumes this customer operates at partial (about 75 percent) output in the near-term to reflect a reasonable overall outlook.

The remaining difference (about 185,000 MWh per year) is due to the balance of many smaller customer assumptions, the secondary economic impacts of these large customers' operations, and some methodological forecast process enhancements described above.

Overall, Minnesota Power's current energy sales outlook grows at about 1.2 percent per year compound annual growth rate from 2017 to 2030 with the majority of the growth occurring in 2020, when Silver Bay Power idles their remaining coal-fired generation and increases their take from Minnesota Power. Silver Bay Power has already idled some of its coal-fired generation and increased its reliance on Minnesota Power, but this sale is not reflected in the sales forecast; instead, the increased sales between 2017 and 2019 are assumed to be offset by a bilateral purchase. Given that the bilateral purchase offset the increased energy sales, resulting in zero increase in overall demand, the increase in energy for this period was not modeled.

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

Figure 3: Minnesota Power's Annual Peak Demand Forecast Comparison (2015 Plan compared to Energy*Forward* Resource Package)



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. By 2020, the Energy*Forward* Resource Package 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.

This growth in 2020 and beyond roughly coincides with the shutdown of BEC1&2, phasing out of power purchase from Young 2, and with the idling of the Silver Bay Power/Northshore Mining's coal-fired generating facilities. Therefore, even under conservative sales forecast assumptions, the Company's modeling indicates a need for new generation in the mid-2020s timeframe.

2.3.1.3. Energy*Forward* Resource Package Comparison to Recently-Filed 2017 AFR

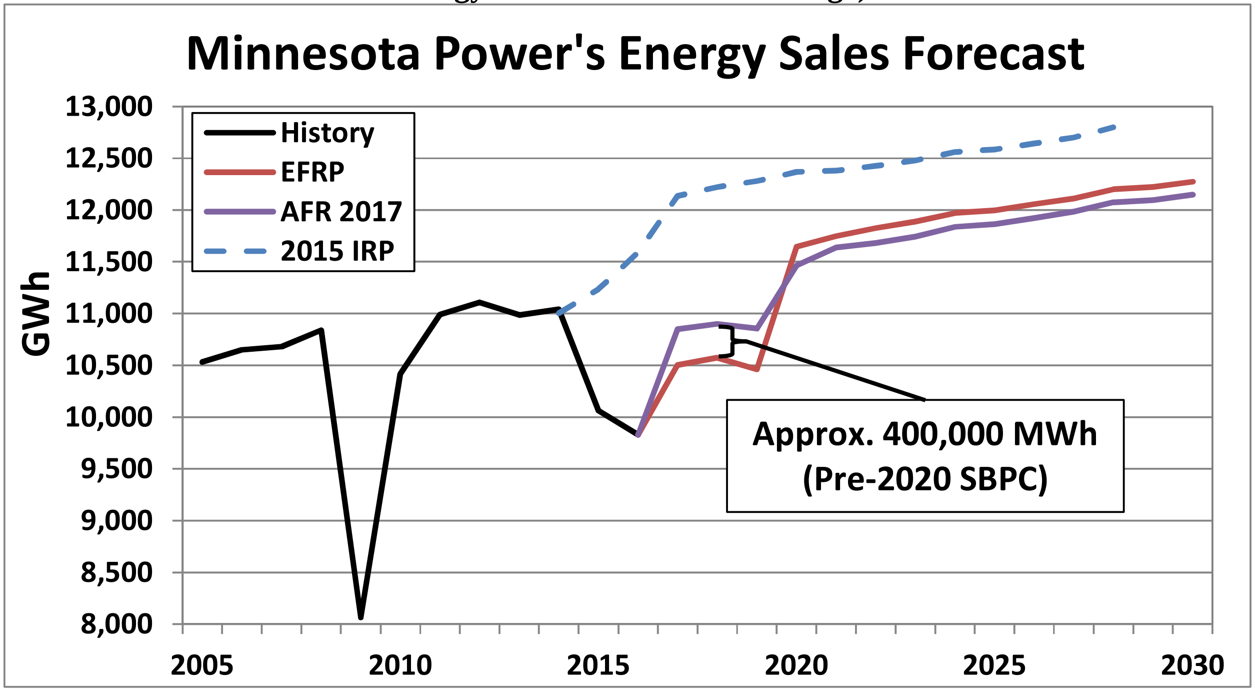
The 2017 AFR forecast, which was filed on June 29, 2017,[36] is similar to the forecast used in this Energy*Forward* Resource Package filing and contains similar large industrial customer assumptions. The only notable difference in the two outlooks is that the 2017 AFR includes the pre-2020, 50 MW Silver Bay Power transaction in the sales projection; whereas the Energy*Forward* Resource Package Forecast accounted for the pre-2020 transaction as offset by a 50 MW bilateral purchase outside the Strategist modeling. This results in the 2017 AFR outlook being approximately 355,000 MWh higher in the pre-2020 timeframe, compared to the Energy*Forward* Resource Package Forecast presented in this filing.

Beyond 2020, the difference between the 2017 AFR and the Energy*Forward* Resource Package Forecast is minimal. In particular, the 2017 AFR forecast is only 130,000 MWh lower than the Energy*Forward* Resource Package Forecast and there was no material change to the peak demand outlook.

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

Figure 4 below compares the energy sales outlook used in this filing ("EFRP" in Red) to the 2017 AFR forecast (Purple), and the 2015 Plan forecast (Blue dotted). As can be seen, the long-term resulting sales levels in the Energy*Forward* Resource Package Forecast and the recently-filed 2017 AFR are quite close.

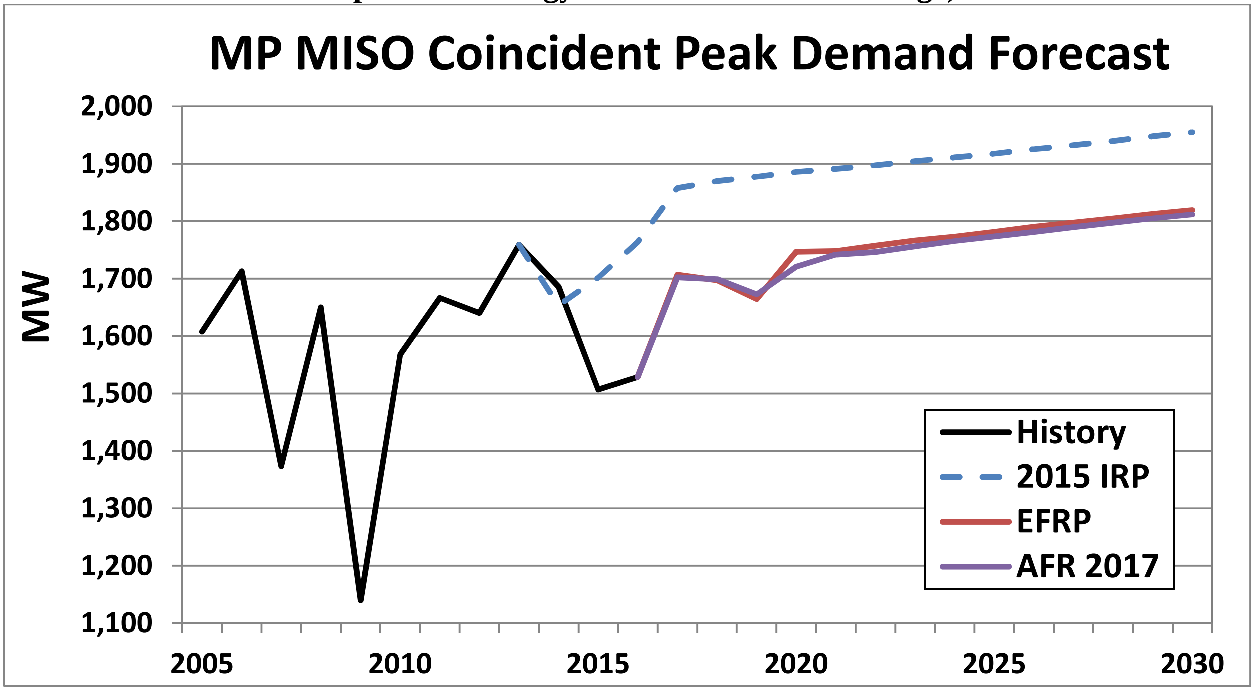
Figure 4: Minnesota Power's Energy Sales Forecast (2017 AFR compared to Energy*Forward* Resource Package)



The only substantive difference between the 2017 AFR forecast and the Energy*Forward* Resource Package Forecast is pre-2020 Silver Bay Power sales, which do not affect the Minnesota Power system load or peak demands. System load includes all demand on Minnesota Power's system regardless of how the demand is met, so whether Silver Bay Power's demand was met by their own generation or by Minnesota Power deliveries has no effect on system load.

Figure 5 below compares the 2017 AFR forecast (Purple) to the Energy*Forward* Resource Package Forecast (Red) and 2015 Resource Plan (Blue dotted). The figure makes clear that there is virtually no difference between the 2017 AFR and Energy*Forward* Resource Package peak demand forecasts.

Figure 5: Minnesota Power's MISO Coincident Peak Demand Forecast (2017 AFR compared to Energy*Forward* Resource Package)



2.3.2 MISO Planning Reserve Margin Requirements

MISO's 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.[37]

2.3.3 Load and Capability Base Case Need Assessment

Minnesota Power has historically been a winter peaking utility, and is projected to remain winter peaking based on recent observable season trends. However, the Company plans for resource

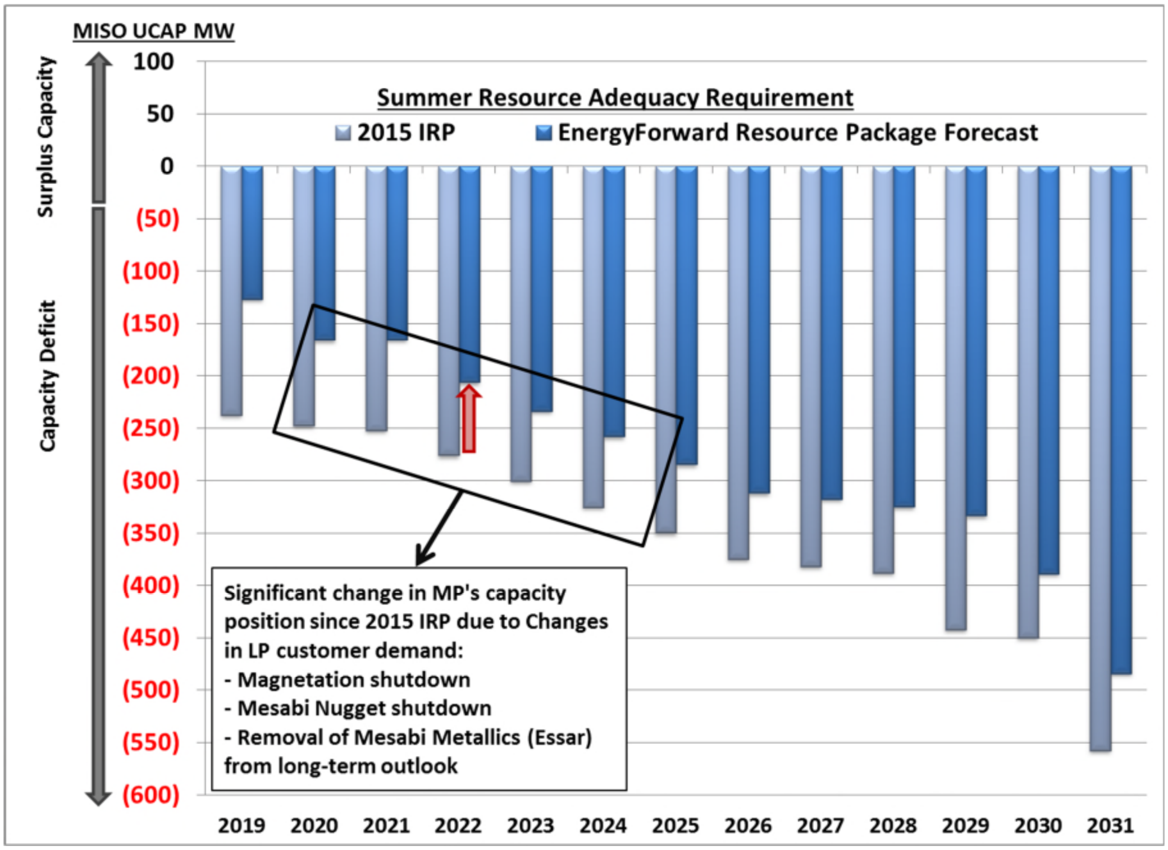
[37] MISO's Planning Year 2017-2018 Loss of Load Expectation Study Report (Oct. 31, 2016), *available at* https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf.

adequacy based on the expected MISO-coincident peak (“CP”) demand (i.e., Minnesota Power’s load at the time of MISO’s peak) based on the MISO seasonal construct.

One important nuance of the MISO CP outlook is that, unlike the Company’s projected energy sales, the system load outlook includes all demand on Minnesota Power’s system, regardless of how the demand is met. Customers can and do self-generate to complement their purchases from Minnesota Power. Consequently, whereas the Company’s sales forecast reflects the increased sales to Silver Bay Power as it idles small coal generation, the system demand outlook is unaffected. While the facility’s operation and total demand are unchanged, this demand is now met by Minnesota Power deliveries instead of Silver Bay Power generation.

Figure 6 below illustrates changes to Minnesota Power’s projected capacity needs under the current outlook compared to the Company’s 2015 Plan. While projected capacity needs under the updated outlook are less than projected in the 2015 Plan forecast, Minnesota Power continues to project a need for significant capacity additions to meet projected needs.

Figure 6: Change in Minnesota Power's Capacity Position Since 2015 Plan



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 chosen for further examination: the Energy*Forward* Resource Package High, and Energy*Forward* Resource Package Low scenarios. The outlooks, shown in Figure 7 and Figure 8, were used to recognize the range of uncertainty that exists with the Company's unique customer base.

Figure 7: Minnesota Power's Energy Sales Forecast (Energy*Forward* Resource Package High/Low Comparison)

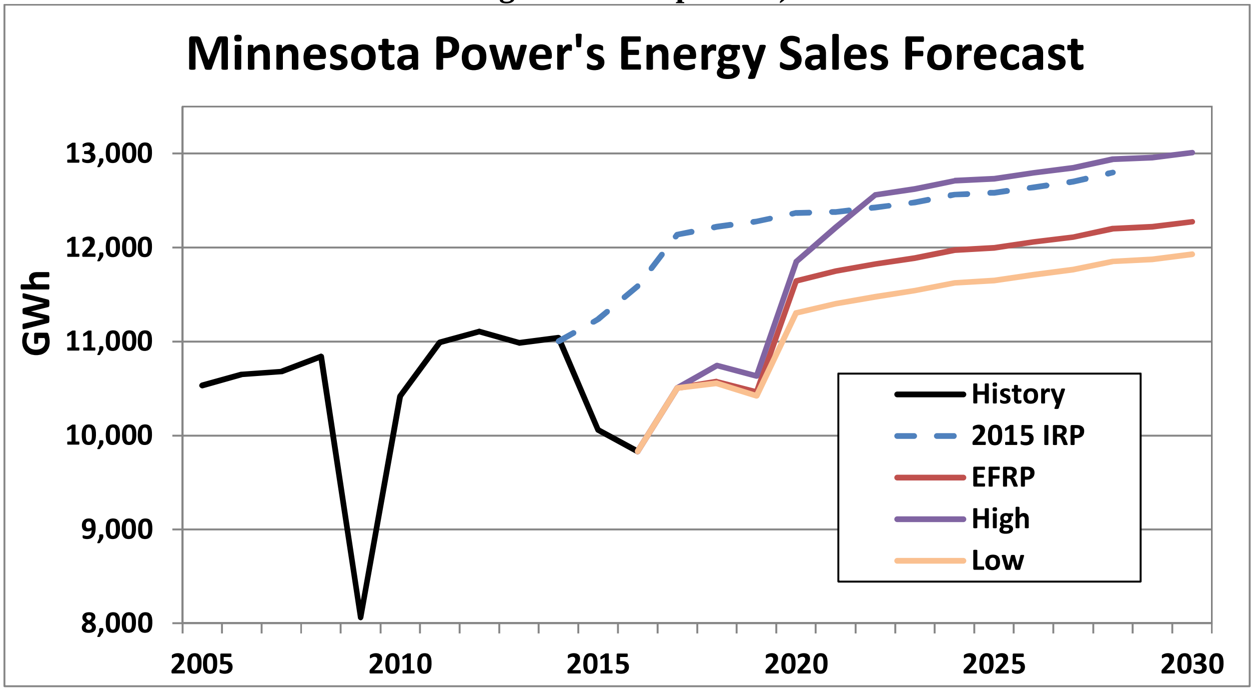
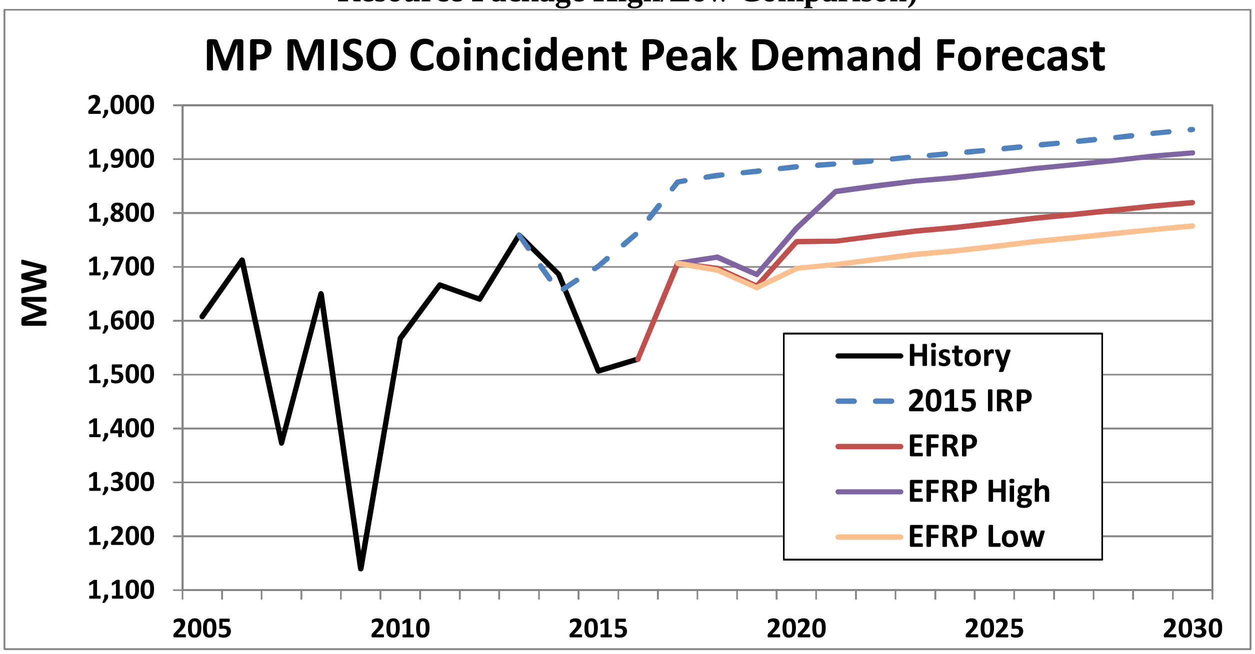


Figure 8: Minnesota Power's MISO Coincident Peak Demand Forecast (Energy*Forward* Resource Package High/Low Comparison)



The "Energy*Forward* Resource Package 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 "Energy*Forward* Resource Package 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. The "Energy*Forward* Resource Package Low" outlook is about 45 MW lower than the expected case, and with fairly slow underlying growth rate, system loads do not rebound to pre-2015 levels until 2025. 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 northeastern Minnesota. Making prudent and reasonable power supply plans for meeting future electric needs of large industrial and all other customers is critical in helping to keep economic balance in place to best serve all customers.

2.3.5 Conclusions Regarding 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 reductions include Laskin Energy Center ("LEC"),[38] THEC,[39] Young 2,[40] and BEC1&2.[41] 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

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

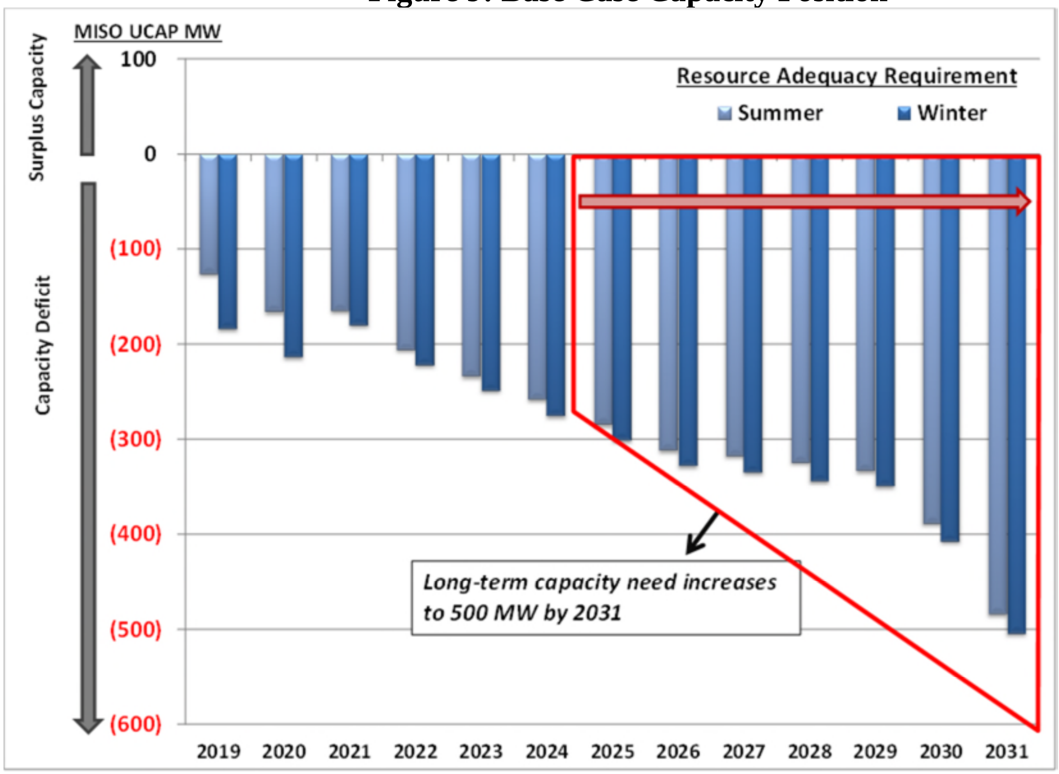
[39] THEC3 was shut down in June 2015. Subsequently, THEC1&2 were idled in 2016, with coal-fired operation of these units scheduled to cease by the end of 2020.

[40] 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.

[41] 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).

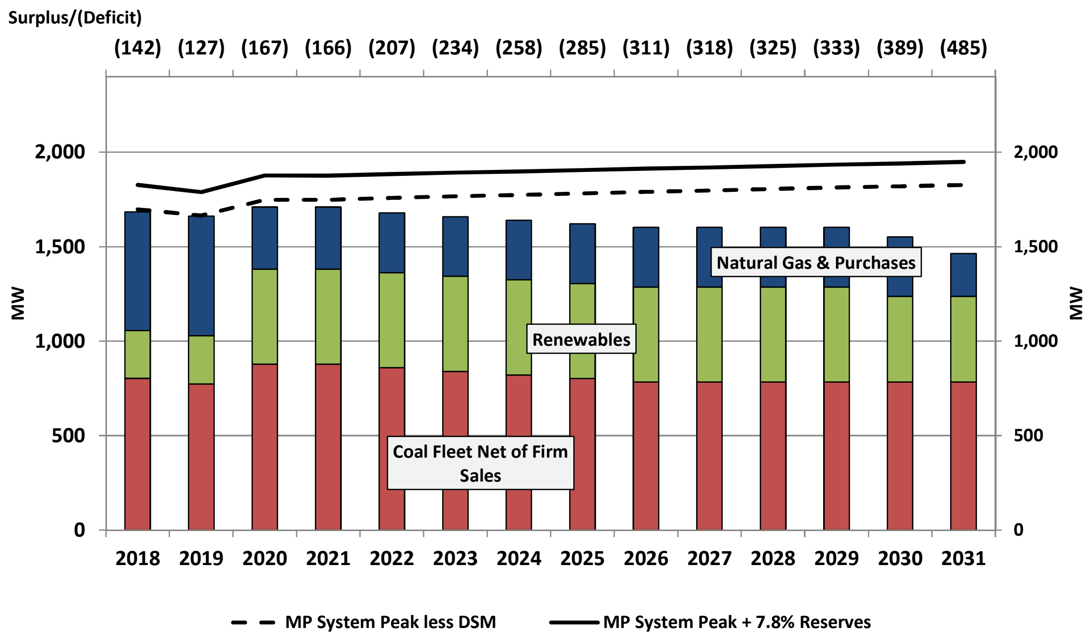
resulted in a growing capacity and energy need in the mid-2020's. Figure 9 demonstrates Minnesota Power's projection for the capacity need to reach nearly 300 MW by 2025 and grow to around 500 MW by 2031. Minnesota Power is a winter peaking utility, which results in a slightly greater capacity need during the winter season, as also reflected in Figure 9 below.

Figure 9: Base Case Capacity Position



The detailed capacity position for the base case with the summer demand and capacity outlook is shown in Figure 10. For the summer period, Minnesota Power's capacity need increases to 285 MW by 2025 and by 2030 the need is 485 MW.

Figure 10: 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 11. For the winter period, Minnesota Power's capacity need increases to 315 MW by 2025 and by 2031 the need is 525 MW. Minnesota Power's winter peak is typically between 20 and 30 MW higher than its summer season peak; therefore, the surplus and deficit outlook is slightly different when shown for the winter season peaks.

Figure 11: Base Case Winter Season Capacity Outlook

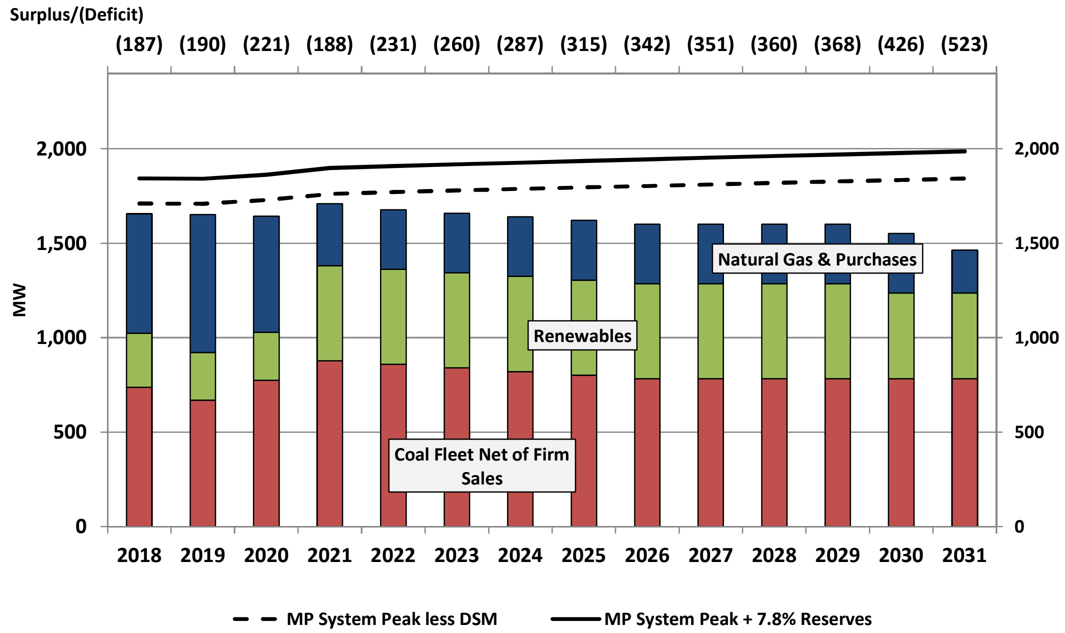
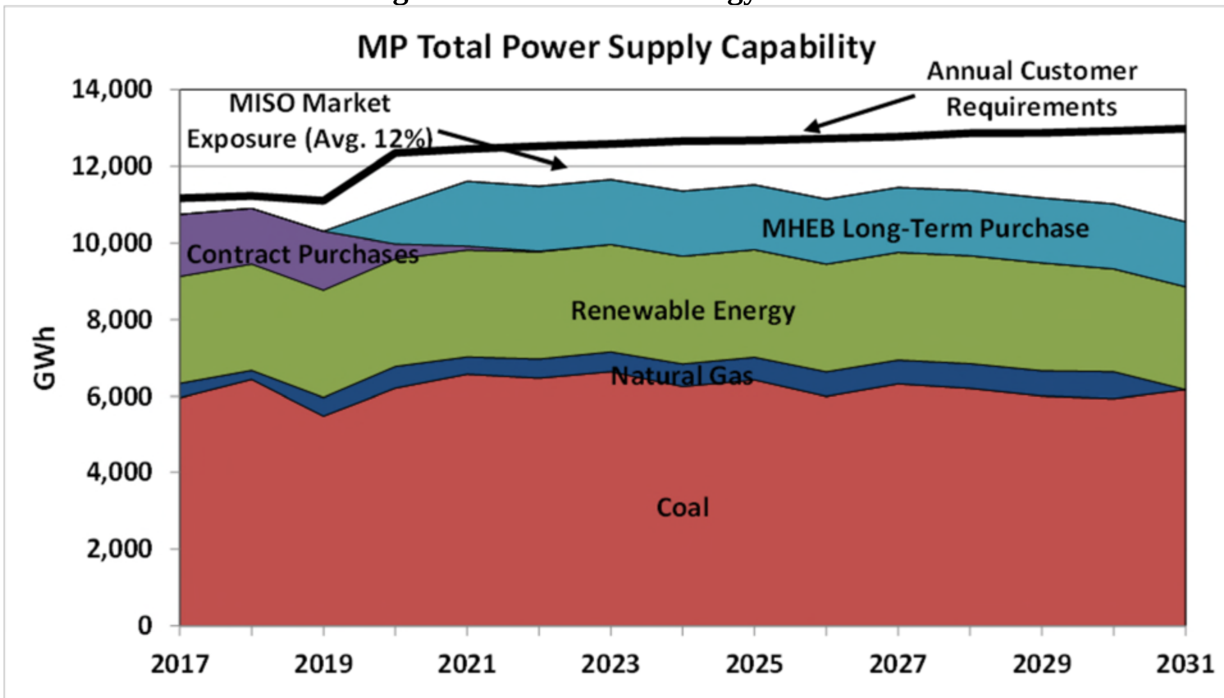


Figure 11 further shows that under its base case, Minnesota Power has growing energy needs starting in 2020, around 1 million MWh and increasing to 2.3 million MWh by 2031, as BEC1&2, along with Young 2's baseload energy, are removed from the power supply and customer energy needs grow. In the absence 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 12 below shows current power supply capability and projected need through 2031.

Figure 12: Base Case Energy Position



What the above Figure 12 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 low-cost wind, as recommended in the Energy*Forward* Resource Package, Minnesota Power's energy position could vary up to 850 MW in an hour, creating additional need for flexible energy to be available to mitigate and balance the exposure to energy markets.

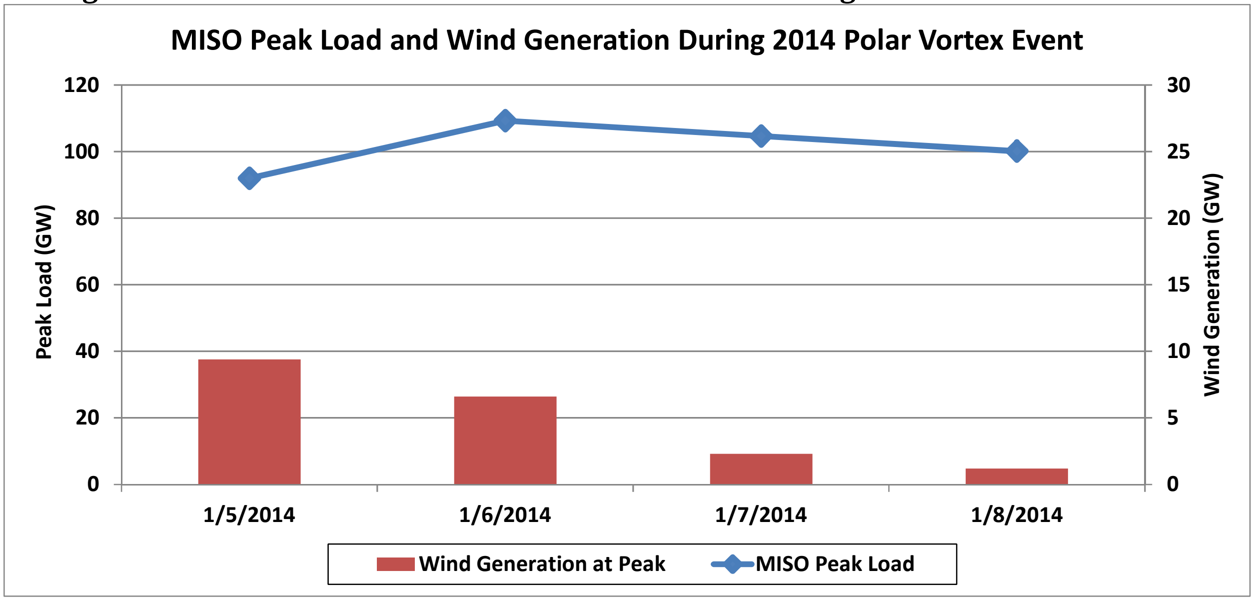
The variable characteristic of wind energy can create rapidly changing energy profiles that a utility needs to plan for to minimize market exposure risk for customers. These drastic changes in wind energy can vary from rapid decreases and increases in energy, long periods of time where no energy is available, 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 the availability of wind. For Minnesota Power, this challenge is exacerbated by the fact that Minnesota Power 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 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 was back to 500 MW.
- Changes in wind availability can also be experienced across the MISO footprint. Figure 13 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.[42] Without that coal-fired generation, Minnesota Power customers would have been exposed to the higher energy prices on that day. Having a dispatchable resource such as NTEC will help provide energy and help protect against higher energy prices when the wind is not available. Additionally, during this period, the daily peaks in MISO occurred during either the early morning or late evening when solar energy is not available.

[42] These reductions include the retirement of THEC3 in 2015 (75 MW), the idling of THEC1&2 in 2016 with coal-fired operations scheduled to cease by 2020 (150 MW), refueling of LEC (110 MW), phase out of Young 2 (227 MW in 2014 and 100 MW in 2026), and retirement of BEC1&2 in 2018 (135 MW).

Figure 13: 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 Energy*Forward* Resource Package. Based on the updated Energy*Forward* Resource Package Forecast and evaluation of a range of potential forecast scenarios, the proposed Energy*Forward* Resource Package of resource additions is needed and the size and timing of the proposed resources is appropriate in light of projected capacity and energy needs.

SECTION 3 DEVELOPMENT OF PROPOSED ENERGY*FORWARD* RESOURCE PACKAGE

In this Section of this Petition, the Company presents its current resource planning analysis that resulted in and supports the proposed Energy*Forward* Resource Package.

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 for (1) wind, (2) solar, (3) dispatchable natural-gas-fired capacity (combined-cycle), and (4) demand response, in accordance with the Commission's July 2016 IRP Order.

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. 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 Energy*Forward* Resource Package combination of resource additions presents the most cost-effective alternative to meet Minnesota Power's system need and address 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 and customer demand response 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 mix of resources from the RFP offers to meet customer needs using the Strategist software. The results from this evaluation form the baseline for recommending the Energy*Forward* Resource Package.

The Company identified options from the offers received through the RFP processes and fully evaluated and compared those options based on relevant evaluation criteria, including stakeholder feedback and Commission direction provided in the 2015 Plan proceeding. As discussed in greater detail below, and in Appendix J: Detailed Resource Planning Analysis, this analysis supports the conclusion that the proposed Energy*Forward* Resource Package 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. Minnesota Power's Energy*Forward* Resource Package continues 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"),[43] 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[44] 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[45] finalized the Company's preferred plan for MATS compliance by identifying

[43] *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).

[44] *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).

[45] *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).

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”).[46]

3.1.2 Commission Order Approving 2015 Plan With Modification

This Energy*Forward* Resource Package proposal 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.[47] 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.” The Commission also directed the Company to “initiate a competitive-bidding process to procure 100–300 MW of installed wind capacity,” “acquire solar units of 11 MW by 2016, 12 MW by 2020, and 10 MW by 2025 to meet its SES obligations,”[48] and found that up to 100 MW of solar generation may be an economic resource by 2022.[49] The Commission also directed the Company to issue a demand-response competitive-bidding process.[50]

[46] *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).

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

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

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

[50] 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

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 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 MHEB contracts filling much of that need beginning in 2020.

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.[51] 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

While Minnesota Power is not required to obtain a certificate of need for approval of the proposed Energy*Forward* Resource Package, the Company determined that a decision regarding the size and 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 in the most recent July 2016 IRP Order, as well as further refined analysis based on 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

reporting the findings of such investigation in the next resource plan. Additional discussion of the Company's plans to comply with this Order Point are discussed in Section 3.4.8.

[51] *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).

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 utilized key planning principles to help guide the analysis process. This ensured the outcome of its refined resource evaluation was robust and in the best interest of all its customers, and shaped the recommended Energy*Forward* Resource Package:

1. **Diversity –** A power supply mix that cost-effectively manages risks in environmental regulation, fuel cost, and generation technology.
2. **Flexibility –** A power supply adaptable to industry changes and fleet transitions.
3. **Reduced Carbon Emissions –** Effectively reduce carbon emissions of the power supply while managing customer costs.
4. **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, 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 Energy*Forward* Resource Package as the least-cost and most reasonable way to answer these questions.

- *What amount of additional wind provides the best fit for Minnesota Power's portfolio?*

  In Minnesota Power's 2015 Plan, the Company concluded that under the current favorable tax treatment of wind farms, there is an opportunity to procure low-cost wind resources that could serve as an energy price or fuel price hedge for customers. However, the Company also recognized the need to exercise caution to not procure too much wind, resulting in an energy surplus and net cost to customers if the Company were unable to generate sufficient revenue by selling the surplus on the wholesale market. Based on the record in the 2015 Plan proceeding, the Commission concluded that Minnesota Power should begin a competitive acquisition process to procure 100–300 MW of installed wind capacity, a range reflecting the different recommendations of the Company, the Department, and the CEO based on modeling results.

Because a megawatt range was identified, further analysis was needed to determine the right amount to purchase. Following completion of that IRP proceeding, Minnesota Power continued to investigate cost effective renewable energy resources and solicited bids for additional wind. Minnesota Power discovered through the analysis process that an additional 250 MW of wind generation, in a different geographical region than the current wind assets located in North Dakota, provides valuable diversification of wind energy production. The 250 MW wind project was selected most often from the various wind RFP responses modeled in the Strategist expansion plan analysis. Additionally, the selection of 250 MW balances meeting customer needs and reducing customer cost without oversupplying the power supply with additional wind energy.

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

  With 250 MW of additional wind capacity, Minnesota Power's portfolio of wind resources will reach over 870 MW of installed capacity. As wind production ramps up and down, 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 250 MW of combined-cycle natural gas capacity as the ideal resource to support increasing variable renewable generation resources. 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 all alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response. This natural gas generation will help to balance the variable resources being added.

- *In the near-term, what level of solar build should be pursued beyond compliance with the SES?*

  Minnesota Power has begun to implement its strategy to comply with the SES requirements. In 2016, Minnesota Power implemented a 10 MW solar array located at

Camp Ripley near Little Falls, Minnesota (the "Camp Ripley Solar Project").[52] 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.[53] The remainder of the solar capacity needed to comply with the SES will be added in 2020 and 2025. While the Commission found that up to 100 MW of solar by 2022 may be an economic resource for Minnesota Power's system,[54] additional analysis was again needed to determine an appropriate amount, especially in combination with resources like wind being added at about the same time. The Company's analysis of current pricing for solar resources indicates that additional solar generation remains uneconomic at this time. While solar costs are declining and efficiency is increasing, large scale solar is still substantially more expensive than wind resources and does not provide the same capacity benefits for Minnesota Power customers due to Minnesota Power's system peaking in the evening hours of winter. Consequently, Minnesota Power's refined analysis did not identify cost-effective additions of solar capacity beyond those identified as part of SES compliance in the near term. Minnesota Power nonetheless received bids for a range of solar project sizes for consideration in this Energy*Forward* Resource Package, and selected 10 MW of solar from the RFP process for its next phase in implementing its strategy to comply with the SES requirements. The Company will also continue to monitor pricing of utility scale solar projects while implementing its recently-expanded customer-sited solar rebate program. This initial 10 MW of solar from the RFP is the solar component of Minnesota Power's Energy*Forward* Resource Package.

- *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

[52] *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).

[53] *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).

[54] 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.").

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 Minnesota Power's resource additions 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 stayed 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 44 percent by 2025 with acceptance of this 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, then, 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 2017 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 its idling of 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 steam 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 the Commission's approved CO_2 range in one of the Base Case ("Futures") scenarios. The start of the CO_2 regulation penalty is 2022 to align with the proposed timing in the stayed EPA CPP. Another Base Case scenario assumes no CO_2 regulation penalty. As the final carbon regulation mechanism has not been determined for the electric industry or state, and the timing of a regulation penalty may exceed the 2022 timeframe, Minnesota Power included both outcomes as it selected its Energy*Forward* Resource Package for recommendation. 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 for DSM programs, generation technology, 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. Minnesota Power's energy demand outlook was updated based on the 2016 AFR submitted on June 30, 2016, in Docket No. E999/PR-16-11, as modified to integrate new information that has become available since the 2016 AFR was first developed and filed.[55] These updates and forecast modifications address 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.[56]

[55] See Section 2 of this Petition.

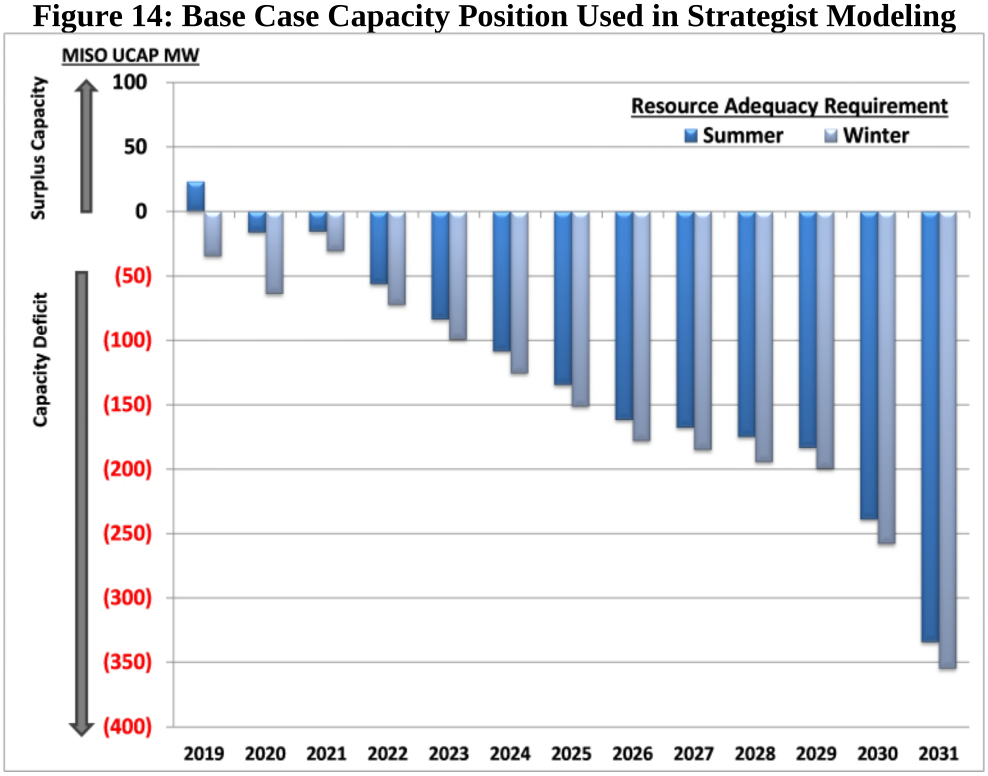
[56] *See In the Matter of Minn. Power's 2015-2029 Integrated Res. Plan*, Docket No. E015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 14 (July 18, 2016) ("Minnesota Power's range of load forecasting used for its 2015 IRP is reasonable for planning purposes; however, in light of updated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

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 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 SES is included in the Base Case (Camp Ripley Solar Project and Minnesota Power's solar garden pilot project).

9. 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 Energy*Forward* Resource Package 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 used in the Energy*Forward* Resource Package analysis. Figure 14 below shows Minnesota Power's capacity position for summer and winter seasons when the 150 MW of large industrial interruptible demand is included. This is the summer and winter capacity position used in the expansion plan analysis performed with Strategist.

Figure 14: Base Case Capacity Position Used in Strategist Modeling



Together, these updates and modifications from the 2015 Plan 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. 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 and the Commission's directives in the July 2016 IRP Order. The Energy*Forward* Resource Package was ultimately selected as the most reasonable and prudent alternative by first determining which RFP offers for wind, solar, combined-cycle, and demand response (as anticipated in the July 2016 IRP Order) in the early to mid-2020's best served customer needs during this period. 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 over the planning period. Short-listed RFP offers for wind, solar, combined-cycle, and customer demand response were evaluated to address anticipated need in the shorter term. Generic wind, solar, natural gas, and demand response programs were available to fulfill capacity requirements through the end of the planning period. This step includes a series of eight Futures with over 34 sensitivities each that stress key power supply cost drivers such as delivered fuel, CO_2 penalties, capital costs, 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.
>
> *Step 2: "Swim Lane Comparative Analysis"* – This step involves comparing and stress-testing the Energy*Forward* Resource Package against three other viable power supply

portfolio alternatives in a swim lane[57] analysis. The results of this step support selection of the Energy*Forward* Resource Package across 92 percent of cases and sensitivities. The four swim lane alternatives include these action plans:

1. The Energy*Forward* Resource Package – Consisting of an approximately 250 MW share of the NTEC combined-cycle gas turbine 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).[58]

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.

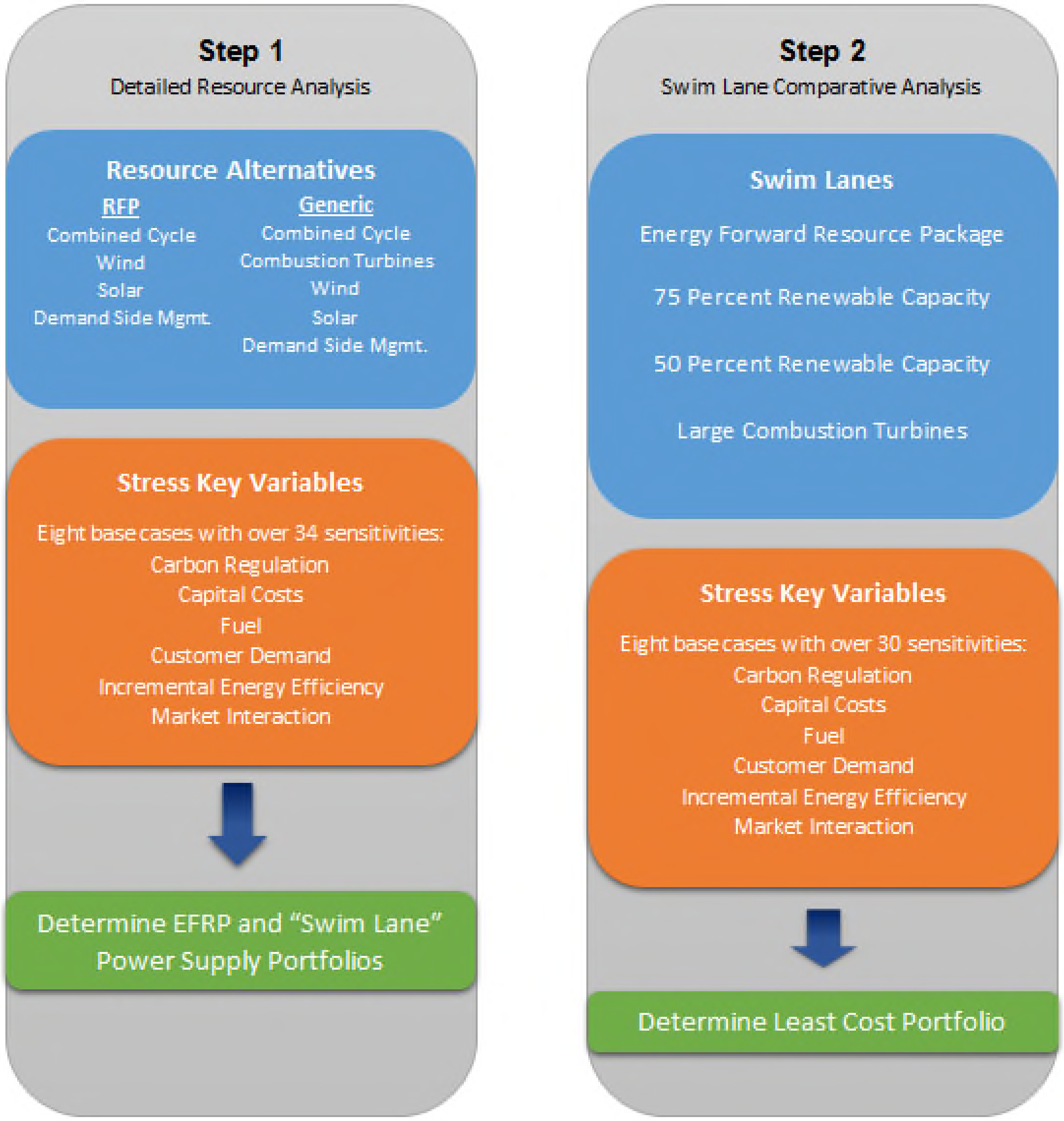
4. Large combustion turbine portfolio – 456 MW of gas peakers with the first 228 MW added in 2025 and the second in 2031, and 250 MW of wind in 2020.

The comparison of the four swim lane alternatives includes a series of eight Futures with over 30 sensitivities each that stress key power supply cost drivers such as delivered fuel, CO_2 penalties, capital costs, 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 15 for Step 1 and Step 2:

[57] 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.

[58] With this filing, Minnesota Power is seeking Commission approval of only the 250 MW share of the NTEC combined-cycle natural gas plant, 250 MW of wind through the Nobles 2 PPA, and 10 MW of solar through the Blanchard Solar Project PPA. 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 solar resources will be addressed in future IRP filings.

Figure 15: 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 and demand-side resources to select the resources included in the Energy*Forward* Resource Package. 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 resources are least cost for customers and should be included in the

Energy*Forward* Resource Package. 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 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 evaluates and compares various outcomes with a series of sensitivity impacts. This is done prior to finalizing the resource alternatives included in the Energy*Forward* Resource Package. 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 2020's, such that Minnesota Power's conservative forecast includes load growth during this period.

Minnesota Power is using a conservative outlook for customer demand that assumes in the base assumptions the taconite processing facilities that are currently idled remain in this status and only one of the several large-scale mining projects on the horizon starts operations,[59] 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 the Petition and incorporated here. 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 Energy*Forward* Resource Package was identified as least cost under both the base case and low and high growth scenarios. Thus, while a conservative base case growth projection provides protection against the risk of over-building, the proposed Energy*Forward* Resource Package 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 Green House 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 exceeds the 2025 goal by achieving a 41 percent reduction by 2025. The EPA final CPP Rule was released August 3, 2015. And while the United States Supreme Court issued a stay of the EPA's final CPP rule on February 9, 2016, 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.

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

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

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, \$34/ton, and the social cost of carbon regulation penalty.
- 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. Analysis 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 developing the proposed Energy*Forward* Resource Package.

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 Energy*Forward* Resource Package 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 will place the Company in good position to comply with future CO_2 regulations.

3.4 ALTERNATIVES EVALUATED

Minnesota Power issued RFPs for wind, solar, combined-cycle, and demand response in 2015 and 2016 and used the RFP results to determine what least-cost generation resources are available to meet capacity and energy requirements and further its Energy*Forward* strategy. Details on the wind, solar, and natural gas RFP processes and results are included in Sections 4 through 6 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 offers from each of the RFPs were evaluated across multiple sensitivities to determine the optimal and prudent mix of resources for customers. Strategist was used to evaluate various alternative expansion plans based on the least-cost responses from the RFP. 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 least-cost offers from the RFPs, as well as generic generation resources that were either not requested as part of the RFP processes or that would be intended to meet future energy and capacity needs beyond the periods requested in the RFPs. For Step 1, the Company allowed Strategist to select from the following supply and demand side resource options:[60]

<u>RFP Alternatives</u>

- 250 MW share of a natural gas-fired 1x1 combined-cycle gas turbine
- 102 MW wind farm
- 200 MW wind farm

[60] 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.

- 250 MW wind farm
- 10 MW solar (representation of least-cost solar offer received in this size category)
- 100 MW solar (representation of least-cost solar offer received in this size category)
- 97 MW of large power interruptible load

<u>Generic Alternatives</u>[61]

- 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
- 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, which in this analysis was the Energy*Forward* Resource Package.

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

[61] 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.

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 EnergyForward Resource Package 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 resources recommended in the Energy*Forward* Resource Package.

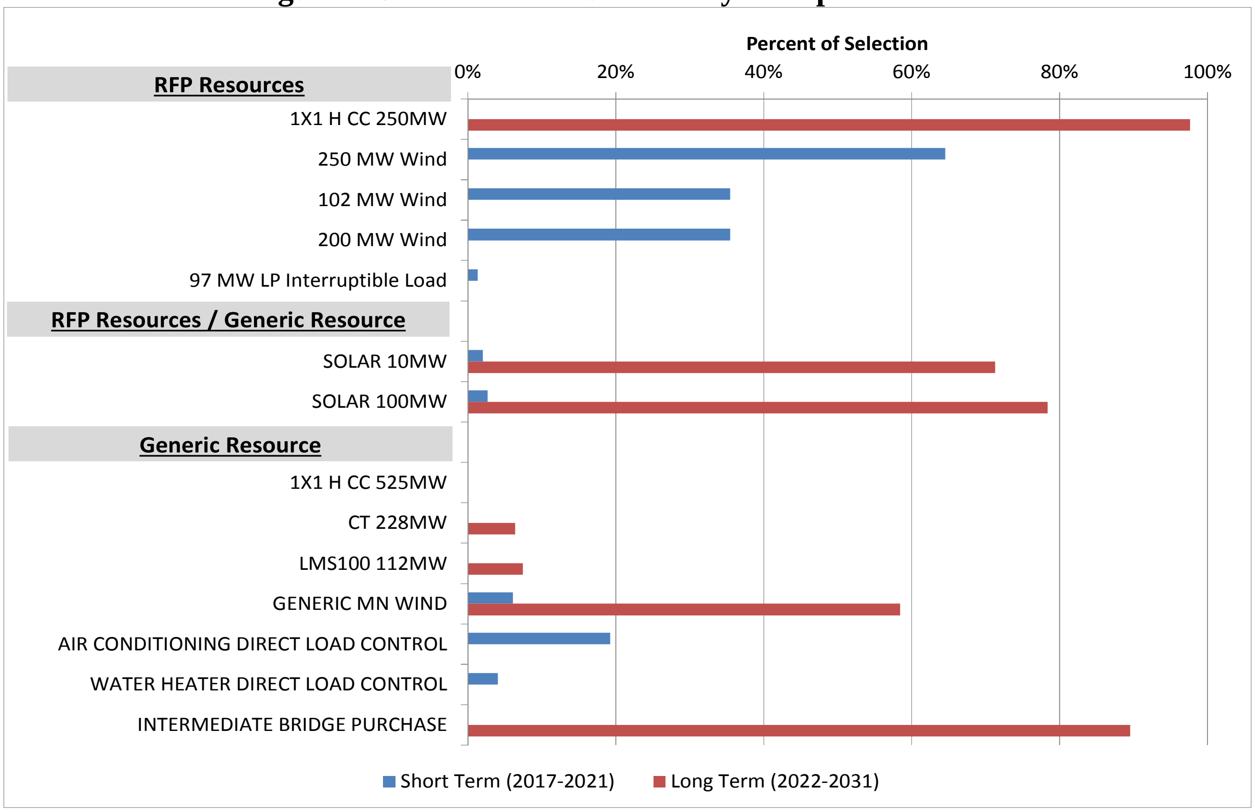
Table 1: Eight Futures Considered in Energy*Forward* Resource Package Analysis

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 generation resources that make up the Energy*Forward* Resource Package were identified as least cost across several optimal expansion plans using 296 sensitivities, including CO_2 regulation penalties, high and low market prices, and variable customer outlooks. Figure 16: 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, NTEC was selected in 98 percent of 296 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 was allowed to select up to 302 MW of wind from the RFP.[62] The 250 MW wind alternative was selected nearly twice as often as the other wind RFP alternatives. 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 pricing and expected performance from the least-cost offers received in the RFP.[63] Large scale solar was selected at a higher frequency in the longer term planning period with it being selected most often post-2030.

Figure 16: Detailed Resource Analysis Expansion Plans



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

3.4.1 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

[62] 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.").

[63] *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.").

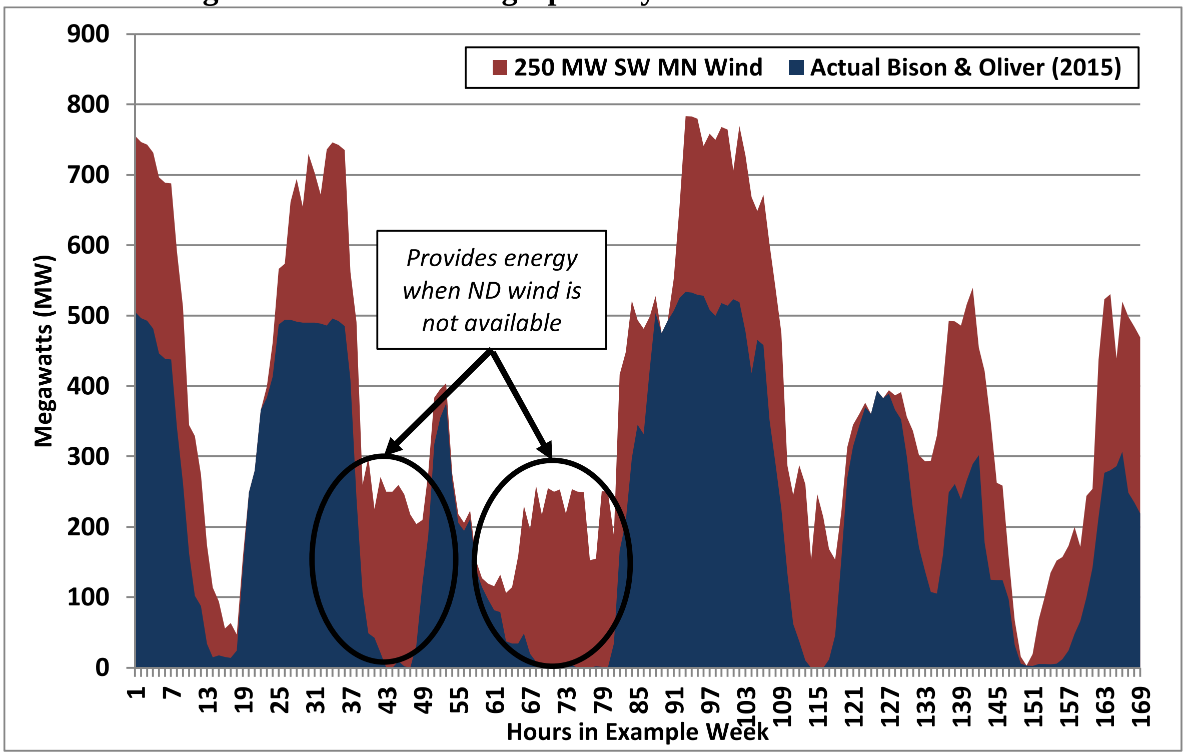
process by the end of 2017 to procure 100–300 MW of installed wind capacity.[64] In compliance with the Commission's Order, Minnesota Power issued an RFP in 2016 for new wind capacity, as discussed in greater detail in Section 4 of this Petition. In Step 1, the detailed resource analysis, up to 550 MW from three different projects of the least-cost and geographically-diverse wind from the RFP process was considered. In compliance with Order Point 9 of the Commission's July 2016 IRP Order, up to 302 MW from the 550 MW considered was allowed to be selected. The three wind projects considered in Strategist from the RFP were located in three different states within MISO's Local Resource Zone 1. This allowed Minnesota Power to evaluate the benefits of procuring wind generation that is geographically diverse from its 600 MW of wind located in North Dakota. The analysis compared the cost of adding wind from the RFP process in the 2019 to 2020 period in increments of 100 MW, 200 MW, 250 MW, or 300 MW.

The 250 MW wind project was selected at the highest frequency (65 percent of expansion plans) in the Strategist capacity expansion analysis. Therefore, Minnesota Power concluded the lowest cost plan for customers includes 250 MW of new wind generation located in southwest Minnesota in 2020 based on a price of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. This RFP proposal came in at a much lower cost than was assumed in the 2015 Plan for new wind (approximately **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**) and has the added benefit of being geographically diverse from Minnesota Power's existing wind generation. The significant decrease in the cost of wind between the 2015 Plan and the offers from the RFP was driven by the extension of the federal Production Tax Credit ("PTC") that occurred on December 18, 2015, after Minnesota Power had submitted its 2015 Plan. Figure 17 below shows the benefit of adding geographically-diverse wind to Minnesota Power's existing wind profile — the 250 MW of new wind within Minnesota and about 350 miles southeast of Minnesota Power's existing North Dakota wind facilities helps smooth out Minnesota Power's wind generation by providing some

[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.").

wind generation during periods when there is no wind in North Dakota. The analysis selected the wind at this low cost to be added regardless of inclusion of a CO_2 regulation penalty.

Figure 17: Value of Geographically Diverse Wind Production



As such, this wind project provides multiple benefits in the context of a broader package. However, the illustration in Figure 17 also shows periods when very little wind would be available—such as hours 16 and 148–150. It was therefore necessary to keep the operational characteristics of variable generation in mind as the Company evaluated resource options.

3.4.2 Solar Generation

In its initial 2015 Plan filing,[65] Minnesota Power identified a broad solar strategy to meet the estimated SES requirement in 2025. 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

[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).

customers due to Minnesota Power's system peaking in the evening hours of winter. For this reason, 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]

Through this proposed 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. In total, Minnesota Power anticipates 33 MW of solar resource additions as part of its strategy to meet 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

[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).

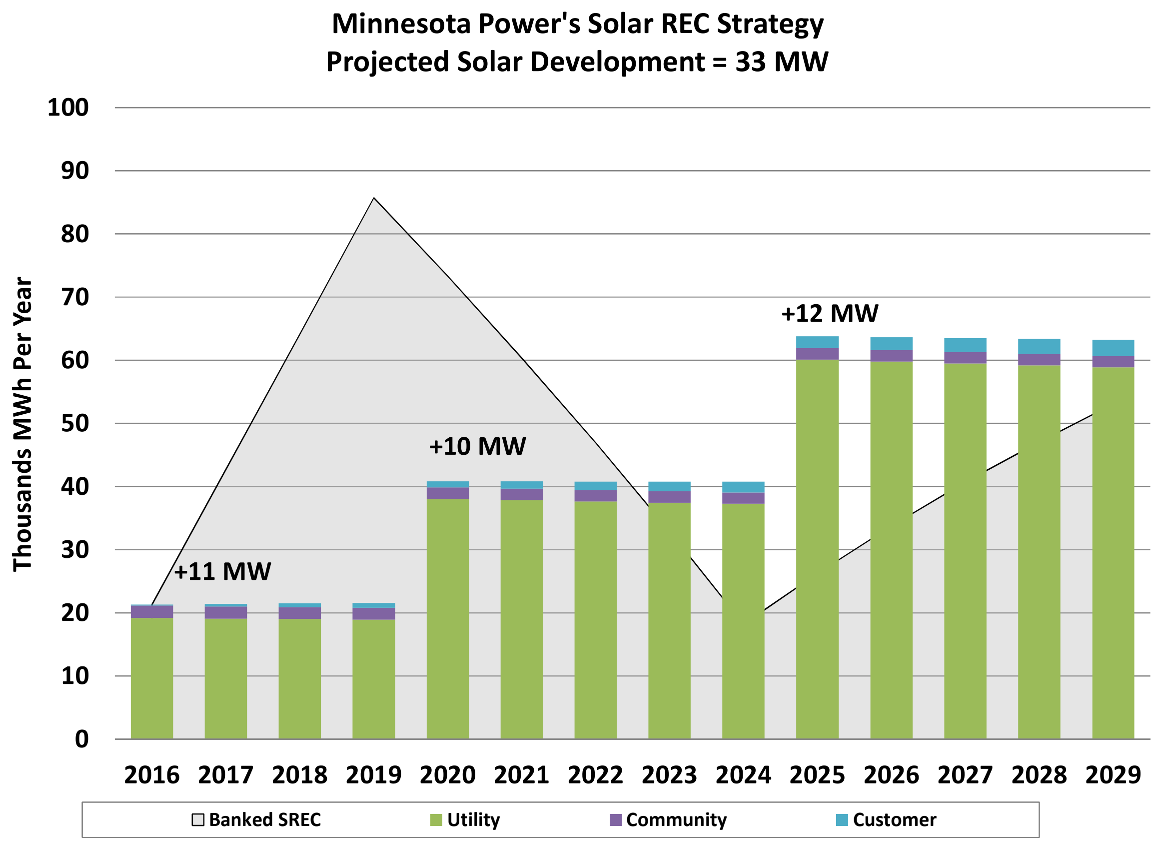
[68] *In the Matter of a Petition by Minn. Power for Approval of a Community Solar Garden Program, Eligibility of the Energy for Small Scale Solar Energy Standard Compliance, and a Recovery Method for Program Cost Recovery,* Docket No. E015/M-15-825, ORDER APPROVING PILOT PROGRAM WITH MODIFICATIONS (July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

[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).

Customer — Minnesota Power is well positioned for compliance with SES requirements in 2025. Figure 18 below illustrates Minnesota Power's anticipated plan for compliance with the SES requirement.

Figure 18: Minnesota Power's Solar Resources to Fulfill Solar Energy Standard



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 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 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

[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).

included that varied the cost of solar in $10/MWh increments from $35/MWh to $75/MWh. 100 MW of solar that was priced in the **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** range started to show economic benefit for customers in the early-2030s. Adding solar in the short-term action plan period (2017–2021) showed no benefit to customers at the cost ranges studied. 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.

3.4.3 Natural Gas Generation

Natural gas generation has been on the horizon for Minnesota Power for some time. Analyses performed for Minnesota Power's Baseload Diversification Study,[72] (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 6 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 unit 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.

Natural gas fits well with variable generation like wind and solar, especially for Minnesota Power's high load factor. 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

[72] *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).

resources into its portfolio (over 600 MW currently, with another 250 MW addition planned for 2020, totaling 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.

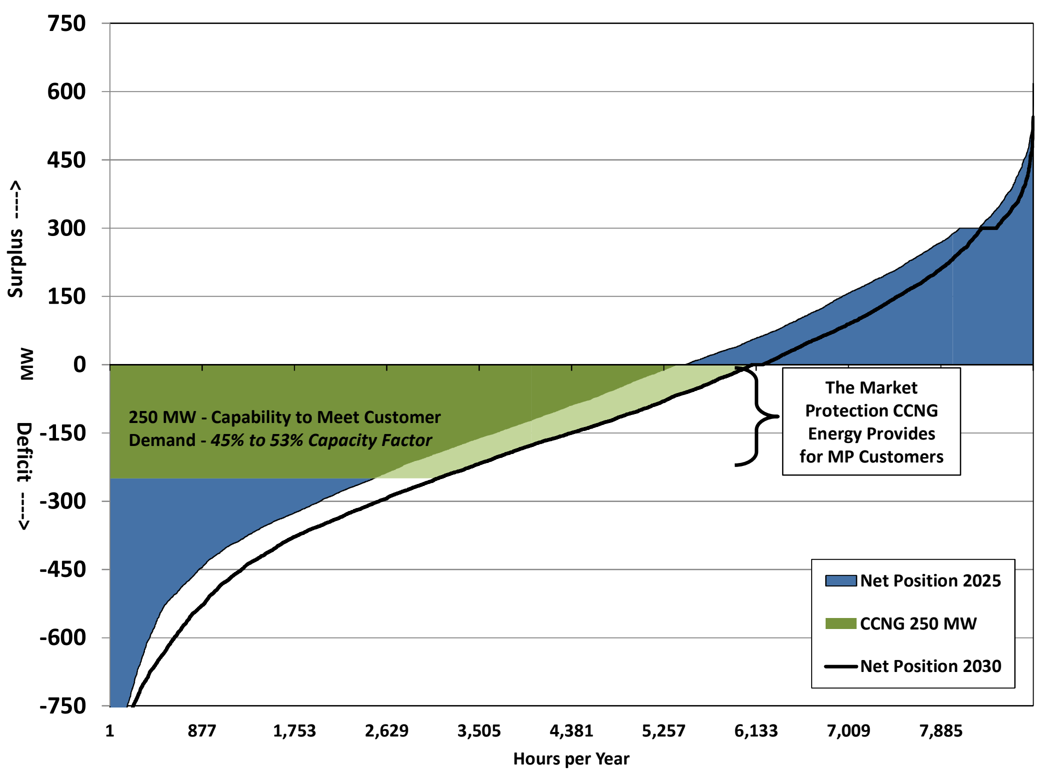
In 2015, Minnesota Power issued an RFP for up to 400 MW of dispatchable natural gas-fired capacity. The Company determined it was necessary to begin its natural gas investigation at that time to ensure the option to access a combined-cycle facility by 2024 would be available. Proposals on the RFP were due by January 7, 2016. And as noted above, the Step 1 expansion planning evaluation analyzed the best available alternatives identified from the responses to the various RFPs. 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 or other renewable options.

Through a thorough evaluation of RFP proposals, short listing, and independent evaluation, NTEC 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 was included in 2025 98 percent of the time.[73] 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 range will increase to 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.

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

The need for a dispatchable capacity resource is supported by Minnesota Power's hourly energy need shown in Figure 19. As demonstrated in the figure, the utilization of a natural gas addition is between 45 percent and 55 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 combined-cycle. 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 19: NTEC Meets Minnesota Power's Incremental Energy Needs



The proposed approximately 250 MW share of NTEC is a matchless opportunity giving customers access to an efficient combined-cycle resource, where typically a utility with a 250 MW capacity need is met by 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 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.[74]

3.4.4 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

[74] Under the CDA that accompanies this Petition, Minnesota Power is obtaining 48 percent of NTEC for use on its utility system, which translates into approximately 250 MW. Note that final size of NTEC has not been selected and will be in the range of approximately 525-550 MW, depending on the manufacturer and size of the final turbine selection. If the economic analysis supports purchasing slightly larger turbines, Minnesota Power's 48 percent stake in NTEC will be slightly larger.

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 summer resource adequacy cases and 2023–2024 for 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 standing 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 mitigate electricity requirements and the power supply allows for certain 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.

3.4.5 Large Industrial Demand Response

Minnesota Power currently has 250 MW of interruptible demand response capability on its system that it utilizes for peak market price shaving and emergency operations. Existing programs include partnerships with large industrial customers and dual fuel rate programs with residential and commercial 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.[75] In

[75] July 2016 IRP Order at 15.

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.[76] 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.[77] Proposals were due by September 26, 2016. Minnesota Power received only one response to its RFP for 96 MW of system capacity demand response available for energy curtailment events during MISO system emergencies or MP local system emergencies, at a price of **[TRADE SECRET DATA BEGINS… … TRADE SECRET DATA ENDS]**. This RFP bid was incorporated in the Step 1 expansion planning evaluation. The expansion planning analysis identified this was not a least-cost alternative for customers. More details on the expansion planning results are shown in Appendix J: Detailed Resource Planning Analysis. Minnesota Power will continue to work to identify reasonable additions to its demand response programs that benefit customers and provide power supply efficiencies.

Minnesota Power notes that its Strategist modeling assumes 150 MW of large industrial customers interruptible demand is available long-term. A change from the previous Resource Plan is including curtailable energy for economics associated with the 150 MW of large industrial customer interruptible demand. 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 as the Company has a long-track record of procuring this quantity of capacity through short-term contracts with large industrial customers.

[76] *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.

[77] 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) MP System Capacity, demand response available for energy curtailment events during MISO system emergencies or MP 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.

3.4.6 Demand Response Peak Shaving

The Company continues to investigate additional demand response opportunities in the Energy*Forward* Resource Package 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 for this Energy*Forward* Resource Package. 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 by 2020. 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 by 2020. 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 were included in the Energy*Forward* Resource Package. 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.

3.4.7 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. Parties have had negative reactions to this proposal in the rate case proceeding, which is currently pending.

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.[78] Minnesota Power received no response to this RFP. As such, no additional customer co-generation was modeled.

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

3.4.8 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 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 the Energy*Forward* Resource Package 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 Energy*Forward* Resource Package remained the least-cost portfolio 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 resources included in the Energy*Forward* Resource Package were 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.[79] 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 short-term action plan, Minnesota Power included additional support of energy efficiency programs for customers to augment its already high-performing programs currently in place.

3.4.9 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 II. The Strategist software was used to determine the lowest cost expansion plan with varying load sensitivities.

[79] 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.

The results show under both lower and higher load sensitivities the resources included in the Energy*Forward* Resource Package were selected at the highest frequency. This is demonstrated in Figure 20 and Figure 21, where the expansion plan results from the low and high load sensitivity (respectively) across the eight Futures are shown. Note the high load sensitivity selected a 228 MW combustion turbine at a high frequency to meet future capacity needs around 2030, and this was being added in addition to the 250 MW combined-cycle being selected in 2025.

Figure 20: Detailed Resource Analysis Expansion Plans with Low Load Sensitivity

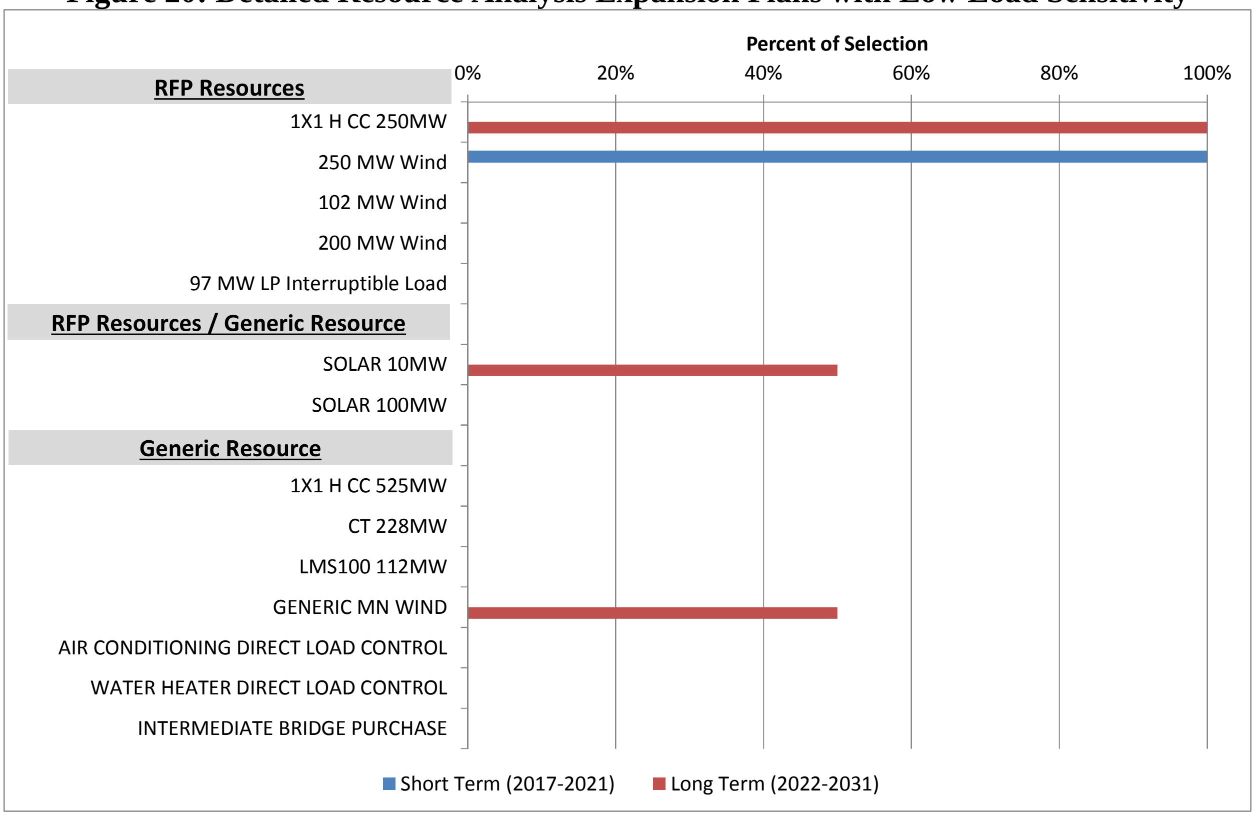
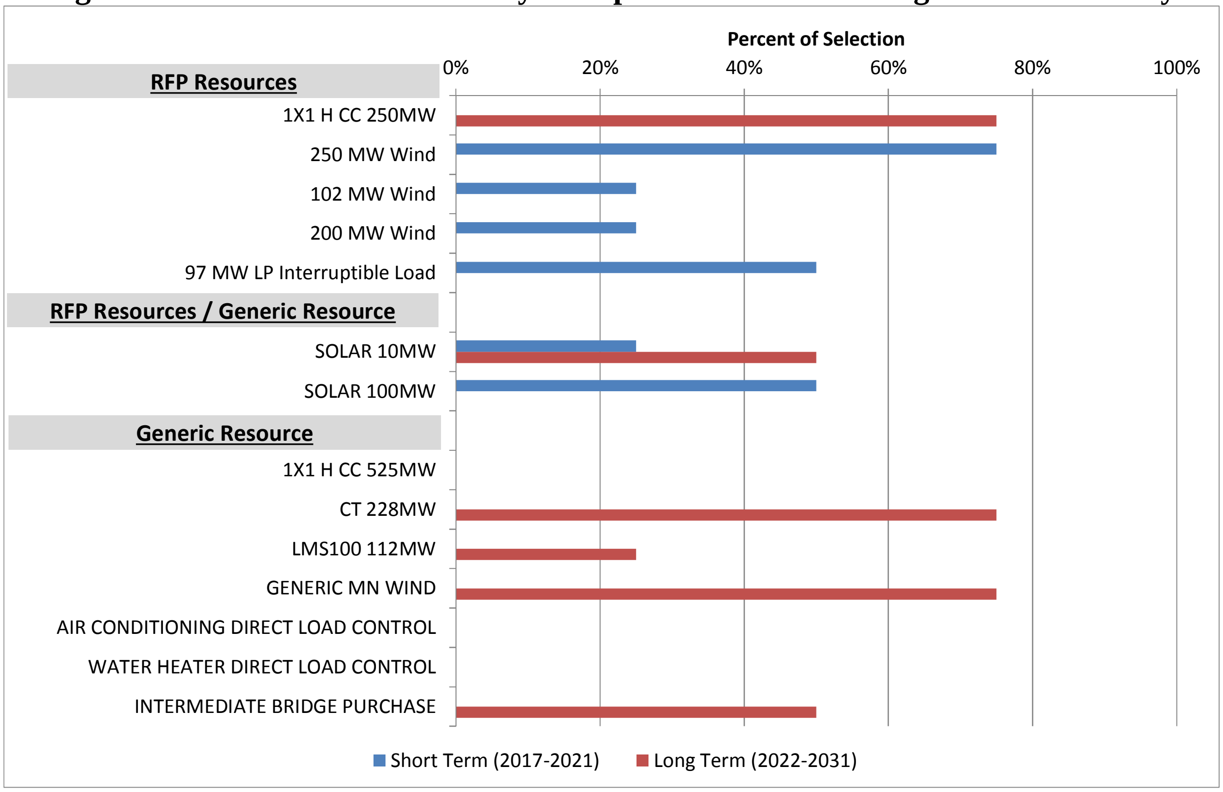


Figure 21: Detailed Resource Analysis Expansion Plans with High Load Sensitivity

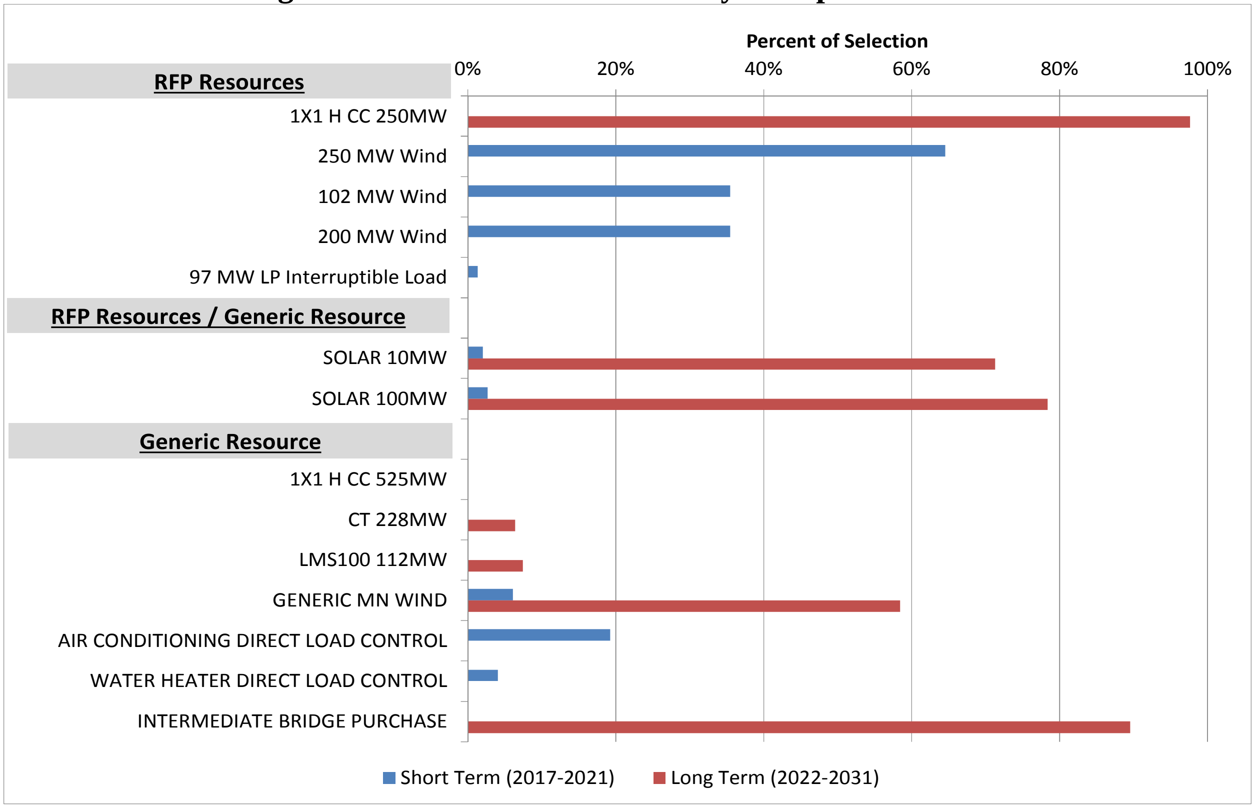


3.4.10 Conclusions from Expansion Planning Analysis

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 22 below, the following actions provide a prudent and flexible set of resources to meet stakeholder requirements, and work to support Company values of maintaining a balanced and affordable power supply portfolio.

- Enter into a PPA for a 250 MW wind facility located in southwestern Minnesota with energy delivery starting in 2020;
- Enter into a PPA for a 10 MW solar facility located on the southern end of Minnesota Power's distribution system with energy delivery starting in 2020; and
- Procure approximately 250 MW of capacity and energy from NTEC prior to 2025.

Figure 22: Detailed Resource Analysis Expansion Plans



While a number of additional alternatives were explored, as described in the foregoing portions of this Section 3, this resource group emerged as the combined best plan to support customer energy, capacity, and affordability needs, meet state policy goals, and fulfill 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 identified resources:

- Increase wind and solar capacity by 260 MW (40 percent increase) from today;
- Result in over 44 percent renewable penetration (including hydro) overall;
- Meet growing needs during a period of declining planning reserve margins in MISO;
- Replace older coal plants with clean-burning dispatchable natural gas generation;
- Contribute to material decreases in CO_2 emissions;
- Ensure a flexible power supply for Minnesota Power customers;
- Position the system for future renewable development; and
- Deliver the least-cost portfolio across hundreds of sensitivities.

This is a unique opportunity to bring a combination of resources into the 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 is in the best interest for customers.

3.5 CHARACTERISTICS OF MINNESOTA POWER'S ENERGY*FORWARD* RESOURCE PACKAGE

The Energy*Forward* Resource Package 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 Energy*Forward* Resource Package implements capacity additions 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 with reasonable cost increases for customers. The Energy*Forward* Resource Package 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 purchases, 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 23 and Figure 24 demonstrate the resulting summer and winter capacity of the Energy*Forward* Resource Package. 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. Incorporating all the action items above brings the Company's capacity position into compliance with future resource adequacy requirements.

Figure 23: Energy*Forward* Resource Package Summer Season Capacity Outlook

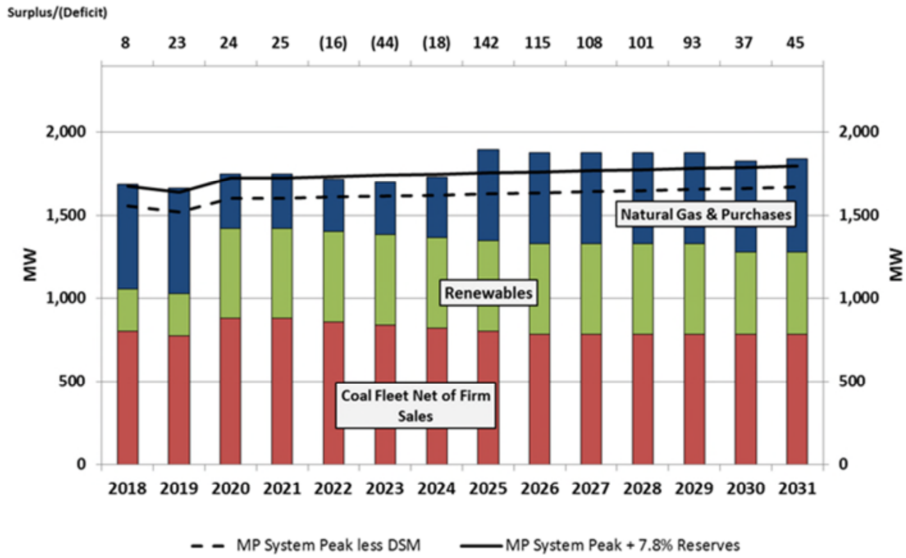


Figure 24: Energy*Forward* Resource Package Winter Season Capacity Outlook

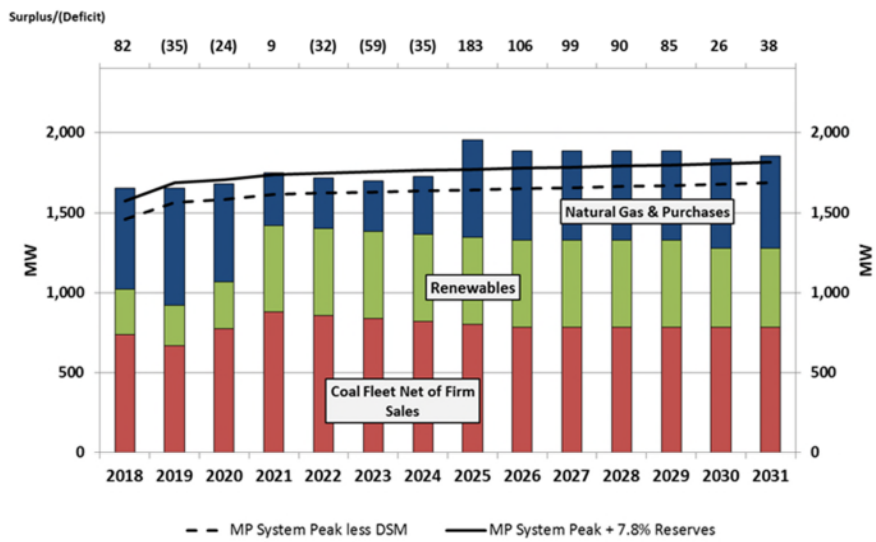


Figure 25 provides a long-term look at Minnesota Power's expected energy position. The Energy*Forward* Resource Package provides sufficient energy resources to serve customer requirements with minimal market reliance risk while abiding by the Company's planning principles.

Figure 25: Energy*Forward* Resource Package Energy Position Outlook[80]

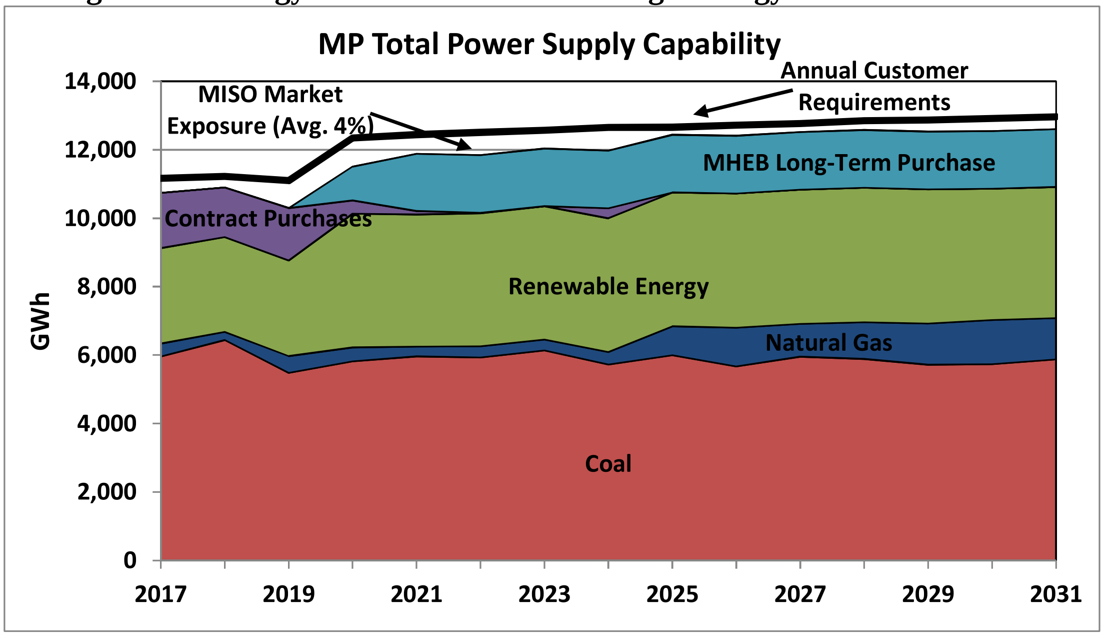
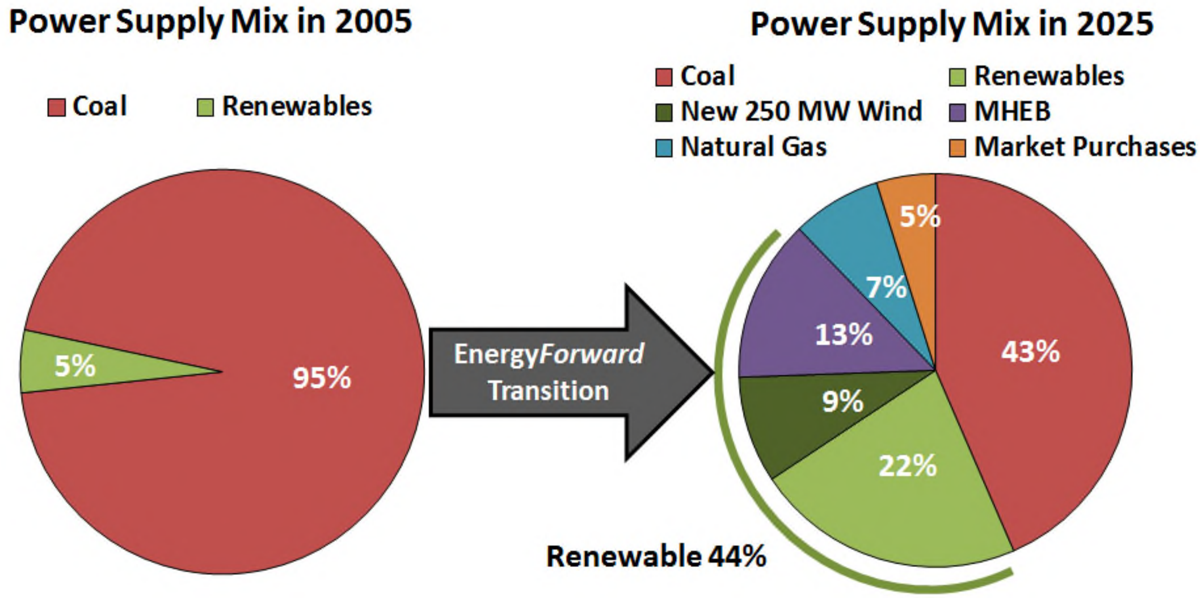


Figure 26 shows the Energy*Forward* Resource Package brings additional diversity to Minnesota Power' power supply mix, reducing coal below 45 percent and augmenting both the renewable and natural gas components. The new power supply mix brings the Company one step closer to its vision for two-thirds renewables and renewable-enabling natural gas and purchases, and one-third coal. This represents a dramatic and responsive shift from a 95 percent coal-fired generation portfolio as of 2005.

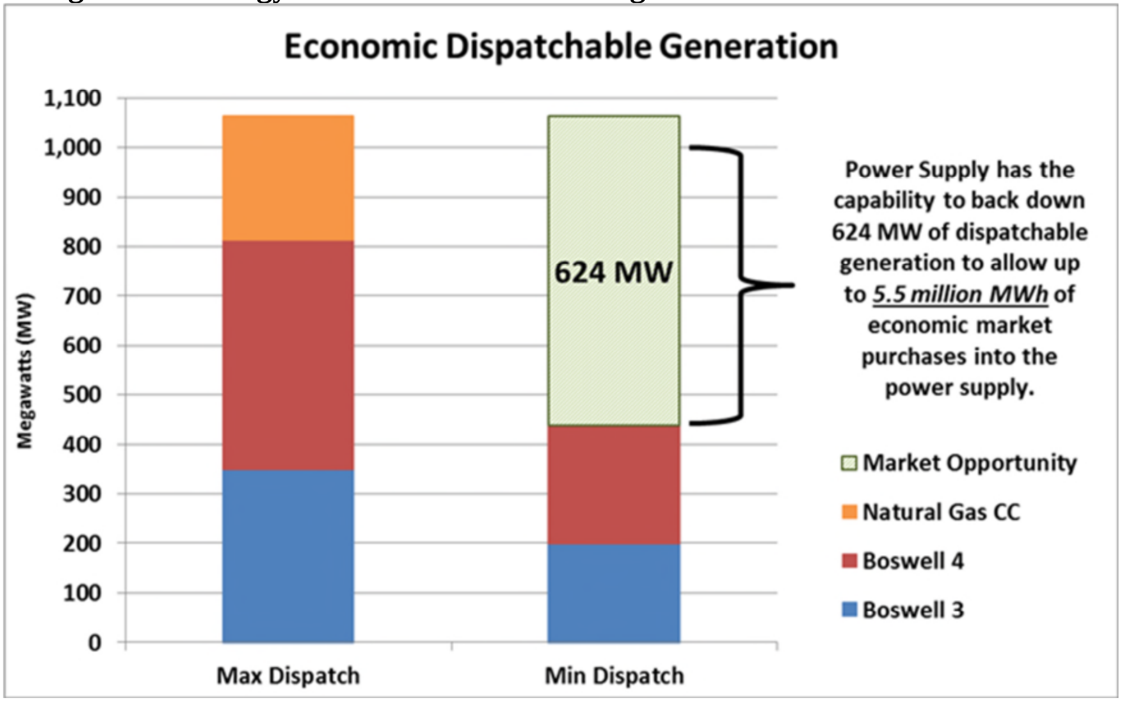
[80] This energy position represents the full capability of energy sources in Minnesota Power's Energy*Forward* Resource Plan. Actual dispatch will vary in real time operations.

Figure 26: Power Supply Mix Transformation by 2025



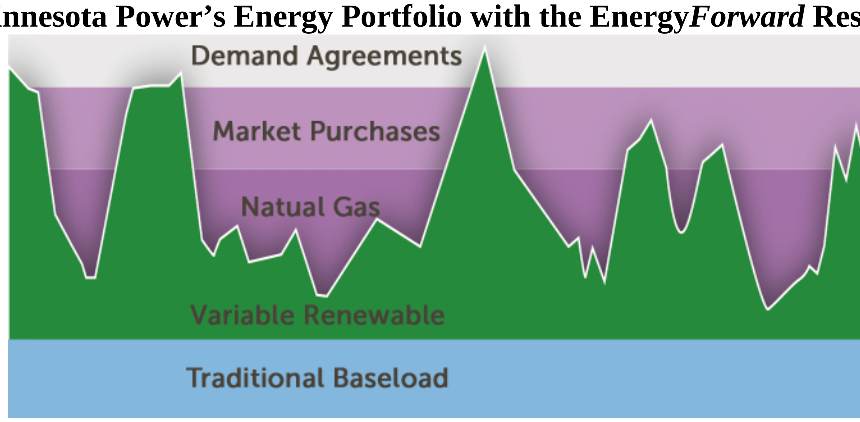
The 250 MW addition of new flexible combined-cycle natural gas to the power supply positions Minnesota Power to take advantage of up to 5.5 million MWh of economical market purchases annually while maintaining a natural price hedge with installed units. Figure 27 below illustrates the magnitude of potential 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 27: Energy*Forward* Resource Package Plan Economic Market Access



The proposed Energy*Forward* Resource Package 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 28 shows how this package fits in with the Company's overall energy portfolio.

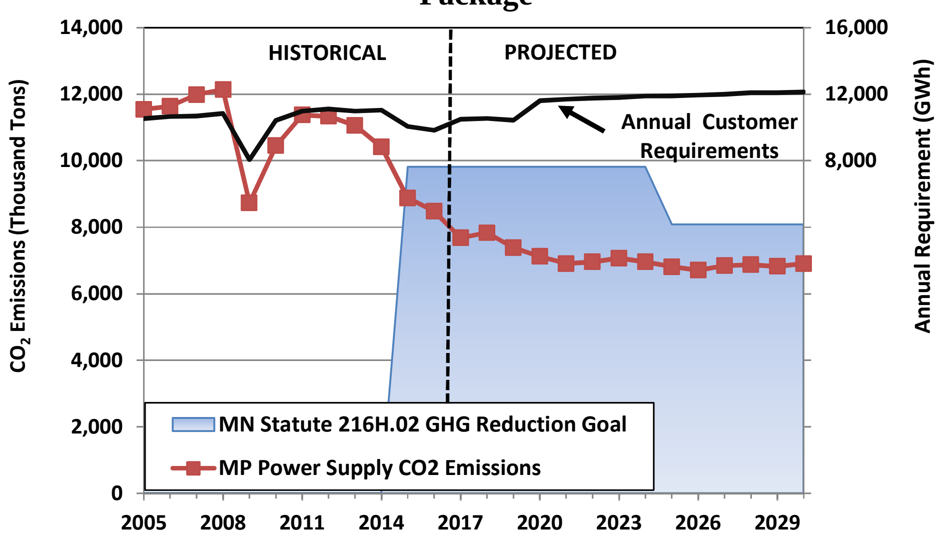
Figure 28: Minnesota Power's Energy Portfolio with the Energy*Forward* Resource Package



Environmental benefits are inherent in this transformation and help position the power supply for future regulations. Since 2005, the Company has committed to add only 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 intensity of its power supply. With the Energy*Forward* Resource Package, Minnesota Power will continue reshaping nearly 2,200 MW of generation in the Company's supply portfolio by 2025 and 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 of renewable energy generation, including over 850 MW of wind, 33 MW of solar, 250 MW from MHEB, 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 by 2024.

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, 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 29.

Figure 29: Greenhouse Emission Reductions Achieved with Energy*Forward* Resource Package



While executing these reductions, Minnesota Power has the potential for its largest growth in industrial customer load since the late 1970s. Minnesota Power remains committed to its planning principle of adding less carbon intensive resources. The Energy*Forward* Resource Package, coupled with recently-announced generation retirements, will result in a reduction of approximately 16.9 million tons of CO_2 from 2020 through 2031, which translates into a reduction of approximately 17 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 Energy*Forward* Resource Package plus three swim lane alternative paths that vary the quantity of renewable generation to comply with 50 percent and 75 percent renewable requirement per Minn. Stat. § 216B.2422, subd. 2 and the type of natural gas-fired generation. The four swim lane alternatives include these action plans:

1. The Energy*Forward* Resource Package – Consisting of 250 MW of wind in 2020, 10 MW of solar in 2020, and an approximately 250 MW share of the NTEC combined-cycle gas turbine in 2025. 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) for general planning purposes; however, the Company is not including these resources in the Energy*Forward* Resource Package nor seeking approval at this time.[81] The Company will revisit need levels in future IRPs and present specific proposals for these time periods at that time.

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

[81] With this filing, Minnesota Power is seeking Commission approval of the 250 MW of wind through the Nobles 2 Wind Project PPA; 10 MW of solar through the Blanchard Solar Project PPA; and the approximately 250 MW (48 percent) share of the NTEC combined-cycle natural gas plant. 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.

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 – 1350 MW of wind added from 2020 through 2031 in 250 MW to 450 MW 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, and 250 MW of wind in 2020.

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 30 and Table 2 below.

The Energy*Forward* Resource Package meets the open energy requirement for customers with 44 percent renewables on average, with the renewable percentage in some years exceeding or meeting 50 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 700,000 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 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 generation such as 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 30 below.

Figure 30: Comparing Annual Percent of Open Energy Need Met With New Renewable Generation

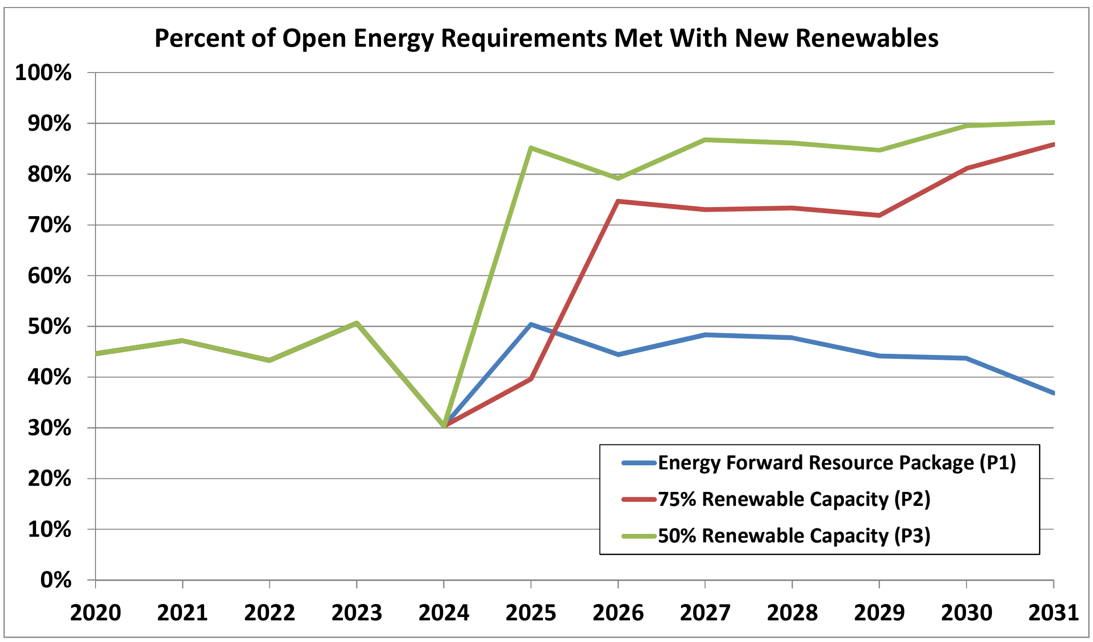


Table 2: Average Percentage of Minnesota Power's Open Energy Need Met With New Renewable Generation From 2020 through 2031

	Average Percentage of Open Energy Requirement Met With New Renewables from 2020 through 2031
Energy*Forward* Resource Package (P1)	44%
75% Renewable Capacity (P2)	64%
50% Renewable Capacity (P3)	73%

The most prominent comparison of the swim lanes is between the Energy*Forward* Resource Package and the Large Combustion Turbine scenario from a power supply cost comparison. Due to the high penetration of renewable generation in the 50 percent and 75 percent renewable scenarios and 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 Energy*Forward* Resource Package and the Large Combustion Turbine scenario.

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 Energy*Forward* Resource Package was least cost in over 90 percent of cases. This demonstrates the robustness of the Energy*Forward* Resource Package to protect customers from additional cost risks in a future where CO_2 is regulated.

Along with the cost protection benefit, the Energy*Forward* Resource Package alternative 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;[82]
- Provides synergy between flexible combined-cycle and variable renewable resources;

[82] 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.

- 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 of combined-cycle generation and costs;
- Delivers least-cost portfolio across hundreds of sensitivities;
- Exceeds Minnesota greenhouse gas goals, while minimizing power supply cost impacts in a future where CO_2 is regulated; and
- Provides a diversified portfolio, with over 44 percent renewable penetration and increased dispatchable generation.

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 Energy*Forward* Resource Package, and to further assess the benefits of the Energy*Forward* Resource Package for stakeholders. The three swim lane alternatives were developed to compare the Energy*Forward* Resource Package to portfolios with higher renewable builds in accordance with the State 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.

Each swim lane alternative and the Energy*Forward* Resource Package was then 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 264 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 economic 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 the best portfolio for customers.

Across this wide range of sensitivities, the Energy*Forward* Resource Package provided 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 Energy*Forward* Resource Package.

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

	Energy*Forward* Resource Package (P1)	**75% Renewable Capacity (P2)**	**50% Renewable Capacity (P3)**	**Large Combustion Turbine (P4)**
Least Cost Count	244	20	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[83]

	Energy*Forward* Resource Package (P1)	**75% Renewable Capacity (P2)**	**50% Renewable Capacity (P3)**	**Large Combustion Turbine (P4)**
Least Cost Count	132	8	0	0
Percent of Cases Least Cost	94%	6%	0%	0%

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

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

	Energy*Forward* Resource Package (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 Energy*Forward* Resource Package represents the 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 tables, the Energy*Forward* Resource Package effectively hedges the customers against a future CO_2 regulation penalty if one was to be implemented.

3.6.3 Cost Impact

The sensitivities and consideration of the swim lane alternatives help solidify that the Energy*Forward* Resource Package will meet Minnesota Power's objective to balance improving environmental performance, preserving reliability, and protecting affordability for customers.

The Energy*Forward* Resource Package 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 31 and Table 6 below compare the annual power supply cost[84] on a dollar per MWh basis between the Energy*Forward* Resource Package 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 Energy*Forward* Resource Package to the other alternative swim lanes, the Strategist model includes all known costs associated with the generation resources and modeled these costs in the alternative swim lanes. The Strategist modeling balances the cost impact to customers of adding more low-cost

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

intermittent generation (i.e., wind) relative to slightly higher cost dispatchable generation (i.e., combined-cycle). When looking at the Energy*Forward* Resource Package as a whole 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.

Figure 31 demonstrates the Energy*Forward* Resource Package is superior to the other swim lanes and it reduces cost for customers compared to taking no actions to meet growing customer demand and replacing coal generation shutdown. Minnesota Power realizes that this is not a complete rate analysis by customer class; however, using the Strategist modeling results is a reasonable indicator that the recommended Energy*Forward* Resource Package will most likely result in lower rates for customers compared to alternative resource scenarios. 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 31: Change in Annual Power Supply Cost between Energy*Forward* Resource Package/Swim Lane Alternatives with Base Case Assumption not Including a CO_2 Regulation Penalty and State Externalities

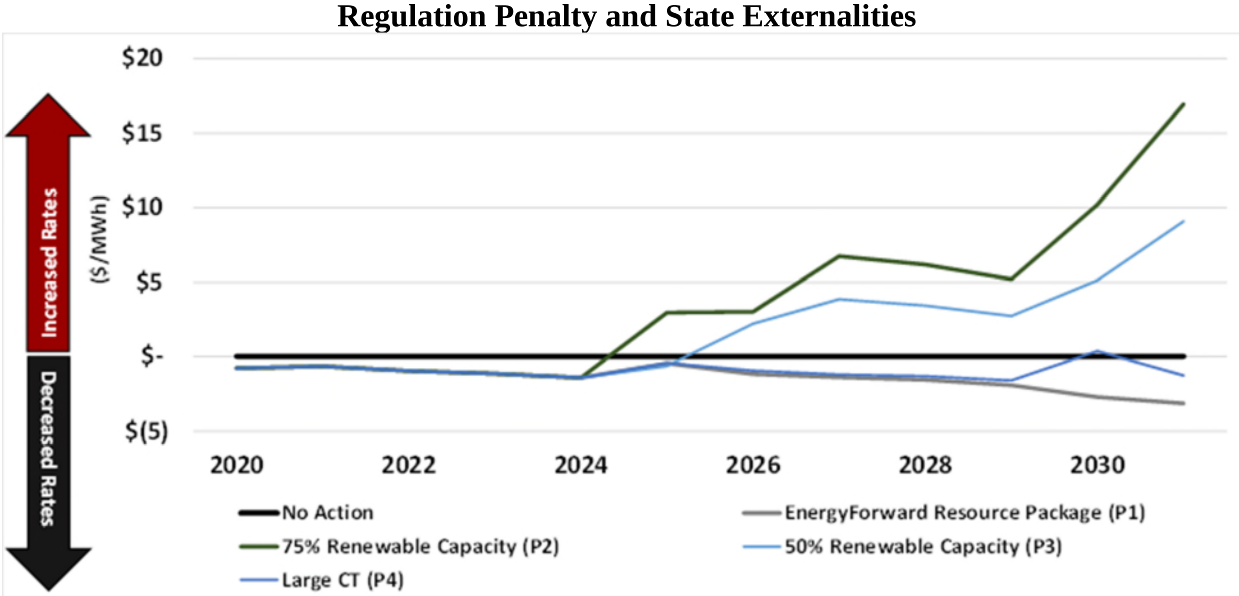


Table 6: Change in Annual Power Supply Cost between EnergyForward Resource Package/Swim Lane Alternatives with Base Case Assumption not Including a CO_2 Regulation Penalty and State Externalities

$/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
Energy*Forward* Resource Package (P1)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	($1)	($2)	($2)	($3)	($3)
75% Renewable Capacity (P2)	($1)	($1)	($1)	($1)	($1)	$3	$3	$7	$6	$5	$10	$17
50% Renewable Capacity (P3)	($1)	($1)	($1)	($1)	($1)	($1)	$2	$4	$3	$3	$5	$9
Large CT (P4)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	($1)	($1)	($2)	$0	($1)

The proposed resource acquisitions presented in this filing represent 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. Minnesota Power's Energy*Forward* Resource Package continues 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 Energy*Forward* Resource Package was identified as in the best interest for customers.

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, the Company engaged Pace Global as a third-party independent evaluator to conduct an independent analysis of available alternatives. As discussed above, this package derives from the Commission's conclusions and directions in the July 2016 IRP Order and subsequent updated analysis. Further, each RFP process and selection was evaluated by a third-party independent evaluator. However, 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. 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 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 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 Energy*Forward* 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 Study Period: 2018-2034	Cost	Risk/ Rate Stability			Market Exposure		Cost Exposure		All-in
	Mean Portfolio Cost NPV ($B)	High Cost Exposure 95th Percentile NPV ($B)	Diversity (# tech-nologies 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 WIND

Minnesota Power is seeking Commission approval of the PPA with Tenaska, Inc.,[85] to purchase 250 MW of wind-generated energy and capacity from the Nobles 2 wind-generation facility in Nobles and Murray counties in southwestern Minnesota. The Nobles 2 Wind Project PPA is an integral component of Minnesota Power's larger Energy*Forward* Resource Package request that is the subject of this Petition. Minnesota Power respectfully requests that the Commission approve the 250 MW Nobles 2 Wind Project PPA as part of the overall Energy*Forward* Resource Package.

In compliance with Order Point 9[86] of the Commission's July 2016 IRP Order, the Company issued an RFP (the "Wind RFP") on July 27, 2016, seeking power supply proposals for up to 300 MW of cost-effective wind resources. Minnesota Power was seeking proposals that utilize the federal PTC, offer capacity that is accreditable under current MISO resource adequacy rules in Minnesota Power's MISO Local Resource Zone (Zone 1), and have an initial term of 20 years or longer. Proposals could have commercial operation dates between January 1, 2018, and December 31, 2020. Responses were due by September 7, 2016.

Minnesota Power provided notice of the Wind RFP to potential bidders through news media as well as industry publications and websites, and received a robust RFP response with proposals for 35 project sites from 17 bidders, totaling over 5,000 MW of nameplate capacity. The Company did not submit a self-build proposal.[87]

Minnesota Power retained the services of an independent evaluator, Sedway Consulting, Inc. ("Sedway Consulting"), to monitor the RFP process and evaluate the proposals. Sedway

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[85] The PPA is between Minnesota Power and Nobles 2 Power Partners, LLC, an affiliate of Tenaska, one of the largest private, independent energy companies in the United States, with a nearly 30-year record of success in development, design, financing, construction management, and operation of energy facilities (http://www.tenaska.com).

[86] Order Point 9 states, "By the end of 2017, Minnesota Power shall initiate a competitive bidding process to procure 100-300 MW of installed wind capacity." July 2016 IRP Order at 15.

[87] *See In the Matter of Minn. Power – Affiliated Interests between ALLETE and ALLETE Clean Energy*, Docket No. E015/AI-17-304, INITIAL FILING at 4-5 (Apr. 19, 2017) (explaining Minnesota Power's decision not to pursue the wind RFP proposal submitted by Minnesota Power's affiliate, ALLETE Clean Energy, Inc.).

Consulting specializes in providing independent evaluation services and has evaluated thousands of power supply proposals in dozens of utility solicitations. All of the proposals were evaluated and ranked based on economics, including the value of energy produced, cost of energy, and debt equivalence on a levelized basis. The top-ranked proposals were also evaluated on non-economic factors (e.g., site control, permitting, interconnection, project team experience). See Section 4.3 for additional detail on the Wind RFP evaluation process and Appendix O for the independent evaluator's Wind RFP evaluation report.[88]

From Sedway Consulting's evaluation and ranking, a short list of projects was established for PPA negotiations. The negotiations with the shortlisted bidders were monitored by the independent evaluator, and concluded with Minnesota Power selecting the Nobles 2 Wind Project, developed by Tenaska.

4.1 PROPOSED 250 MW WIND MEETS IDENTIFIED NEED

Further review by the Company following the submission of Minnesota Power's 2015 Plan in September 2015 found that under the current favorable tax treatment of wind farms with the extension of the PTC, there is an opportunity to procure low-cost wind resources that could serve as an energy-price hedge against fuel prices and the market for the benefit of customers. The PTC was extended on December 18, 2015, more than three months after Minnesota Power submitted its 2015 Plan, providing the full credit amount for a 10-year period to wind facilities that commence construction prior to January 1, 2017, and a phased reduction in the amount of the available credit for wind facilities that commence construction by December 31, 2019. While this development improved the economics of additional wind, the Company also recognized the need to exercise caution to not procure too much wind, resulting in an energy surplus and net cost to customers if the Company was unable to generate sufficient revenue by selling the surplus on the wholesale market. Based on the record in the 2015 Plan proceeding, the Commission concluded that Minnesota Power should begin a competitive acquisition process to

[88] Appendix O: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Wind Resource Solicitation.

procure 100–300 MW of installed wind capacity, a range reflecting the different recommendations of the Company, the Department, and the CEO based on modeling results.

In July 2016, Minnesota Power initiated its Wind RFP process to comply with the July 2016 IRP Order by initiating the required competitive bidding process to procure 100–300 MW of installed wind capacity by the end of 2017;[89] to use the current low-cost wind pricing created by the extension of the PTC to maximize benefits to its customers without creating a significant energy surplus to the detriment of customers; and to investigate the benefits resulting from further geographical diversification of its wind resource portfolio. Based on the outcome of the RFP selection process and associated resource planning analysis, as discussed in greater detail in Section 4.2, Minnesota Power found that an additional 250 MW of wind generation, in a different geographical region than the current wind assets located in North Dakota, provides wind energy diversification at a low cost for its customers. Additionally, the selection of 250 MW of high capacity factor wind energy minimizes the risk of oversupplying customer needs while also reducing customer cost.

4.2 Resource Planning Analysis

Minnesota Power's current wind portfolio consists of more than 600 MW that include both utility-owned and PPA structures. Owned assets include the Bison 1, Bison 2, Bison 3, and Bison 4 Wind projects (totaling 496.6 MW), and the Taconite Ridge project (25 MW). PPA sources include the Oliver County I and II projects (totaling 98.6 MW). The bulk of Minnesota Power's wind portfolio, 595.2 MW, is located near Center, North Dakota.

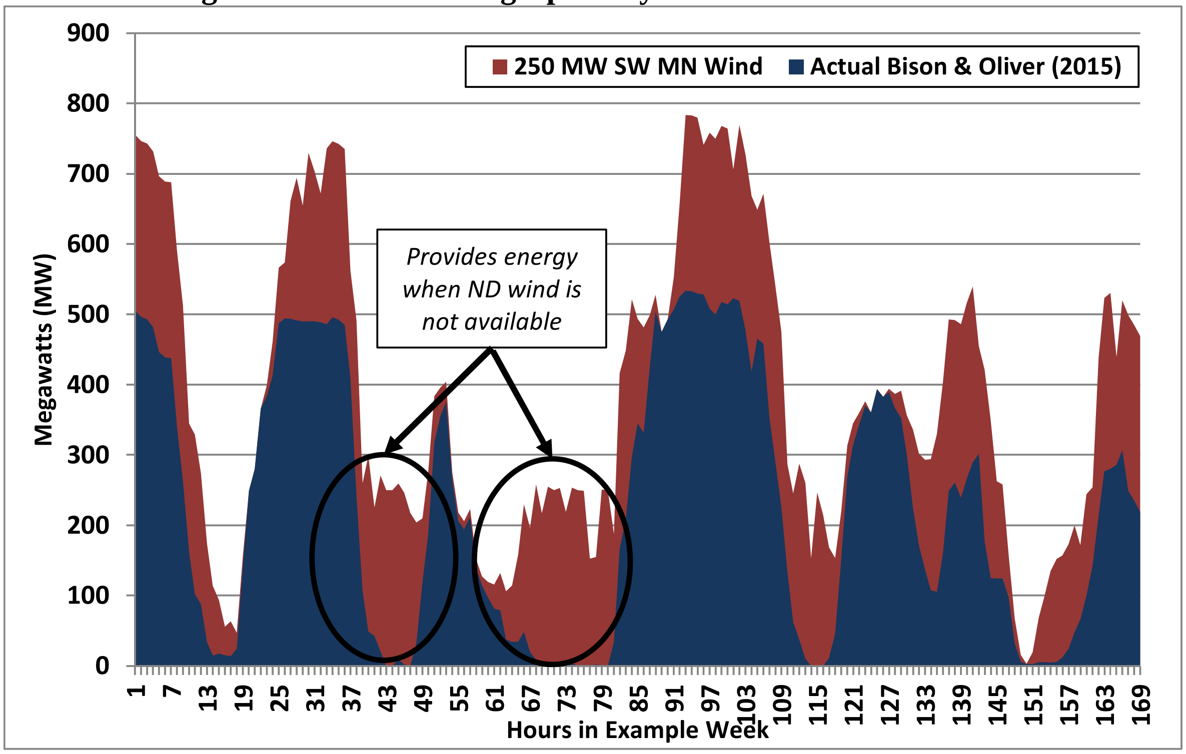
As discussed in Section 3 of this Petition, Strategist was used to conduct the resource planning analysis for the evaluation of wind and other resources. Strategist allows a utility to offer many resource types into a production cost evaluation and optimize the technologies that best fit to meet projected 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,

[89] 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.").

solar, and natural gas. The detailed resource analysis first considered up to 550 MW of additional wind from three different projects of the least-cost and geographically-diverse wind from the RFP process. Up to 302 MW from the 550 MW considered was allowed to be selected. The three wind projects considered in Strategist from the RFP were located in three different states within MISO's Local Resource Zone 1. This allowed Minnesota Power to evaluate the benefits of procuring wind generation that is geographically diverse from the 600 MW of wind located in North Dakota. The analysis showed the lowest-cost plan for customers included 250 MW of new wind generation located in southwest Minnesota in 2020 based on a price of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]**. Minnesota Power used the applicable energy price cap submitted with the RFP bid response in the Strategist analysis to ensure that if the cost came in higher than expected, it would still be economical for customers, and realizing that if the price is lower than the cap, there are additional benefits for customers. The Strategist analysis selected the wind at this low cost to be added regardless of inclusion of a CO_2 regulation penalty.

Figure 32 below shows the benefit of adding geographically-diverse wind to Minnesota Power's existing wind portfolio — the 250 MW of new wind within Minnesota helps smooth out Minnesota Power's wind generation by providing some wind generation during periods when there is no wind in North Dakota.

Figure 32: Value of Geographically-Diverse Wind Production



Compared to a wind portfolio concentrated in a single area, geographic diversity reduces Minnesota Power's exposure to local and regional transmission disruptions, and reduces the variability to total wind energy production. Co-located wind facilities experience similar wind conditions at nearly the same time, resulting in coincident production peaks and valleys. Geographically-diverse wind facilities are less likely to experience similar wind conditions at the same time, smoothing some of the peaks and valleys in total wind energy production.

4.3 Selection of the Nobles 2 Wind Project

As previously noted, to comply with Order Point 9 of the July 2016 IRP Order, Minnesota Power issued an RFP on July 27, 2016, seeking power supply proposals for up to 300 MW of cost-effective wind resources that utilize the federal PTC, offer capacity that is accreditable under current MISO resource adequacy rules in MISO Local Resource Zone 1, and have an initial term of 20 years or longer.[90] This request was part of the Company's broader evaluation process that considered the costs and characteristics of different power supply types (e.g., wind, solar, natural

[90] Minnesota Power's Request for Proposals for Wind Resource is provided in Appendix P of this Petition.

gas, demand response, and distributed generation) to optimize the mix of resources to meet customer needs.[91]

Independent evaluator Sedway Consulting monitored the RFP process and evaluated the proposals received. Sedway Consulting was familiar with Minnesota Power's evaluation processes and available planning assumptions due to providing evaluation services in past RFP processes. Sedway Consulting requested the Company provide as much information as possible prior to the receipt of proposals. This allowed Sedway Consulting to lock down and archive the basic evaluation parameters for the process. Such information included forecasts of regional market energy prices,[92] cost of capital components, discount rate, and historical locational marginal pricing information. These assumptions were incorporated into Sedway Consulting's own evaluation model and formed the basis for independently assessing the benefits and costs of resources that were bid into Minnesota Power's solicitation.

The evaluation process entailed a general review of all proposals and the calculation and ranking of levelized energy prices for all proposed options. In instances where proposals were found to be non-compliant or incomplete, bidders were notified and given an opportunity to supplement their proposal materials. More effort was focused on the higher-ranked proposals, performing a thorough qualitative assessment of those proposals that appeared to have the best quantitative value for Minnesota Power's customers. Concurrent with that qualitative analysis, Sedway Consulting undertook the modeling of all proposals to assess their energy benefits; specifically, Sedway Consulting performed detailed modeling to determine each proposal's net cost. Although the levelized price ranking provided a good approximation of how project economics

[91] The broader evaluation process referenced is customary in Minnesota Power's resource planning process and complies with Order Point 8 of the July 2016 IRP Order which states, "Minnesota Power's next resource plan shall include a full analysis of all alternatives, including renewables, energy efficiency, distributed generation, and demand response, for providing energy and capacity sufficient to meet its needs." July 2016 IRP Order at 15.

[92] In past Minnesota Power wind solicitations, Sedway Consulting has also ascribed a value to the capacity of proposed wind resources. In consultation with the Company, it was decided that such capacity valuation was not necessary in the current evaluation in that it was dependent on MISO capacity accreditation rules that may change, was likely to be quite similar across all wind projects (and thus would not be a differentiating benefit), and might be inappropriately influenced by bidder-supplied generation profiles.

might compare, an assessment of the offers' generation profiles and the energy benefits associated with those profiles provided a comprehensive comparison.

The detailed economic evaluation, which is provided in Appendix O, entailed modeling the bids in Sedway Consulting's Renewable Bid Evaluation Model — a spreadsheet-based tool used to determine a proposal's net cost by calculating the present value of the project's costs and subtracting the present value of a proposed facility's hourly energy benefits. The costs in the net cost calculation included contract payments for delivered energy and an imputed debt cost for PPAs. Energy benefits were the product of the expected hourly generation of a facility and a forecast of hourly $/MWh energy market prices over the term of the contract. Sedway Consulting's evaluation model normalized the net cost by dividing it by the present value of a project's expected energy deliveries, thereby yielding a $/MWh levelized net cost. Minnesota Power received proposals that were clearly cost-effective, relative to expected energy market prices. This may be attributable to the fact that the current wind industry is in a highly-competitive phase and wind turbine costs have been declining; therefore, developers appear to be willing to provide wind projects at lower prices than has been the case in the past. In addition, the federal renewable PTC for wind projects will expire for any facilities that are not under construction prior to January 1, 2020. Thus, many developers may be eager to commence construction on wind projects as fast as possible, even at low prices.

In the fall of 2016, a key subset of the top-ranked projects were shortlisted. Negotiations commenced with the counterparties that proposed these projects and continued through the spring of 2017. One of those shortlisted projects was the Nobles 2 proposal. Sedway Consulting concurred with Minnesota Power's decision to make a final selection of that project and execute the Nobles 2 Wind Project PPA. The other shortlisted proposals had higher net costs and other attributes that made them less attractive for meeting Minnesota Power's resource needs.[93] On May 10, 2017, the Company executed a PPA for the 250 MW Nobles 2 Wind Project. On July 20, 2017, the Company executed the First Amendment to the Nobles 2 Wind Project PPA.

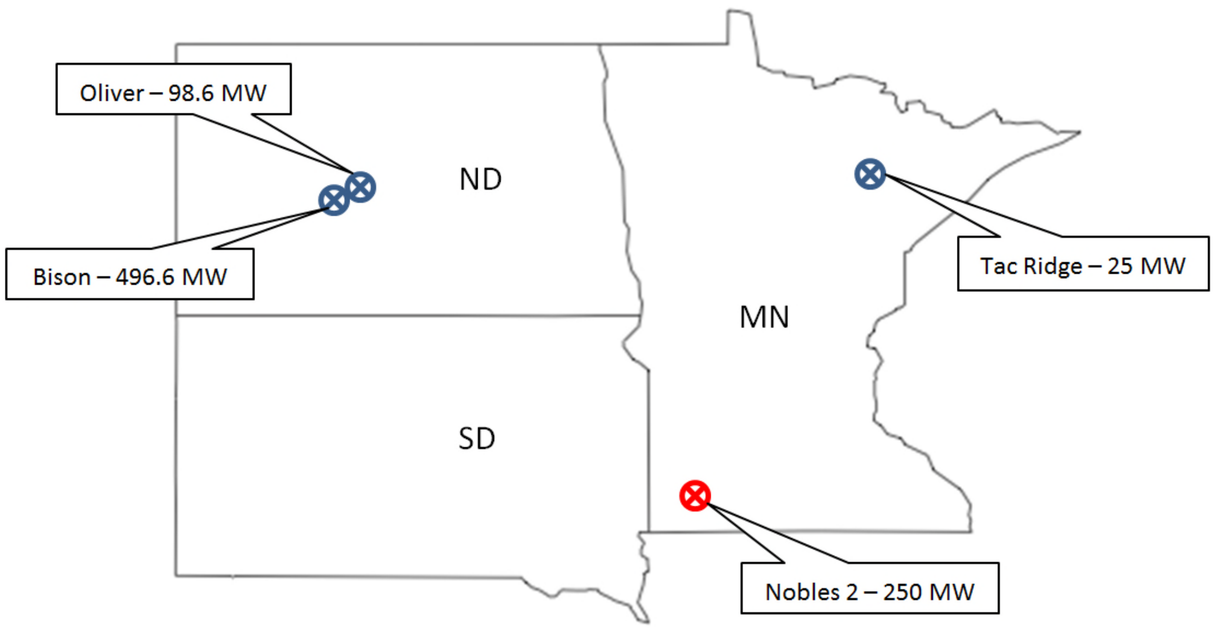
[93] See Appendix O: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Wind Resource Solicitation for details on bid comparisons.

4.4 THE NOBLES 2 WIND PROJECT

4.4.1 Project Overview

The Nobles 2 Wind Project will have a nameplate capacity of about 250 MW and is located in Nobles and Murray counties in southwestern Minnesota. This area is home to Buffalo Ridge, a sixty-mile long expanse of rolling hills that stands 1,995 feet above sea level. The project location has excellent wind quality and adds beneficial geographic diversity to Minnesota Power's existing wind portfolio. Figure 33 below provides a map showing the location of Minnesota Power's existing wind resources relative to the proposed Nobles 2 Wind Project.

Figure 33: Minnesota Power's Existing Wind Resources And Location of Nobles 2 Wind Project



In the Department's December 10, 2013, Response Comments in Docket No. E015/M-13-907 addressing Minnesota Power's petition seeking approval of investments and expenditures related to the development of the Bison 4 Wind project,[94] the Department highlighted the benefits of having a diversified portfolio of wind resources consisting of both owned facilities and PPAs.

[94] *In the Matter of the Petition of Minn. Power for Approval of Investments and Expenditures in the Bison 4 Wind Project for Recovery through Minn. Power's Renewable Res. Rider under Minn. Stat. § 216B.1645*, Docket No. E015/M-13-907, DEP'T RESPONSE COMMENTS (Dec. 10, 2013).

The Nobles 2 Wind Project provides geographical diversity, as well as adds to the 98.6 MW of wind energy and capacity currently under PPA with NextEra Energy Resources from the Oliver I and Oliver II Wind facilities located near Center, North Dakota.

The Nobles 2 Wind Project is anticipated to begin commercial wind production by June 2020. Tenaska has site control for the Nobles 2 Wind Project and is planning to submit the required application to the Commission for a site permit in mid-2017. It is anticipated that Vestas wind turbines will be used for the Nobles 2 Wind Project.

4.4.2 Interconnection and Transmission

The Nobles 2 Wind Project will connect to Xcel Energy's Nobles-Fenton 115 kV transmission line. Tenaska has submitted a generator interconnection request with MISO for interconnection to the MISO system. The MISO generator interconnection process is explained in detail in Appendix T. The Nobles 2 Wind Project is part of MISO's August 2016 Definitive Planning Phase ("DPP") study group. The need for any transmission network upgrades will be determined through MISO's DPP study process, with final cost estimates currently scheduled to become available in August 2018. Final execution of the Nobles 2 Wind Project's Generation Interconnection Agreement ("GIA") with MISO is expected in the first quarter of 2019.

4.5 OVERVIEW OF THE NOBLES 2 WIND PROJECT POWER PURCHASE AGREEMENT

The Nobles 2 Wind Project is an important component of the Company's larger Energy*Forward* Resource Package. Tenaska and Minnesota Power negotiated specific provisions into the PPA to protect the interests of their respective companies and customers. These provisions are mainly standard terms that would be included in a PPA of this scale. Certain terms exist within the PPA solely to address potential scenarios and events and allocate risk between parties in the limited circumstances in which they could occur. In the following paragraphs, the Company explains the PPA's significant terms. The full Nobles 2 Wind Project PPA and first amendment are provided in Appendix D.

4.5.1 Term of the Agreement

Minnesota Power executed a PPA with Tenaska on May 10, 2017. Subject to Commission approval and other contingencies, the term of the agreement begins once the project becomes commercially operational and expires at the end of 20 years. The Nobles 2 Wind Project is anticipated to begin commercial wind production by June 2020.

The PPA is subject to a number of contingencies, identified in Sections 1.2 and 1.3 of the PPA, which recognize that events beyond the parties' control could result in the need to cancel and not proceed with the PPA. These contingencies take effect if the necessary permits and regulatory approvals are not received, **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS]. Lastly, Minnesota Power has the right to terminate the contract if the Energy*Forward* Resource Package (requested wind, solar and combined-cycle natural gas resources) does not receive regulatory approval.

4.5.2 Services Provided from the Agreement

Pursuant to section 2.1.1 of the Nobles 2 Wind Project PPA, beginning with commercial operation, Tenaska is required to generate from the project, and sell the contract energy and accreditable capacity to Minnesota Power at the prices set forth in the PPA. Tenaska construct, own or lease, operate and maintain the Nobles 2 Wind Project in material compliance with all permits and requirements of law, applicable warranty requirements, relevant equipment manufacturer's specifications, and in accordance with standard industry practice.

4.5.3 PPA Pricing

Under the PPA, Minnesota Power will be purchasing the energy and capacity from the Nobles 2 Wind Project. As set forth in Exhibit B to the PPA, energy from the facility is priced at **[TRADE**

SECRET DATA BEGINS…

…TRADE DATA SECRET ENDS]

4.5.4 Energy Curtailments

[TRADE SECRET DATA BEGINS…

…TRADE SECRET DATA ENDS]

Tenaska may suspend energy deliveries due to Force Majeure under Article 10 of the PPA. This clause is standard in contracts of this type and generally allows performance to be suspended when unanticipated events, beyond the party's control, prevent a party from performing its obligations.

4.5.5 Environmental Attributes

Minnesota Power is entitled to all Green Tags (which includes Renewable Energy Credits) associated with the purchase of contract energy under Section 2.3 of the Nobles 2 Wind Project PPA. Under the PPA, Tenaska will assign to Minnesota Power all rights, title, and authority for Minnesota Power to register, own, hold, and manage the Green Tags. The Renewable Energy Credits can be used by the Company to demonstrate compliance with the Minnesota Renewable Energy Standard ("RES").

4.5.6 Interconnection and Delivery

Tenaska has applied for Network Resource Interconnection Service with MISO for the Nobles 2 Wind Project. Under the PPA, Minnesota Power is responsible for all electric losses, transmission and ancillary service arrangements, and costs required to deliver the energy and capacity from the Nobles 2 Wind Project to its customers.

4.5.7 Other Provisions of the PPA

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

- Article 6 contains typical provisions regarding operations and maintenance of the Nobles 2 Wind Project.
- Article 7 contains standard billing terms between the parties.
- Article 8 addresses the establishment of an operating committee designed to address issues that arise pursuant to the PPA.
- Article 9 addresses security provided by Tenaska to Minnesota Power for the project.
- Article 11 defines events of default and the termination of the PPA.
- Article 12 addresses indemnification.
- Article 13 addresses limitations of liability.
- Article 14 contains the standard arbitration clause used to address disputes between the parties of a PPA.
- Article 15 contains general terms and conditions standard in a PPA related to representations, warranties, and covenants.

All the terms outlined in this Section of the Petition are generally standard provisions in purchased power contracts.

4.6 The Nobles 2 Power Purchase Agreement is in the Public Interest

4.6.1 The Pricing in the Agreement is Economic

The current favorable tax treatment of wind farms with the extension of the PTC creates an opportunity to procure low-cost wind resources that could serve as an energy-price hedge for customers. The PTC was extended on December 18, 2015, more than three months after

Minnesota Power submitted its 2015 Plan, providing the full credit amount for a 10-year period to wind facilities that commence construction prior to January 1, 2017, and a phased reduction in the amount of the available credit for wind facilities that commence construction prior to January 1, 2020. Tenaska took the necessary action to qualify the Nobles 2 Wind Project for the full amount of the PTC; therefore, Minnesota Power's customers will benefit from availability of the full PTC amount through the low PPA price.

Minnesota Power received a robust response to its wind RFP, including many competitive proposals. After evaluating the proposals and monitoring the subsequent negotiations, Sedway Consulting concluded that the 250 MW Nobles 2 Wind Project PPA represented the best resource for Minnesota Power's customers that was offered into Minnesota Power's 2016 Wind Resource RFP.

Minnesota Power analyzed three wind projects from the RFP that were located in three different states within MISO's Local Resource Zone 1. This allowed the Company to evaluate the benefits of procuring wind generation that is geographically diverse from the 600 MW of wind located in North Dakota. The analysis demonstrated that the lowest-cost plan for customers included 250 MW of new wind generation located in southwest Minnesota in 2020 based on a price of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** and has the added benefit of being geographically diverse from Minnesota Power's existing wind generation. As discussed above, adding geographically-diverse wind to Minnesota Power's existing wind profile provides benefits by delivering some wind generation during periods when there is no wind in North Dakota.

The analysis selected the wind at this low cost to be added regardless of inclusion of a CO_2 regulation penalty. By limiting the risk of significant market capacity and energy purchases over the course of its long-term plan in part through the PPA, Minnesota Power is employing good utility practice and addressing the capacity and energy needs of its customers while limiting exposure to market forces and the potential for additional environmental regulation in the future.

4.6.2 The Agreement Offers Favorable Terms

The PPA with Nobles 2 provides a new resource that meets Minnesota Power's customers' needs and adds beneficial geographic diversity to the Company's existing wind portfolio, as well as the Company's overall resource portfolio, while at the same time providing protections on behalf of customers prior to the start of the PPA and through the contract term. Under the PPA, customers will receive the energy, capacity, and renewable energy attributes from the Nobles 2 Wind Project at a defined price over the term of the agreement.

4.7 NOBLES 2 WIND PROJECT POWER PURCHASE AGREEMENT RISK FACTORS

Minnesota Power recognizes there are potential risks associated with the development and operation of the Nobles 2 Wind Project. It is Tenaska's intention to construct and have the Nobles 2 Wind Project commercially operational by June 1, 2020. The following areas are intended to provide the Commission, the Department, and other stakeholders with a high-level understanding of the Company's efforts to identify and manage issues related to this project. Minnesota Power has identified the key issues noted below that may impact the Nobles 2 Wind Project. These factors do not include general business risks that might impact any construction project, business operations, or other risks that might impact any business enterprise.

4.7.1 Project Permitting and Regulatory Approval

The Nobles 2 Wind Project requires construction-related permitting, generation interconnection, and regulatory approvals. Certain milestones have been established to ensure timely completion of the project, and that Tenaska can meet its obligation to supply energy and capacity by June 2020. Tenaska and Minnesota Power have negotiated terms to address failure by Tenaska to complete the project by the commercial operation milestone, or to complete any interim major milestone by the applicable date. A significant delay in review and approval from the Commission of Minnesota Power's larger Energy*Forward* Resource Package request could delay construction of the project and potentially result in termination of the PPA.

4.7.2 Reliability and Delivery Curtailment

Once Minnesota Power begins receiving energy under the PPA, the execution risk shifts from having the Nobles 2 Wind Project constructed to operating and maintaining the facilities in order to limit customer risks. Minnesota Power acknowledges that there remains a long-term risk, as is present with any PPA, of transmission outages and operational delays (e.g., weather related, maintenance, etc.) which could temporarily curtail delivery. The PPA addresses reliability through facility operations and maintenance and curtailment provisions.

The PPA contains sufficient provisions for reliable power to be delivered to Minnesota Power.

4.8 COMMUNICATION AND FILING

Minnesota Power recognizes the importance of on-going communication with the Commission, the Department, and other stakeholders following approval of the PPA until the Nobles 2 Wind Project is operational. Minnesota Power has identified three primary milestones where it would be important to communicate project updates to the Commission, Department, and other stakeholders. The first milestone is when Tenaska receives the required Certificate of Need and site permit from the Commission. The second milestone is when the GIA for the Nobles 2 Wind Project is executed. The third milestone will occur when the project is operational. Minnesota Power commits to informing the Commission, the Department, and other stakeholders in a timely manner about the achievement of these milestones. The Company will also inform the Commission of any significant project schedule changes that arise during implementation of the Nobles 2 Wind Project.

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 the Nobles 2 Project.

4.9 CONCLUSION REGARDING NOBLES 2 WIND PROJECT

The Nobles 2 Wind Project was selected through a robust RFP process as the least-cost bid to meet Minnesota Power's customers' needs. As discussed above, Minnesota Power has negotiated commercially-reasonable contract terms with Tenaska to mitigate potential risks related to the

Nobles 2 Wind Project to ensure customers are fully protected. Minnesota Power respectfully requests that the Commission approve the 250 MW Nobles 2 Wind Project PPA as part of the overall Energy*Forward* Resource Package and authorize Minnesota Power to recover the PPA costs through its FPE Rider.

SECTION 5 SOLAR

Minnesota Power is seeking Commission approval of the PPA with Cypress Creek Renewables[95] to purchase 10 MW of solar-generated energy and capacity from the Blanchard solar-generation facility located near Royalton in Morrison County, in central Minnesota. Minnesota Power respectfully requests that the Commission approve the 10 MW Blanchard Solar Project PPA as part of the overall Energy*Forward* Resource Package. While Minnesota Power solicited bids for, and fully evaluated adding additional solar beyond what is required to comply with the SES, the Company's analysis based on current pricing of solar projects indicated that additional solar would not be economical for customers.

In compliance with Order Points 10 and 11 of the Commission's July 2016 IRP Order, the Company issued an RFP on August 4, 2016, seeking power supply proposals for 1 MW to 300 MW of utility-scale solar generation that qualifies under Minnesota's SES. Minnesota Power sought proposals that maximized the benefits from the federal Investment Tax Credit ("ITC") for the benefit of customers (the "Solar RFP"). The RFP required offers be for capacity that is accreditable under MISO resource adequacy rules in MISO Local Resource Zone 1, and have an initial term of at least 20 years. Proposals could have commercial operation dates between January 1, 2018, and December 31, 2022. Responses were due by September 14, 2016.[96]

Minnesota Power provided notice of the RFP to potential bidders through news media as well as industry publications and websites. Minnesota Power received a robust RFP response with proposals for 83 projects from 26 bidders, totaling approximately 3,400 MW of nameplate capacity. Minnesota Power submitted proposals for two self-build projects.

Independent evaluator Sedway Consulting monitored the RFP process and evaluated the proposals. All of the proposals were evaluated and ranked based on economics, including the value of energy produced, cost of energy, and debt equivalence on a levelized basis. The top-ranked proposals were also evaluated on non-economic factors (e.g., site control, permitting,

[95] The PPA is executed with Blanchard Solar, LLC, an affiliate of Cypress Creek Renewables.

[96] Minnesota Power's Request for Proposals for Solar Resource is provided in Appendix Q of this Petition.

interconnection, project team experience). See Section 5.3 for additional detail on the RFP evaluation process and Appendix R for the independent evaluator's Solar RFP report.[97]

From Sedway Consulting's evaluation and ranking, a short list of projects were identified for PPA negotiations. The negotiations concluded with Minnesota Power selecting the 10 MW Blanchard Solar Project.

5.1 10 MW Solar Project Meets Identified Need

Order Point 10 of the Commission's July 2016 IRP Order required that Minnesota Power acquire solar units of 11 MW by 2016, 12 MW by 2020, and 10 MW by 2025, to meet its SES obligations. Order Point 11 of the Commission's July 2016 IRP Order found 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." The SES requires Minnesota's public utilities to generate or procure sufficient electricity from solar sources so that by the end of 2020, at least 1.5 percent of the utility's retail electricity sales in the state that are non-exempt from the SES are produced from solar energy resources.

Minnesota Power began to implement its strategy to comply with the SES requirement in 2016 with the addition of approximately 11 MW between a small community solar garden pilot and the Camp Ripley Solar Project. While the Commission found that up to 100 MW of solar by 2022 was likely to be an economic resource for Minnesota Power's system,[98] the Company's analysis of current pricing for solar resources indicates that additional solar generation remains uneconomic at this time.

Solar costs are declining and efficiency is increasing; however, large scale solar is still substantially more expensive than wind and does not provide the same capacity benefits for Minnesota Power customers due to Minnesota Power's system peaking in the evening hours of winter. Consequently, Minnesota Power's refined analysis did not identify cost-effective

[97] Appendix R: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation.

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

additions of solar capacity beyond those identified as part of SES compliance in the near term. Minnesota Power therefore identified 10 MW of solar from the RFP process for its next phase in implementation of its strategy to comply with the SES requirements. An additional 10 MW of solar meets Minnesota Power's identified need to comply with SES requirements in a timely manner.

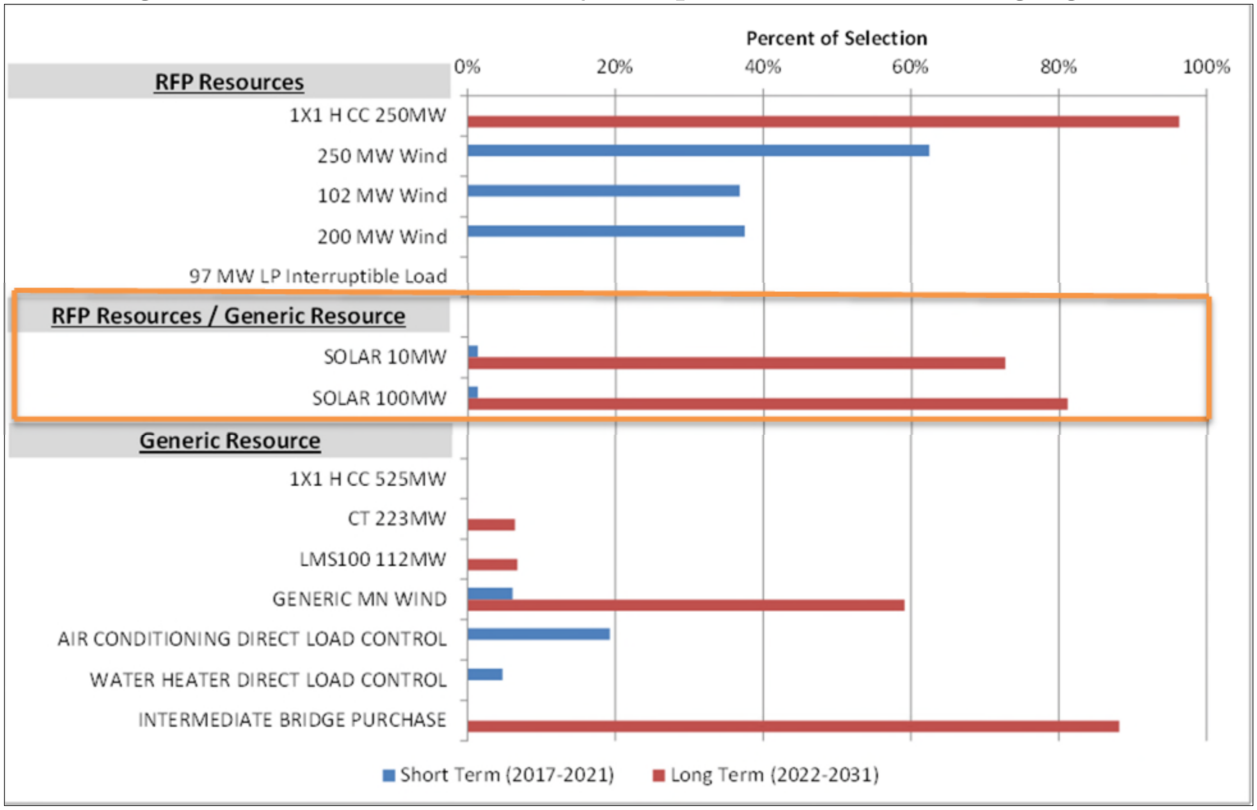
Based on the outcome of the RFP selection process and associated resource planning analysis (see Section 5.2), Minnesota Power found that additional solar beyond what is required to meet the SES, would not be cost effective for customers.

5.2 RESOURCE PLANNING ANALYSIS

As discussed in Section 3 of this Petition, Strategist was used to conduct the resource planning analysis for the evaluation of solar and other resource additions. 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, and natural gas. The detailed resource planning analysis evaluated adding solar in 10 and 100 MW block sizes based on pricing and expected performance from the least-cost offers received in the RFP. This analysis indicated that solar is still substantially more expensive than wind and does not provide the same capacity benefits for Minnesota Power customers.

A sensitivity was included in the resource planning analysis that varied the cost of solar in $10/MWh increments from $35/MWh to $75/MWh. As shown in Figure 34 below, adding 100 MW of solar did not start to show economic benefit for customers until the late-2020s through early 2030s. This is due in part to Minnesota Power's high load factor as well as the Company's winter peak, which limit the peak-following benefits of a solar resource.

Figure 34: Detailed Resource Analysis Expansion Plans – Solar Highlighted



Consistent with Order Point 11 from the Commission's Order, Minnesota Power also evaluated adding solar in 10 and 100 MW block sizes based on pricing and expected performance from the least-cost offers received in the RFP.[99] Large scale solar was selected at a higher frequency in the longer-term planning period with it being selected most often post-2030.

The solar pricing, while decreasing in nature from previous evaluations, did not identify that solar is the least-cost alternative for customers at this time. Due to these factors, Minnesota Power has selected one 10 MW project to continue its progress towards meeting the SES. 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.

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

5.3 Selection of the Blanchard Solar Project

Pursuant to Order Points 10 and 11 of the Commission's July 2016 IRP Order, Minnesota Power issued an RFP on August 4, 2016, seeking power supply proposals for up to 300 MW of utility-scale solar generation that qualifies under Minnesota's SES. Minnesota Power sought proposals that maximized the benefits from the federal ITC for the benefit of customers. The RFP required offers be for capacity that is accreditable under current MISO resource adequacy rules in MISO Local Resource Zone 1, and have an initial term of at least 20 years. Proposals could have commercial operation dates between January 1, 2018 and December 31, 2022. Responses were due by September 14, 2016. This request was part of the Company's broader evaluation process that considered the costs and characteristics of different power supply types (e.g., wind, solar, natural gas, demand response, and distributed generation) to optimize the mix of resources to meet customer needs.

Sedway Consulting, as an independent evaluator, monitored the RFP process and evaluated the proposals received in response to the solar RFP. Like the Company's wind RFP, Sedway Consulting requested the Company provide as much information as possible prior to the receipt of proposals, allowing Sedway Consulting to lock down and archive the basic evaluation parameters for the process. Such information included forecasts of regional market energy prices, cost of capital components, discount rate, and historical locational marginal pricing information. These assumptions were incorporated into Sedway Consulting's own evaluation model and formed the basis for independently assessing the benefits and costs of resources that were bid into Minnesota Power's solicitation.

The evaluation process entailed a general review of all proposals and the calculation and ranking of levelized energy prices for all proposed options. In instances where proposals were found to be non-compliant or incomplete, bidders were notified and given an opportunity to supplement their proposal materials. More effort was focused on the higher-ranked proposals, performing a thorough qualitative assessment of those proposals that appeared to have the best quantitative value for Minnesota Power's customers. Concurrent with that qualitative analysis, Sedway Consulting undertook the modeling of all proposals to assess their energy benefits; specifically, Sedway Consulting performed detailed modeling to determine each proposal's net cost. Although the levelized price ranking provided a good approximation of how project economics might compare, an assessment of the offers' generation profiles and the energy benefits associated with those profiles provided a comprehensive comparison.

The detailed economic evaluation, which is provided in Appendix R: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation, entailed modeling the bids in Sedway Consulting's Renewable Bid Evaluation Model. The costs in the net cost calculation included contract payments for delivered energy and an imputed debt cost for PPAs. Energy benefits were the product of the expected hourly generation of a facility and a forecast of hourly $/MWh energy market prices over the term of the contract. Sedway Consulting's evaluation model normalized the net cost by dividing it by the present value of a project's expected energy deliveries, thereby yielding a $/MWh levelized net cost. As bid prices varied depending on the project size, projects were evaluated based on three size groups: 25 MW or less, 26 to 74 MW, and 75 MW or greater.

In its evaluation, Minnesota Power determined that pursing a 10 MW project would best serve customer needs and the top-ranked project counterparties were shortlisted and presented with the opportunity to resubmit bids for a 10 MW project. Shortlisted bidders submitted updated proposals on December 1, 2016. In January 2017, a key subset of the top-ranked projects from the updated bid pool were shortlisted for negotiations. Negotiations commenced with the counterparties that proposed these projects.

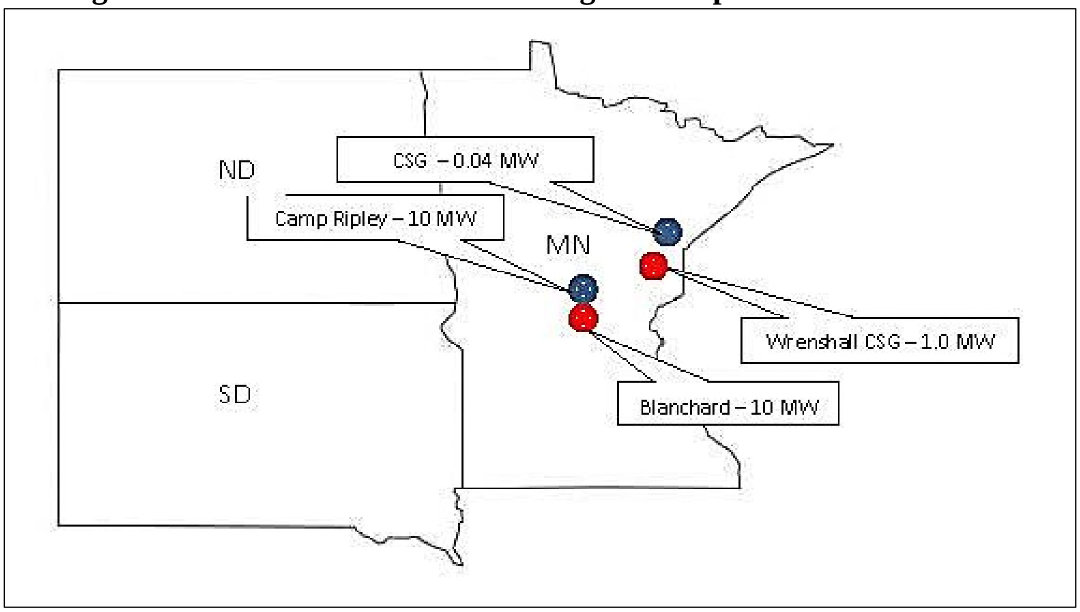
One of those shortlisted projects was the Blanchard Solar Project. Sedway Consulting concurred with Minnesota Power's decision to make a final selection of the Blanchard Solar Project and execute the Blanchard Solar Project PPA. The other shortlisted proposals had higher net costs and other attributes that made them less attractive for meeting Minnesota Power's SES obligations.[100] On June 7, 2017, the Company executed a PPA for the 10 MW Blanchard Solar Project.

5.4 THE BLANCHARD SOLAR PROJECT

5.4.1 Project Overview

The Blanchard Solar Project is a 10 MW capacity solar project located near Royalton in Morrison County, in central Minnesota. Figure 35 below provides a map showing the location of the Blanchard Solar Project, as well as Minnesota Power's other existing and planned solar projects.

Figure 35: Minnesota Power's Existing and Proposed Solar Resources



The anticipated commercial operation date for the Blanchard Solar Project is mid-2020. Cypress Creek Renewables has site control for the project and is planning to submit the required applications to the local governmental authorities in the third quarter of 2017. The Blanchard Solar Project will utilize Canadian Solar, Inc. solar panels.

[100] *See* Attachment R: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation for details on bid comparisons.

5.4.2 Interconnection and Distribution

The Blanchard Solar Project will be connected directly to Minnesota Power's distribution system. Because the project will be handled through Minnesota Power's interconnection procedures, there is a relatively low risk of delay. Minnesota Power's interconnection process is explained in Appendix S of this Petition. The PPA anticipates Cypress Creek Renewables will complete the interconnection process and execute necessary agreements by approximately July 2019. System upgrades and associated cost estimates, if any, will be identified when the interconnection studies are completed.

5.5 Overview of Blanchard Solar Power Purchase Agreement

Cypress Creek Renewables and Minnesota Power negotiated specific provisions into the PPA to protect the best interests of their respective companies and customers. These provisions are mainly standard terms that would be included in a PPA of this scale. Certain terms exist within the PPA solely to address potential scenarios and events and allocate risk between parties in the limited circumstances in which they could occur. In the following sections, the Company explains the PPA's significant terms. The full PPA is provided in Appendix E.[101]

5.5.1 Term of the Agreement

The Blanchard Solar Project PPA was executed between Minnesota Power and Cypress Creek Renewables on June 7, 2017. Subject to Commission approval, the term of the agreement begins once the project becomes commercially operational and expires at the end of twenty-five years. Construction of the project is expected to begin November 1, 2018, and be completed by June 30, 2020.

The PPA is subject to a limited number of contingencies (identified in Sections 1.2 and 1.3 of the PPA), which recognize that events beyond the parties' control could result in the need to delay or cancel the PPA. These contingencies include if the necessary permits and regulatory approvals

[101] The public version of the Blanchard Solar Project PPA has been redacted to remove commercially-sensitive trade secret information. This information is trade secret information under Minn. Stat. § 13.37, as it is subject to efforts to maintain its secrecy and which derive independent economic value from not being generally known or readily ascertainable by other persons, who could obtain economic value from their disclosure or use.

are not received, or if **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS].

5.5.2 Services Provided from the Agreement

Pursuant to Section 2.1.1. of the Blanchard Solar Project PPA, beginning with commercial operation, Cypress Creek Renewables is required to generate from the project, and sell contract energy and accreditable capacity to Minnesota Power at the prices set forth in the PPA. Additionally, Cypress Creek Renewables will construct, own or lease, operate, and maintain the project in material compliance with all permits and requirements of law, applicable warranty requirements, relevant equipment manufacturer's specifications, and in accordance with standard industry practice.

5.5.3 PPA Pricing

Under the PPA, Minnesota Power will be purchasing the energy and capacity from the Blanchard Solar Project. As set forth in Exhibit B to the PPA, energy from the facility is priced at a fixed price of **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS] for the entire 25-year term.

5.5.4 Energy Curtailments

As specified under Section 7.6 of the PPA, Minnesota Power is only responsible for payment for energy delivered and is not responsible for payment in the event of **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS].

5.5.5 Environmental Attributes

Under Section 2.3 of the PPA, Minnesota Power is entitled to all Green Tags, or Renewable Energy Credits, associated with the purchase of contract energy. The Solar Renewable Energy Credits will be used by the Company to demonstrate compliance with the SES.

5.5.6 Interconnection and Delivery

Cypress Creek Renewables is required to apply for and use commercially-reasonable efforts to obtain interconnection services necessary to interconnect the project to Minnesota Power's 34.5 kV distribution system.

Minnesota Power is responsible to design, install, own, and maintain all electric metering devices used to measure the energy and capacity made available to the Company by Cypress Creek Renewables under the PPA, and to monitor and coordinate operation of the Blanchard Solar Project. Cypress Creek Renewables and the Company have negotiated terms under Section 5.4 of the PPA in the event an electric metering device or back-up metering fails to register, or if the measurement by these devices is found to be inaccurate by more than one percent.

5.5.7 Other Provisions of the PPA

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

- Article 6 contains typical provisions regarding operation and maintenance of the Blanchard Solar Project.
- Article 7 contains standard billing terms.
- Article 8 addresses the establishment of an operating committee designed to address issues that arise pursuant to the PPA and also the solar data and capacity requirements.
- Article 9 addresses security provided by Cypress Creek Renewables to Minnesota Power for the Blanchard Solar Project.
- Article 11 defines events of default and the termination of the PPA.
- Article 12 addresses indemnification.
- Article 13 addresses limitations of liability.
- Article 14 contains the standard arbitration clause used to address disputes between the parties of a PPA.
- Article 15 contains general terms and conditions standard in a PPA related to representations, warranties, and covenants.

These provisions are generally standard provisions in purchased power contracts.

5.6 THE AGREEMENT IS IN THE PUBLIC INTEREST

5.6.1 The Agreement Meets SES Obligations

During the 2013 legislative session, Minn. Stat. § 216B.1691, the statute establishing Minnesota's RES, was amended to include an additional solar requirement — the SES. The SES requires 1.5 percent of a public utility's retail sales, net of customer exclusions, to be served by solar energy resources by 2020. Of the 1.5 percent SES, at least 10 percent must come from solar energy generated by or procured from solar photovoltaic ("PV") devices with a nameplate capacity of 40 kW or less.[102] As discussed above, Minnesota Power is seeking approval of the Blanchard Solar Project PPA to comply with Minnesota's SES. In total, Minnesota Power is estimating 33 MW of solar resource additions are necessary to meet the SES. Minnesota Power intends to meet its SES compliance requirements between 2020 and 2025 with banked solar renewable energy credits and approximately 21 MW of installed solar capacity. This 21 MW of installed capacity is expected to come from about 20 MW of utility-scale solar and 1 MW of community and customer-sited solar projects. Approximately 11 MW of qualifying solar installations are in service to date. The Blanchard Solar Project PPA fulfills the 10 MW of planned utility-scale resource additions. The remainder of the solar capacity needed to comply with the SES will be added by 2025. Minnesota Power is committed to working with communities and customers to explore opportunities for solar projects that benefit both the local communities it serves and its rate payers.

5.6.2 The Agreement Offers Favorable Terms

The PPA with Cypress Creek Renewables provides a new resource that meets Minnesota Power customer needs and the Company's compliance obligations, while at the same time providing protections on behalf of customers prior to the start of the PPA and through the contract term. Under the PPA, customers will receive the energy, capacity, and renewable energy attributes from the Blanchard Solar Project at a defined price over the term of the agreement.

[102] Chapter 95, Article 10, Section 9 (2017) (amending Minn. Stat. § 216B.1691, subd. 2f).

5.7 BLANCHARD SOLAR POWER PURCHASE AGREEMENT RISK FACTORS

Minnesota Power recognizes that since new facilities must be constructed in order to implement the Blanchard Solar Project PPA and related approvals must occur as set forth in the PPA, potential risks exist with this transaction. The Company believes these risks are manageable and that they do not overshadow the benefits for customers.

5.7.1 Project Permitting and Regulatory Approval

The Blanchard Solar Project requires construction-related permitting approvals and a separate interconnection agreement to connect to the Minnesota Power distribution system.

Certain milestones have been established to ensure timely completion of the project. A significant delay in review and approval from the Commission of Minnesota Power's larger Energy*Forward* Resource Package request could delay construction of the project and potentially result in termination of the PPA.

5.8 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 Blanchard Solar Project PPA. Minnesota Power has identified three primary milestones where it would be important to communicate project updates to the Commission, Department, and other stakeholders. The first milestone is when Cypress Creek Renewables receives the required site permit from local governmental authority. The second milestone is when the generation interconnection agreement for the project is executed. The third milestone will occur when the project is operational. Minnesota Power commits to informing the Commission, the Department, and other stakeholders in a timely manner about the achievement of these milestones. The Company will also inform the Commission of any significant project schedule changes that arise during implementation of the Blanchard Solar Project.

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 the Blanchard Solar Project.

5.9 CONCLUSION REGARDING BLANCHARD SOLAR PROJECT

The Blanchard Solar Project was selected through a robust RFP process as the least-cost bid to meet Minnesota Power's SES requirements. As discussed above, Minnesota Power has negotiated commercially-reasonable contract terms with Cypress Creek Renewables to mitigate potential risks related to the Blanchard Solar Project to ensure customers are fully protected. Minnesota Power respectfully requests that the Commission approve the 10 MW Blanchard Solar Project PPA as part of the overall Energy*Forward* Resource Package. As a solar energy resource that can be used to meet the SES, the Company also requests approval to recover the PPA costs through the Company's FPE Rider pursuant to Minn. Stat. § 216B.1645.

SECTION 6 GAS

The third component of the Company's Energy*Forward* Resource Package is a 48 percent share in the 1x1 combined-cycle natural gas NTEC power plant to be located in Superior, Wisconsin and placed in service by the end of 2024. This approximately 250 MW increment[103] of reliable and dispatchable natural gas capacity and economical combined-cycle energy was selected as part of the proposed Energy*Forward* Resource Package, first and foremost because it was the least-cost resource presented through the RFP process to meet the Company's identified need for dispatchable capacity and economical energy. Second and importantly, this resource provides additional benefits for customers in the form of (1) supporting Minnesota Power's expanding portfolio of variable renewable energy production, and (2) facilitating the Company's ongoing effort to transform its fleet by retiring older coal generation and generally reducing greenhouse gas and other power plant emissions.

Consistent with the Commission's July 2016 IRP Order, the Company undertook a full analysis of options to meet its energy and capacity needs with the retirement of BEC1&2 and THEC1&2[104] 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. As discussed in Section 3 of this Petition, Minnesota Power determined that adding approximately 250 MW of dispatchable capacity in 2024 is a prudent system addition supported by the Company's forecasted need and resource planning analysis across the vast majority of future scenarios.

[103] 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 assumes 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 NTEC could range from approximately 250-264 MW. Minnesota Power acknowledges that the soft cost cap will apply regardless of the final size of NTEC. In other words, customers may be able to obtain the benefit of the additional MW of a slightly larger unit without incurring incremental cost risk.

[104] 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 by the end of 2020. Additionally, the July 2016 IRP Order required the Company retire BEC1&2 when sufficient energy and capacity are available, but no later than 2022. July 2016 IRP Order at 14-15.

The Company sought proposals and fully investigated options available to fill this need, including additional renewables, energy efficiency, distributed generation, 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 that can serve customers' requirements 24-hours per day. When coupled with the significant reduction in coal generation (nearly 700 MW) and the overall projected wind portfolio of 850 MW, adding dispatchable capacity helps balance the overall system.

Without question, additional renewable generation will continue to be a significant part of Minnesota Power's ongoing fleet transition from a predominantly coal-based energy mix toward more diversity and flexibility and with fewer emissions and less carbon intensity. In light of that plan, 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 energy-efficient combined-cycle unit, rather than proceeding with a smaller and solely-owned combustion turbine plant. Minnesota Power recognized that partnering with Dairyland allows the Company 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.[105]

The Company therefore concluded that an approximately 250 MW share in NTEC would provide significant customer benefits including:

[105] 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.

- 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;
- 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; and
- taking advantage of projected low natural gas prices.

Overall, adding this increment of dispatchable capacity will facilitate the wind and solar additions proposed in this filing 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 purchase of 48 percent of NTEC will meet 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 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.

6.1 THE NEED FOR DISPATCHABLE CAPACITY

Minnesota Power's 2012 Baseload Diversification Study,[106] 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

[106] *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).

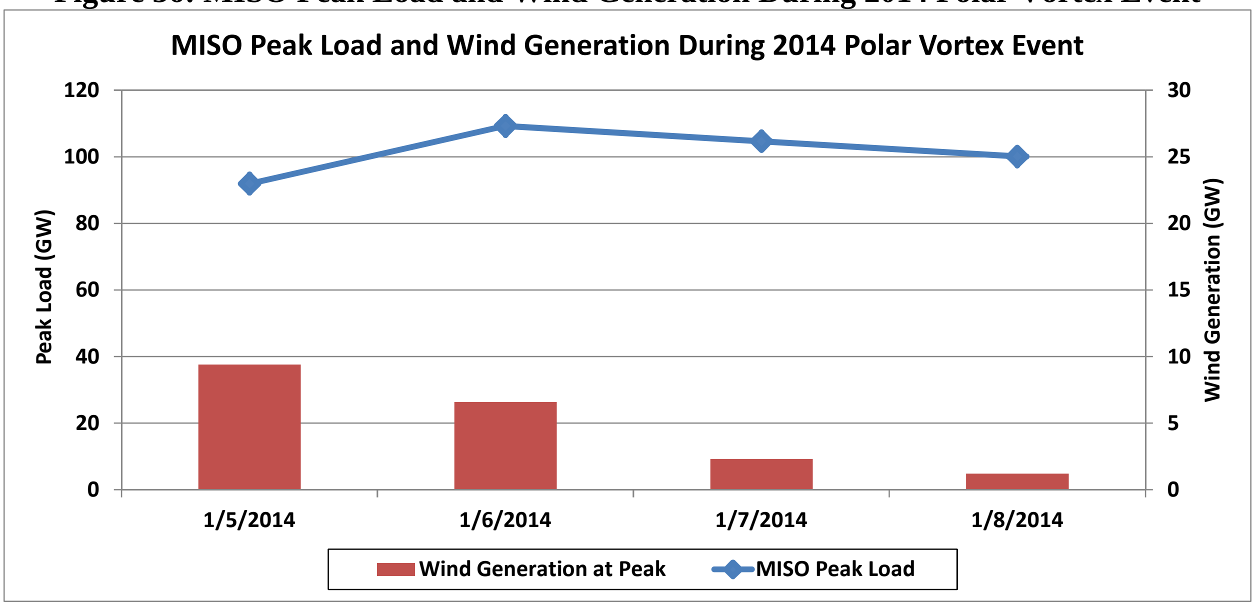
power supply with a combined-cycle natural gas unit include the ability to replace some of the capacity lost by retiring coal units and decrease the variability of renewable generation with increased flexibility and power supply diversity; the low cost of natural gas; the natural synergies between combined-cycle 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.

As previously discussed, over the past decade Minnesota Power has constructed or contracted to purchase more than 600 MW of wind generation (increasing to 850 MW through this proceeding), has signed long-term agreements with MHEB to purchase 250 MW of hydroelectric generation beginning in 2020, and has begun adding solar power to its generation fleet with the 10 MW Camp Ripley Solar Project, 1 MW Community Solar Garden Pilot Program, and 10 MW of solar in this Energy*Forward* Resource Package. At the same time, Minnesota Power ceased coal-fired operations at THEC3 in 2015, refueled LEC with natural gas in 2015, idled THEC1&2 in 2016, and has announced plans to close the coal-fired BEC1&2 in 2018 — an aggregate removal of nearly 700 MW of coal-fired generation. The 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 overly rely on intermittent technologies. The addition of a combined-cycle generation resource increases Minnesota Power's capability to bring generation on and offline 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.

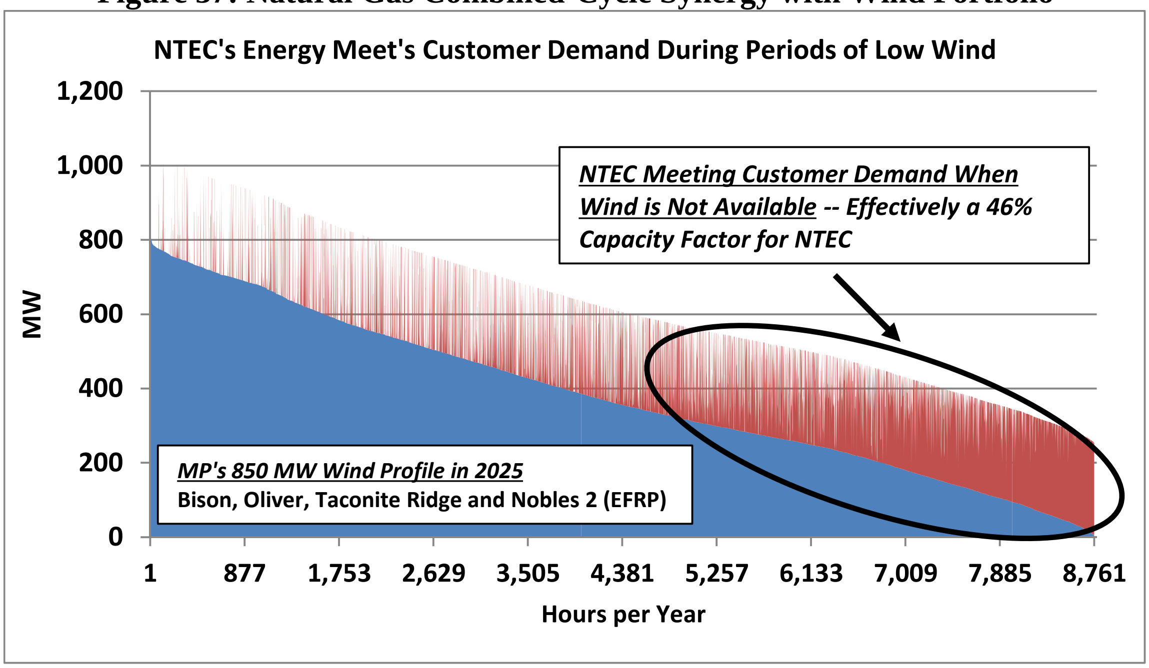
Currently, as noted in Section 2 of this Petition, Minnesota Power's energy position can vary from 600 MW in an hour — a variability often caused by the intermittency of the Company's renewable generation. That variability will grow to over 850 MW per hour with the addition of 250 MW of wind and 10 MW of solar that are 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 36 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 36: MISO Peak Load and Wind Generation During 2014 Polar Vortex Event



Currently missing from Minnesota Power's portfolio is dispatchable capacity that can 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 37, 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 37 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 37: Natural Gas Combined-Cycle Synergy with Wind Portfolio



Without an additional dispatchable resource, Minnesota Power's energy mix is made up 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.

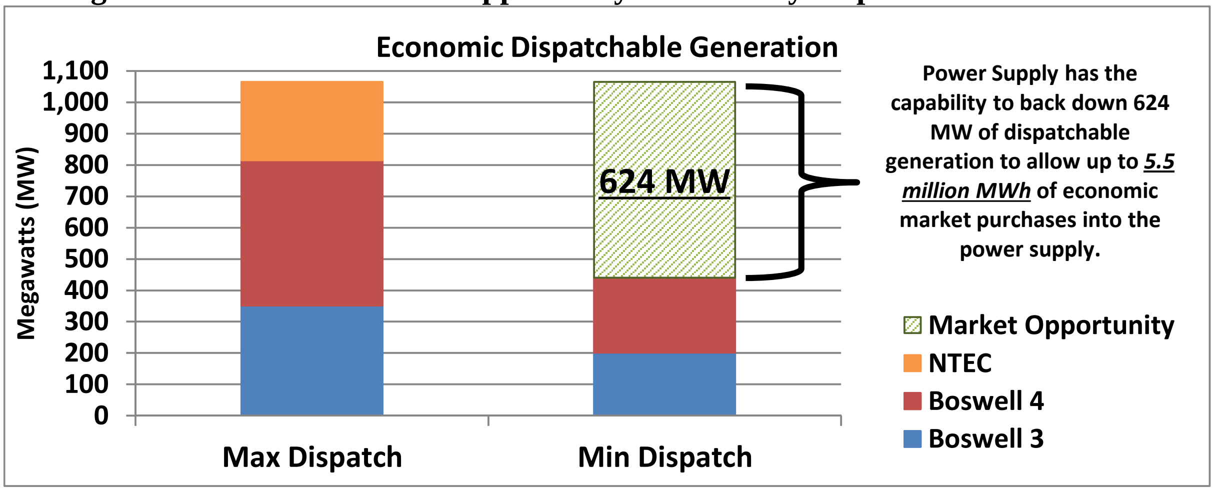
Not only does a combined-cycle natural gas resource offer dispatchable energy, flexibility, diversity, and capacity to balance variable generation, it does so at a lower cost than potential alternatives, including a combustion turbine natural gas generation facility. Natural gas prices are currently ranging between $2.50/MMBtu and $3.00/MMBtu and likely to remain lower than historical values for the foreseeable future.[107] 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.[108]

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 38 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.

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

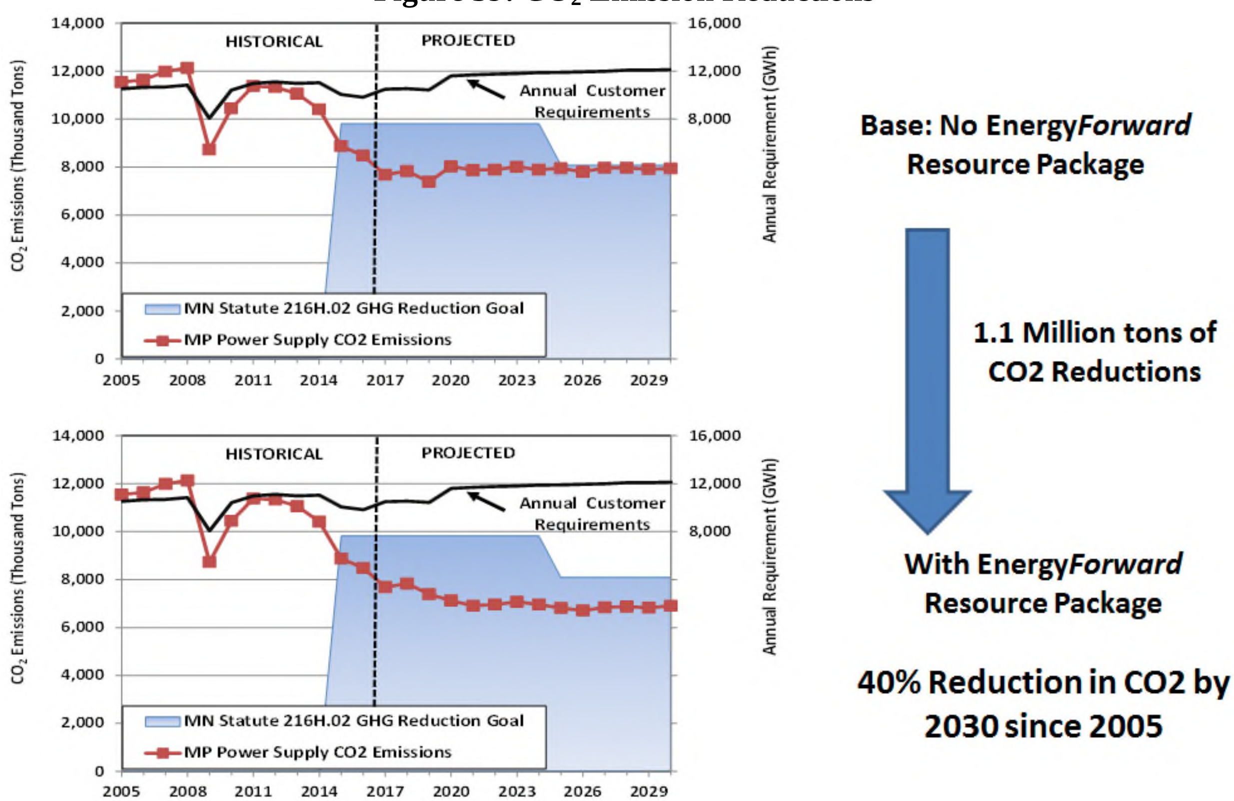
[108] As discussed in Section 3.4.3, above, a combustion turbine generation facility consumes approximately 55 percent more fuel than a combined-cycle generation facility.

Figure 38: Market Purchase Opportunity Provided by Dispatchable Generation



As a further benefit, the Energy*Forward* Resource Package results in 1.2 million tons of CO_2 reductions, as shown in Figure 39, below.

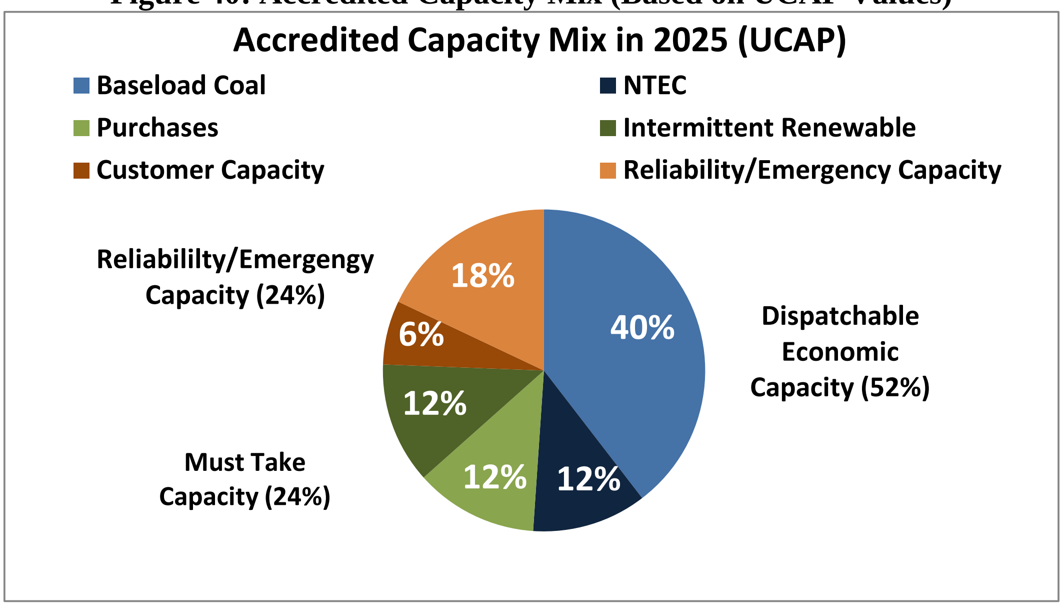
Figure 39: CO_2 Emission Reductions



Moreover, NTEC's 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 generation on a per MWh basis. NTEC allows Minnesota Power to successfully integrate the additional wind and solar from the Energy*Forward* Resource Package into its power supply with no impact to overall CO_2 emissions.

Finally, Figure 40, 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 40: Accredited Capacity Mix (Based on UCAP Values)



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 approximately 250 MW of dispatchable capacity 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 discussed in this Petition, Minnesota Power concludes that now is the right time to pursue a specific natural gas combined-cycle facility for its customers as part of the Energy*Forward* Resource Package, and that NTEC 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.

The detailed resource analysis selected approximately 250 MW of NTEC 98 percent of the time across 296 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 is needed in the mid-2020 timeframe.

6.2 SELECTION OF NTEC

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."[109] Earlier in this Petition, the Company presented its analysis indicating a combined-cycle addition of approximately 250 MW will best serve customer needs in the mid-2020s. In this section of the Petition, the Company discusses the process by which it has complied with the Commission's direction regarding a potential combined-cycle natural gas RFP and the basis for selection of NTEC in particular.

6.2.1 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").[110] 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 6.2.3 and 6.2.4 for additional detail on the RFP evaluation process and Appendix V for Sedway Consulting's Independent Evaluation Report for Minnesota Power's 2015 Gas-Fired Resource Solicitation.

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

[110] The Gas RFP is provided as Appendix U to the Petition.

6.2.2 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.[111] 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 ("NAEMA"). An updated version of the RFP was posted on December 15, 2015.

- *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.[112] 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. 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.

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

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

- *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.[113]

6.2.3 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 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 V.

- *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 considered by Minnesota

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

Power 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 proposal for 300 MW of capacity and energy from a new facility in Superior, Wisconsin was ultimately 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.[114] Minnesota Power therefore selected the approximately 250 MW capacity proposal with an in-service date of December 1, 2024, ultimately, NTEC.

6.2.4 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 V. 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;

[114] 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 250 MW share of NTEC was the best and least-cost alternative to meet Minnesota Power's needs.

- 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;
- 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 V: 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 V, Sedway Consulting concluded that South Shore's proposal was more cost-effective than any of the other PPA 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.

6.3 NTEC PROJECT

6.3.1 Overview of Proposed Project

After further development and negotiations, the final proposal calls for South Shore to dedicate 48 percent of the capacity of NTEC (approximately 250 MW) to Minnesota Power. NTEC is a 1x1 combined-cycle generating facility to be located in Superior, Wisconsin, at the 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.[115] 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).

More specifically, NTEC will consist of one H-class (290–330 MW nominal) 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 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 east of the NTEC site. Existing transmission lines that traverse the site will also be relocated elsewhere on the site.

[115] *See* Appendix W: Combined-Cycle Site Selection Study.

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.

6.3.2 Viable Location

The NTEC site is located near Superior, Wisconsin. This location was first assessed as part of a 2014 broad-range site selection study performed by Burns & McDonnell, on behalf of Minnesota Power to evaluate potential joint development of a combined-cycle power plant (the "Combined-Cycle Site Selection Study").[116] 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.[117]

[116] *See* Appendix W: Combined-Cycle Site Selection Study.

[117] 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

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.

6.3.3 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"). 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.

6.3.3.1 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")

Minnesota Power decide to proceed with the project. Appendix W: Combined-Cycle Site Selection Study (Executive Summary).

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.

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.[118] 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]. 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 Great Lakes options.

[118] The Transport RFP is provided as Appendix X of this Petition.

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

…TRADE SECRET DATA ENDS].

Ongoing negotiations with **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** were initiated **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS].** During the selection **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** had disclosed that it **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS].** This factor was considered as part of the RFP selection process. In addition, the NTEC team is negotiating **[TRADE SECRET DATA BEGINS…**

TRADE SECRET DATA ENDS]. Minnesota Power will update the Commission regarding the fuel transportation contracting process as the process moves forward.

6.3.3.2 Lateral Connection to Interstate Pipeline

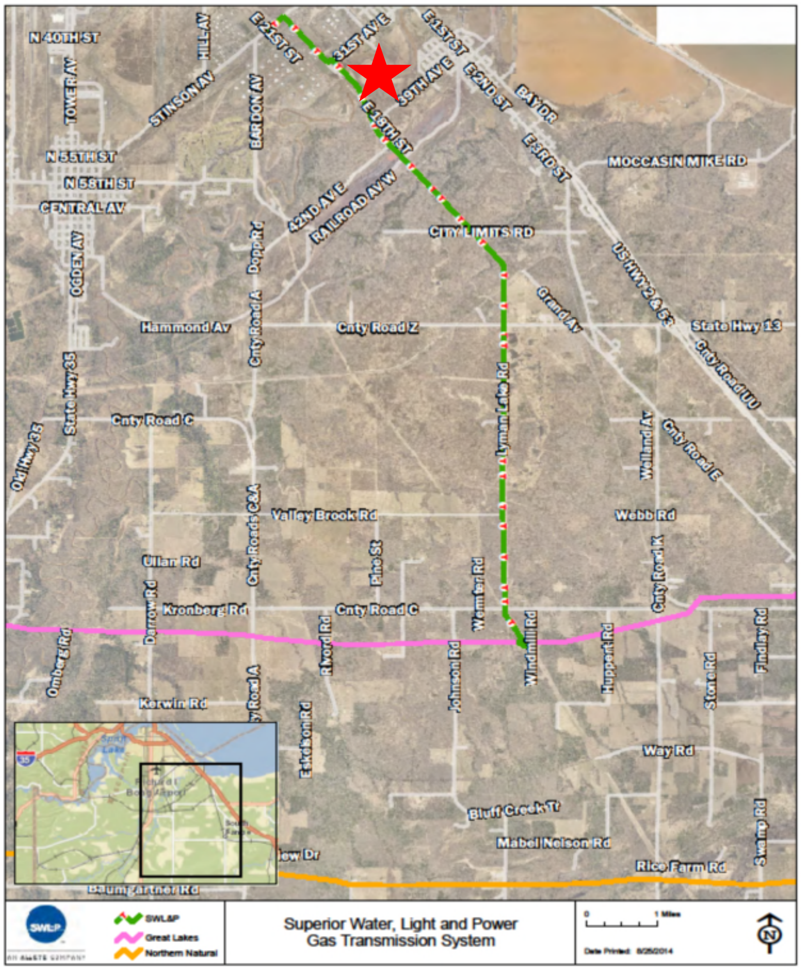
Apart from the negotiations for fuel transportation, it was necessary to assess the options for lateral connection to the available interstate pipelines. The NTEC site is located approximately seven miles from the Great Lakes interstate pipeline from which the natural gas for the project will be transported. 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
- Great Lakes Pipeline owned and operated.

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

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 the Great Lakes pipeline 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 Great Lakes transmission pipeline is depicted in Figure 41 below.

Figure 41: NTEC Project Natural Gas Connection



Comparing the Great Lakes and SWL&P options, **[TRADE SECRET DATA BEGINS…**

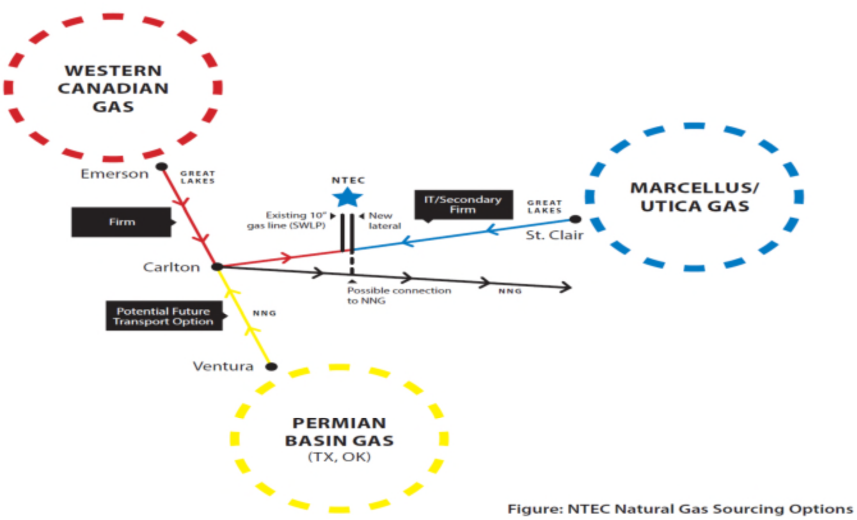
…TRADE SECRET DATA ENDS]. Further, selecting the **[TRADE SECRET DATA BEGINS…**

…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.[120] 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.

Ultimately, utilizing the SWL&P lateral connection to the Great Lakes pipeline provides access to multiple fuel transportation and sourcing options, as indicated in Figure 42, below.

Figure 42: NTEC Project Natural Gas Sourcing Options



As Figure 42 illustrates, the anticipated configuration and sourcing optionalities offered by the NTEC site provides flexibility and cost management opportunities for customers.

[120] 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.

6.4 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 corporate 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 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.[121] 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)….[122]

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.

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

[122] 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).

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 or 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,"[123] 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.[124] 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" 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*,[125] 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.

[123] Wis. Stat. § 196.485(1)(d).

[124] Wis. Stat. § 196.485(1)(dm).

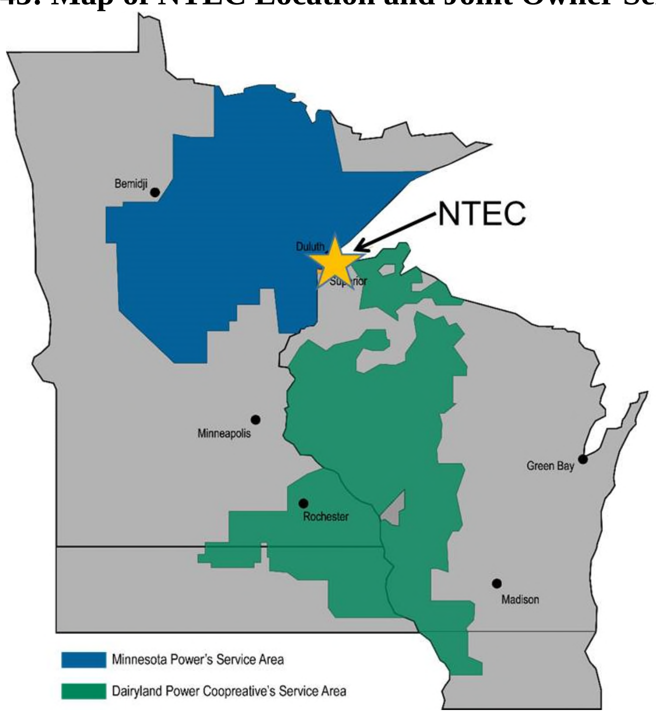
[125] 330 F.3d 904 (7th Cir. 2003).

6.4.1 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 43 below is a map showing Minnesota Power and Dairyland's respective service territories and the location of NTEC.

Figure 43: Map of NTEC Location and Joint Owner Service Areas



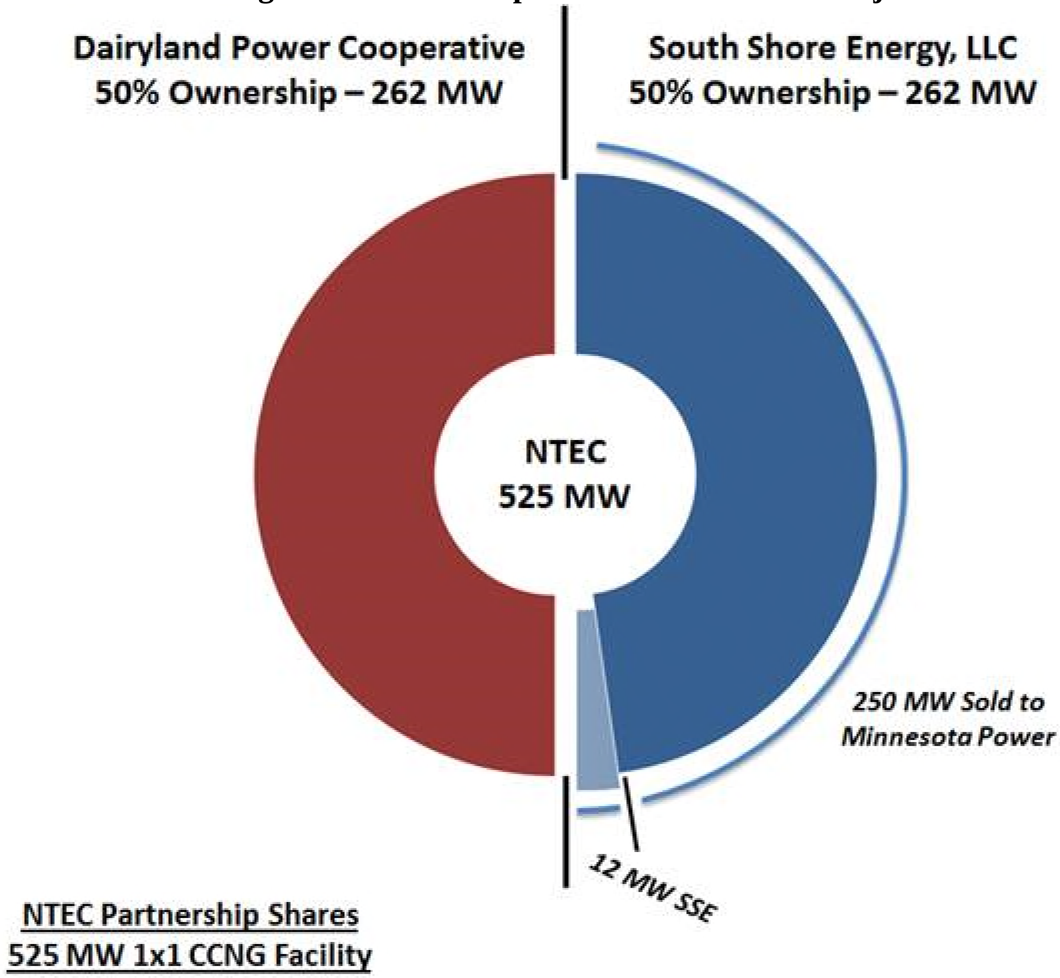
On June 30, 2017, Dairyland filed an Optional Resource Plan Compliance Report with the Commission in Docket No. ET6125/RP-17-525 ("Dairyland's O-IRP"). In Dairyland's O-IRP, Dairyland outlined its plan to add natural gas generation, in the form of a new combined-cycle natural gas plant.[126] Joint ownership 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 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 44 below, Dairyland and South Shore will each own an equal share of the 525 MW NTEC facility. The NTEC Owner rights and responsibilities, as governed by the NTEC Agreements, are discussed in detail in Section 6.5 of this filing.

[126] *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).

Figure 44: Ownership Structure for NTEC Project



6.4.2 Interconnection and Delivery

6.4.2.1 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 DPP process that is largely subdivided into four segments, DPP Studies 1 through 3 and the 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 T.

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, with preliminary cost estimates currently scheduled to become available in late-2018 and final cost estimates currently scheduled to become available in May 2019.[127]

6.4.3 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.

6.4.3.1 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 the 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. As the Construction Agent, Minnesota Power intends to select the gas turbine vendor by the third quarter of 2017.

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

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 an additional milestone payment in the fourth quarter of 2018. Another milestone payment will follow approximately 2 months later, likely in the first quarter of 2019.

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.

6.4.3.2 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. 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.

6.4.3.3 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.

6.4.3.4 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.

6.5 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 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 forty-eight percent of the total NTEC capacity (approximately 250 MW) to Minnesota Power and its customers;

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 Y).

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 Z).

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 Y and Z, respectively. Each of the NTEC Project Agreements, the CDA, and the Assignment Agreements are summarized below.

6.5.1 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.

6.5.1.1 Term of the Agreement

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

6.5.1.2 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.

6.5.1.3 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 shall 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.

6.5.1.4 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.

6.5.1.5 Other Provisions of the D&C Agreement

The following is a listing 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 generally standard in development and construction contracts.

6.5.2 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.

6.5.2.1 Term of the Agreement

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

6.5.2.2 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 parties' O&M responsibilities for NTEC 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.

6.5.2.3 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 shall 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 project costs is covered under Article V of the O&O Agreement.

6.5.2.4 Other Provisions of the O&O Agreement

The following is a listing 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.

6.5.3 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.

6.5.4 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 rights to 48 percent of NTEC (approximately 250 MW) 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 any issues about NTEC on the same basis as if Minnesota Power owned the asset in its own name and the asset was held in rate base.

As a result, 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.

6.5.4.1 Term of the Agreement

The CDA has a 40-year term and dedicates 48 percent of the NTEC baseline capacity (approximately 250 MW) 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 BB.

6.5.4.2 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.

6.5.4.3 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 (de-escalates) 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 ratepayers 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 and the associated network upgrade payment are calculated as set forth in Exhibits C and D to the CDA and is based on the estimated total investment in NTEC (including capitalized interest) in 2025 of about $700 million. The Dedicated Capacity represents 48 percent of this amount based on the amount of capacity being dedicated to Minnesota Power through the CDA. For the first Contract Year, 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[128] of **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA 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 ratepayers are responsible only for their 48 percent share of NTEC.

The fixed-price design is advantageous to customers particularly because the revenue requirement design means that ratepayer costs decrease over time.

[128] 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.

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 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 and transportation costs and other 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.

6.5.4.4 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.

6.5.4.5 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 reap the benefits of the innovative energy pricing and ultimately, the production profile of this combined cycle plant will provide cost effective energy that will be a net benefit to customers.

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

Pursuant to the NTEC Project Agreements and affiliated interest agreements, Minnesota Power and its customers will receive the benefit of 48 percent (approximately 250 MW) of 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 market 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 site is located on the outskirts of the city of Superior — 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.

6.6.1 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.

6.6.1.1 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 6.5.3.3 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 an 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.

6.6.1.2 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 6.4.3 of this filing, includes some schedule allowance so that delays are less likely to impact the in-service date.

6.6.1.3 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 take over a year or more to obtain agency approval: (1) CPCN approval from the PSCW for construction of a large electric generating facility;[129] (2) certificate of authority from the PSCW for construction of the SWL&P lateral pipeline;[130] and the WDNR permit for construction and operation of new source of air emissions.[131] 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 the Project. 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.

[129] Wis. Stat. § 196.491(3).

[130] Wis. Stat. § 196.49.

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

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

6.6.1.5 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 NTEC Project Agreements.

6.6.1.5.1 Transmission Cost Risk and Cost 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 Project Agreements include provisions to reevaluate the viability of NTEC if network upgrades costs are projected to exceed the agreed-upon level.

Appendix T: 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 T 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 in fourth quarter 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 first quarter 2019. 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 the next required milestone payment, Minnesota Power has sought to mitigate the risk of having to forfeit milestone payments.

6.6.1.5.2 Transmission Timeline Risk and Timeline 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 T. 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.

6.7 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[132] 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

[132] 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 AA 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.

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 Dedicated Capacity 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 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.

6.7.1 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.

6.7.2 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.

6.7.3 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.

6.7.4 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.

6.8 COMMUNICATION AND FILING

As with the other projects proposed as part of this Energy*Forward* Resource Package, 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. For NTEC, Minnesota Power has identified three primary milestones where it would be important to communicate project updates to the Commission, Department, and other stakeholders. The first milestone is when Minnesota Power, on behalf of the NTEC Owners, MISO, and ATC sign the GIA. The second milestone is when Minnesota Power, on behalf of the NTEC Owners, receives the required CPCN authorization from the PSCW. The third milestone will occur 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.

6.9 CONCLUSION REGARDING NTEC PROJECT

NTEC was selected through 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. Minnesota Power respectfully requests that the Commission approve this portion of NTEC and related affiliated interest agreements as part of the overall Energy*Forward* Resource Package and approve the requested modifications to Minnesota Power's FPE Rider to allow the Company to structure the flow of costs, charges, and revenues related to NTEC in a manner that replicates utility generation ownership for the benefit of Minnesota Power customers.

SECTION 7 PROCESS AND PROPOSED TIMELINE FOR REVIEW

Minnesota Power is filing this Petition for approval of the Energy*Forward* Resource Package in compliance with the Commission's July 2016 IRP Order.

With this Petition, the Company presents proposals for the acquisition of additional wind, solar, and natural gas resource additions in a manner that is consistent with and follows from the Commission's July 2016 IRP Order. This Petition reflects a full analysis of not only the proposed projects but also all alternatives, including renewables, energy efficiency, distributed generation, and demand response, for providing energy and capacity sufficient to meet Minnesota Power's needs.

The Commission's July 2016 IRP Order also required Minnesota Power to file its next IRP on February 1, 2018. Subsequently, on June 8, 2017, the Company submitted a request for approval of a delay of at least one year to approximately February 2019, or longer, as determined by the Commission's overall schedule and workload, to allow adequate time for the Commission and interested parties to review and act on the Company's Energy*Forward* Resource Package by October 2018. As reflected in the Company's June 8, 2017, extension request letter, because of the importance of the requested approvals as well as the important issues raised, Minnesota Power is proposing referral of the Energy*Forward* Resource Package filing to the Office of Administrative Hearings for a contested case to allow for full consideration of the important resource planning and generation need considerations that will be fundamental to evaluating the Company's Petition. Additionally, Minnesota Power requested that the Commission issue a notice seeking comments on its request to delay the next IRP and Minnesota Power's proposed procedural process for the Energy*Forward* Resource Package.

On June 13, 2017, the Commission issued a Notice Seeking Comment on Procedure and Schedule, requesting interested parties to provide comments by June 30, 2017, regarding whether the Commission should grant the requested extension on Minnesota Power's next IRP filing and whether Minnesota Power's proposed process for evaluation of the Energy*Forward* Resource Package is reasonable.

The Department, the CEO, and the Large Power Intervenors ("LPI")[133] submitted comments on June 30, 2017. The Department recommended that the Commission approve the Company's request for an extension to file its next Plan to October 1, 2019. The Department also recommended that the Commission evaluate each element of Minnesota Power's proposed Energy*Forward* Resource Package separately and questioned whether a need existed to refer any of the components of the proposed Energy*Forward* Resource Package to a contested case. CEO recommended that the Commission deny the Company's request for an extension on filing its next IRP and concluded that a contested case would not be reasonable or necessary. CEO also recommended that each of the components of the proposed Energy*Forward* Resource Package be evaluated separately. LPI similarly recommended that the Commission deny the Company's request for extension to file its next IRP, concluding that the appropriate process for evaluation of specific wind, solar, and natural gas resources should be in the context of an IRP proceeding.

Minnesota Power submitted Reply Comments on July 12, 2017, continuing to recommend review of the Energy*Forward* Resource Package together in a single contested case proceeding to allow for full development of a record. This combined record development process for all the resources that are being proposed enables consideration of the important and interrelated resource acquisition issues that will be fundamental to evaluating the Company's Petition.

Minnesota Power recognizes that its requests in this proceeding raise issues and considerations beyond a typical affiliated interest agreement filing or IRP compliance filing. The underlying transactions are complex and raise important factual and policy considerations relating both to resource planning and the need for additional generation on the Company's system. While no certificate of need is required for the proposed Energy*Forward* Resource Package, Minnesota Power views this Petition to be an appropriate opportunity for the Commission and interested stakeholders to fully evaluate the proposed resource package and all alternatives considered. As a result, Minnesota Power has structured this Petition to provide the type of information that would be considered by the Commission in a certificate of need proceeding, as well as information and

[133] LPI includes ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy, Limited Partnership; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and Verso Corporation.

analysis responsive to and in compliance with the Commission's July 2016 IRP Order and information necessary to fully evaluate the agreements that effectuate Minnesota Power's acquisition of the wind, solar, and natural gas components of the Energy*Forward* Resource Package. Minnesota Power respectfully requests that the Commission review this filing to determine whether it is sufficient to assess the alternatives and allow for a robust review, similar to the Commission's initial filing "completeness" requirement under the Minnesota certificate of need rules.

As reflected in the Company's June 8, 2017, letter and subsequent July 12 Reply Comments, Minnesota Power respectfully supports referral of this matter to the Office of Administrative Hearings for a contested case. This will allow for full consideration of the important resource planning and generation need considerations that are fundamental to evaluating the Company's Petition. A contested case will also allow for full development of the factual record, consistent with the certificate of need rules.

A contested case will serve multiple purposes. First, it will ensure that a full and complete record is developed on all aspects of the Petition, and that the Commission has the benefit of an ALJ recommendation. Second, it will allow the Commission to consider important issues of need for the package in light of Minnesota Power's overall system requirements. This Petition provides an important opportunity for the Commission to review the need and the alternatives available for the resource package.[134] Third, and importantly, a contested case proceeding will help manage the timing of this proceeding.

Minnesota Power respectfully requests that the Commission make a determination on the proposed Energy*Forward* Resource Package by the end of September 2018 in order to (1) accommodate conditions precedent in the wind, solar, and natural gas agreements that allow the competitive resource package to be available and in service for customers, (2) ensure adequate time to complete all required regulatory reviews and approvals, and (3) accommodate the long lead times required for completion of the NTEC facility. Additionally, as discussed previously, in order to achieve commercial operation in 2024, MISO's

[134] Notably, in its IRP Order, the Commission stated that in order for Minnesota Power to proceed with new natural gas generation, the Company's plan must "include a full analysis of all alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response, for providing the energy and capacity sufficient to meet the Company's needs." July 2016 IRP Order at 9.

schedule for the interconnection queue of which NTEC is a part has a major payment due for study work in the fourth quarter of 2018, further supporting the need to obtain regulatory certainty by the end of September 2018. The Company has proposed the following schedule to provide adequate time for robust analysis and thoughtful decision making, with a proposed Commission decision in autumn of 2018 to accommodate contractual deadlines, federal tax credit utilization for the wind and solar projects, and to provide enough time to conduct thorough review.

Milestone/Event	Proposed Target Date
Request for Extension to File Next IRP and to Establish Procedures for Review of Energy*Forward* Resource Package	June 8, 2017 (filed in Docket No. E015/RP-15-690).
Commission Notice Seeking Comment on Procedure and Schedule	June 13, 2017
Initial Comments on Procedure and Schedule	June 30, 2017
Reply Comments on Procedure and Schedule	July 12, 2017
Energy*Forward* Resource Package Petition	July 28, 2017
Commission Hearing on Procedures and Schedule (Requested)	August 2017
Commission Referral to Contested Case Proceedings (Requested)	August 2017
Initial ALJ Prehearing Conference (Requested)	September 2017
Minnesota Power Direct Testimony	October 6, 2017
Deadline for Intervention	November 17, 2017
Intervenor Direct Testimony	December 22, 2017
All Parties' Rebuttal Testimony	February 9, 2018
All Parties' Surrebuttal Testimony	March 2, 2018
Prehearing Conference	March 16, 2018
Evidentiary Hearings	March 19-23, 2018
Initial Briefs	April 27, 2018

Milestone/Event	Proposed Target Date
Reply Briefs/Proposed Findings of Fact	May 18, 2018
ALJ Report	June 22, 2018
Exceptions to ALJ Report	July 12, 2018
Replies to Exceptions	July 19, 2018
Commission Agenda Meeting	August 30, 2018
Commission Order	September 28, 2018

SECTION 8 CONCLUSION

Based on the foregoing, Minnesota Power respectfully requests that the Commission approve the proposed Energy*Forward* Resource Package as proposed in this filing. Specifically, Minnesota Power respectfully requests that the Commission grant the following requests:

- Approval of the 250 MW Nobles 2 Wind Project PPA and authorization of cost recovery;
- Approval of the 10 MW Blanchard Solar Project PPA and authorization of cost recovery;
- 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.

As described in this Petition, the best way to proceed to make decisions on the requested approvals is to build a record through a contested case proceeding. Timing is an important consideration as the Company has important deadlines in the third and fourth quarters of 2018. Minnesota Power respectfully requests that the Commission process support final decisions on this Petition by the end of September 2018. This will ensure a robust discussion of all of the relevant issues and will allow the proceeding to progress on regular and predictable timelines.

This next step in Minnesota Power's Energy*Forward* plan to diversify its resource mix will result in renewable resources providing 44 percent of the Company's energy supply by 2025 at the same time reducing carbon emissions by 40 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 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: July 28, 2017

Respectfully submitted,

David R. Moeller
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
218-723-3963

APPENDIX A: MISCELLANEOUS FILING INFORMATION, MINN. R. 7829.1300

1. GENERAL FILING INFORMATION (MINN. R. 7829.1300)

Pursuant to Minn. R. 7829.1300, Minnesota Power provides the following required general filing information.

i. Summary of Filing (Minn. R. 7829.1300, subp. 1)

A one-paragraph summary accompanies this Petition.

ii. Service on other Parties (Minn. R. 7829.1300, subp. 2)

Pursuant to Minn. Stat. § 216B.17, subd. 3 and Minn. R. 7829.1300, subp. 2, Minnesota Power has served a copy of this Petition on the Minnesota Department of Commerce – Division of Energy Resources and the Residential Utilities and Antitrust Division of the Office of the Attorney General. A summary of the filing prepared in accordance with Minn. R. 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

iii. Name, Address, and Telephone Number of Filing Party (Minn. R. 7829.1300, subp. 3(A))

Minnesota Power
30 West Superior Street
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(218)722-2641

iv. Name, Address, Electronic Address, and Telephone Number of Attorney Representing the Filing Party (Minn. Rules 7829.1300, subp. 3(B))

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v. Date of Filing and Date Proposed Effective Date (Minn. R. 7829.1300, subp. 3(C))

Minnesota Power makes this filing on July 28, 2017. The Company requests that the Commission approve the proposed Energy*Forward* Resource Package as proposed in this filing by September 28, 2018.

vi. Statute Controlling Schedule for Processing the Filing (Minn. R. 7829.1300, subp. 3(D))

There is no statute controlling the schedule for processing this Petition. This Petition falls within the definition of a "Miscellaneous Filing" under Minn. R. 7829.0100, subp. 11. Under Minn. R. 7829.1400, initial comments are due within 30 days of filing, with reply comments due 10 days thereafter. As described in Section 7 of this filing, aspects of the Petition implicate important factual and policy questions concerning the need for and the implementation of power supply choices and the consideration of alternative sources of supply. As a result, this Petition includes elements that are analogous to a request for a certificate of need and resource choices arising out of a resource plan. Minnesota Power respectfully requests that the Commission order that this Petition be processed using formal contested case procedures, as discussed in Section 7 of the Petition, to ensure the development of a full and complete record for the Commission's consideration.

vii. Signature, Electronic Address, and Title of Utility Employee Responsible for Filing (Minn. R. 7829.1300, subp. 3(E))

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viii. Impact on Rates and Services (Minn. R. 7829.1300, subp. 3(F))

Through this Petition, Minnesota Power is requesting Commission approval of the following:

- Approval of the 250 MW Nobles 2 Wind Project Power Purchase Agreement ("PPA") and authorization for Minnesota Power to recover the PPA costs through its Fuel and Purchased Energy ("FPE") Rider;
- Approval of the 10 MW Blanchard Solar Project PPA and authorization for Minnesota Power to recover the PPA costs through the Solar Energy Adjustment;
- Approval of the affiliated CDA, dedicating 48 percent of NTEC to Minnesota Power and energy cost recovery through the 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
- 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.

Approval of the agreements as requested will in and of itself will have no effect on Minnesota Power's base rates. When the NTEC project goes in service in 2024, the capacity costs incurred by Minnesota Power in procuring approximately 250 MW of capacity will be included in base rates through a general rate case filed at or after the time the NTEC project goes into service. The PPA costs under the Nobles 2 Wind Project PPA and Blanchard Solar Project PPA will be assigned through Minnesota Power's Rider for Fuel and Purchased Energy to customers. Minnesota Power is also seeking approval for the recovery of energy costs related to its share of NTEC and for approval of a variance to recover the fuel costs related to its share of NTEC and to flow MISO revenues from NTEC back to customers through the Rider for Fuel and Purchased Energy.

2. SERVICE LIST (MINN. R. 7829.0700)

Pursuant to Minn. R. 7829.0700, Minnesota Power requests that the following persons be placed on the Commission's official service list for this matter:

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APPENDIX B

REQUIRED FILING INFORMATION FOR THE PROPOSED AFFILIATED INTEREST AGREEMENTS BETWEEN MINNESOTA POWER AND SOUTH SHORE ENERGY, LLC FOR CAPACITY DEDICATION OF THE NEMADJI TRAIL ENERGY CENTER AND ASSIGNMENT AGREEMENTS

Pursuant to Minn. R. 7825.2200, subp. B and the Commission's September 14, 1998, ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES in Docket No. E, G-999/CI-98-651, Minnesota Power (or the "Company") provides the following required filing information regarding proposed affiliated interest agreements between Minnesota Power, a Minnesota public utility and an operating division of ALLETE, Inc., and South Shore Energy, LLC, ("South Shore") a wholly-owned second-tier subsidiary of ALLETE, Inc., to dedicate a share of capacity and associated energy production from the Nemadji Trail Energy Center ("NTEC") natural gas combined-cycle generation facility, and for the assignment of rights to Minnesota Power to act as construction agent and operating agent under the NTEC agreements

1. A heading that identifies the type of transaction.[1]

There are three affiliate transactions presented in this Petition.

i. *Nemadji Trail Energy Center Unit Contingent Capacity Dedication Agreement* between Minnesota Power, an operating division of ALLETE, Inc., and South Shore Energy, LLC, a wholly-owned subsidiary of ALLETE, Inc., dated July 28, 2017.

ii. *Assignment of Rights Agreement (Construction Agent)* between Minnesota Power, an operating division of ALLETE, Inc., and South Shore Energy, LLC, a wholly-owned subsidiary of ALLETE, Inc., dated July 28, 2017

[1] Minn. R. 7825.2200(B)(1); ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 1.

iii. *Assignment of Rights Agreement (Operating Agent)* between Minnesota Power, an operating division of ALLETE, Inc., and South Shore Energy, LLC, a wholly-owned subsidiary of ALLETE, Inc., dated July 28, 2017.

2. The identity of the affiliated parties in the first sentence.[2]

The affiliated interest agreements are between Minnesota Power, a Minnesota public utility and an operating division of ALLETE, Inc., and South Shore Energy, LLC, a wholly-owned second-tier subsidiary of ALLETE, Inc.

3. A general description of the nature and terms of the agreement, including the effective date of the contract or arrangement and the length of the contract or arrangement.[3]

Please refer to Section 6.5.4 of the Petition for the general description of the nature and terms of the Capacity Dedication Agreement ("CDA"). The CDA was entered into on July 28, 2017. Under the terms of the CDA, South Shore dedicates forty-eight percent of the total NTEC capacity (approximately 250 MW) to Minnesota Power and its customers. The CDA is effective through the useful life of NTEC and decommissioning.

Please refer to Section 6.5.3 of the Petition for the general description of the nature and terms of the Operating Agent Assignment of Rights Agreement and the Construction Agent Assignment of Rights Agreement. The Operating Agent Assignment of Rights Agreement was entered into on July 28, 2017. Under the Operating Agent Assignment of Rights Agreement, South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to the Ownership and Operating Agreement between South Shore and Dairyland Power Cooperative. The Operating Agent Assignment of Rights Agreement is effective for the term of the Ownership and Operating Agreement and continues through decommissioning of NTEC.

The Construction Agent Assignment of Rights Agreement was entered into on July 28, 2017. Under the Construction Agent Assignment of Rights Agreement, South Shore assigns to

[2] ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 2.

[3] ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 3.

Minnesota Power the right to act as the Construction Agent under the Development and Construction Management Agreement between South Shore and Dairyland Power Cooperative. The Construction Agent Assignment of Rights Agreement is effective for the term of the Development and Construction Management Agreement and continues until NTEC is commercially operational.

4. A list and the past history of all current contracts or agreements between the utility and the affiliate, the consideration received by the affiliate for such contracts or agreements, and a summary of the relevant cost records related to these ongoing transactions. [4]

These are the first affiliated interest agreements between Minnesota Power and South Shore.

5. A descriptive summary of the pertinent facts and reasons why such contract or agreement is in the public interest. [5]

See Section 6.6 of the Petition. The NTEC Agreements are in the public interest for a variety of reasons described in Section 6 of the filing.

6. The amount of compensation, and, if applicable, a brief description of the cost allocation methodology or market information used to determine cost or price. [6]

See Section 6.5.4.3 of the Petition and Appendix H, the CDA, for the amount of compensation to be paid under the terms of the affiliated interest agreements.

[4] Minn. R. 7825.2200(B)(3); ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 4.

[5] Minn. R. 7825.2200(B)(4); ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 5.

[6] ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 6.

7. If the service or good acquired from an affiliate is competitively available, an explanation must be included stating whether competitive bidding was used, and if it was, a copy of the proposal or a summary must be included. If it was not competitively bid, an explanation must be included stating why bidding was not used.[7]

Please refer to Section 6.2 of the Petition for a discussion of the Company's competitive bidding process. A copy of the Request for Proposals for Up to 400 MW of Capacity and Energy in provided in Appendix U to this filing. A summary of the terms of the proposals received and independent evaluation of those proposals is provided in Appendix V to this filing, Sedway Consulting's Independent Evaluation Report for Minnesota Power's 2015 Gas-Fired Resource Solicitation.

8. If the arrangement is in writing, a copy of that document must be attached.[8]

The three affiliate transactions are in writing and included as appendixes in this filing. The CDA is attached as Appendix H. The Construction Agent Assignment of Rights Agreement is attached as Appendix Y. The Operating Agent Assignment of Rights Agreement is attached as Appendix Z.

9. Whether, as a result of the affiliate transaction, the affiliate would have access to customer information, such as customer name, address, usage or demographic information.[9]

South Shore has not and will not have any access to Minnesota Power's customer information or demographic information as a result of the proposed affiliated transaction. Such information is not required in the course of performance under the Agreements. All relations with utility customers continue to be directly maintained by Minnesota Power notwithstanding the existence of, or the interaction with, South Shore.

[7] Minn. R. 7825.2200(B)(5); ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 7.

[8] Minn. R. 7825.2200(B)(2); ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 8.

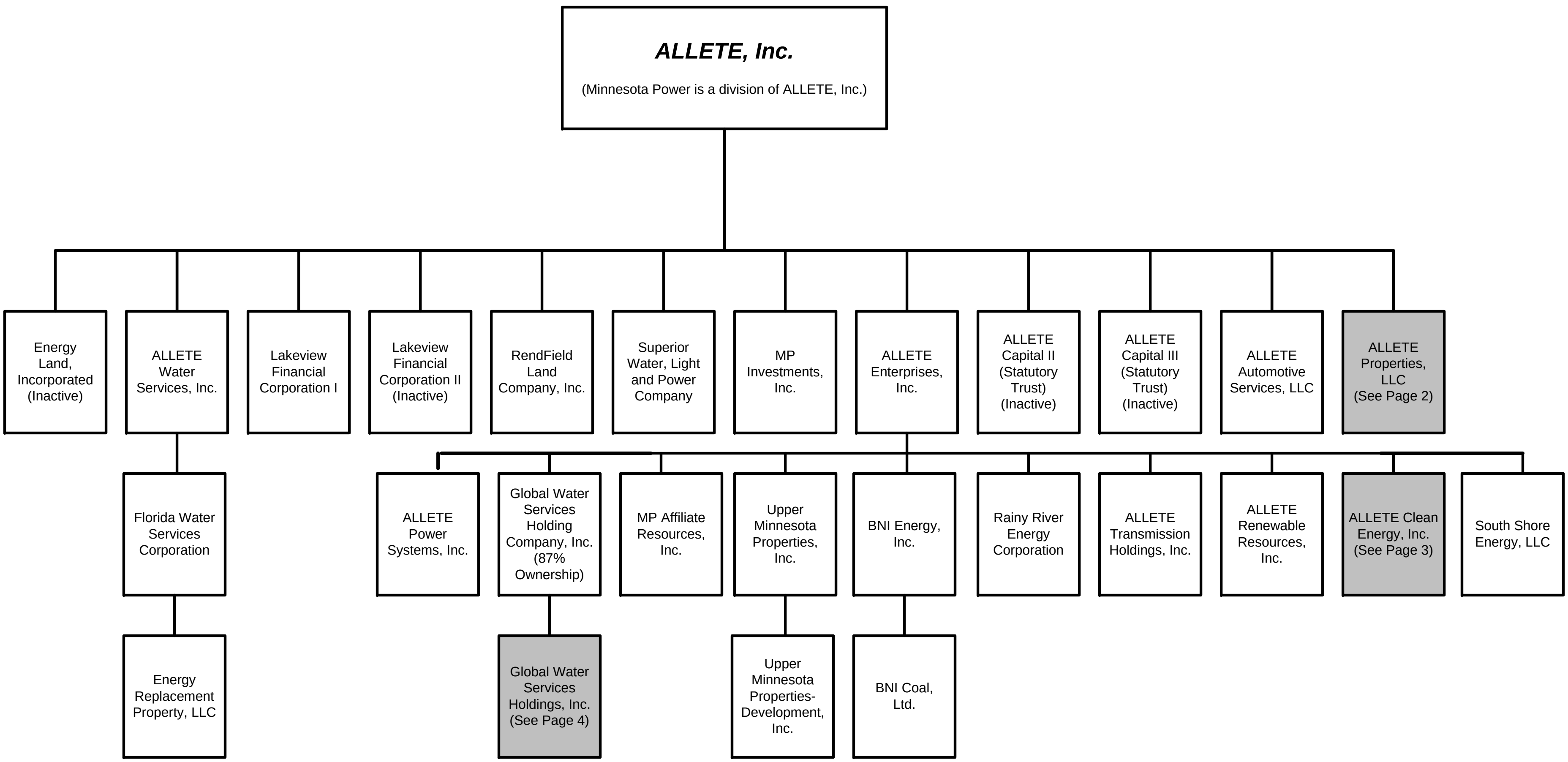
[9] ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 9.

10. The filing must be verified.[10]

A verification of this Petition is attached as Appendix BB.

[10] ORDER INITIATING REPEAL OF RULE, GRANTING GENERIC VARIANCE, AND CLARIFYING INTERNAL OPERATING PROCEDURES, Attachment A, Requirement 10.

ALLETE, Inc.
Legal Organization Chart



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APPENDIX C: RESOURCE PLANNING, AFFILIATED INTEREST, AND CERTIFICATE OF NEED INFORMATION

Source/Authority	Information	Location
E015/RP-15-690	**In the Matter of Minnesota Power's 2016-2020 Integrated Resource Plan** **ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS (July 18, 2016)**	
Order Point 2	Minnesota Power's range of load forecasting used for its 2015 resource plan is reasonable for planning purposes; however, in light of updated information, Minnesota Power's load forecast scenarios used in its 2015 resource plan may overstate the size or timing of future needs.	Section 2, Energy and Demand Forecast and Resource Need; Section 2.2, Forecasting Process Updates from Prior Filings.
Order Point 6	Minnesota Power shall retire Boswell Energy Center Units 1 and 2 when sufficient energy and capacity are available, but no later than 2022.	Section 3.1.2, Commission Order Approving 2015 Plan with Modifications.
Order Point 7	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.	Section 6.2, Selection of NTEC
Order Point 8	Minnesota Power's next resource plan shall include a full analysis of all alternatives, including renewables, energy efficiency, distributed generation, and demand response, for providing energy and capacity sufficient to meet its needs.	Section 3.4, Alternatives Evaluated.
Order Point 9	By the end of 2017, Minnesota Power shall initiate a competitive-bidding process to procure 100–300 MW of installed wind capacity.	Section 4.3, Selection of the Nobles 2 Wind Project.
Order Point 10	Minnesota Power shall acquire solar units of 11 MW by 2016, 12 MW by 2020, and 10 MW by 2025 to meet is SES obligations.	Section 5.3, Selection of the Blanchard Solar Project.
Order Point 11	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.	Section 5.2, (Solar) Resource Planning Analysis.

Source/Authority	Information	Location
Order Point 13	Minnesota Power shall propose a demand-response competitive-bidding process within six months of the date of this order.	Section 3.4.5, Large Industrial Demand Response; Appendix L: Large Customer Demand Response Resources RFP. *See also In the Matter of Minn. Power's 2016-2030 Integrated Res. Plan*, Docket No. E015/RP-15-690, COMPLIANCE FILING (Jan. 18, 2017).
Order Point 14	Minnesota Power shall investigate the potential for an energy-efficiency competitive-bidding process to supplement its existing conservation-improvement program, open to both CIP-exempt and non-CIP-exempt customers, and shall summarize its investigation and findings in its next resource plan.	Section 3.4.8, Energy Efficiency and Demand-Side Management.

Source/Authority	Information	Location
Affiliated Interest Filing Requirements		
Minn. Stat. § 216B.48	**Relations with Affiliated Interest**	
Subd. 3	No contract or arrangement, including any general or continuing arrangement, providing for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial, or similar services, and no contract or arrangement for the purchase, sale, lease, or exchange of any property, right, or thing, or for the furnishing of any service, property, right, or thing, other than those above enumerated, made or entered into after January 1, 1975 between a public utility and any affiliated interest as defined in subdivision 1, clauses (1) to (8), or any arrangement between a public utility and an affiliated interest as defined in subdivision 1, clause (9), made or entered into after August 1, 1993, is valid or effective unless and until the contract or arrangement has received the written approval of the commission. The commission shall approve the contract or arrangement made or entered into after that date only if it clearly appears and is established upon investigation that it is reasonable and consistent with the public interest. No contract or arrangement may receive the commission's approval unless satisfactory proof is submitted to the commission of the cost to the affiliated interest of rendering the services or of furnishing the property or service to each public utility. Proof is satisfactory only if it includes the original or verified copies of the relevant cost records and other relevant accounts of the affiliated interest, or an abstract or summary as the commission may deem adequate, properly identified and duly authenticated, provided, however, that the commission may, where reasonable, approve or disapprove the contracts or arrangements without the submission of cost records or accounts. The burden of proof to establish the reasonableness of the contract or arrangement is on the public utility.	Section 6.6, the NTEC Agreements and Affiliated Interest Agreements are in the Public Interest; Appendix B: Affiliated Interest Agreement Filing Information.
Minn. R. 7825.2200	**Utilities with Affiliated Interests; Filing**	
B.	Petitions for approval of affiliated interest contracts or agreements accompanied by the following:	Appendix B: Affiliated Interest Agreement Filing Information.
(1)	a descriptive title of each contract or agreement;	Appendix B: Affiliated Interest Agreement Filing Information, Section (1)(i)-(iii).

Source/Authority	Information	Location
(2)	a copy of the contract or agreement, or modifications or revisions of an existing contract or agreement;	Appendix H: Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power; Appendix Y: Assignment of Rights Agreement (Construction Agent) between South Shore and Minnesota Power; Appendix Z: Assignment of Rights Agreement (Operating Agent) between South Shore and Minnesota Power.
(3)	a list and the past history of all contracts or agreements outstanding between the petitioner and affiliated interest, the consideration received by the affiliated interest for such contracts or agreements, and a verified summary of the relevant cost records pertaining to the same;	Appendix B: Affiliated Interest Agreement Filing Information, Section (4).
(4)	a descriptive summary of the pertinent facts and reasons why such contract or agreement is in the public interest;	Section 6.6, The NTEC Project Agreements and Affiliated Interest Agreements are in the Public Interest; Appendix B: Affiliated Interest Agreement Filing Information, Section (5).
(5)	competitive bidding: (a) if invitations for sealed written public proposals for the furnishing of the service sought under the contract or agreement have been made, a summary of the terms of the proposals received, including the name of each bidder or representative of a bidding group; and as an exhibit to the petition, a copy of each proposal received; (b) if invitations for sealed written proposals have not been made, an explanation of the decisions to that effect will be submitted.	Appendix B: Affiliated Interest Agreement Filing Information, Section (7); Section 6.2, Selection of NTEC; Appendix V: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation; Appendix U: Request for Proposals for Up to 400 MW of Capacity and Energy.
Docket No. E,G999/CI-98-651	**Order Initiating Repeal of Rule, Granting Generic Variance, and Clarifying Internal Operating Procedures, Attachment A**	
(1)	A heading that identifies the type of transaction	Appendix B: Affiliated Interest Agreement Filing Information, Heading.
(2)	The identity of the affiliated parties in the first sentence	Appendix B: Affiliated Interest Agreement Filing Information, Heading and Section (2).
(3)	A general description of the nature and terms of the agreement, including the effective date of the contract or arrangement and the length of the contract or arrangement.	Section 6.5.3, Proposed Assignment Agreements; Section 6.5.4, Capacity Dedication Agreement; Appendix B: Affiliated Interest Agreement Filing Information, Section (3).

Source/Authority	Information	Location
(4)	A list and the past history of all current contracts or agreements between the utility and the affiliate, the consideration received by the affiliate for such contacts or agreements, and a summary of the relevant cost records related to these ongoing transactions.	Appendix B: Affiliated Interest Agreement Filing Information, Section (4).
(5)	A descriptive summary of the pertinent facts and reasons why such contract or agreement is in the public interest.	Section 6.6, The NTEC Project Agreements and Affiliated Interest Agreements are in the Public Interest; Appendix B: Affiliated Interest Agreement Filing Information, Section (5).
(6)	The amount of the compensation and, if applicable, a brief description of the cost allocation methodology or market information used to determine cost or price.	Section 6.5.4, Capacity Dedication Agreement; Appendix B: Affiliated Interest Agreement Filing Information, Section (6).
(7)	If the service or good acquired from an affiliate is competitively available, an explanation must be included stating whether competitive bidding was used and, if it was used, a copy of the proposal or a summary must be included. If it is not competitively bid, an explanation must be included stating why bidding was not used.	Section 6.2, Selection of NTEC; Appendix B: Affiliated Interest Agreement Filing Information, Section (7); Appendix V: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation; Appendix U: Request for Proposals for Up to 400 MW of Capacity and Energy.
(8)	If the arrangement is in writing, a copy of that document must be attached.	Appendix B: Affiliated Interest Agreement Filing Information, Section (8); Appendix H: Unit Contingent Capacity Dedication Agreement Between South Shore and Minnesota Power; Appendix Y: Assignment of Rights Agreement (Construction Agent) between South Shore and Minnesota Power; Appendix Z: Assignment of Rights Agreement (Operating Agent) between South Shore and Minnesota Power.
(9)	Whether, as a result of the affiliate transaction, the affiliate would have access to customer information, such as customer name, address, usage or demographic information.	Appendix B: Affiliated Interest Agreement Filing Information, Section (9).
(10)	The filing must be verified	Appendix B: Affiliated Interest Agreement Filing Information, Section (10); Appendix BB: Verification of Filing.

Source/Authority	Information	Location
Certificate of Need Information[1]		
Minn. R. 7849.0200[2]	**Application Procedures and Timing**	
Subp. 2	Title Page and Table of Contents	Title page and Table of Contents
Subp. 4	**Cover Letter.** An application for a certificate of need must be accompanied by a cover letter signed by an authorized officer or agent of the applicant. The cover letter must specify the type of facility for which a certificate of need is requested.	Cover Letter
Minn. R. 7849.0240	**Need Summary and Additional Considerations**	
Subp. 1	**Need Summary.** An application must contain a summary of the major factors that justify the need for the proposed facility. This summary must not exceed, without the approval of the commission, 15 pages in length, including text, tables, graphs, and figures.	Section 2, Introduction; Section 2.3, Forecast Results and Need.

[1] None of the elements of the proposed Energy*Forward* Resource Package require Minnesota Power to obtain a certificate of need.

- The size of the Blanchard Solar Project exempts it from a certificate of need under Minn. Stat. § 216B.243.
- The Nobles 2 Wind Project PPA does not require Minnesota Power to obtain a certificate of need, although the project developer, Tenaska, requires a certificate of need to proceed with the underlying project. Nevertheless, the Company is providing the type of information considered in a certificate of need proceeding to assist the Commission and interested parties in evaluating Minnesota Power's Petition. Minnesota Power is willing to provide information from Tenaska's permitting process to the Commission and stakeholders as further data points.
- NTEC is located in Wisconsin and thus does not require a Minnesota certificate of need. It will require a Certificate of Public Convenience and Necessity ("CPCN") from the Public Service Commission of Wisconsin ("PSCW"), which will be sought by the NTEC Owners in the normal course of business. Minnesota Power is willing to provide information from the CPCN process to the Commission and stakeholders as further data points.

[2] Under Minn. R. 7849.0220, an application for a certificate of need for a Large Electric Generating Facility ("LEGF") must include the information required by Minn. R. 7849.0240, 7849.0250, and 7849.0270 to 7849.0340. Additionally, if the proposed LEGF is to be owned jointly by two or more utilities or by a pool, the information required by Minn. R. 7849.0010 to 7849.0400 must be provided by each joint owner for its system. If the facility is designed to meet the long-term needs, in excess of 80 megawatts, of a particular utility that is not to be an owner, that utility must also provide the information required by parts 7849.0010 to 7849.0400. Joint applicants may use a common submission to satisfy the requirements of any part for which the appropriate response does not vary by utility. While these rules do not specifically apply to the Energy*Forward* Resource Package, the following is intended to provide the type and quality of information that would be included in a formal certificate of need proceeding.

Source/Authority	Information	Location
Subp. 2	**Additional Considerations**. Each application shall contain an explanation of the relationship of the proposed facility to each of the following socioeconomic considerations: A. socially beneficial uses of the output of the facility, including its uses to protect or enhance environmental quality; B. promotional activities that may have given rise to the demand for the facility; and C. the effects of the facility in inducing future development.	Section 2.1, Overview of Forecast Methodology; Section 2.3, Forecast Results and Need; Section 4.2, Resource Planning Analysis (Wind); Section 5.2, Resource Planning Analysis (Solar); Section 6.1, the Need for Dispatchable Capacity.
Minn. R. 7849.0250	**Proposed LEGF and Alternatives Application**	
	An application for a proposed LEGF must include:	
A.	A description of the facility, including	Section 6, Introduction; Section 6.3, NTEC Project.
(1)	The nominal generating capability of the facility, as well as a discussion of the effect of the economies of scale on the facility size and timing;	Section 4.4, the Nobles 2 Wind Project; Section 5.4, the Blanchard Solar Project; Section 6.3, NTEC Project; Section 6.4.1, Joint Ownership Structure.
(2)	A description of the anticipated operating cycle, including the expected annual capacity factor;	Section 1.2.3, Natural Gas; Section 3.4.2, Solar Generation; Section 3.4.3, Natural Gas Generation; Section 4.1, Proposed 250 MW of Wind Meets Identified Need; Appendix J: Detailed Resource Planning Analysis.
(3)	The type of fuel used, including the reason for the choice of fuel, projection of the availability of this fuel type over the projected life of the facility, and alternate fuels, if any;	Section 3 generally; Sections 4, 5, and 6 for each resource.
(4)	The anticipated heat rate of the facility; and	Section 6.2.3, RFP Review Process; Appendix V: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation.
(5)	To the fullest extent known to the applicant, the anticipated areas where the proposed facility could be located;	Section 4.4.1, Project Overview; Section 5.4.1, Project Overview; Section 6.3.2, Viable Location.

Source/Authority	Information	Location
B.	A discussion of the availability of alternatives to the facility, including but not limited to:	Section 3.4, Alternatives Evaluated.
(1)	Purchase power;	Section 3.4.4, Bilateral Transactions.
(2)	Increased efficiency of existing facilities, including transmission lines;	Not applicable
(3)	New transmissions lines;	Not applicable
(4)	New generating facilities of a different size or using a different energy source (fuel oil, natural gas, coal, nuclear fission, and the emergent technologies); and	Section 3.4, Alternatives Evaluated; Appendix J: Detailed Resource Planning Analysis, Appendix N: Pace Global 2017 Independent Resource Analysis.
(5)	Any reasonable combinations of the alternatives listed in subitems (1) to (4);	Section 3.4, Alternatives Evaluated; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
C.	For the proposed facility and for each of the alternatives provided in response to item B that could provide electric power at the asserted level of need, a discussion of:	Section 3.4, Alternatives Evaluated; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(1)	Its capacity cost in current dollars per kilowatt;	Section 3.4, Alternatives Evaluated; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(2)	Its service life;	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(3)	Its estimated average annual availability;	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.

Source/Authority	Information	Location
(4)	Its fuel costs in current dollars per kilowatt hour;	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(5)	Its variable operating and maintenance costs in current dollars per kilowatt hour;	Section 3.4, Alternatives Evaluated, Section 3.6, Analysis and Insights, Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(6)	The total cost in current dollars of a kilowatt hour provided by it;	Section 3.4, Alternatives Evaluated, Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(7)	An estimate of its effect on rates systemwide and in Minnesota, assuming a test year beginning with the proposed in-service date;	Section 3.4, Alternatives Evaluated, Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(8)	Its efficiency, expressed for a generating facility as the estimated heat rate, or expressed for a transmission facility as the estimated losses under projected maximum loading and under projected average loading in the length of the transmission lines and at the terminals or substations; and	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis.
(9)	The major assumptions made in providing the information in subitems (1) to (8), including projected escalation rates for fuel costs and operating and maintenance costs, as well as projected capacity factors;	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N, Pace Global 2017 Independent Resource Analysis; Appendix I: Assumptions and Outlooks.
D.	A map (of appropriate scale) showing the applicant's system; and	Appendix K: Existing Power Supply.
E.	Such other information about the proposed facility and each alternative as may be relevant to determination of need.	Section 3.4, Alternatives Evaluated; Section 3.6, Analysis and Insights; Appendix J: Detailed Resource Planning Analysis; Appendix N: Pace Global 2017 Independent Resource Analysis; Appendix I: Assumptions and Outlooks.
Minn. R. 7849.0270	**Peak Demand and Annual Consumption Forecast**	

Source/Authority	Information	Location
Subp. 1	**Scope**. Each application shall contain pertinent data concerning peak demand and annual electrical consumption within the applicant's service area and system, as provided in part 7849.0220, including but not limited to the data requested in subpart 2, item B. When recorded data is not available, or when the applicant does not use the required data in preparing its own forecast, the applicant shall use an estimate and indicate in the forecast justification section in subparts 3 to 6 the procedures used in deriving the estimate. The application shall clearly indicate which data are historical and which are projected. It is expected that data provided by the applicant should be reasonable and internally consistent	Section 2.3, Forecast Results and Need. *See generally Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT (June 30, 2016).
Subp. 2	**Content of forecast**. For each forecast year, the following data must be provided:	
A.	When the applicant's service area includes areas other than Minnesota, annual electrical consumption by ultimate consumers within the applicant's Minnesota service area;	Not applicable
B.	For each of the following categories, estimates of the number of ultimate consumers within the applicant's system and annual electrical consumption by those customers:	*See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See also Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(1)	Farm, excluding irrigation and drainage pumping (for reporting purposes, any tract of land used primarily for agricultural purposes shall be considered farm land);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(2)	Irrigation and drainage pumping;	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(3)	Nonfarm residential (when electricity is supplied through a single meter for both residential and commercial uses, it shall be reported according to its principal use, and apartment buildings shall be reported as residential even if not separately metered);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(4)	Commercial (this category shall include wholesale and retail trade; communication industries; public and private office buildings, banks, and dormitories; insurance, real estate and rental agencies; hotels and motels; personal business and auto repair services; medical and educational facilities; recreational, social, religious, and amusement facilities; governmental unites, excluding military bases; warehouses other than manufacturer owned; electric, gas, water and water pumping, excluding water pumping for irrigation, and other utilities);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(5)	Mining	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(6)	Industrial (this category shall include all manufacturing industries, construction operations and petroleum refineries);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(7)	Street and highway lighting;	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(8)	Electrified transportation (this category shall include energy supplied for the propulsion of vehicles, but shall not include energy supplied for office buildings, depots, signal lights or other associated facilities that shall be reported as commercial or industrial);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(9)	Other (this category shall include municipal water pumping facilities, oil and gas pipeline pumping facilities, military camps and bases, and all other consumers not reported in subitems (1) to (8)); and	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(10)	The sum of subitems (1) to (9);	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item A. System Forecast of Annual Electric Consumption by Ultimate Consumers (June 30, 2016). *See Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
C.	An estimate of the demand for power in the applicant's system at the time of annual system peak demand, including an estimated breakdown of the demand into the consumer categories listed in item B;	Section 2.4, Forecast Results and Need. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item C. Peak Demand by Ultimate Consumers at the Time of Annual System Peak (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
D.	The applicant's system peak demand by month;	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Minn. R. 7610.0310 Item D. Peak Demand by Month for the Last Calendar Year (June 30, 2016).
E.	The estimated annual revenue requirement per kilowatt hour for the system in current dollars; and	Overall cost impact from the Energy*Forward* Resource Package described in Section 3.6.3
F.	The applicant's estimated average system weekday load factor by month; in other words, for each month, the estimated average of the individual load factors for each weekday in the month.	*Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 2.C, Peak Demand and Energy Outlooks by Scenario (June 30, 2016),.

Source/Authority	Information	Location
Subp. 3	**Forecast Methodology**. An applicant may use a forecast methodology of its own choosing, with due consideration given to cost, staffing requirements, and data availability. However, forecast data provided by the applicant is subject to tests of accuracy, reasonableness, and consistency. The applicant shall detail the forecast methodology employed to obtain the forecasts provided under subpart 2, including:	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1, Forecast Methodology, Data Inputs, and Assumptions (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
A.	The overall methodological framework that is used;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.A, Overall Framework (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
B.	The specific analytical techniques which are used, their purpose, and the components of the forecast to which they have been applied;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B.ii, Specific Analytical Techniques and Section 1.E, Econometric Model Documentation (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
C.	The manner in which these specific techniques are related in producing the forecast;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B.i, Process Description and Section 1.E, Econometric Model Documentation (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
D.	Where statistical techniques have been used:	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1, Forecast Methodology, Data Inputs, and Assumptions (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(1)	The purpose of the technique;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process and Section 1.E, Econometric Model Documentation (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(2)	Typical computations (e.g., computer printouts, formulas used), specifying variables and data; and	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.E, Econometric Model Documentation (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(3)	The results of appropriate statistical tests;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.E, Econometric Model Documentation and Section 2, 2016 Forecast and Alternative Scenarios (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
E.	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumptions, as well as a description of their derivation;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
F.	A brief analysis of the methodology used, including:	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process and Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(1)	Its strengths and weaknesses;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B.v, Methodological Strengths and Weaknesses (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report,* Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(2)	Its suitability to the system;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report,* Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(3)	Cost considerations;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process and Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(4)	Data requirements;	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process and Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
(5)	Past accuracy; and	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
(6)	Other factors considered significant by the applicant; and	Section 2.1, Overview of Forecast Methodology; Section 2.2, Forecasting Process Refinements from Prior Filings. *See also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B, Minnesota Power's Forecast Process and Section 1.F, Confidence in Forecast & Historical Accuracy (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
G.	An explanation of discrepancies that appear between the forecasts presented in the application and the forecasts submitted under chapter 7610 or in the applicant's previous certificate of need proceedings.	Section 2.2, Forecasting Process Refinements from Prior Filings.
Subp. 4	**Data base for forecasts**. The applicant shall discuss the data base used in arriving at the forecast presented in its application, including:	*See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C, Inputs and Sources (June 30, 2016).
A.	A complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer's office);	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C, Inputs and Sources (June 30, 2016).

Source/Authority	Information	Location
B.	A clear identification of any adjustments made to raw data in order to adapt them for use in forecasts, including:	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C.ii, Adjustments to Raw Data (June 30, 2016).
(1)	The nature of the adjustment;	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C.ii, Adjustments to Raw Data (June 30, 2016).
(2)	The reason for the adjustment; and	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C.ii, Adjustments to Raw Data (June 30, 2016).
(3)	The magnitude of the adjustment.	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C.ii, Adjustments to Raw Data (June 30, 2016).

Source/Authority	Information	Location
Subp. 4(B) cont.	The applicant shall provide to the commission or the administrative law judge on demand copies of the data sets used in making the forecasts, including both raw and adjusted data, input and output data.	The data set used to make the forecast is available for stakeholder review on request, and will be provided in a format that addresses the data categories in this rule. *See Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.C, Inputs and Sources (June 30, 2016).
Subp. 5	**Assumptions and special information**. The applicant shall discuss each essential assumption made in preparing the forecast, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions. The application shall discuss the assumptions made regarding:	Section 2.1, Overview of Forecast Methodology; *see Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.D, Overview of Key Assumptions (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
A.	The availability of alternate sources of energy;	*See* Appendix I: Assumptions and Outlooks.
B.	The expected conversion from other fuels to electricity or vice versa;	*See* Appendix I: Assumptions and Outlooks.
C.	Future prices of electricity for customers in the applicant's system and the effect that such price changes will likely have on the applicant's system demand;	*See* Appendix I: Assumptions and Outlooks.
D.	The data requested in subpart 2 that is not available historically or not generated by the applicant in preparing its own internal forecast;	Section 2.1, Overview of Forecast Methodology; *see also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).

Source/Authority	Information	Location
E.	The effect of energy conservation programs on long-term electrical demand; and	Section 2.1, Overview of Forecast Methodology; *see also Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B.iv, Treatment of Demand-Side Management, Conservation Improvement Programs, and Distributed Generation (June 30, 2016); *Minn. Power's 2017 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-17-11, INITIAL FILING (June 29, 2017).
F.	Any other factor considered by the applicant in preparing the forecast.	Section 2.1, Overview of Forecast Methodology; Section 2.3, Forecast Results and Need
Subp. 6	**Coordination of forecasts with other systems.** The applicant shall provide:	
A.	A description of the extent to which the applicant coordinates its load forecasts with those of other systems, such as neighboring systems and associate systems in a power pool or coordinating organization; and	Section 2.3.2, MISO Planning Reserve Margin Requirements; Section 2.3.3, Load and Capability Base Case Need Assessment; Section 6.1, The Need for Dispatchable Capacity. *Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 3.B. Other Information, Coordination of Forecasts with Other Systems (June 30, 2016).
B.	A description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.	Section 2.3.2, MISO Planning Reserve Margin Requirements; Section 2.3.3, Load and Capability Base Case Need Assessment. *Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 3.B. Other Information, Coordination of Forecasts with Other Systems (June 30, 2016).

Source/Authority	Information	Location
Minn. R. 7849.0280	**System Capacity**	
	The application shall describe the ability of its existing system to meet the demand for electrical energy forecast in response to part 7849.0270 and the extent to which the proposed facility will increase this capability. In preparing this description, the applicant shall present the following information:	Section 2.3, Forecast Results and Need, generally
A.	A brief discussion of power planning programs, including criteria, applied to the applicant's system and to the power pool or area within which the applicant's planning studies are based;	Section 2.3, Forecast Results and Need, generally
B.	The applicant's seasonal firm purchases and seasonal firm sales for each utility involved in each transaction for each of the forecast years;	Section 2.3, Forecast Results and Need, generally
C.	The applicant's seasonal participation purchases and seasonal participation sales for each utility involved in each transaction for each of the forecast years;	Section 2.3, Forecast Results and Need, generally
D.	For the summer season and for the winter season corresponding to each forecast year, the load and generation capacity data requested in subitems (1) to (13), including the anticipated purchases, sales, capacity retirements, and capacity additions, except those that depend on certificates of need not yet issued by the commission:	Section 2.3, Forecast Results and Need, generally
E.	For the summer season and for the winter season corresponding to each forecast year subsequent to the year of application, the load and generation capacity data requested in item D, subitems (1) to (13), including purchases, sales, and generating capability contingent on the proposed facility;	Section 2.3, Forecast Results and Need, generally
F.	For the summer season and for the winter season corresponding to each forecast year subsequent to the year of application, the load and generation capacity data requested in item D, subitems (1) to (13), including all projected purchases, sales, and generating capability;	Section 2.3, Forecast Results and Need, generally
G.	For each of the forecast years subsequent to the year of application, a list of proposed additions and retirements in net generating capability, including the probable date of application for any addition that is expected to require a certificate of need;	Section 2.3, Forecast Results and Need, generally

Source/Authority	Information	Location
H.	For the previous calendar year, the current year, the first full calendar year before the proposed facility is expected to be in operation and the first full calendar year of operation of the proposed facility, a graph of monthly adjusted net demand and monthly adjusted net capability, as well as a plot on the same graph of the difference between the adjusted net capability and actual, planned, or estimated maintenance outages of generation and transmission facilities; and	Section 2.3, Forecast Results and Need, generally
I.	A discussion of the appropriateness of and the method of determining system reserve margins, considering the probability of forced outages of generating units, deviation from load forecasts, scheduled maintenance outages of generation and transmission facilities, power exchange arrangements as they affect reserve requirements, and transfer capabilities.	Section 2.3, Forecast Results and Need, generally
Minn. R. 7849.0290	**Conservation Programs, Application.** An application must include:	
A.	The name of the committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management;	*In the Matter of Minn. Power's Conservation Improvement Program 2016 Status Report*, Docket No. E015/CIP-13-409.03, 2016 CONSERVATION IMPROVEMENT PROGRAM STATUS REPORT (Apr. 3, 2017).
B.	A list of the applicant's energy conservation and efficiency goals and objectives;	Section 2.1, Overview of Forecast Methodology; Section 3.4.8, Energy Efficiency and Demand-Side Management. *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).
C.	A description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented;	*In the Matter of Minn. Power's Conservation Improvement Program 2016 Status Report*, Docket No. E015/CIP-13-409.03, 2016 CONSERVATION IMPROVEMENT PROGRAM STATUS REPORT (Apr. 3, 2017).

Source/Authority	Information	Location
D.	A description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency;	*In the Matter of Minn. Power's Conservation Improvement Program 2016 Status Report*, Docket No. E015/CIP-13-409.03, 2016 CONSERVATION IMPROVEMENT PROGRAM STATUS REPORT (Apr. 3, 2017).
E.	A description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency; and	Section 3.4.8, Energy Efficiency and Demand-Side Management. *Minn. Power's 2017-2019 Triennial Conservation Improvement Program (CIP),* Docket No. E015/CIP-16-117, 2017-2019 ELECTRIC CONSERVATION IMPROVEMENT PROGRAM (June 1, 2016).
F.	A quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subpart 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities.	Section 2.1, Overview of Forecast Methodology; *Minn. Power's 2016 Annual Elec. Util. Forecast Report*, Docket No. E999/PR-16-11, REPORT at Section 1.B.iv, Treatment of Demand-Side Management, Conservation Improvement Programs, and Distributed Generation (June 30, 2016).
Minn. R. 7849.0300	**Consequences of Delay**	
	The applicant shall present a discussion of anticipated consequences to its system, neighboring systems, and the power pool should the proposed facility be delayed one, two, and three years, or postponed indefinitely. This information must be provided for the following three levels of demand: the expected demand provided in response to part 7849.0270, subpart 2, and the upper and lower confidence levels provided in response to part 7849.0270, subpart 3, item E.	Section 2, Energy and Demand Forecast and Resource Need, Introduction; Section 2.3, Forecast Results and Need; Section 2.3.5, Conclusions Regarding Resource Need.
Minn. R. 7849.0310	**Environmental Information Required**	

Source/Authority	Information	Location
	Each applicant shall provide environmental data for the proposed facility and for each alternative considered in detail in response to part 7849.0250, item C or 7849.0260, item C. Information relating to construction and operation of each of these alternatives shall be provided as indicated in parts 7849.0320 to 7849.0340, to the extent that such information is reasonably available to the applicant and applicable to the particular alternative. Where appropriate, the applicant shall submit data for a range of possible facility designs. Major assumptions should be stated, and references should be cited where appropriate.	*See* Section 3.4, Alternatives Evaluated; 3.6.3, Cost Impact; Appendix I: Assumptions and Outlooks; Appendix J: Detailed Resource Planning. As discussed in Appendix J: Detailed Resource Planning, the Strategist modeling analysis incorporated data and assumptions regarding the total costs of each resource evaluated. The levelized busbar cost for each power generation alternative included estimated capital, transmission, operation and maintenance (fixed and variable), and fuel costs (combustible fuel or purchased electrical energy). Additionally, heat rate assumptions for each resource alternative evaluated are incorporated into the Strategist modeling analysis.
Minn. R. 7849.0320	**Generating Facilities**.	
	The applicant shall provide the following information for each alternative that would involve construction of an LEGF:	
A.	The estimated range of land requirements for the facility with a discussion of assumptions on land requirements for water storage, cooling systems, and solid waste storage;	Section 4.4, Nobles 2 Wind Project, generally; Section 5.4, Blanchard Solar Project, generally; Section 6.3, NTEC Project, generally; Appendix G: Ownership and Operating Agreement between Dairyland and South Shore; Section 2.1, Project and Project Site. Supplemental information on this category may be available in the upcoming Nobles 2 Wind Project Certificate of Need proceeding and the NTEC CPCN proceeding before the PSCW.

Source/Authority	Information	Location
B.	The estimated amount of vehicular, rail, and barge traffic generated by construction and operation of the facility;	Supplemental information on this category may be available in the upcoming Nobles 2 Wind Project Certificate of Need proceeding and the NTEC CPCN proceeding before the PSCW. See generally Section 6.3 for a discussion pertaining to the NTEC Project.
C.	For fossil-fueled facilities:	Applicable to NTEC Project only Supplemental information on this category may be available in the upcoming NTEC CPCN proceeding before the PSCW.
(1)	The expected regional sources of fuel for the facility;	Section 6.3.3, Gas Infrastructure
(2)	The typical fuel requirement (in tons per hour, gallons per hour, or thousands of cubic feet per hour) during operation at rated capacity and the expected annual fuel requirement at the expected capacity factor;	Section 6.3.3, Gas Infrastructure; Section 3.4.3, Natural Gas Generation
(3)	The expected rate of heat input for the facility in Btu per hour during operation at rated capacity;	*See* Section 3, Development of Proposed Energy*Forward* Resource Package, generally on economic analysis of gas plant at projected heat rate; Appendix V, Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation, Appendix A.
(4)	The typical range of the heat value of the fuel (in Btu per pound, Btu per gallon, or Btu per 1,000 cubic feet) and the typical average heat value of the fuel; and	Appendix V, Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation, Appendix A.
(5)	the typical ranges of sulfur, ash, and moisture content of the fuel;	Not applicable to natural gas unit
D.	For fossil fueled facilities:	Supplemental information on this category may be available in the upcoming NTEC CPCN proceeding before the PSCW.

Source/Authority	Information	Location
(1)	The estimated range of trace element emissions and the maximum emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds per hour during operation at rated capacity; and	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5, Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
(2)	The estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from the stack of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter during operation at rated capacity and assuming generalized worst-case meteorological conditions;	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
E.	Water use by the facility for alternate cooling systems, including:	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
(1)	The estimated maximum use, including the groundwater pumping rate in gallons per minute and surface water appropriation in cubic feet per second;	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
(2)	The estimated groundwater appropriation in million gallons per year; and	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.

Source/Authority	Information	Location
(3)	The annual consumption in acre-feet;	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
F.	The potential sources and types of discharges to water attributable to operation of the facility;	See Sections 3.1.4, Refinements from 2015 Plan; 3.3.2, CO2 Regulation; and 3.5 Characteristics of Minnesota Power's Energy*Forward* Resource Package, generally, for environmental performance of the Energy*Forward* Resource Package.
G.	Radioactive releases, including:	Not applicable
(1)	For nuclear facilities, the typical types and amounts of radionuclides released by the facility in curies per year for alternate facility designs and levels of waste treatment; and	Not applicable
(2)	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year;	Not applicable
H.	The potential types and quantities of solid wastes produced by the facility in tons per year at the expected capacity factor;	Not applicable
I.	The potential sources and types of audible noise attributable to operation of the facility;	Not applicable
J.	The estimated work force required for construction and operation of the facility; and	Section 1.4, The Energy*Forward* Resource Package is in the Public Interest; Section 6.6, The NTEC Project Agreements and Affiliated Interest Agreements are in the Public Interest. Supplemental information on this category may be available in the NTEC CPCN proceeding before the PSCW.

Source/Authority	Information	Location
K.	The minimum number and size of transmission facilities required to provide a reliable outlet for the generating facility.	Section 4.4.2, Interconnection and Transmission (Wind); Section 5.4.2, Interconnection and Distribution (Solar); Section 6.4.2, Interconnection and Delivery (Gas); Appendix S: Summary of Minnesota Power's Interconnection Process; Appendix T: Summary of MISO's Generator Interconnection Process.
Minn. R. 7849.0340	**No-Facility Alternative**.	
	For each of the three levels of demand specified in part 7849.0300, the applicant shall provide the following information for the alternative of no facility:	Supplemental information on this category may be available in the upcoming Nobles 2 Wind Project Certificate of Need proceeding and the NTEC CPCN proceeding before the PSCW.
A.	Description of the expected operation of existing and committed generating and transmission facilities;	Appendix K: Existing Power Supply.
B.	A description of the changes in resource requirements and wastes produced by facilities discussed in response to item A, including:	Not applicable
C.	A description of equipment and measures that may be used to reduce the environmental impact of the alternative of no facility.	*See generally* Section 2, Energy and Demand Forecast and Resource Need. Supplemental information on this category may be available in the upcoming Nobles 2 Wind Project Certificate of Need proceeding and the NTEC CPCN proceeding before the PSCW.