



2025-2039 Integrated Resource Plan

March 3, 2025 | MPUC Docket No. E015/RP-25-127





AN ALLETE COMPANY

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March 3, 2025

VIA E-FILING

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Application for
Approval of its 2025-2039 Integrated Resource Plan
Docket No. E015/RP-25-127

Dear Mr. Seuffert:

With this filing, Minnesota Power hereby presents its 2025-2039 Integrated Resource Plan ("IRP") for Minnesota Public Utilities Commission (or the "Commission") approval.

Minnesota Power is pleased to submit this IRP, referred to throughout the filing as the "2025 Plan," which outlines the next chapter in the Company's *EnergyForward* resource strategy. *EnergyForward* has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering the most renewable energy to customers in the State of Minnesota, between 50 and 60 percent renewable energy. The 2025 Plan, if approved, will enable an annual energy portfolio that is 80 percent renewable by 2030 and 90 percent renewable by 2035, demonstrating Minnesota Power's proposed actions for a sustainable path to compliance with Minnesota's Carbon-Free Standard ("CFS") passed into law on in 2023. The 2025 Plan represents continued progress in reducing carbon on the electric system, including ceasing coal for customers at the Company's last two remaining coal fired units, and will result in 95 percent carbon reduction from 2005 levels while maintaining energy reliability.

Importantly, this IRP outlines Minnesota Power's plan to achieve critical next steps in the energy transition that are centered on a commitment to provide increasingly clean electricity to customers while ensuring safe and reliable service at a reasonable cost to customers. The 2025 Plan also demonstrates Minnesota Power's continued commitment to the region and communities it serves by outlining the importance of reliable local supply and refueling options as part of the Company's cease coal plan. Moreover, Minnesota Power recognizes its responsibility and the importance of serving new economic growth emerging in the region, and the 2025 Plan outlines and is responsive to its customer plans for load growth. Having served some of the nation's largest industrial customers for decades, Minnesota Power specializes in its ability to serve large industrial customers and therefore presents a plan that incorporates near-term and long-term actions that will

I AM
ZERO INJURY.

*Together we choose to work safely for our families, each other, and the public.
We commit to be injury-free through continuous learning and improvement.*

Mr. Seuffert
March 3, 2025
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ensure the Company has flexibility to meet the region's economic needs and projected customer growth.

The 2025 Plan incorporates feedback from customers, community members and organizations, state agencies, advocates, and Tribal Nations, who participated in a year-long engagement process that informed both technical modeling and societal cost-benefit analyses. Minnesota Power is grateful for the time and collaboration from those who provided input that helped shape the 2025 Plan.

This IRP is organized into seven sections with supporting appendices, as presented in the enclosed Table of Contents. With the core plan evaluation submitted with this filing, the Company's analysis will be supplemented with information in additional appendices by the end of the month.

Certain portions of the IRP 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. Rule 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 Affidavit of Service, the Executive Summary has been e-filed on the attached service list.

Please contact me at (218) 355-3297 or jkuklenski@mnpower.com with any questions regarding this filing.

Respectfully,



Jennifer Kuklenski
Regulatory Strategy and Policy Manager
Minnesota Power
30 W Superior Street
Duluth, MN 55802

JK:th
Attach.
cc: Service List

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Minnesota Public Utilities Commission's Revised Procedures for Handling Trade Secret and Privileged Data in furtherance of Minn. Stat. § 13.37 and Minn. Rule 7829.0500, Minnesota Power has designated portions of its 2025-2039 Integrated Resource Plan ("2025 Plan") as Trade Secret.

The 2025 Plan contains confidential financial information that is materially sensitive and commercially valuable to Minnesota Power. Minnesota Power follows strict internal procedures to maintain the secrecy 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. The 2025 Plan also contains specific customer data that consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Minnesota Power believes that this statement and the attached "Index of Trade Secret/Nonpublic Information Contained in the 2025 Plan" provides the justification as to why the information excised from the 2025 Plan should remain trade secret under Minn. Stat. § 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designations provided herein.

Index of Trade Secret/Nonpublic Information Contained in 2025 Plan

Location/Item	Trade Secret Justification
Appendix A: Minnesota Power's 2024 Annual Electric Utility Forecast	The information contained in this appendix is confidential, competitive information regarding Minnesota Power's methods, techniques, and process for supplying electric service to its customers and customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Appendix J: Assumptions and Outlooks	The information contained in this appendix is confidential information related to generation, fuel supply, transmission, and wholesale market energy prices that the Company considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has 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.



AN ALLETE COMPANY

MINNESOTA POWER 2025-2039
INTEGRATED RESOURCE PLAN

PETITION FOR APPROVAL

March 3, 2025
Docket No. E015/RP-25-127



THE NEXT CHAPTER

A reliable path to 90% renewable energy and replacing coal by 2035

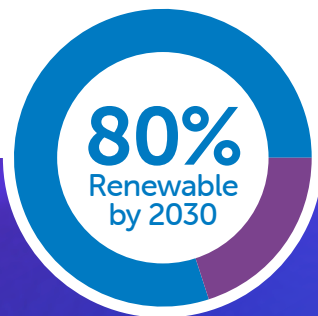
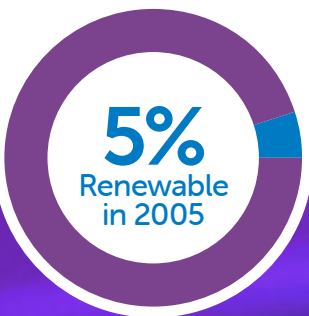
Our 2025 Integrated Resource Plan outlines the realistic next steps in our *EnergyForward* strategy to reduce carbon while maintaining 24/7 reliable energy to customers.

We're adding new renewable resources and energy storage, positioning to meet increasing demand for energy, reducing carbon emissions, and ceasing coal at Boswell Energy Center for our customers by 2035.

Through this diverse combination of resources, Minnesota Power will meet the requirements of the state of Minnesota's carbon-free standard while continuing to safeguard energy security, provide reliable electric service to customers and continue investing in our region.

Together we're moving *EnergyForward*.

OUR PROGRESS: 2005-2035



PLAN HIGHLIGHTS



400 megawatts of new wind

Add 400 megawatts of new wind projects by 2035 in addition to the 700 megawatts of renewables now in development



Expand energy storage resources by 100 megawatts by 2035



Maximize and expand customer-focused programs

Including energy efficiency and demand response



Add approximately 1,000 megawatts of natural gas capacity

Replacing the company's last coal-fired baseload generation at Boswell Energy Center for immediate carbon reductions

- Refuel Boswell Unit 3 to natural gas by 2030—355 megawatts
- Add about 750 megawatts of new natural gas
- Boswell Unit 4—Committed to cease utilizing coal in our power supply by 2035
- Will develop refueling options for Boswell Unit 4 and revisit in next Integrated Resource Plan

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I. ABOUT MINNESOTA POWER

Minnesota Power (or the “Company”), a division of ALLETE, Inc., is an investor-owned utility that serves approximately 150,000 retail electric customers and 14 non-affiliated municipal customers. Minnesota Power is defined by Minnesota statute as a public utility³⁸ and is the sole electricity provider across a 26,000-square-mile service area in central and northeastern Minnesota, where it employs over 1,000 people. The Company got its start in 1906 by harnessing the energy of the St. Louis River near Duluth, Minnesota. Hydroelectricity powered the homes and businesses of the Duluth area for years. Then, during and after World War II, the region saw a significant expansion of iron ore mining, forestry, and paper industries, grain exports, and ship building on Lake Superior. To accommodate northeastern Minnesota’s industrial growth, Minnesota Power’s generation fleet grew through the construction of the coal generating power plants at Laskin Energy Center (“LEC”), Taconite Harbor Energy Center (“THEC”), and Boswell Energy Center (“BEC”), which were built during the 1950s through the 1970s. Minnesota Power’s *EnergyForward* strategy to diversify its energy supply portfolio began in the 2000s, and since then the Company has closed or re-missioned seven of its nine coal plants, and transitioned from being 95 percent coal to between 50 and 60 percent renewable today. Minnesota Power remains committed to providing safe, reliable, affordable, and increasingly clean electricity to its customers.

This section covers the following topics:

- Background;
- Minnesota Power’s Unique Customer Mix; and
- Minnesota Power’s *EnergyForward* Journey.

A. Background

Public utilities provide essential services needed by every individual, business, and institution in society, and have a responsibility to ensure services are available and reliable. The investor-owned public utility model allows Minnesota Power to fund investments in infrastructure, such as transmission lines or renewable energy projects, through upfront money invested by shareholders. The costs for project development and delivery are recovered over time from customers through electric service rates to help mitigate the rate impact of large investments needed to maintain and upgrade the electric system.

As a public utility, Minnesota Power provides safe and reliable power to all customers within its service territory at a reasonable cost. The Company is regulated by the Minnesota Public Utilities Commission (or the “Commission”) which ensures that customers are charged just and reasonable rates, that infrastructure investments are prudent and useful, and that utility actions comply with state policy. Minnesota Power is currently a publicly traded company, meaning its ownership, and upfront capital investment needed for electric infrastructure, are distributed among many shareholders through public markets such as stock exchanges.

The Company is currently undergoing an acquisition proceeding before the Commission that if approved, will result in private ownership of ALLETE and Minnesota Power distributed among two experienced infrastructure investors – Global Infrastructure Partners and the Canada Pension

³⁸ At a high level, Minn. Stat. § 216B.02, subd. 4 defines a public utility as “persons, corporations, or other legal entities, their lessees, trustees, and receivers, now or hereafter operating, maintaining, or controlling in this state equipment or facilities for furnishing at retail natural, manufactured, or mixed gas or electric service to or for the public or engaged in the production and retail sale thereof”

Plan Investment Board.³⁹ The private acquisition of Minnesota Power will not change the Company's public utility designation under Minnesota statute and the Company will continue to be regulated by the Commission. The acquisition will provide stable access to the upfront capital needed to fund important infrastructure investments to support the Company's continued reliable service and carbon reduction actions outlined in the 2025 Integrated Resource Plan ("2025 Plan").

B. Minnesota Power's Unique Customer Mix

Minnesota Power serves 150,000 total customers today, including some of the nation's largest industrial operations. In 2023, 74 percent of Minnesota Power's kilowatt-hour ("kWh") total sales served retail industrial customers primarily in the taconite mining, paper, pulp and secondary wood products, and pipeline industries. The Company has a long history of serving these large industrial customers and today has eight Large Power customer contracts, each serving at least 10 megawatts ("MW") of load. Under these eight contracts, the Company provides electric service to six taconite producing facilities and four paper and pulp mills. In fact, 80 percent of American steel is born on Minnesota's Iron Range in the mining operations that Minnesota Power serves.

Most of these customers operate 24/7, which gives the utility a uniquely high load factor featuring power requirements with less variation in demand than most utilities. This high load factor ensures efficient utilization of Minnesota Power's system, creating value for all of its customers. Additionally, Minnesota Power has the largest amount of industrial demand response capability on its system in the state due to the unique partnership it has with these customers.

In part because of its uniquely high concentration of industrial customers and relatively low proportion of residential customers from a kWh sales perspective, Minnesota Power is expected to remain a winter-peaking utility for the foreseeable future. The Company's peak load is currently approximately 1,625 MW.

C. Minnesota Power's EnergyForward Journey

Minnesota Power continues to transform the way it energizes communities and businesses through its *EnergyForward* strategy. Today, the Company has evolved its energy supply mix by bringing more renewable power to all customers while reducing dependence on fossil fuels. *EnergyForward*, through the last several approved Integrated Resource Plans ("IRPs"), has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering between 50 and 60 percent renewable energy to customers. The Company was the first Minnesota utility to achieve the milestone of delivering 50 percent renewable energy to customers and is proud of how far it has come on this clean-energy transformation. The Company is continuing its leadership in the renewable energy space and ALLETE is the largest investor in renewable energy of any investor-owned utility in the country for its size. There is more work to do to achieve Minnesota's Carbon-Free Electricity Standard ("CFS") by 2040 and the 2025 Plan ensures necessary investments will be made in new resources and grid resiliency to maintain an electric system that is safe and reliable at a reasonable cost. Over the past two decades, the Company has undertaken actionable steps to integrate renewable generation into its power supply portfolio. In 2006 and 2007, Minnesota Power began purchasing the entire output of the Oliver County Wind Energy Center 1 and 2 (just under 100 MW), wind farms built and operated by NextEra Energy in North Dakota. In 2008, Minnesota Power constructed the Taconite Ridge Wind Energy Center ("Taconite Ridge"), the first commercial wind generating station in northern Minnesota. The Bison Wind Energy Center ("Bison") in North Dakota came next, with four phases of the project completed between 2010 and 2015. Bison,

³⁹ *In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners*, Docket No. E-015/PA-24-198.

now the largest wind farm in North Dakota with a capacity of just under 500 MW, leverages premier wind resources to deliver carbon-free energy via the Company's 465-mile High Voltage Direct Current line ("HVDC Line") to the Company's customers. In 2024, the Commission approved Minnesota Power's certificate of need ("CN") application for the HVDC Modernization Project, which will replace and upgrade the existing HVDC Line converter stations that are beyond their anticipated operational lives.⁴⁰ The upgraded converter stations will make it possible to increase the capacity of the HVDC Line from 550 MW to up to 1,500 MW if needed in the future. Minnesota Power secured \$75 million in state and federal funding awards to support this project and reduce overall costs for customers.

The Company operates a hydroelectric system capable of generating 120 MW of renewable energy across 11 hydroelectric facilities on five rivers in central and northeastern Minnesota, making it the largest producer of hydroelectricity in Minnesota. After record rainfall and flooding in June 2012, Minnesota Power had to repair and restore its Thomson Hydro Station. In 2014, Thomson returned to generating electricity enabling to the Company to maintain a key 72 MW hydroelectric resource on its system. The Company was recently selected for \$3.1 million in federal awards to maintain the Scanlon and Blanchard hydroelectric dams. In 2020, the Company implemented a Power Purchase Agreement ("PPA") with Manitoba Hydro, providing 250 MW of hydroelectric power to Minnesota after the 500 kilovolt ("kV") Great Northern Transmission Line ("GNTL") was energized. Minnesota Power also operates the Hibbard Renewable Energy Center ("HREC") in Duluth, Minnesota – a 50 MW biomass facility that utilizes primarily waste wood and forest residue that operates on the Day-Ahead Midcontinent Independent System Operator ("MISO") energy market, supporting critical reliability needs in the region.

In 2016, Minnesota Power completed the 10 MW Camp Ripley solar project. In 2018, the Company's 1.04 MW Community Solar Garden program officially started. In late 2020, Minnesota Power added 250 MW of wind energy through a PPA with the completion of the Nobles 2 Wind Farm. In 2020, the Commission asked the state's utilities to accelerate planned projects to help kick-start local economies affected by the COVID-19 pandemic. The Company's three resulting utility-scale solar projects generate 22.4 MW of carbon-free energy for customers, boost the tax base of local economies, created local union jobs, contracted with local and diverse suppliers whenever possible, and were built with solar panels from regional manufacturers. Minnesota Power also offers rebates for distributed residential and commercial solar generation and a first-of-its-kind income-qualified ("IQ") solar grant program for low-income customers through its unique SolarSense program.

Combined, Minnesota Power's renewable energy portfolio includes over 1,450 MW of generation. In its approval of Minnesota Power's 2021 IRP ("2021 Plan"), the Commission ordered the Company to procure additional cost-effective resources to meet its customer and renewable product needs between 2025 and 2030 by acquiring additional wind, solar, and storage demonstration projects with up to 400 MW of wind in service, up to 300 MW of regional/in-service territory or net-zero solar, and storage demonstration projects of at least 100 MW by 2026, as practicable.⁴¹

⁴⁰ *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/CN-22-607, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

⁴¹ *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33, Order Approving Plan and Setting Additional Requirements at 13 (Jan. 9, 2023).

In its effort to implement additional solar energy, Minnesota Power has filed petitions for approval of the Regal Solar Project⁴² near Royalton, Minnesota, and the Boswell Solar Project⁴³ in Cohasset, Minnesota. The Regal Solar Project will have a capacity of 119.5 MW, while the Boswell Solar Project will have a capacity of 85 MW. Both projects are expected to be in-service by mid-2027. Additionally, the Company issued a Request for Proposals (“RFP”) on January 30, 2025 in an effort to procure an additional 65 to 85 MW of DG solar by 2030.⁴⁴

Minnesota Power filed an RFP for up to 400 MW of wind resources regionally located within MISO Local Resource Zone 1 for the Commission’s review in December of 2023, and issued the RFP in February 2024. The RFP sought to maximize the economic benefits of wind development by including preferences for diverse bidders and domestically-sourced materials, project labor resource requirements for using local union labor for construction and permanent staffing, and the development of apprenticeship programs. The Company is currently conducting further evaluation on a short list of qualified projects. Final project selection has been delayed by widespread price and schedule uncertainties that have emerged during the shortlist period and delays in market interconnection studies. Minnesota Power continues to monitor and engage with bidders, contractors, and market representatives to resolve these uncertainties and will announce project selection as soon as possible.

Minnesota Power is also actively exploring various technologies to determine the optimal integration of energy storage within the Company’s electric system. Notably, Minnesota Power partnered with Lockheed Martin to submit a grant application for \$30 million in federal funding for a demonstration project of the GridStar Flow (“GSF”) long duration energy storage (“LDES”) battery. This partner demonstration project sought to install and operate a 4 MW/10-hour (40 MWh) GSF system at BEC and would have demonstrated the first operation of a grid connected GSF unit that could provide flexible support to the MISO market at a cold climate location. Minnesota Power’s LDES project was ultimately not selected for an award, which made the project infeasible for customers at this time. The Company continues to evaluate options to integrate energy storage projects into its electric system.

Minnesota Power is committed to providing safe, reliable, and increasingly clean energy for customers at a reasonable cost. In the 2025-2039 IRP, Minnesota Power has established a plan to deliver an annual energy portfolio that is 80 percent renewable by 2030 and 90 percent renewable by 2035, demonstrating compliance with the milestones outlined in the CFS. The Company will continue evaluating technology options and economic pathways to develop an annual energy portfolio that is compliant with the 100 percent by 2040 milestone in the CFS without sacrificing reliability, and while ensuring incremental cost increases to support the infrastructure buildout required to meet the state’s clean energy goals are transparent and reasonable.

⁴² *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Regal Solar Project for Recovery through Minnesota Power’s Renewable Resources Rider under Minn. Stat. § 216B.1645 and Related Tariff Modifications*, Docket No. E-015/24-343, Petition (Nov. 13, 2024).

⁴³ *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Boswell Solar Project for Recovery through Minnesota Power’s Renewable Resources Rider under Minn. Stat. § 216B.1645*, Docket No. E-015/M-24-344, Petition (Nov. 13, 2024).

⁴⁴ “Minnesota Power is seeking proposals for distributed solar resources,” available at <https://www.mnpower.com/Environment/DSESRFP>.

II. 2025 RESOURCE PLAN SUMMARY

This filing presents Minnesota Power's 2025 Plan for the period of 2025 through 2039. The 2025 Plan is filed pursuant to Minn. Stat. § 216B.2422, Minn. Rules Ch. 7843, and the Commission's January 9, 2023 Order on extending the filing deadline and setting additional requirements for this IRP.⁴⁵

Minnesota Power is pleased to submit the 2025 Plan, which outlines the next chapter in the Company's **EnergyForward** resource strategy and the Company's commitment to continuing its carbon reduction journey. **EnergyForward** has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering between 50 and 60 percent renewable energy to customers, making Minnesota Power the top provider of renewable energy in the state of Minnesota. The 2025 Plan, if approved, will enable an annual energy portfolio that is 80 percent renewable by 2030 and 90 percent renewable by 2035, demonstrating Minnesota Power's commitment to a sustainable path to compliance with Minnesota's CFS.⁴⁶ The 2025 Plan represents Minnesota Power's continued progress in decarbonizing its electric system, including ceasing coal utilization for its customers, resulting in a 95 percent carbon reduction from 2005 levels. Minnesota Power looks forward to iterative resource planning over the next 15 years to thoughtfully and sustainably identify a path toward full compliance with the CFS.

Importantly, this IRP outlines Minnesota Power's plan to achieve critical next steps in the energy transition that are centered on a commitment to provide increasingly clean electricity to customers without sacrificing reliability and affordability. The 2025 Plan also demonstrates Minnesota Power's continued commitment to the communities it serves by outlining refueling options as part of the Company's cease coal plan that provide reinvestment opportunities in our BEC host community. Moreover, Minnesota Power recognizes the importance of adding new economic growth to the region and communities it serves and the 2025 Plan is responsive to potential load growth scenarios. The Company specializes in its ability to serve large industrial load and therefore presents a plan that incorporates near-term and long-term actions that will allow flexibility for plans that optimize the economic and reliability needs for the region while accounting for anticipated growth.

As we look ahead to the next 15 years, Minnesota Power finds itself with a strong foundation of clean energy leadership, having ensured both reliability and affordability as it has transitioned to a power supply that is now over half renewable. The Company continues to serve a high load factor, energy-intensive customer base that presents unique challenges associated with it; therefore, progressing to the next levels of carbon reduction will become more complex and require technological innovation, while maximizing existing infrastructure to keep the transition affordable for customers. Both Minnesota Power's historical roots and its future success are tied to the region's unique natural resources-based economy, as it serves some of the nation's largest industrial customers in iron mining and forest product industries. Having served a large industrial base for decades, Minnesota Power looks forward to the opportunity to add new economic growth

⁴⁵ *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E015/RP-21-33, Order Approving Plan and Setting Additional Requirements (Jan. 9, 2023).

⁴⁶ Minn. Stat. § 216B.1691, subd. 2g requires "each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least" 80 percent by the end of 2030 for public utilities, 90 percent by the end of 2035 for all electric utilities, and 100 percent by the end of 2040 for all electric utilities.

to the region, while continuing to serve all customers' electricity needs. As Minnesota Power charts the next 15 years of its energy transformation, safeguarding reliability, supporting energy security, providing transparency, and maintaining reasonable rates for existing and new customers within the Minnesota planning framework are critical considerations as the Company continues to decarbonize its electric system.

Following Commission approval of Minnesota Power's 2021 Plan, the Company has taken several actions to continue its clean energy transition while maintaining safe and reliable service for customers. The Company has made several notable achievements in compliance with the Commission's Order in the 2021 IRP, including:

- Activated over 20 MW of utility scale solar across three sites at Laskin Energy Park near Hoyt Lakes, Minnesota, near Minnesota Power's Sylvan Hydro Station, west of Brainerd, Minnesota, and in Duluth, Minnesota.⁴⁷
- Retired the THEC in 2023.
- Petitions filed with the Commission for approval of the Boswell Solar Project and Regal Solar Project, which combined, will have a capacity of approximately 200 MW of regional solar in-service before the end of 2027.⁴⁸
- RFP issuance for 65 to 85 MW of DG solar projects.⁴⁹
- RFP issuance and evaluation for up to 400 MW of wind projects.⁵⁰
- Commission approval of a CN for the Duluth Loop Reliability Project, which will enhance power system stability and support, which was previously provided by local coal-fired generators that are now idled.⁵¹
- Commission approval of a CN for the HVDC Modernization Project, which will facilitate the continued delivery of high efficiency resources directly to Minnesota Power customers and pave the way for additional transmission capacity.⁵²

⁴⁷ "Local Solar, Local Benefits," available at www.mnpower.com/Environment/SolarProjects.

⁴⁸ *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Regal Solar Project for Recovery through Minnesota Power's Renewable Resource Rider under Minn. Stat. § 216B.1645*, Docket Nos. E-015/M-24-343, Petition (Nov. 13, 2024); *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Boswell Solar Project for Recovery through Minnesota Power's Renewable Resource Rider under Minn. Stat. § 216B.1645*, Docket No. E015/M-24-344, Petition (Nov. 13, 2024).

⁴⁹ *In the Matter of the Implementation of the New Distributed Solar Energy Standard pursuant to 2023 Amendments to the Minnesota Statutes, Section 216B.1691*, Docket No. E-002,E-015,E-017/CI-23-403, Request for Proposals Compliance Filing (Nov. 1, 2024).

⁵⁰ "Minnesota Power advances **EnergyForward** with request for proposals for up to 400 megawatts of wind energy," (Feb. 13, 2024), available at <https://investor.allete.com/news-releases/news-release-details/minnesota-power-advances-energyforward-request-proposals-400>.

⁵¹ *In the Matter of the Application of Minnesota Power for a Certificate of Need and a Route Permit for the Duluth Loop Reliability Project in St. Louis County, Minnesota*, Docket No. E-015/CN-21-140, Order Granting Certificate of Need and Issuing Route Permit (April 3, 2023).

⁵² *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/CN-22-607, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

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- Commission approval of two MISO Tranche 1 Long Range Transmission Planning (“LRTP”) projects that will support reliability needs in Minnesota and regionally as the electricity system continues to transition to cleaner sources of generation.⁵³
 - Securing \$78.1 million in state and federal funding awards to support needed upgrades to the Company’s existing transmission and hydroelectric infrastructure.
 - Achieved the Company’s 15th consecutive year of meeting or exceeding state energy conservation goals in 2024.
 - Commission approval of an extension of the Company’s SolarSense customer-sited distributed solar generation (“DG solar”) rebate and income-qualified solar grant program with modifications to improve equity within the program.
 - Acquired new distribution system planning software to improve forecasting and hosting capacity mapping to support distributed energy resource deployment.

The 2025 Plan builds on these achievements and outlines actions to continue the Company’s efforts to reduce carbon while maintaining a resilient and reliable electricity system that is responsive to customer needs and conscious of community and environmental impacts. The following components of Section II are organized as follows:

- Subsection A: Key Themes for the 2025 Plan;
- Subsection B: Critical Items Shaping this IRP;
- Subsection C: A Plan Responsive to Customers, Communities, the Climate, and the Region;
- Subsection D: Thoughtful, Sustainable, and Just Carbon Reduction;
- Subsection E: Action Taken to Support Continued Renewable Energy Integration;
- Subsection F: Leading on Energy Efficiency, Distributed Generation and Electrification Efforts;
- Subsection G: Managing Uncertainty with Flexibility for a Unique Region;
- Subsection H: Resource Plan Overview: Short- and Long-Term Action Plans; and
- Subsection I: Meaningful Progress with Reasonable Rate Impacts.

A. Key Themes for the 2025 Plan

Minnesota Power’s 2025 Plan represents a sound approach to delivering safe and reliable energy while making necessary investments to advance the clean energy transition. The key themes of the 2025 Plan reflect the Company’s long-held resource planning principles while meeting current state policy objectives.

⁵³ *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket No. E-015,ET2/CN-22-416, Order Granting Certificate of Need and Issuing Route Permit (Feb. 28, 2025); *In the Matter of the Application of for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Docket No. E-002,E-017,E-T2,E-015, E-T10/CN-22-538, Order Granting Certificate of Need and Issuing Route Permit (Oct. 30, 2024).

Reliability

The 2025 Plan prioritizes reliability and energy security to ensure customer electricity needs are met and system resiliency is not degraded, helping minimize disruptions in electricity service. Minnesota Power recognizes that the next steps of its *EnergyForward* strategy must be carefully coordinated to maintain the strong and resilient electricity system needed to serve its customers. This IRP has identified the largest need of dispatchable generation for Minnesota Power in the past 45 years. Minnesota Power's last remaining source of baseload capable generation – the BEC – continues to play a critical role in providing reliable energy to residents, businesses, and the unique industries that operate in northern Minnesota. As Minnesota Power advances its cease coal plan at BEC Unit 3 (“BEC3”) and BEC Unit 4 (“BEC4”), reliable fuel source alternatives are necessary before the Company can transition from existing coal generation. An innovative and new approach to ensuring reliability was integrated into the planning process with the addition of “reliability criteria” designed to monitor and inform planning decisions. Minnesota Power is committed to replacing coal and has identified natural gas as the cleanest, most reliable, flexible, and least cost option to replace nearly 1,000 MW of baseload generation supported by BEC3 and BEC4 in order to continue providing 24/7 electricity service to Minnesota Power's customers. Accordingly, to meet the Company's existing customer load, the 2025 Plan calls for the refuel of BEC3 with natural gas by 2030 and the immediate development of combined cycle natural gas generation to replace power removed at the cease coal dates for Minnesota Power customers by 2035 for BEC4. Additionally, the 2025 Plan incorporates future customer-driven activities like energy conservation and demand response, as well as additional investigation into biomass as a fuel source to support dispatchable and baseload energy needs.

Sustainability

The 2025 Plan offers bold next steps and necessary actions required to advance additional carbon reductions and complying with Minnesota's CFS while also considering the social and economic needs of Minnesota Power's customers and communities. The electric system must continue to provide increasingly sustainable and reliable sources of electricity that meets the necessary physical criteria to protect customers. The Company continues to make progress on its 2021 Plan, including approximately 200 MW of additional utility-scale solar, approximately 65 to 85 MW of DG solar additions, up to 400 MW of additional wind energy, and up to 500 MWh of new energy storage, by 2030 or sooner.

The 2025 Plan will result in the Company providing a transition to a coal-free power supply and, along with the cleaner natural gas support identified above, will include up to an additional 400 MW of wind energy, at least 100 MW of enhanced industrial demand response with economic curtailments, and 100 MW of energy storage by 2035. The 2025 Plan calls for continued operations at the HREC and will explore additional biomass investments as a future solid fuel alternative. This exploration will be based on the outcome of the Commission proceeding to develop a Life-Cycle Analysis (“LCA”) for biomass to be utilized as a carbon-free fuel source in compliance with the CFS and ongoing consultation with Tribal Nations and other stakeholders. This IRP represents an iterative planning approach and the 2025 Plan, if approved, will deliver an annual energy portfolio that is 80 percent carbon-free by 2030 and pave the path to deliver 90 percent carbon-free energy by 2035. Furthermore, the 2025 Plan results in 95 percent carbon reductions from 2005 levels.

The pursuit of cleaner technologies and evolution are paramount as we move forward. While not all technology is commercially available for full grid deployment at this time, the Company maintains its commitment to work with customers to support ongoing development of carbon minimizing alternatives. In the 2025 Plan, the Company has proposed a research and

development (“R&D”) fund to support new firm clean technology development, pilots, and demonstrations to support ongoing sustainability goals. Recognizing the importance of compliance with the CFS and continued progress on reducing carbon, the 2025 Plan presents a balanced approach to sustainability that considers environmental impacts of resource decisions along with social and economic needs of customers and communities served by Minnesota Power.

Transparency

Minnesota Power remains committed to working with customers, the communities it serves, and local and regional advocates in advancing the 2025 Plan. There are a number of uncertainties regarding the readiness of and costs associated with clean energy technology’s ability to reliably support 24/7 energy needs, as well as questions about expected customer load growth as electrification advances and prospective large power customers advance their economic interests in northern Minnesota. The action plans and timelines proposed in this IRP are meant to create greater certainty for customers and communities so they can do their necessary planning for the future. Additionally, the 2025 Plan identifies the incremental requirements for meeting state energy goals and incorporates actions associated with the infrastructure buildout necessary to comply with the CFS to encourage awareness for all customers and stakeholders. Minnesota Power is committed to continued work with regional partners to support its customers and communities during this time of historic energy transition. The Company completed a socioeconomic evaluation of the impact of HREC as well as a societal cost benefit analysis of HREC and BEC4 to ensure benefits of being a host utility were identified and were used to inform the 2025 Plan. The 2025 Plan recognizes the critical infrastructure located in both Duluth and Cohasset, Minnesota, and identifies actions that will continue leveraging existing infrastructure for cleaner energy options going forward.

Load Readiness

A unique feature of this IRP is the prospect for significant customer load additions. While uncertainty in customer demand outlook is inherently part of any IRP analysis, the 2025 Plan includes a future where Minnesota Power’s customer load could more than double with existing and new prospective customer operations. Indeed, the energy sector is experiencing historic levels of load growth across the nation as re-industrialization, beneficial electrification, advances in artificial intelligence (“AI”) technology, and associated data centers are prompting increased customer electricity demand. Minnesota Power recognizes that utilities must be ready to meet this moment, as the load growth the Company is anticipating will have the potential for positive economic impacts for the state, the region, and Minnesota Power customers specifically. At the same time, the Company understands the importance of the resource planning process in Minnesota and wants to help ensure that its planning can efficiently pivot should new customer load be added to its system and has proposed a set of actions that, if approved, would take effect should new customer load up to 1100 MW emerge. Minnesota Power’s uniquely large industrial customer mix has often resulted in large swings in customer demand for which the Company is accustomed to planning (reference Figure 3 in Section III to see how industrial demand has varied since 1990). The magnitude of load growth potential Minnesota Power is planning for is unmatched in recent study periods, but the Company is well positioned to accommodate an expanded industrial sector given its history in serving these types of customers both reliably and cost-effectively. To capture the variety of possible future demand scenarios, the 2025 IRP analysis included a range of load sensitivities from a large industrial customer increase (+1500 MW) to the loss of industrial load (-200 MW).

B. Critical Items Shaping this IRP

Minnesota Power's 2025 Plan presents the next phase of the Company's *EnergyForward* resource strategy and while some resources included in our near-term and long-term plans have naturally changed from the Company's 2021 Plan in response to a changing policy landscape and market conditions, the overall direction is the same.

Stakeholder Input

In 2019, Minnesota Power established a first-of-its-kind stakeholder engagement process to inform its last IRP. Minnesota Power enhanced this engagement process by working intentionally to include stakeholders from groups historically not represented in these types of regulatory proceedings and expanded engagement opportunities to include opportunities for stakeholders to interact outside of formal meetings and tour Minnesota Power generation facilities. Stakeholders participated in a series of in person, virtual, and hybrid meetings to inform the Company's modeling inputs and help create a societal cost-benefit analysis framework used to assess the impacts of the 2025 Plan as well as the costs and benefits of associated with BEC4 and HREC.

Together, stakeholders evaluated the positive and negative impacts of these generation facilities on host communities, local economies and workforce, customer costs, public health, the environment, and system reliability. It was clear throughout the engagement process that stakeholders were concerned about reliability as Minnesota Power advances its cease coal plan, and that ratepayer impacts of the Company's clean energy transition be transparent, incremental, and reasonable. Commitment to maintaining jobs in host communities, particularly at BEC, was also noted as a priority among stakeholders, as was the importance of additional economic opportunities for transitioning communities, such as those associated with large power load growth.

Capacity Replacement at BEC

The consideration of replacing the power capability of the remaining two units at BEC makes this 2025 IRP one of the largest planning deficits identified in many decades. BEC makes up approximately 30 percent of customers' energy supply and is a strong baseload pillar for the Company's energy-intensive customer base making up 40 percent of the capacity that serves customers. Evaluation in this IRP has demonstrated that in order to maintain Minnesota Power's current customer load and meet the timeline for cease coal commitments, new natural gas generation is the cleanest, least cost resource that can match BEC's current capacity and contributions to the reliable and flexible power supply that Minnesota Power customers require and expect.

Natural gas allows for a significant reduction in the carbon profile from coal on an ongoing basis and can provide additional flexibility in an increasingly variable system. Hearing feedback from stakeholders and recognizing the need for capacity replacement after ceasing coal at BEC, Minnesota Power's 2025 Plan proposes a near-term gas refuel at BEC3. Doing so will allow the Company to leverage existing infrastructure to support cost efficiencies for capacity replacement needs and will allow the Company to reinvest in the host community surrounding BEC while maintaining existing jobs at BEC. In concert with the refuel, the Company has identified that 750 MW of combined cycle natural gas generation is needed by 2035 to modernize and prepare Minnesota Power's system for operating without coal-fired generation. New natural gas additions will position the Company for minimizing carbon emissions with additional fuel or technology advancements as available.

Additionally, to position the Company for compliance with existing federal greenhouse gas (“GHG”) emissions rules for 2030, the 2025 Plan proposes preparing for a partial gas refuel at BEC4 with at least 40 percent natural gas capability. Further review of this project will be done if there are changes to GHG rules or requirements.

Finally, the Company’s 2025 Plan, if approved, will allow Minnesota Power to make R&D investments to integrate emerging clean firm technology with customers and investigate biomass as a future solid fuel alternative. Pending a Commission decision deeming biomass an eligible energy technology for compliance with the CFS,⁵⁴ federal recognition for Production Tax Credit (“PTC”) qualification, and ongoing consultation with Tribal Nations and other stakeholders, Minnesota Power will work to advance the ability to co-fire biomass as part of the annual BEC fuel plan.

Preparing for Load Growth

Minnesota Power understands the importance of its responsibility in serving customers and supporting regional economic opportunities that result from customer load additions. Therefore, the Company is actively planning for approximately 1100 MW of expected load growth based on existing customer plans and commitments. The 2025 IRP evaluation distinctly identifies the resources and least cost plans needed to serve new load at these levels while also continuing to meet CFS requirements.

The 2025 Plan offers an innovative and flexible approach that will prepare the Company’s system as new load emerges by requesting approval of a Growth Plan adaptable to developing economic conditions as new customer load is added to the Company’s service territory, and resulting in benefits to customers and the region. Minnesota Power’s approved plan must be nimble enough to meet the economic moment and position for load growth possibilities in a way that is unique to past IRPs.

The Company’s long-term action plan therefore seeks to prepare plans to implement up to 750 MW of new peaking generation and increase renewable implementation to include up to 2200 MW of wind, 200 MW of solar, and 300 MW of energy storage to ensure Minnesota Power’s renewable portfolio is positioned to comply with the CFS. Minnesota Power will also work with new industrial customers on incorporating demand response into their operations, where it is feasible and economic. Furthermore, any new supply additions will be brought forward to the Commission as part of a power supply agreement that outlines the new customer’s responsibility for resource additions and the benefits they will provide to existing customers. If additional load emerges above the 2025 planning level, Minnesota Power will submit a dedicated power supply plan for Commission approval as needed prior to its next IRP submission date.

Compliance with the Carbon-Free Standard

Underlying the development of the 2025 Plan is compliance with the CFS, which requires Minnesota utilities to generate an amount of carbon-free electricity equivalent to their Minnesota retail sales by 2040. The Company is proud to be able to present a plan in 2025 that results in an annual energy portfolio that is 90 percent carbon-free and compliant with the CFS requirement to be 90 percent carbon-free by 2035. In this IRP, Minnesota Power evaluated what would be required to develop an annual energy portfolio that results in 100 percent compliance with the CFS with the commercially available technology anticipated to be available by the cease coal commitment timeline. The preliminary results indicated that exorbitant amounts of wind, solar,

⁵⁴ *In the Matter of a Commission Investigation into a Fuel Life-Cycle Analysis Framework for Utility Compliance with Minnesota’s Carbon-Free Standard*, Docket No. E-999/CI-24-352, Order Initiating New Docket and Clarifying “Environmental Justice Area” (Nov. 7, 2024).

and storage overbuild would be required at very high and volatile cost to customers while destabilizing the system and increasing the likelihood of power outages. With 15 years left to plan for compliance with the CFS, Minnesota Power is encouraged by the considerable progress made to date in its carbon-free energy portfolio and is confident that the Company will continue to get closer to full compliance with the 2040 CFS with each subsequent IRP. Further, this IRP proposes a first-of-its-kind for Minnesota Power R&D fund to continue exploring clean firm technologies for future implementation.

The 2025 Plan's proposal for an R&D budget, in addition to the evaluation of biomass as a future solid fuel capacity replacement at BEC, would allow the Company to explore other projects with customers on emerging clean, firm technology. Recognizing that public utilities are usually not early adopters of emerging technology, due to reliability requirements and the costs associated with developing pilot and demonstration projects, the proposed R&D budget will provide Minnesota Power an avenue to explore projects with interested customers during this historic time as technology continues to evolve as we near 2040.

For example, Minnesota Power submitted a partnership grant application for \$30 million in U.S. Department of Energy ("DOE") funding available through the Bipartisan Infrastructure Law ("BIL") and federal Infrastructure Investment and Jobs Act ("IIJA") for a demonstration project of the GSF LDES battery. This partner demonstration project sought to install and operate a 4 MW/10-hour (40 MWh) GFS system at BEC and would have demonstrated the first operation of a grid connected GSF unit that could provide flexible support to the MISO market at a cold climate location. While the application was a finalist for consideration, Minnesota Power's LDES project was ultimately not selected for an award which made the project too expensive for customers to move forward with at this time. However, innovative partnerships with new customers on projects like this demonstration project are the kinds of efforts the new R&D fund could support.

In its next IRP, Minnesota Power will evaluate additional actions needed to meet the 2040 CFS requirement, including a review of the Manitoba Hydro and other renewable PPAs' terms and replacement alternatives, as well as progress on biomass including the outcome of the ongoing CFS LCA proceeding expected to conclude at the end of 2025.⁵⁵ The Company will also continue exploration of additional transmission alternatives for accessing broader regional capacity and optimization in its next IRP. Finally, Minnesota Power affirms its commitment and takes meaningful steps to advance ceasing coal at BEC4 in the 2025 Plan, and the Company intends to further clarify its cease coal plan for BEC4 and provide specific actions to be taken at the facility in its next IRP in coordination with the facility's co-owner partner, WPPI Energy, while continuing to prioritize reliability of the system and affordability as customer needs and the power supply evolves.

C. A Plan Responsive to Customers, Communities, the Climate, and the Region

As noted above, Minnesota Power engaged again for this 2025 IRP in a year-long stakeholder engagement process to inform the development of the 2025 Plan. The engagement process brought together a diverse group of participants representing various customer groups, environmental organizations, economic development entities, local government, industry, the host communities, and others. Multiple engagement meetings allowed participants the opportunity to provide their perspectives regarding Minnesota Power's future energy mix and the impacts of

⁵⁵ *In the Matter of a Commission Investigation into a Fuel Life-Cycle Analysis Framework for Utility Compliance with Minnesota's Carbon-Free Standard*, Docket No. E-999/CI-24-352, Order Initiating New Docket and Clarifying "Environmental Justice Area" (Nov. 7, 2024).

transitioning the current power system. In response to the Commission’s Order in the Company’s last IRP, participants also provided input on a societal cost-benefit analysis of BEC4 and HREC, considering impacts on host communities, workforce, economics, public health, system reliability, the environment, and customers.⁵⁶ The Center for Energy and the Environment and the Great Plains Institute were hired as independent facilitators of the stakeholder process.

The engagement process included three overlapping groups of interested parties:

1. *The Engagement Group*: a broad set of participants that convened four times to build a shared understanding of the policy, technology, and socio-economic landscape for the 2025 IRP.
2. *The Societal Advisory Group*: a subgroup of participants from the Engagement Group that convened three times to inform the development of a societal cost-benefit analysis (“SCBA”) for any Minnesota Power generation facility, including but not limited to HREC and BEC4.
3. *The Technical Advisory Group (“TAG”)*: a subgroup of participants from the Engagement Group that convened regularly over several months to discuss modeling assumptions and methodologies for the IRP, as well as technical topics such as MISO’s transmission planning process and seasonal resource adequacy construct.

The work of these three subgroups were intended to be complementary to one another. At the onset of this IRP’s engagement process that began in February 2024, Minnesota Power heard from participants – many of whom participated in the Company’s last IRP engagement process – that they did not want to reinvent a process but rather preferred to refine and build from the first-of-its-kind engagement process developed for the 2021 IRP. Minnesota Power appreciates the time that participants and facilitators dedicated to this process and has incorporated their feedback to evaluate the social, economic, and environmental impacts of the 2025 Plan in addition to the societal costs and benefits of HREC and BEC4.

While the full engagement report is included in Appendix N to this IRP, in order to organize stakeholder feedback in a way that could be used to inform the development of the 2025 Plan, participants developed a framework for what an “acceptable,” “unacceptable,” and “best case” future situation might look like for a refined set of impact areas from the customer, environmental, local economy, and utility perspective as shown in Figure 1 below.

Minnesota Power used this forward-looking impact map to develop a plan that is responsive to what engagement participants shared was most important. The Company heard clearly from participants that stakeholders were concerned about the costs of compliance with the CFS, as well as reliability concerns, as Minnesota Power advances its cease coal plan. Uncertainty about the readiness of technologies that could replace the capacity currently provided by BEC3 and BEC4 was a common theme throughout the engagement meetings, as were the customer impacts of the overbuild of wind and solar resources required if replacement technologies do not prove to be commercially available or reliable prior to 2040.

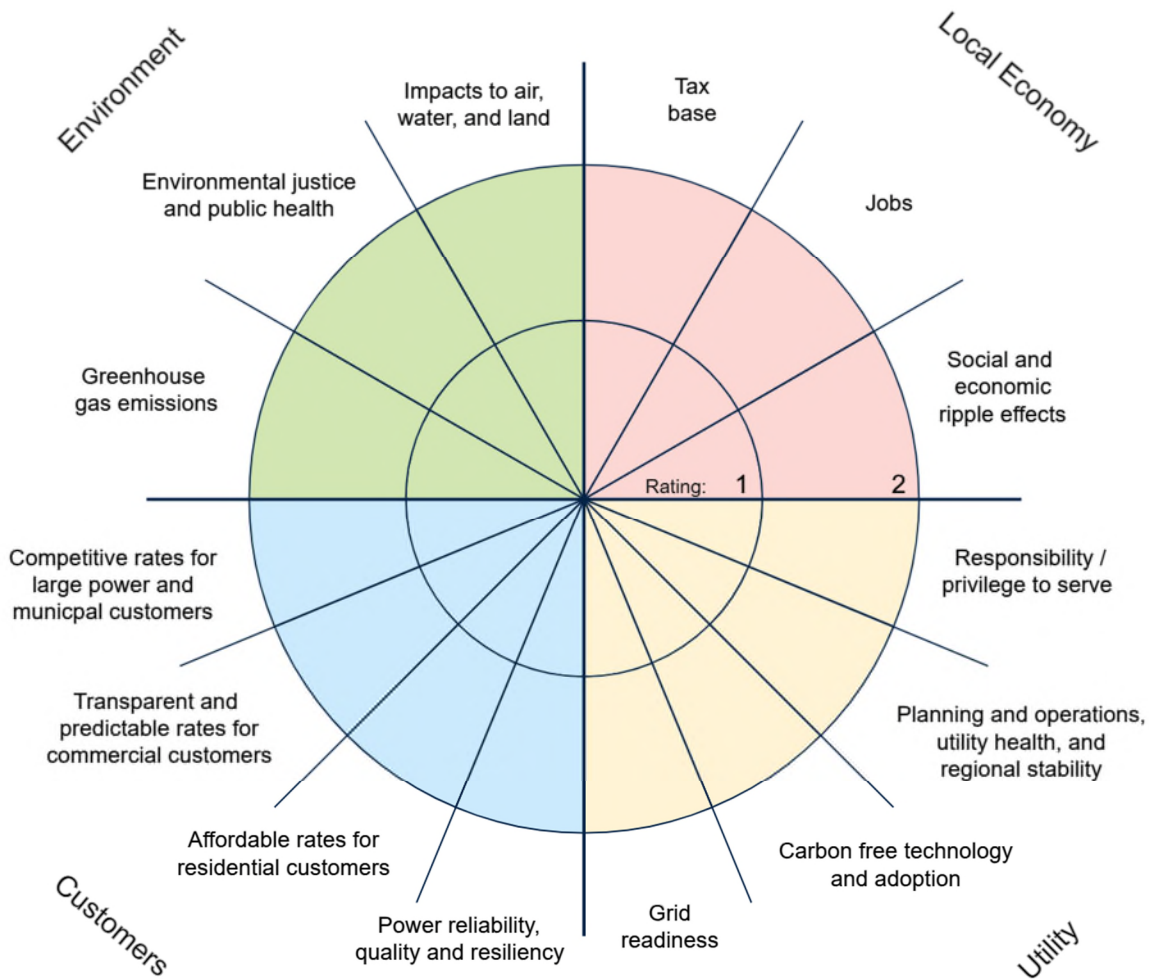
As was identified in the 2021 IRP engagement process, commitment to maintaining jobs in host communities, particularly at BEC, continues to be a priority among participants along with the importance of additional economic opportunities for transitioning communities, such as those associated with large power load growth. Impacts to the local tax base and school district funding in Cohasset as BEC3 and BEC4 cease coal were also identified as a high priority among

⁵⁶ *In the Matter of Minnesota Power’s 2021- 2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33. Order Approving Plan and Setting Additional Requirements at Order Point 11b (Jan. 9, 2023).

participants in northern Minnesota. While participants clearly recognized the importance of transitioning the electric power system amidst extreme weather events that are increasing in frequency and severity as the climate changes, participants are concerned about the costs associated with the infrastructure buildout necessary to make that transition in the timeframe outlined in the CFS. Minnesota Power heard that transparent and incremental cost increases were important to participants to avoid rate shocks and ensure that households, businesses, and communities can effectively plan for their economic futures.

Finally, in addition to the formal facilitated stakeholder process, Minnesota Power gave all customers an opportunity to share their preferences related to their future energy supply via an electronic survey. The survey included questions regarding system reliability, affordability, carbon-free energy renewable goals, and local economic impacts. Despite a limited response rate, the survey results clearly indicated that reliability and affordability were the top concern for the majority of respondents, with over 80 percent indicating one of these two concerns were most important to them, and approximately 20 percent of customers indicating the environmental impacts of electricity generation was their top concern. Survey respondents ultimately signaled a preference for a balanced approach to resource planning to ensure reliability and affordability while managing environmental impacts. Minnesota Power values all input from customers, community members, and regional advocates, and will continue to engage them through bill messages, social media, the Minnesota Power website, and additional engagement meetings after the submission of this IRP filing.

Figure 1. Minnesota Power’s IRP Impact Map⁵⁷



D. Thoughtful, Sustainable, and Just Carbon Reduction

Thoughtful planning for compliance with the CFS and transitioning Minnesota Power’s last remaining coal units is not only critical to ensuring reliability for energy customers at rates they can afford, but also key to ensuring the Company’s commitment to a just transition for employees and host communities who have helped power the region for decades. Since 2005, Minnesota Power has reduced carbon emissions by 50 percent and retired, idled, or re-missioned seven of its nine coal-fired generation units, removing approximately 700 MW of coal-fired generation from its approximately 1600 MW system. The 2025 Plan identifies actions that will deliver an annual energy portfolio that is 80 percent carbon-free by 2030 and pave a sustainable path to meet the 90 percent carbon-free electricity CFS requirement by 2035. Minnesota Power’s *EnergyForward* strategy has already made significant carbon emissions reductions by leveraging existing

⁵⁷ The impact map and corresponding discussion is captured in Appendix N.

infrastructure and maintaining a dispatchable generation portfolio to deliver near perfect reliable electric service to customers. The 2025 Plan, as described in detail in Section V, will take further carbon reduction actions while modernizing the dispatchable generation portfolio that is responsible for ensuring necessary reliability in all 24/7 operating conditions and by 2035 will result in 95 percent carbon reductions from 2005 levels.

Minnesota Power is continually following and studying technology developments to determine the best path forward in meeting the CFS. While this IRP identifies specific steps the Company will take to reduce carbon emissions, new technology deployment is needed to meet the CFS by 2040. Technology evolution in the energy industry is occurring rapidly, and the Company is optimistic that due to technological advances in lower carbon dispatchable alternatives, renewable energy, energy storage, and demand side resources, more cost-effective options will be available in future years to support the next chapters in carbon reduction efforts. Minnesota Power's customers are best served by a resource strategy that is diverse, flexible, and nimble to be able to help develop and capitalize on these technology developments at the right time to maintain affordability. Advancing too soon, or adopting unproven technologies at large scale, can create unnecessary risk and cost for customers.

Refueling with natural gas at BEC represents a thoughtful, sustainable approach to maintaining a reliable electricity supply for customers while working toward the CFS requirement that Minnesota Power generate or procure an amount of electricity from carbon-free energy technologies that is equivalent to 100 percent of its total retail electric sales to retail customers by the end of 2040. While exact carbon emissions associated with coal and natural gas can vary depending on environmental controls at the generating facility, as well as the type of coal used as fuel, burning natural gas for energy results in significantly fewer carbon dioxide emissions than burning coal to produce an equal amount of energy. Natural gas consumption for electricity generation produces approximately 45 percent less carbon emissions compared to coal. Additionally, natural gas-fired generators, particularly those that operate in a combined-cycle configuration, are more efficient than coal-fired generators, requiring significantly less energy input to produce the same amount of electricity and further reducing carbon emissions.⁵⁸ A natural gas refuel at BEC will result in other immediate benefits, including significant reduction in coal handling and associated dust, including a reduction in the size of the coal pile, no new coal ash waste, and coal no longer being transported by rail to the facility. Refueling with natural gas at BEC therefore offers an efficient and economical source of capacity replacement that will result in immediate carbon emissions reductions for Minnesota Power's energy portfolio and meet the 2030 commitment to cease coal operations at BEC3 by 2030. Progress on carbon emissions reductions in the 2025 Plan is discussed further in Section V.

For Minnesota Power, sustainability means more than just reaching the landmark environmental goal of providing a carbon-free power supply. Sustainability also extends to supporting the Company's customers and unique region. As such, for a carbon-free energy future to be truly sustainable it needs to ensure a just transition for workers and communities directly affected by energy system changes and ensure our customers can afford the energy they rely on. A natural gas refuel at BEC allows the Company to leverage existing infrastructure while making investments that support the transitioning BEC host community by maintaining some of the existing jobs at the facility and the tax base the surrounding communities rely on. Minnesota Power is committed to charting a future energy path that considers the quality of life in our region,

⁵⁸ U.S. Energy Information Administration, "Electric power sector CO₂ emissions drop as generation mix shifts from coal to natural gas," (June 9, 2021), available at <https://www.eia.gov/todayinenergy/detail.php?id=48296>.

while addressing climate change, promoting economic growth, and supporting strong communities.

While this 2025 Plan represents meaningful action on carbon reduction, the Company is also investigating carbon neutrality efforts and the ability to make key advancements in that field in the near term. Minnesota Power is particularly interested in carbon neutrality efforts that leverage the natural resources in northern Minnesota and that invest in the unique region it serves. As an example of this effort, in January 2021, Minnesota Power partnered with the University of Minnesota's Natural Resources Research Institute on a grant application to the United States Forest Service to investigate the production of biochar at Minnesota Power facilities, evaluate carbon credit opportunities, and deploy a biochar soil amendment at a Minnesota Power or customer site. Biochar is carbonized biomass that is obtained from sustainable sources (like northern Minnesota timber) and sequestered in soils to sustainably enhance their agricultural and environmental value.⁵⁹ In 2022, the Company applied roughly three tons of balsam fir biochar to an ash landfill at BEC as part of a re-vegetation study.⁶⁰ In 2023, the Company was awarded a \$271,480 U.S. Department of Agriculture ("USDA") Forest Service Wood Innovations Grant to study biochar soil application and production methods.⁶¹ As the paper industries that have supported northern Minnesota's economy for over a century are in decline, finding new and sustainable markets for wood resources is critical to the regional economy and forest management. Minnesota Power looks forward to investigating this, and other, carbon neutrality efforts on its path to a carbon-free energy future.

E. Action Taken to Support Continued Renewable Energy Integration

In addition to ceasing all coal operations, the 2025 Plan identifies Minnesota Power's near-term plan to further reduce carbon emissions by adding renewable energy. Minnesota Power was the first utility in the state to offer a power supply that was 50 percent renewable, exceeding the state's Renewable Energy Standard ("RES") a full decade early. Today, the Company is proud to offer between 50 to 60 percent renewable energy to customers. With wind and solar being implemented from the 2021 IRP, Minnesota Power will exceed the state's newly updated RES several years early, which requires that 55 percent of electric retail sales be generated from eligible energy technologies by 2035.⁶² In the 2025 Plan, Minnesota Power is proposing to continue its state-leading renewable energy additions by adding an estimated 400 MW of new wind energy and 100 MW of additional energy storage for implementation by 2035 in its Base Plan⁶³ and even more with its Growth Plan.⁶⁴ The Company also intends to bring forward a proposal for Commission consideration for up to 500 MWh of new energy storage in 2026 and finalize the implementation of wind and solar projects called for in the 2021 IRP. These actions will bring the total RES eligible renewable percentage to just over 90 percent by 2035. Additional information about Minnesota Power's renewable energy portfolio can be found in Appendix H.

⁵⁹ Biochar for Sustainable Soils, "What is Biochar?," available at <https://biochar.international/the-biochar-opportunity/what-is-biochar/>.

⁶⁰ University of Minnesota Duluth, "Ancient biochar method revamped for modern challenges," (Feb. 7, 2023), available at <https://nrri.umn.edu/news/balsam-fir-biochar>.

⁶¹ Dovetail Partners, "Dovetail Partners Receives \$271,480 from USDA Forest Service Wood Innovations Grant Program," (July 6, 2023), available at <https://dovetailinc.org/blogdetail.php?id=64a7158aa706d>.

⁶² Minn. Stat. § 216B.1691, subd. 2(a).

⁶³ The proposed plan to meet the Base Case discussed in Section V.

⁶⁴ The proposed plan to meet the +1100 MW Growth Scenario discussed in Section V.

Solar and Wind Resource Acquisitions

Minnesota Power continues to advance its last approved IRP by submitting for Commission approval projects that will add approximately 200 MW of regional in-service territory solar capacity to the Company's electricity portfolio by end of 2027. Since filing its 2021 IRP, Minnesota Power has energized three local utility-scale solar projects that have a combined capacity of 22.4 MW.⁶⁵ Additionally, in January 2025, Minnesota Power issued its first RFP in an effort to add an additional 65 to 85 MW of DG solar by 2030. In early 2024, the Company issued an RFP for up to 400 MW of regionally located wind projects and has since shortlisted four wind projects for further evaluation.

Hydro Power Upgrades

Minnesota Power operates 10 regulated hydroelectric facilities and one non-regulated hydroelectric facility on five rivers in central and northeastern Minnesota. The facilities are operated under seven licenses from the Federal Energy Regulatory Commission ("FERC") and produce more than 120 MW of electricity in total. While the Company has no current plans to construct new hydroelectric stations, the relicensing process with FERC will continue for existing stations. The Final License Application ("FLA") was submitted for the Prairie River Project in 2021. The Pre-Application Documents ("PAD") and Notice of Intent ("NOI") for re-licensure of the Little Falls, Sylvan, and Pillager facilities were submitted in 2023 and will be submitted for the Saint Louis River Project in 2030, Blanchard in 2038, and Winton in 2039. The Company recently received \$3.1 million in federal awards from the DOE under section 247 Hydro Maintaining and Enhancing Hydroelectricity Incentives to maintain the Scanlon and Blanchard dams, reducing operations and maintenance ("O&M") costs for customers.

Biomass Operations

Sustainably managed wood species provide a renewable energy option for power generation in northern Minnesota. Minnesota Power currently operates one biomass generation facility: HREC in Duluth, Minnesota. HREC utilizes primarily waste wood and forest residue, which provides a renewable, recyclable, low sulfur fuel source. Previously, HREC also sold steam to a pulp and paper mill in Duluth, Minnesota. Following a change in ownership of the paper mill and a transition from printing and writing papers to the production of tissue papers, steam from HREC was no longer needed at the Duluth mill. HREC now exclusively operates as a dispatchable resource in the Day-Ahead MISO energy market, while supporting critical reliability needs. The 2025 Plan proposes to continue operations at HREC to support regional reliability needs and renewable integration, making investments in the facility as necessary to support efficiency and environmental improvements, such as the installation of Fuel Feeders on both boilers in 2025 and 2026. As mentioned above, Minnesota Power continues to explore biomass generation options, both as potential new facilities and as generation alternatives such as co-firing at BEC. The evaluation of these options is detailed in Appendix J.

⁶⁵ "Local Solar, Local Benefits," available at www.mnpower.com/Environment/SolarProjects.

F. Energy Efficiency, Distributed Generation, and Electrification Efforts

As Minnesota Power continues its state-leading path in adding renewable energy and reducing carbon, customer-driven resources like energy efficiency, demand response, distributed generation (“DG”), and electrification will play an important role in reducing carbon on the system.

Energy Efficiency and Conservation

Minnesota Power, together with its customers, community stakeholders, and trade allies, has achieved success through its energy conservation programs and has surpassed Minnesota’s energy savings goal each year since it was implemented in 2010. On average, nearly 70 million kWh of energy savings were achieved each year over that decade. The Company intends to continue building upon its successful track record of supporting energy efficiency and has committed in its most recent Energy Conservation and Optimization (“ECO”) Triennial Filing to an energy savings goal between 2.8 and 2.9 percent through 2026, well above the state’s 1.75 percent energy savings goal.⁶⁶ Minnesota Power has committed to continued, ambitious energy savings goals over the next several years.

Partnerships with the Company’s customers for efficiently meeting their energy needs is at the core of Minnesota Power’s business. Through decades of optimizing the infrastructure in the region, Minnesota Power has created a strong reputation and trust with its customers as the Company helps educate and implement new programs and energy options. Minnesota Power has offered a rebate program for customers to install their own DG solar systems since 2004, nearly a decade before Minnesota passed the 2013 Solar Energy Standard (“SES”). The Company has since expanded that program and was the first in Minnesota to offer a dedicated solar grant program to help income-qualified customers overcome solar adoption barriers. Between 2014 and 2023, the Company provided grant funding for more than 20 low-income solar projects. On January 8, 2025, the Commission approved Minnesota Power’s petition to extend the SolarSense rebate and grant program for an additional three years with modifications that would improve equity within the program.⁶⁷

Electrification

In addition to conservation and renewable energy programs for customers, Minnesota Power is committed to facilitating electrification and offers a number of electric vehicle (“EV”) programs to customers. The Company has offered a Residential Off-Peak EV Service Tariff since 2015.⁶⁸ Specifically for commercial customers, Minnesota Power’s EV Commercial Charging Rate Pilot was approved by the Commission on December 12, 2019.⁶⁹ On July 31, 2020, the Company also filed a petition for approval of a portfolio of EV programs designed to address persistent barriers to residential EV adoption in northern Minnesota, including a Residential EV Charging Rebate Program, and a dedicated Education and Outreach budget for EV programs. The Company is nearing construction of the first of 16 public Direct Current Fast Chargers (“DCFC”), intended to equitably expand access to charging infrastructure across Minnesota Power’s service territory.

⁶⁶ *Minnesota Power’s 2024-2026 Triennial Energy Conservation and Optimization Program Filing*, Docket No. E-015/CIP-23-93, Minnesota Power’s ECO Triennial Compliance Filing (June 30, 2023).

⁶⁷ *In the Matter of Minnesota Power’s Ongoing Compliance of its SolarSense Program with Minnesota’s Solar Energy Standards*, Docket No. E-015/M-20-607, Order Accepting Report and Approving Program Extension with Certain Proposed Modifications (Jan. 8, 2025).

⁶⁸ *In the Matter of Minnesota Power’s Petition for Approval of a Residential Off-Peak Electric Vehicle Service Tariff*, Docket No. E-015/M-15-120, Order Approving Tariffs and Requiring Filings (June 22, 2015).

⁶⁹ *In the Matter of the Petition for Approval of Minnesota Power’s Portfolio of Electric Vehicle Programs*, Docket No. E-015/M-20-638, Order Approving Proposals with Modifications (April 21, 2021).

When this project is complete, no driver in Minnesota Power's service area will be more than 30 miles from EV charging infrastructure. In December of 2024, the Company proposed a make-ready pilot to enable at-home charging for residents of multiple unit dwellings to continue expanding charging infrastructure for customers wherever they live. More information about Minnesota Power's electrification efforts can be found in its annual Transportation Electrification Plan filing, submitted to the Commission as part of its Integrated Distribution Plan ("IDP") on November 1, 2023.⁷⁰

Demand Response

Minnesota Power has been optimizing, with its industrial customers, one of the largest demand response programs in the nation, implementing a robust emergency demand response program that will continue to evolve. Leveraging the flexibility of its unique customers to assist in managing the electricity needs of the region will continue to be vital as Minnesota Power moves towards an efficient decarbonization of the system. The need for long-term demand response opportunities is emerging as Minnesota Power bridges and manages volatility in available resources and paves the pathway with new innovative technologies. The continued energy system transformation will require all tools to be available and provide value to the grid. Minnesota Power will continue to work with its customers to implement a long-term enhanced demand response product, which would add energy curtailment needed to help manage renewables, and monitor MISO requirements for qualification as a capacity resource to maximize this resource for our region. The Company utilizes this customer-focused program to augment its portfolio and reduce capacity deficits, reducing the need for additional generation capacity.

Distributed Solar Energy

In 2023, the Minnesota Legislature established the Distributed Solar Energy Standard ("DSES") in Minnesota Statute § 216B.1691, subd. 2h, which requires that at least 3 percent of Minnesota Power's total retail electric sales in Minnesota be generated from solar energy generating systems by the end of 2030. Compliance with the DSES is meant to be an iterative process that incorporates stakeholder feedback into multiple "rounds" of RFPs to identify projects that will help meet the DSES. Minnesota Power issued its first DSES RFP on January 30, 2025⁷¹ and currently expects to need approximately 65 to 85 MW of DSES projects to be in compliance with the DSES by the end of 2030. The DSES presents an opportunity to work with interested customers and communities to support their direct participation in the clean energy transition and local renewable energy goals.

Rate Design and Advanced Metering

Finally, Minnesota Power continues to prepare both the technical infrastructure and electric rate structure to facilitate a future clean energy system that leverages a more dynamic grid, capturing the benefits of conservation, distributed energy resources, electrification, and more. In December 2020, the Company submitted to the Commission an innovative proposal, developed with extensive stakeholder engagement, to transition its electric rate design from its historical Inverted Block Rate structure to a modern Time of Day rate for all residential customers – which

⁷⁰ *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-23-258, Integrated Distribution Plan (Nov. 1, 2023).

⁷¹ *In the Matter of the Implementation of the New Distributed Solar Energy Standard Pursuant to 2023 Amendments to the Minnesota Statutes, Section 216B.1691*, Docket No. E-002, E-015, E-017/CI-23-403, DSES Request for Proposals Issuance Notice (Jan. 31, 2025).

is the first such proposal in Minnesota.⁷² The Commission approved the Company's transition from Inverted Block Rates to Time of Day rates on August 27, 2021. Minnesota Power has a fully deployed Advanced Metering Infrastructure ("AMI") metering system and is working diligently to develop strong use cases for the data which will enhance innovative rate design. These infrastructure investments, coupled with an innovative rate design, have helped the Company prepare for a future that incentivizes and optimizes the grid for clean energy options like conservation, distributed energy resources, and electrification.⁷³

G. Managing Uncertainty with Flexibility for a Unique Region

Minnesota Power presents the 2025 Plan with robust power supply options to position its customers towards a sustainable energy future, while mitigating unnecessary reliability and cost risk. The Company's planning process evaluates and compares resource strategy outcomes with a series of sensitivities that focus on various levels of demand growth. The 2025 Plan has also identified key areas of uncertainty as the Company looks ahead to the next 15 years, including maintaining reliability, availability of transmission, customer demand outlooks, and technology advancements.

Maintaining Reliability

Minnesota Power has an established history of robust resource planning processes that ensure reliable energy service, while at the same time positioning for an energy future with less carbon-intensive resources. As coal generation continues to retire in the region, the electricity system is becoming more reliant on intermittent wind and solar resources that are not always available when demand is high. Along with traditional resource adequacy planning methods, Minnesota Power has incorporated reliability criteria into its IRP development process to plan a reliable power supply across operating conditions and position the Company to have sufficient capacity to meet MISO resource adequacy requirements while these programs continue to evolve. The Company takes its responsibility seriously to plan its system and ensure its integrity for providing vital electric services to its customers.

The core tenets of the resource adequacy construct in place when Minnesota Power filed its last IRP were formed when MISO's energy mix contained mostly dispatchable coal and gas generation. As the power supply transitioned and accommodated the addition of more renewable energy, MISO's resource adequacy construct has adapted to include enhanced requirements for demand response and better capturing storage and renewable contribution to resource adequacy in the region. MISO, along with Minnesota Power, recognizes that the resource adequacy construct needed to continue to adapt for even higher levels of renewable energy penetration, and to ensure there can be energy coverage for all system conditions to ensure reliability. Since the 2021 IRP, MISO worked with stakeholders on several changes to the MISO resource adequacy construct that better capture availability of generation resources when needed by the system during stressed periods. MISO refers to these changes as the Seasonal Accredited Capacity ("SAC") and Direct Loss of Load ("DLOL") resource adequacy methodologies. MISO has also proposed material changes to the requirements for demand response to qualify as a capacity resource. These proposed changes could impact the quantity of demand response industrial customers make available to Minnesota Power, because the requirements as currently proposed are more onerous for customers and their industrial operations.

⁷² *In the Matter of the Petition for Approval of Changes to Minnesota Power's Residential Rate Design*, Docket No. E-015/M-20-850, Petition (Dec. 1, 2020).

⁷³ *In the Matter of Minnesota Power's 2023 Integrated Distribution Plan*, Docket No. E-015/M-23-258 *Minnesota Power's 2023 Integrated Distribution Plan* (Oct. 16, 2023).

As MISO noted in its February 2024 update⁷⁴ to the December 2020 Reliability Imperative report,⁷⁵ current reliability challenges are more concerning with higher levels renewable energy being added to the system and traditional baseload generation retirements. Extreme weather events also highlight the importance of ensuring reliability during system transformation. During the Polar Vortex of January 2019, the coldest temperature recorded in the lower 48 states was set in the northern Minnesota community of Cotton, with a temperature of -56 degrees Fahrenheit.⁷⁶ Winter Storm Uri in February 2021 and Winter Storm Elliot in December 2022 also stressed system resources. MISO and the local utilities are responsible for working together to ensure there are adequate resources including dispatchable resources and demand response, to manage reliability on an ongoing basis.

These reliability challenges are further evidenced by the fact that MISO has declared an increasing number of emergencies since the summer of 2016, which is changing MISO's overall risk profile. The Company evaluated the reliability profile of its proposed Base Plan and Growth Plan to ensure the actions being brought forward meet the needs of the transformation underway in the energy portfolio. Reliability criteria considered in the development of the 2025 Plan are further discussed in Section V and Appendix K.

Transmission Planning

An important component of a successful transition to an energy future with more variable generation is having a robust transmission system that can integrate increasing levels of renewable energy, while facilitating the retirement of baseload generation and ensuring energy can be delivered to where it is needed when it is needed. Minnesota Power has been at the leading edge of integrated system planning – from distribution to resource to transmission planning. The Company has been leading the development and implementation of transmission in the upper Midwest for decades while transitioning its system to lower carbon alternatives. A strong transmission planning presence in an integrated planning environment is vital to the energy transition and the Company's track record in its last IRP submittals demonstrates this excellence.

In 2024, the Commission approved Minnesota Power's HVDC Modernization Project,⁷⁷ which was developed to upgrade and replace the existing converter stations for the Company's 465-mile HVDC Line, enabling to the continued reliable operation of HVDC Line that currently transports 550 MW of generation from energy-rich North Dakota to the Company's customers in northeast Minnesota. To mitigate customer cost impacts for the project, the Company submitted a federal funding application for \$50 million through the Grid Resilience and Innovation Partnerships ("GRIP") Program created as part of the IIJA. Minnesota Power was selected for the \$50 million award in October 2023 and secured its contract for the award in September 2024.

⁷⁴ MISO, "MISO's Response to the Reliability Imperative," (Feb. 2024), available at <https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216>.

⁷⁵ MISO, "MISO's Response to the Reliability Imperative," (Dec. 2020), available at <https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf>.

⁷⁶ National Weather Service, "Late January 2019 Cold," available at <https://www.weather.gov/dlh/January2019Cold>.

⁷⁷ *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Power Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket Nos. E-015/CN-22-607 and E-015/TL-22-611, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

Additionally, the Company has been awarded \$25 million in state funding to support the HVDC Modernization Project.

MISO's LRTP initiative has begun to address this issue for its region and, to date, has approved two tranches of transmission projects to improve reliability and support the energy transition underway in the Midwest.

The Tranche 1 portfolio consists of 18 projects that span the MISO Midwest subregion and includes two Minnesota Power partner projects. At a January agenda meeting, the Commission approved the CN and route permit for the Northland Reliability Project, a partner project with Great River Energy that includes construction of a new double-circuit 345 kV high-voltage transmission line and improvements to the power grid, from the Grand Rapids area in Itasca County to the Becker area in Sherburne County.⁷⁸ The Northland Reliability Project, expected to be in-service in 2030, will ensure that the power grid in northern and central Minnesota continues to operate safely and reliably as energy resources in Minnesota and the region continue to evolve. On October 30, 2024, the Commission issued an order granting a CN for the Big Stone South – Alexandria – Big Oaks 345 kV Project in central Minnesota, a partner project between Minnesota Power, Xcel Energy, Great River Energy, Otter Tail Power, and Western Minnesota Municipal Power Agency, for which Minnesota Power owns a small share of the eastern (Alexandria – Big Oaks) segment, expected to be in service in 2027.⁷⁹ The project will address regional reliability issues, capacity issues, and issues concerning the addition of renewable resources on the existing 230 kV system in western and central Minnesota, eastern North Dakota, and South Dakota.

The Tranche 2.1 portfolio consists of 24 projects across the MISO Midwest subregion and includes three Minnesota Power partner projects. The Maple River – Cuyuna 345 kV Project, expected to be in service in 2033, is a partner project with Otter Tail Power and Great River Energy that involves installing new, 166-mile single-circuit 345 kV line on double-circuit capable structures between the Maple River and Cuyuna substations. The Iron Range – St. Louis County – Arrowhead 345 kV Project, expected to be in service in 2032, is a partner project with American Transmission Company that involves installing new single circuit 345 kV line between Iron Range and St. Louis County, and installing double circuit 345 kV lines between St. Louis County and Arrowhead. The Bison – Alexandria 345 kV Project, expected to be in service in 2032, is a partner project with the same ownership structure as Alexandria – Big Oaks Project and will provide outlets for generation from the west, supports large power transfers to load centers, and reduces congestion. Notices of Intent to Construct, Own, and Maintain for all three projects were filed in February 2025.⁸⁰ CN applications for the projects will be filed with the Commission by February

⁷⁸ *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket No. E-015, E-T2/CN-22-416 and E-015, E-T2/TL-22-415, Order Granting Certificate of Need and Issuing Route Permit (Feb. 28, 2025).

⁷⁹ *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket No. E-015, E-T2/CN-22-416, Order Granting Certificate of Need and Issuing Route Permit (Feb. 28, 2025); *In the Matter of the Application of for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Docket No. E-002, E-017, E-T2, E-015, E-T10/CN-22-538, Order Granting Certificate of Need and Issuing Route Permit (Oct. 30, 2024).

⁸⁰ *In the Matter of the Application for a Certificate of Need for the Maple River to Cuyuna 345 kV Transmission Line Project*, Docket No. E-015, E-T2, E-017/CN-25-109, Notice of Intent to Construct, Own, and Maintain the Maple River – Cuyuna 345 kV Transmission Project LRTP Project #20 (Feb. 7, 2025); *In the Matter of the Application for a Certificate of Need for the Iron Range – St. Louis County – Arrowhead*

2026. Additional information on Minnesota Power’s transmission planning can be found in Appendix F.

Customer Load Growth

The 2025 Plan offers a flexible approach to planning during a time of historic load growth potential. Based on discussions with existing and prospective customers, Minnesota Power’s customer load has the potential to more than double in this planning period. Therefore, the 2025 Plan includes a “Growth Scenario,” which outlines a set of actions the Company will take if additional customer load for up to 1100 MW emerges. This planning approach will allow the Commission to approve actions that will take effect if prospective customer load does become a reality for Minnesota Power’s system. This approach provides some flexibility in planning and negates the need to file an entirely new IRP to address the load growth Minnesota Power currently anticipates but cannot say definitely will emerge, or if it does, how much will emerge. This approach also ensures that certain actions are not taken based on prospects but are taken when they are needed to meet confirmed demand increases.

In this IRP, Minnesota Power is therefore requesting Commission approval of specific actions if up to 1100 MW of new customer load emerges, as outlined in Section H below. If additional load emerges above this planning level, Minnesota Power will increase these initial activities with a dedicated power supply plan brought to the Commission as needed prior to submission of the Company’s next IRP.

Technology Advancements

Finally, advancement in carbon-free technologies will be a key driver of how quickly and cost effectively Minnesota Power can move towards compliance with the CFS. While the Company recognizes that achieving a 100 percent carbon-free electricity system today based on current technological readiness is not possible, while maintaining reliability and reasonable cost, Minnesota Power is confident that the industry will continue to make progress in the coming years through pilots and demonstration projects. Like with the Company’s last IRP, uncertainties remain about how quickly costs will decline for critical technologies trying to reach full commercialization, such as LDES, carbon capture, advanced nuclear (i.e., Small Modular Reactor (“SMR”)), enhanced geothermal, and carbon-free fuels (i.e., hydrogen, and biofuels) needed to achieve compliance with the CFS. Additional uncertainty exists concerning their contributions as a reliable energy solution for customers and the policy landscape for incorporating some of the emerging technology into a utility’s power supply continue to challenge planning efforts. However, Minnesota Power has proposed a flexible plan that will create opportunities for these innovative technologies to be included as future actions once they are proven and commercially available.

H. Resource Plan Overview: Short- and Long-term Action Plans

Minnesota Power’s robust resource planning analysis considered a number of options in developing the 2025 Plan and identifying the path to 90 percent renewable generation in compliance with the CFS 2035 milestone. The proposed short- and long-term action plans identified below include the steps needed to achieve ambitious carbon goals, while also maintaining reliability of the regional grid and reasonable costs for customers within Minnesota’s

345 kV Transmission Project, Docket No. E-015,ET-2,E-017/CN-25-111, Notice of Intent to Construct, Own, and Maintain the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project, (Feb. 7, 2025); and *In the Matter of the Application for a Certificate of Need for the Bison to Alexandria Second Circuit 345 kV High Voltage Transmission Line Project*, Docket No. E-002,E-T2,E-015,E-017,ET-6135/CN-25-116, Notice of Intent to Construct, Own, and Maintain the Bison-Alexandria 345 kV Transmission Line Project, (Feb. 7, 2025).

approved utility planning framework. Supported by the information and analysis in the appendices of this IRP, the actions outlined in the following sections identify both short- and long-term steps that will help Minnesota Power continue to meet customer needs near term (over the next five years) and be poised to deliver safe and reliable service to customers for many years to come.

Short-Term Action Plan (2025 through 2030)

Minnesota Power's short-term action plan during the five-year period of 2025 through 2030 is comprised of steps that will immediately reduce carbon emissions in the near term and continue the addition of carbon-free energy renewables, conservation, and other demand side resources to the Company's resource portfolio. The specific strategic and necessary actions to achieve these steps include:

- Complete the 2021 IRP actions already in progress, including finalizing the Company's implementation plan for 400 MW of new wind energy by 2028 and completing the implementation of the Regal Solar Project and the Boswell Solar Project, which will result in an approximately 200 MW of additional utility-scale solar resources. The Company will also bring forward a filing outlining the Company's plan for up to 500 MWh of new energy storage in 2026 and progress on IDP non-wires alternatives.
- Maximize demand side management and customer options by continuing the Company's ECO and energy efficiency programs and creating the necessary tariff mechanisms to acquire at least 100 MW of new long-term demand response capacity by 2028 that includes an annual energy curtailment requirement. The Company will also work to complete the addition of 65 to 85 MW of new DG solar resources and implement an EV multi-dwelling unit ("MDU") program to further support customers' electrification needs.
- Add new renewable energy to the Company's portfolio by releasing an RFP for 400 MW of additional wind energy and 100 MW of energy storage for implementation by 2035.
- Advance the Company's plan to cease coal at BEC3 by 2030 by beginning the engineering and acquisition of materials required for a natural gas refuel of the unit. Pending the outcome of state and federal regulatory processes and economic evaluations related to biomass as a net carbon-free resource, Minnesota Power will conduct additional investigation into the economic prospects of co-firing biomass as part of the refuel plan at BEC. The Company will cease coal at BEC3 once new gas refuel capability is in service. This refueling will result in an immediate carbon emissions reduction while supporting reliability in the region and continuing to provide economic benefits for the local host community.
- In order to comply with the Environmental Protection Agency's ("EPA") Section 111(d) carbon regulations, begin development and engineering required for at least a 40 percent natural gas capability for BEC4, in coordination with WPPI Energy.
- Continue operations at HREC to support regional reliability needs and ensure all environmental requirements are met for this renewable facility.
- Work with customers to integrate emerging clean firm technology with a proposal requesting \$30 million to pursue R&D projects that will be rider recoverable.

Long-Term Action Plan (2030 through 2039)

Minnesota Power will focus its long-term action plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix after it ceases utilizing coal. This long-term strategy will continue resource diversification and position Minnesota Power to be able to

successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a reasonable cost. Each component of this long-term action plan has been proven through the least cost planning analysis to be flexible and robust to keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. However, these transition dates are dependent upon the ability to replace the needed system attributes required to maintain the quality of customer electric service in place today. Planned components include:

- To ensure Minnesota Power has dispatchable reliability resources to meet expected customer needs, immediately begin to develop 750 MW of combined cycle natural gas generation to be in service by 2035 to enable ceasing coal on Minnesota Power's system. BEC infrastructure reinvestment will be prioritized in siting activities.
 - On receipt of final permits for the Nemadji Trail Energy Center ("NTEC"), and if available to meet IRP needs, the Company will refile with the Commission as required.⁸¹
 - Any new natural gas resource additions will position the Company for minimizing carbon emissions with alternative fuel or technology as it reasonably becomes available.
- Cease utilizing coal in Minnesota Power's supply portfolio once new combined cycle generation replacement is complete to ensure reliability is not degraded. To ensure Minnesota Power meets the latest GHG requirements, including EPA's Section 111(d) carbon regulations by 2030, Minnesota Power will develop along with WPPI Energy, a refueling alternative of BEC4 for operating capability of at least 40 percent natural gas, which will create additional emission reductions for the facility five years ahead of the Company's cease coal plan.
- Continue developing and implementing transmission solutions to address reliability issues related to the Company's cease coal plan, including working with regional partners to complete three approved MISO LRTP Tranche 2.1 projects and continued work with MISO to determine if additional transmission solutions are necessary for regional reliability needs as decarbonization of the electricity system continues.

Load Growth Scenario

As additional load growth emerges for 1100 MW, Minnesota Power will need to be flexible and nimble and will add the following actions under the Growth Plan as necessary:

- Increase natural gas additions to 1500 MW to meet system requirements.
- Increase renewable implementation to include up to 2200 MW of wind and 200 MW of solar resources to position the Company for compliance with the CFS.
- Increase energy storage to 300 MW to ensure economic management of Minnesota Power's renewable portfolio.
- New supply additions identified in the Growth Plan will be brought forward for Commission consideration and approval as part of a power supply agreement that outlines customer responsibility for the additions required and benefits provided to existing customers.

⁸¹ *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33, Order Approving Plan and Setting Additional Requirements at Order Point 3 (Jan. 9, 2023).

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- If additional load emerges above the Growth Scenario planning level, Minnesota Power will increase these initial activities with a dedicated power supply plan brought to the Commission as needed prior to submission of the Company's next IRP.

IRPs offer an iterative planning process and Minnesota Power will continue to evaluate carbon-free technology adoption and economic pathways for CFS compliance. In its next IRP, Minnesota Power will evaluate options to continue its transition from an annual energy portfolio that is 90 percent renewable in compliance with the CFS 2035 requirement to compliance with the 100 percent CFS 2040 requirement. Minnesota Power will also:

- Evaluate the economic prospects of biomass as an additional fuel source if state and federal policy indicates biomass is a net carbon-free resource based on a life-cycle analysis.
- Review its Manitoba Hydro contract and other renewable PPA terms, as well as alternatives for replacement if necessary.
- Evaluate additional transmission alternatives for accessing broader regional capacity and optimization.
- Clarify the cease coal plan for BEC4 and action being taken at the facility.
- Continue to prioritize reliability needs of the system as it continues to transform.

I. Meaningful Progress with Reasonable Rate Impacts

The 2025 Plan evaluation identified that the Company's short- and long-term action plans result in meaningful progress toward compliance with the CFS while ensuring least cost energy supply scenarios within Minnesota's approved utility planning framework. Providing reliable electric service for customers at a reasonable cost continues to be a priority for Minnesota Power.

The 2025 Plan will result in an annual energy portfolio that is 80 percent renewable by 2030 and 90 percent renewable by 2035, demonstrating full compliance with the CFS requirements during the planning period. The 2025 Plan, if approved, includes bold carbon reduction actions while modernizing the dispatchable generation portfolio that is responsible for ensuring 24/7 reliability in all operating conditions and will result in 95 percent carbon reductions from 2005 levels. Minnesota Power will continue to evaluate additional actions needed to develop an annual energy portfolio that meets the CFS requirements for 100 percent carbon-free by 2040.

In accordance with Minn. R. 7843.0400, subp. 4, Minnesota Power's 2025 resource planning analysis considers the likely effect of plan implementation on electric rates. Appendix L includes additional details of the incremental cost of the "5 Year Power Supply Plan" by customer class from 2025 to 2029. This outlook includes both the approved actions from the 2021 IRP and the actions from this 2025 Plan in the five-year timeframe. These actions advance the Company's progress and compliance with the CFS will result in a reasonable increase of approximately 2 percent per year. Minnesota Power believes its 2025 Plan will continue to serve its customers in a thoughtful and forward-looking way during the 2025-2039 planning period and proudly presents a plan that reflects our commitment to providing safe, affordable, reliable electric service to our customers, as well as our commitment to the climate and the communities we are privileged to serve. Minnesota Power respectfully submits this 2025 Plan for the Commission's review and approval.

III. CURRENT OUTLOOK

This section identifies the major items contributing to Minnesota Power's outlook for customer demand for electricity and the existing supply resources that will be utilized as the foundation for the 2025 IRP. The Company enters this IRP planning period with significant generation deficiencies in the mid- to long-term with the Company's commitment to cease coal operations for its customers at BEC3 and BEC4 from the 2021 IRP and customer plans that require additional power to expand their operations. The 2025 IRP includes a range of outlooks and proposes a resource plan that meets two primary outlooks: the "Base Case" and a "+1100 MW Growth Scenario" (or "Growth Scenario"), which includes approximately 1100 MW of load growth within the industrial class, as described in Appendix A.

A core focus of the 2025 IRP is developing the plan to replace 815 MW of baseload coal energy and capacity capability, while meeting the CFS, reliability standards, and a growing need for energy in the region. This IRP has identified a significant need for dispatchable generation to meet Minnesota Power's power supply and reliability requirements – the largest need identified in the past 45 years. With Minnesota Power's commitment to reduce carbon emissions in its portfolio and comply with the Minnesota CFS, additional carbon-free energy will also be needed to optimize the portfolio so that any dispatchable energy resources are only needed when wind and solar are not available and energy storage has been depleted.

Since the 2021 Plan, Minnesota Power has added over 20 MW of utility-scale solar and is working toward adding approximately another 300 MW of solar, 400 MW of wind, and up to 500 MWh of energy storage prior to 2030. With these renewable additions, Minnesota Power will be about 70 percent renewable by 2030 which is ahead of the current RES requirement of 55 percent by 2035.

This section covers the following topics:

- Current Outlook – Base Case and Growth Scenario
- Minnesota Power Load and Capability Forecast
- Minnesota Power's Large Industrial Customer Base

A. Minnesota Power Load and Capability and Energy Need Forecast

The Load and Capability ("L&C") combines peak customer demand levels in the most recent Annual Electric Utility Forecast Report ("AFR 2024")⁸² and other customer plans with the capacity resources in Minnesota Power's portfolio to understand the potential capacity outlook for the next 15-year planning period. For more information on the Company's approach to developing customer demand forecast scenarios, refer to Appendix A of this IRP. The 2025 IRP includes a "Base Case" and a "+1100 MW Growth Scenario," which represents the latest planning information from customers at the time of this IRP filing and includes 1100 MW of additional demand.

Minnesota Power creates the L&C with the Planning Year 2024-2025 MISO Module E L&C calculations as a starting point. The L&C calculation takes into consideration Minnesota Power's customer load forecast for peak demand coincident with MISO's peak, expected demand-side resources, bilateral purchases and sales, the SAC changes to the accredited capacity value of wind and solar as those resources increase on the system using an Effective Load Carrying

⁸² *In the Matter Annual Electric Utility Reports*, Docket No. E-999/PR-24-11, Minnesota Power's 2024 Annual Electric Utility Forecast Report (Aug. 1, 2024). The AFR 2024 is the foundation for the forecast used in the 2025 IRP analysis and can be found in Appendix A.

Capability methodology, and MISO's required percent planning reserve margin from Planning Year 2024-2025.

New generation resources approved by the Commission or anticipated new resources identified in prior IRPs are included, such as the 700 MW of renewables and 500 MWh of storage approved in the 2021 IRP. NTEC is not included in this starting point L&C given Minnesota Power is restudying the need for natural gas generation in this IRP per the requirement ordered in the 2021 IRP. Lastly, BEC3 and BEC4 capacity is removed for Minnesota Power customers at the cease coal commitment dates of 2030 and 2035, respectively. As shown in Table 1 below, the result of the L&C calculation is a capacity surplus or deficit for each MISO Planning Year in the 15-year outlook.

Minnesota Power is a winter peaking utility and monitors the capacity position for all four MISO seasons to ensure year-round reliability for its customers. The Company's winter peak demand coincident with MISO is typically between 15 and 45 MW higher than its summer peak. MISO's existing resource adequacy construct requires utilities to demonstrate they have sufficient capacity resources for each season. For the purposes of the IRP analysis, the capacity expansion analysis was performed over the four seasons.

Table 1 shows the L&C capacity position for the summer and winter seasons and the starting capacity position in the 2025 IRP and the EnCompass Power Planning Software ("EnCompass") evaluation for the Base Case and Growth Case. A positive number demonstrates excess capacity on Minnesota Power's system, while a negative number denotes the capacity deficiency or need in that year. The capacity position for the spring and fall season are shown in Appendix K. In this outlook, without coal operations at BEC and NTEC removed, Minnesota Power has a need for capacity in both summer and winter. Minnesota Power's capacity deficit increases to approximately 700 MW after BEC3 and BEC4 cease coal operations and increases to over 800 MW by 2039. With these large capacity deficits, Minnesota Power cannot remove coal from the power supply until the capacity and energy is replaced with adequate generation resources. Note that Minnesota Power's customers maintain a critical portfolio of generation resources and Demand Side Management ("DSM") resources that contribute to meeting the capacity need and this is factored into the capacity position.

Table 1. Capacity Position for Base Case and +1100 MW Growth Scenario Customer Outlooks

(Positive = Surplus / Negative = Deficit)

	Summer		Winter	
	Base Case MW	Growth Scenario +1100 MW	Base Case MW	Growth Scenario +1100 MW
2025	16	16	139	139
2026	-89	-89	218	218
2027	82	82	61	61
2028	48	-27	331	243
2029	72	-153	278	34
2030	-245	-634	-67	-503
2031	-248	-802	-69	-701
2032	-250	-970	-80	-933
2033	-252	-1139	-108	-1158
2034	-255	-1307	-138	-1385
2035	-655	-1799	-684	-2040

	Summer		Winter	
	Base Case MW	Growth Scenario +1100 MW	Base Case MW	Growth Scenario +1100 MW
2036	-658	-1803	-719	-2075
2037	-662	-1807	-755	-2111
2038	-667	-1811	-793	-2149
2039	-674	-1823	-821	-2182

Minnesota Power expects industrial customers' demand for energy will grow significantly over the study period. To capture the impact of the significant demand growth, Minnesota Power included three load growth scenarios and one load decrease scenario in the analysis. The timing and size of the load growth will have significant impacts on Minnesota Power's capacity needs and will need to be carefully planned for, so the Company has sufficient resources available to reliably serve the changes in demand. The impact the load scenarios have on the capacity position is discussed further Appendix K. The specific load scenarios and associated assumptions are explained later in this section and in Appendix A and Appendix J.

The L&C capacity accreditation values and planning reserve margins used in the EnCompass model are based on MISO's current SAC methodology for accreditation and Accredited Unforced Generating Capability ("UCAP") methodology for the planning reserve margin. After Minnesota Power started its set-up of the EnCompass model for this IRP, FERC approved MISO's DLOL methodology for the supply-side portion of resource adequacy. MISO has not submitted to FERC how demand obligations will be calculated for DLOL, which is still being discussed with stakeholders and will be filed later in 2025. The DLOL methodology replaces some of the elements in the SAC and UCAP methodology, including how the total capacity by class is accredited for resources, what demand is used (moved from demand at system peak to demand when system is stressed), and the reserve margin calculation. Minnesota Power included a sensitivity on how the DLOL methodology could impact the capacity needs in the 2025 Plan. The MISO DLOL methodology will begin in Planning Year 2028-2029. MISO has provided limited information on the impact to Minnesota Power's current portfolio and has provided some system level outlooks on how accredited capacity for wind, solar, and energy storage will likely decline with DLOL. In general, Minnesota Power is anticipating that the capacity needs on the system will increase with the DLOL methodology, and it will require more dispatchable generation in the portfolio to meet that need because the accredited capacity value of wind, solar, and energy storage will decline when MISO moves to DLOL and as more renewable generation is added to the MISO system.

The Base Case and Growth Scenario unserved energy outlook is shown in Table 2, which identifies that the Company also has extensive energy needs to be addressed over the study period given the current outlooks for demand, generation available to serve customers, future cease coal operations at BEC, and removal of NTEC. In the Base Case, without energy replacement, Minnesota Power cannot serve nearly 20 percent of its customer demand. This deficit increases to over 50 percent in the +1100 MW Growth Scenario. Table 2 shows the need for significant resource additions to fill the unserved energy gap.

Table 2. Unserved Energy Outlook for Base Case and +1100 MW Growth Scenario Customer Outlooks

	Base Case		Growth Scenario +1100 MW	
	GWh of Unserved Energy	Percent of Power Supply	GWh of Unserved Energy	Percent of Power Supply
2025	104	1%	95	1%
2026	342	3%	334	3%
2027	140	1%	136	1%
2028	84	1%	146	1%
2029	86	1%	322	2%
2030	458	4%	2,316	16%
2031	730	6%	4,145	26%
2032	607	5%	4,924	29%
2033	569	5%	6,431	35%
2034	503	4%	7,734	39%
2035	2,487	18%	12,071	58%
2036	2,600	19%	12,170	58%
2037	2,696	19%	12,135	58%
2038	2,696	19%	12,176	58%
2039	2,626	19%	12,234	58%

Minnesota Power’s customer mix is uniquely weighted with resource-based industry and trends in sales are largely driven by global demand for iron ore, steel, paper, and oil transportation. About 74 percent of the Company’s retail and required resale energy sales serve industrial customers. Demand for iron and steel is highly cyclical across economic cycles and the impacts of the general economic downturn (2009), the industry-specific downturn (2015-2016), and recent COVID-19 pandemic induced recession have resulted in dramatic reductions in Minnesota Power’s overall retail sales that have since rebounded post-2022. The Company’s paper customers’ demand has stabilized with the mills being cost competitive in their markets and expected to operate at a steady rate. Oil and natural gas pipeline customers served by the Company tend to have more consistent operations, though they require significantly smaller amounts of energy than the Company’s mining or paper customers. The dynamics of Minnesota Power’s industrial customers is changing with green steel, electrification, and demand opportunities from new sectors. Customers are expecting their energy demand will increase significantly and that Minnesota Power will plan to meet these needs through an IRP. Customers are indicating growth of 1100 MW in energy demand by 2035. Minnesota Power worked closely with its customers to develop the forecast assumptions used in the 2025 IRP to ensure consistency with customer expectations and the current macroeconomic outlook.

B. Current Outlook – Base Case and Growth Scenario

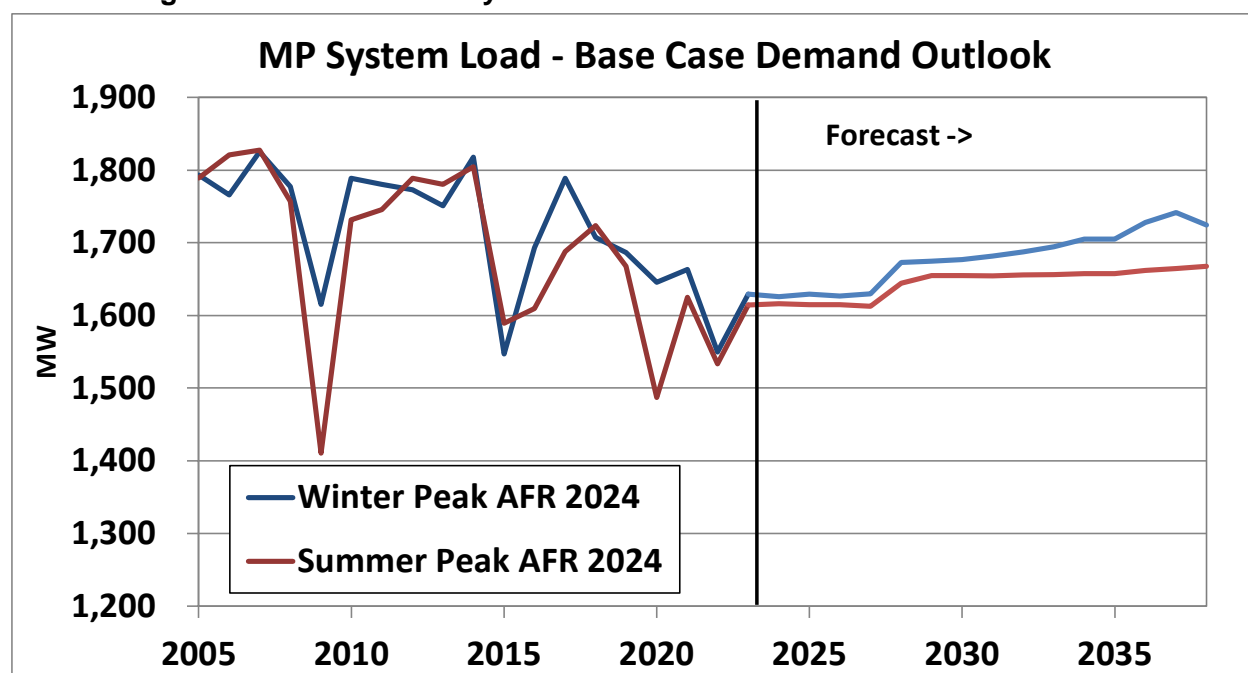
As noted above and discussed in Appendix A, the 2025 IRP considered a range of potential customer load forecast scenarios. Minnesota Power’s developed the 2025 Plan to meet two outlooks: the “Base Case” and a “+1100 MW Growth Scenario,” reflecting the latest outlook for customer needs on the Company’s system. Additionally, the Company evaluated other scenarios as sensitivities in the IRP analysis process including a “+1500 MW” scenario, which includes an additional 1500 MW of industrial load growth between 2027 and 2032, along with 150 percent load growth in the residential and commercial classes; a “-200 MW” scenario, which includes a 200 MW decline in industrial demand starting in 2028; and a “+500 MW” scenario, based on the AFR 2024 load growth planning scenario that takes into consideration potential load growth from accelerated rates of EV and DG solar adoption.

The AFR 2024 Expected Scenario is utilized as the Base Case outlook in this IRP. The AFR 2024 Expected Scenario features an annual energy sales increase of about 0.3 percent per year (on average) from 2024 through 2038. Summer and winter peak demands are projected to increase at average annual rates of 0.2 percent and 0.4 percent, respectively. The AFR 2024 Expected Scenario load forecast reflects 74 MW of system load gain by 2034.⁸³

Minnesota Power is historically a winter peaking utility, and based on monthly trends in load behavior is expected to remain winter peaking for the AFR 2024 period of 2024 to 2038. Throughout the forecast timeframe, the seasonal peaks run in parallel with some slight divergence in the later years of the forecast due to increasing saturation of DG solar and EVs.

Figure 2 presents the Company’s historical and forecast peak demand by season from the Expected Scenario in AFR 2024, which is the foundation for the Base Case in this IRP. Figure 2 depicts the significant near-term impacts of the COVID-19 pandemic recession (2020), a partial recovery by industrial customers (2021), an anticipated load increase for mining and metals customers, and the long-term underlying decline in loads due to conservation.

Figure 2. Peak Demand by Season - Base Case Demand Outlook

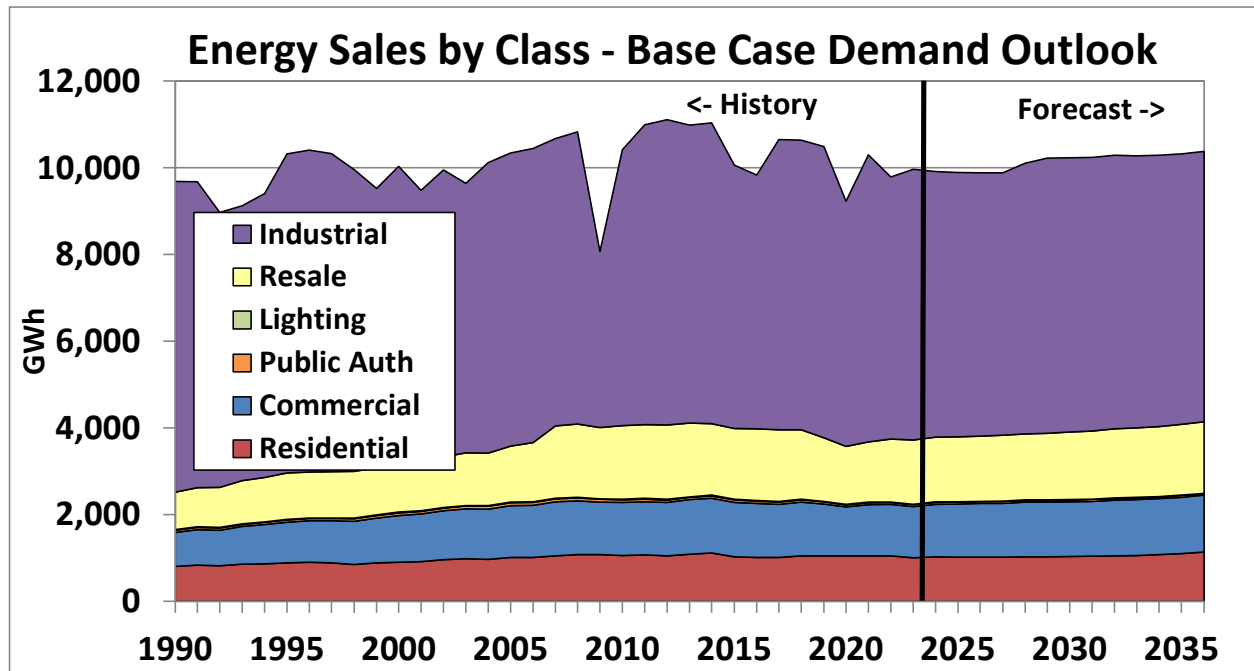


Minnesota Power’s Base Case system load forecast reflects projected (summer) peak demands with an annual average of 1660 MW for the post-2030 timeframe with winter peaks averaging 46 MW higher. It is also important to note that an industrial customer load factor of nearly 80 percent drives the energy supply requirements of the Company.

Figure 3 shows historical and forecast energy requirements by customer class and depicts the large influence the industrial class continues to have on the Company’s energy requirements.

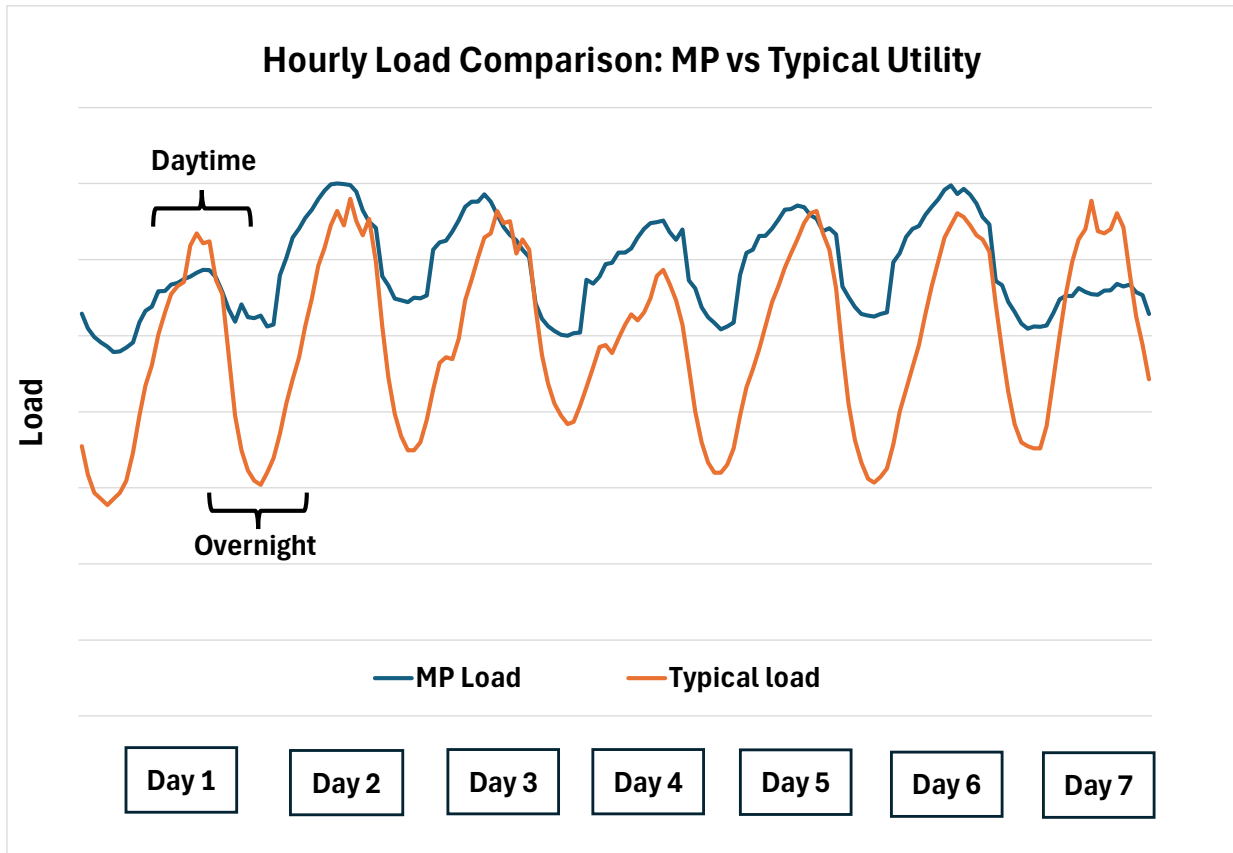
⁸³ Relative to the 2023 annual peak.

Figure 3. Energy Sales by Class - Base Case Demand Outlook



Minnesota Power has a unique load profile compared to typical electric utilities, due to the higher levels of industrial customers as shown in Figure 3 above. The large industrial customers Minnesota Power serves operate 24/7 with a constant need for energy. The higher percentage of industrial load drives up the average load factor to nearly 80 percent compared to a typical utility load factor of 55 to 60 percent. This results in a relatively steady load, with less energy peaks, meaning throughout a typical day, the total energy demand does not increase or decrease to the level of neighboring utilities. Figure 4 compares a sample typical week hourly load of Minnesota Power with a typical utility load, illustrating the fact that Minnesota Power's load does not decrease overnight, as a typical electric utility's load does. This hourly shape profile affects the IRP planning evaluation and the type of generation resources Minnesota Power requires to reliably serve customers. More energy is needed around the clock to meet a high load factor system and ensure reliability metrics can be met. Minnesota Power's customer mix has a direct impact on system planning that differentiates its system from other utilities, which serve a customer mix with higher concentrations of residential and commercial demand.

Figure 4. Hourly Load Shape Comparison Between Minnesota Power and Typical Utility



Sensitivities for Demand and Energy used in the 2025 Plan Development

To capture the plausible ranges of uncertainty in Minnesota Power’s customer outlooks, three load growth sensitivities were chosen for further examination. They are included as the “+500 MW,” “+1100 MW Growth Scenario”, and “+1500 MW” sensitivities. The +1100 MW Growth Scenario, along with the Base Case are the two primary outlooks used to develop the 2025 Plan as they represent the latest in customer expectations. The evaluation of the other growth scenarios, +500 MW and +1500 MW, are included to inform how the 2025 Plan would change if demand growth was slower or faster than anticipated. Minnesota Power also studied how the 2025 Plan would be impacted if there is a net loss of a large industrial customer with the inclusion of a “-200 MW” sensitivity. These outlooks, shown in Figures 5 and 6, demonstrate that the 2025 IRP evaluated the range of uncertainty that exists within the Company’s unique customer base.

The +1100 MW Growth Scenario includes approximately 1100 MW of load coming online within the industrial customer class by 2035. The +1500 sensitivity includes 150 percent load growth in the residential and commercial classes compared to the Base case. Additionally, it includes 1500 MW of industrial load growth by 2038. The -200 sensitivity includes 200 MW of load loss within the industrial class by 2028. Appendix A contains additional details on the +500 MW, +1100 MW Growth Scenario, +1500 MW, and -200 MW load change scenarios.

Figure 5. Demand Outlook Sensitivities for MISO Coincident Peak (CP)

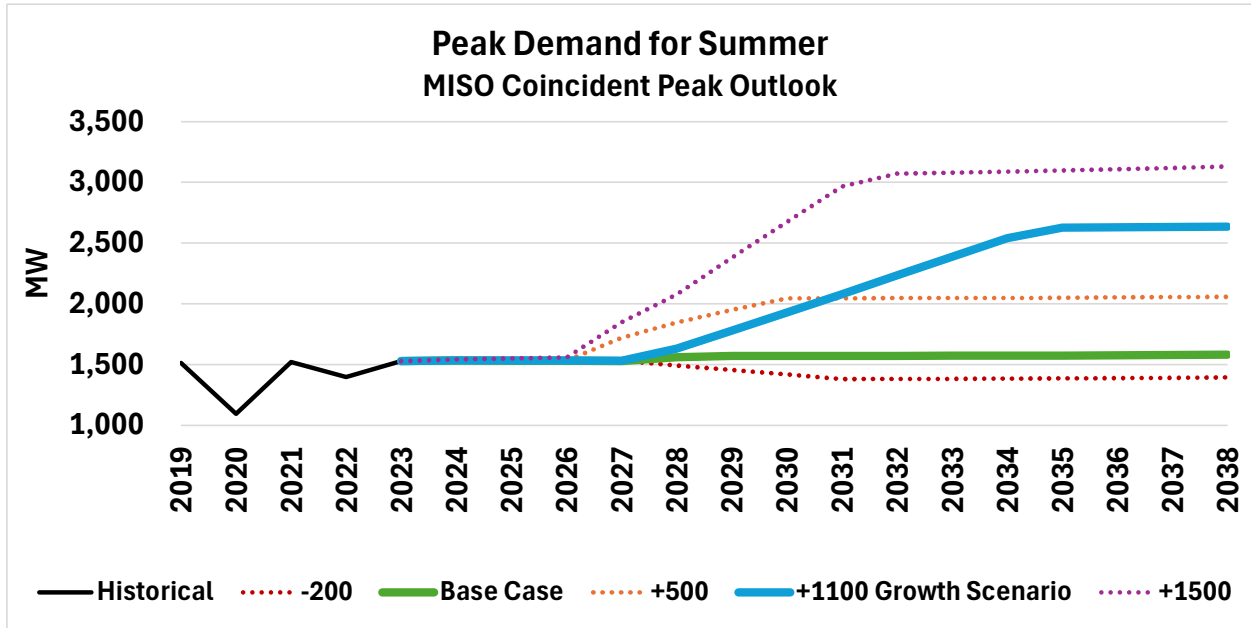
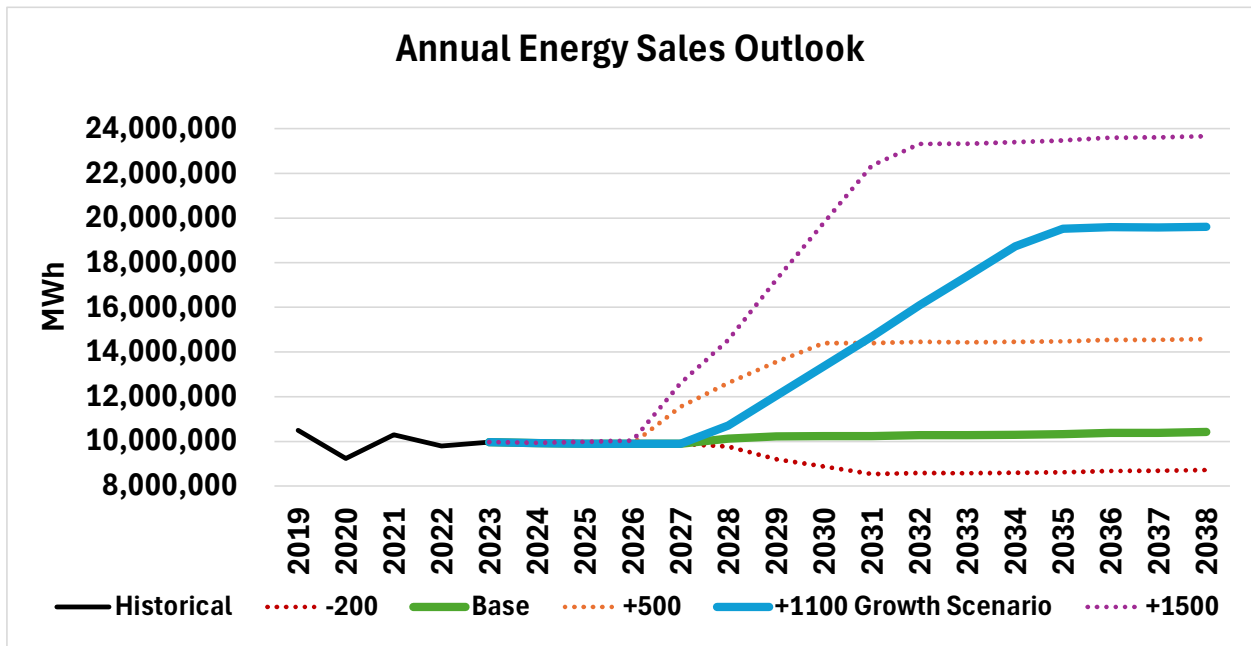


Figure 6. Energy Outlook Sensitivities



Minnesota Power continually monitors rate competitiveness, industry trends, and opportunities for load growth in northeastern Minnesota. The 2025 IRP is demonstrating historic potential for the region. Hence, making prudent and reasonable power supply plans for meeting the future electric needs of its customers is critical to maintain reliability, sustainability, and economic benefits available as the region grows.

C. Minnesota Power's Large Industrial Customer Base

Major industries served by Minnesota Power are summarized below.

Mining Customers

Minnesota Power provides electric service to six taconite mining facilities with current annual production capability of up to 41 million tons of taconite pellets (see Table 3). Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities and are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry.

Table 3. Minnesota Power Taconite Customer Production

Minnesota Power Taconite Customer Production	
Year	Tons (Millions)
2008	39
2009	17
2010	35
2011	39
2012	39
2013	37
2014	39
2015	31
2016	29
2017	38
2018	39
2019	37
2020	30
2021	39
2022	32
2023	35
Average	35

Business cycles and short-term market corrections have and will continue to impact Minnesota's large mining operations. The Base Case and +1100 MW Growth Scenario load forecasts assume continued operation at all six of mining customers through the end of the forecast timeframe. This equates to a 35-million-ton level of production and is consistent with the long-term (2008-2023) historical average.

The Company's Base Case load forecast assumes operations begin at the NewRange Copper Nickel Project ("NewRange"). NewRange is a joint venture between Glencore and Teck Resources that took ownership of the former PolyMet mine development company with plans to develop an open-pit copper-nickel mine on the Iron Range that will annually produce 72 million pounds of copper, 15.4 million pounds of nickel, 720,000 pounds of cobalt, and 106,000 troy ounces of precious metals.

Minnesota Power is also seeing interest in green steel manufacturing opportunities. Steel manufacturing is transitioning to less carbon intensive methods, which increase the utilization of electricity for advanced processing of minerals and ultimate manufacturing of cleaner steels. Green steel methods are electric and hydrogen intensive. The potential for higher demand driven by mining is factored into the load growth evaluated in this IRP. Minnesota Power continues to work closely with mining customers to ensure their latest outlook ranges for energy demand are captured in the load forecast sensitivities.

Paper & Pulp Customers

Minnesota Power serves four paper and pulp customers that produce market pulp and various grades of printing and writing paper used in office papers, magazines, catalogs, tissue, and print advertising/direct mail. The North American printing and writing paper manufacturing industry has experienced a decline resulting in mill consolidation and closures. Minnesota Power’s customers’ operations have reflected the industry’s decline; Boise Paper (owned by Packaging Corporation of America) idled its number 2 and number 4 paper machines and Blandin Paper Company (owned by UPM-Kymmene) idled its number 5 paper machine.

As shown in Figure 7, U.S. printing and writing paper demand was projected to continue to decline prior to the COVID-19 pandemic recession, which reduced consumption of printing and writing papers by over 20 percent. The decline in demand for printing and writing paper was driven by electronic media substitution and the associated migration of advertising budgets away from catalogs, newspaper inserts, brochures, and direct mail. However, starting in 2023, demand for paper started to stabilize, indicating more steady demand going forward.

Figure 7. U.S. Paper Demand 2008-2025 (est.)



The four operating paper mills served by the Company, representing approximately 1.5 million tons of paper production and about 360 thousand tons of dissolving pulp, are owned by well-established, major paper industry leaders (Sappi, Blandin Paper Company, Boise Paper, and Sofidel America). As reflected in this 2025 Plan, Minnesota Power’s assessment is that these corporations view their Minnesota assets as strategic to their respective business strategies. Each of the Minnesota mills is well positioned and cost-competitive in their respective paper markets with excellent customer relationships. The Company projects steady capacity utilization rates for

these mills over the forecast period, as these mills successfully control costs, reshape their products, and compete for market share.

Pipeline Customers

Minnesota Power has two pipeline customers, Enbridge Energy and Minnesota Pipe Line Company, both of which rely heavily on Western Canadian crude oil production. Enbridge Energy transports crude oil across North America. Minnesota Pipe Line Company receives oil from Enbridge Energy at Clearbrook, Minnesota, and delivers it to refining centers in the Twin Cities metropolitan area. A significant oil discovery in northern Alberta in the early 1990s has led to increased throughputs on both the Enbridge Energy and Minnesota Pipe Line Company systems. At the same time, shale oil production in North Dakota has also been increasing. Oil sands and North Dakota shale oil production are forecast to continue to increase over present day levels over the next few years. This will prompt the need for increased transport capacity on the Enbridge Energy and Minnesota Pipe Line Company systems.

Both Enbridge Energy and Minnesota Pipe Line Company take service under Minnesota Power's Large Light and Power Service Schedule ("LLP Schedule"). Neither Enbridge Energy nor Minnesota Pipe Line Company is currently required to provide Minnesota Power with demand nominations under the LLP Schedule. Pipeline maintenance and replacement activities at these companies is not expected to result in a net load increase across the Minnesota Power and Superior Water, Light and Power service territories.

IV. 2025 MODELING APPROACH

Consistent with the Company's previous 2021 IRP, the 2025 IRP analysis utilized the EnCompass to help inform planning decisions. EnCompass is a granular modeling tool that can analyze complex power supply scenarios under various assumptions, while helping the Company identify pathways to meet the Minnesota CFS milestones for the planning period. Minnesota Power believes EnCompass has sufficient granular modeling capabilities to accurately reflect alternatives to meet customer energy and capacity needs and can be relied upon to provide additional insights and support critical reliability analysis.

Minnesota Power is following a similar approach used in prior IRP submittals where the Company evaluated removing coal from its system along with replacement energy and capacity needs. This IRP includes performing a multi-step Capacity Expansion Analysis that selects resources to replace coal energy and capacity at BEC3 and BEC4 across Minnesota's designated carbon regulation and environmental cost futures and meets the Minnesota CFS requirements. Minnesota Power also performed a retirement study for HREC, where the Company evaluated the impacts of retirement of this facility on the power supply and transmission system. Lastly, the IRP analysis looks beyond the planning period and evaluated pathways to reach Minnesota's 100 percent CFS by studying a wind, solar, battery only system, and evaluated impacts to the 2025 Plan if emerging technologies were commercially available today.

In its January 9, 2023 Order in the 2021 IRP, the Commission directed Minnesota Power to consult with stakeholders to develop the modeling inputs and parameters to be used in the Company's next IRP.⁸⁴ As part of the formal IRP engagement process, independent third-party facilitators from the Great Plains Institute and Center for Energy and Environment convened a subgroup of interested participants, identified as TAG, to work with Minnesota Power staff on developing modeling assumptions. A description of the specific activities to date can be found in Appendix N. Multiple participants expressed that they did not want to be asked to reach a final consensus on modeling assumptions. While agreed upon assumptions were not a direct product of the engagement process, the input and feedback received during the meetings helped shape some of the key modeling inputs Minnesota Power used in the EnCompass analysis. The Company appreciates the feedback received and enjoyed the conversations with participants in the engagement process. The assumptions resulting from working with internal subject matter experts and external participants are provided in Appendix J.

New to this IRP and as its system reaches new levels of transformation of its supply portfolio, Minnesota Power felt it was critical to clearly demonstrate that as the Company reduces carbon in the power supply, the reliable energy service delivered today will not change. Minnesota Power reviewed the resulting plans from the analysis to ensure they met specific reliability criteria that were developed by the Company, in alignment with North American Electric Reliability Corporation ("NERC") and regional standards, referred to as the Minnesota Power Reliability Criteria ("MPRC"). At the TAG meetings, Minnesota Power reviewed the proposed reliability criteria framework with participants and sought feedback. As a result of that work and feedback, the Company developed a set of reliability criteria it can use as part of its integrated planning that focuses on four core areas: (1) Traditional Planning, (2) Energy Adequacy, (3) Operational Flexibility, and (4) Grid Essential Services. Components of the reliability criteria can be used as a valuable benchmarking tool that helps identify deficiencies or degradation to reliability of the power supply system and provides insights into identifying options that could mitigate issues. How

⁸⁴ *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33, Order Approving Plan and Setting Additional Requirements at Order Point 11 (Jan. 9, 2023).

the reliability criteria were applied in this IRP analysis, and how it could be applied to future planning, is discussed further in Section V and Appendix K.

This section introduces the analysis process used to develop the 2025 Plan, the cease coal scenarios at BEC3 and BEC4 and alternative operational scenarios, pathways to Minnesota's CFS, Hibbard Retirement Study, and new resource alternatives that were available for EnCompass to select.

This section covers the following topics:

- Analysis Process;
- Early Retirement Scenarios and Refueled Alternatives Evaluated;
- Demand and Supply Side Alternatives; and
- Environmental Futures Considered in the IRP Analysis.

A. Analysis Process

A multi-step planning evaluation was used to conduct an extensive analysis, evaluating different scenarios for ceasing coal at BEC3 and BEC4, retirement at HREC, and to select the least cost resource alternatives to augment the Company's power supply for long-term customer requirements and to meet carbon-free requirements. The extensive scope of the 2025 IRP as it identifies replacement for its last baseload capable resources and historic load growth scenarios is a complex evaluation that includes consideration of Minnesota Power's current and future power supply needs, cost to replace the energy and capacity, environmental profiles, and impacts to the reliability of the power supply and transmission systems. To accomplish this, the 2025 IRP introduces several new steps that thoroughly evaluate different load growth scenarios, clarifies additional actions needed to meet the CFS, dives into power supply reliability, and began evaluating the impact emerging technology could have on a power supply plan. The analysis and associated EnCompass modeling incorporate the Minnesota planning requirements per Minn. Stat. §§ 216B.2422 and 216H.06 for carbon regulation and environmental cost. The 2025 IRP evaluation was done by using the following steps:

1. "Traditional Capacity Expansion Analysis" – Identify which resource alternatives should be added to the power supply. This includes resource alternatives that replace BEC3 and BEC4 coal capacity and energy at the cease coal commitment dates from the approved 2021 Plan.
2. "Pathways for Industrial Demand Scenarios" – Identify the resource alternatives mix needed to meet multiple demand forecasts.
3. "Pathways to Minnesota CFS Analysis" – Identify which additional carbon-free resource alternatives are needed to augment the 2025 Plan established in Step 1 and 2 to meet Minnesota's CFS requirements. This step also explores what Minnesota Power's system could look like and operate under if only wind, solar, and energy storage are available to augment the energy portfolio to meet the loss of baseload supply and the CFS Requirements.
4. "Emerging Technology Capacity Expansion Analysis" – Identify how the capacity expansion analysis changes if emerging technologies, that are not expected to be commercially available at the time of BEC3 and BEC4 cease coal dates, were available.
5. "2025 Plan Selection" – Finalize two preferred plans, one for the base customer forecast ("Base Plan") and one for the +1100 MW Growth Scenario ("Growth Plan").

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6. “2025 Plan Reliability Criteria Evaluation” – This is the core analysis that evaluates the resiliency and reliability of the two plans and identifies if any modifications are needed to improve resiliency and reliability.
 7. “2025 Plan Energy and Capacity Outlook” – Detailed review of Minnesota Power’s 2025 Plan.
 8. “Hibbard Retirement Study” – Identify the impacts to the 2025 Plan if HREC’s renewable dispatchable energy and capacity is retired. The results of this analysis are discussed in more detail in the Hibbard Retirement Study in Appendix O.

For this IRP analysis, Minnesota Power included several carbon-free emerging technologies as resource alternatives. Many of these technologies are still in development and have not reached commercialization or full pilot stage. With emerging technologies there is uncertainty on actual generation performance and cost until the technology reaches commercialization and several years of operations. Included in the analysis are the latest operational and cost expectations for these emerging technologies. In order to continue to advance the development and evolution of carbon reducing technologies, Minnesota Power is requesting in this 2025 IRP, a development fund for initially \$30 million to support working with customers to advance the development and integration of emerging technologies. Minnesota Power will continue to report in future IRPs on advancements in design and economics of emerging technologies for customers.

There are several considerations and variables that contribute to the decision to continue current operations, refuel, or retire a facility. For example, time to engineer, procure, and construct new transmission needed to mitigate transmission issues caused by retirement can take several years and needs to be factored into choosing the dates considered for early retirement. The Hibbard Retirement Study (Appendix O) identified that there is a need for local transmission upgrades and was one of the key factors in determining the earliest feasible retirement date, along with time to build replacement capacity and renewable energy and community impacts caused by retirement. The EnCompass analyses factors in the appropriate cost for studying early retirement, including transmission upgrades, decommissioning costs, environmental costs, and changes to O&M and capital cost at the facility. The dates considered for BEC3 and BEC4 cease coal and refuel options are based on the cease coal commitments from the 2021 IRP, by 2030 and 2035, respectively. The retirement date considered for HREC is discussed further in Appendix O.

See Appendix K for more details on the analysis used to screen resource alternatives and demand-side resources to select the most cost-effective options for customer needs.

B. Early Retirement Scenarios and Refueled Alternatives Evaluated

The Capacity Expansion Analysis evaluated retirement and/or refuel scenarios for BEC3, BEC4 and HREC. Factored into the earliest timing for a HREC retirement was the magnitude of the impact to the bulk and local electric system and the timing to implement solutions to address these impacts, which could include new transmission or new local generation.⁸⁵ Shown below are the retirement scenarios included in the EnCompass Capacity Expansion Analysis.

Retirement Scenarios:

1. BEC3 retires by end of 2029;

⁸⁵ Refer to Minnesota Power’s Hibbard Retirement Study (Appendix O), on how the Company identified a retirement scenario for HREC.

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2. BEC4 retires by end of 2034; and
 3. HREC retires by end of 2032.

The Capacity Expansion Analysis evaluated refueling opportunities at BEC3 and BEC4, which included biomass and natural gas, along with demand and supply side replacement options. The options studied to replace BEC3 and BEC4 coal operations are discussed later in this section. Factored into the biomass refuel scenarios was biomass availability based on recent fuel availability studies performed by Minnesota Power. Because of the availability of biomass, the Company studied co-firing biomass and natural gas in the IRP, along with a 100 percent natural gas refuel scenario. Also included for BEC4 was a 40 percent natural gas refuel scenario that meets the requirements for the current EPA's Section 111(d) carbon regulation.

Refuel Scenarios:

1. BEC3 refueled with 100 percent natural gas by end of 2029;
2. BEC3 refueled with co-firing biomass and natural gas by end of 2029;
3. BEC4 refueled with co-firing biomass and natural gas by end of 2034; and
4. BEC4 refueled with 40 percent natural gas by end of 2029 and cease coal operations by end of 2034.

Lastly, at the request of engagement participants, a scenario was included as a reference case for cost impact comparisons where BEC3 and BEC4 continue to operate on coal. Additional information on this scenario is included in Appendix K.

Given the potential for significant remaining customer energy and capacity requirements when evaluating extensive retirements such as BEC and load growth scenarios, several generation alternatives and supply-side resource alternatives were modeled to replace the energy and capacity retired and meet long-term customer demand for electricity. These resource alternatives can also be selected to reduce overall system carbon emissions if it is economical to do so or to meet the CFS.

C. Demand and Supply Side Alternatives

For Steps 1-3 of the Capacity Expansion Analysis, EnCompass selected from the following demand and supply side resource options:⁸⁶

Demand Side Alternatives:

1. Up to 100 MW Long-Term Enhanced Industrial Demand Response with Energy Curtailment;
2. Air Conditioning Load Control and Hot Water Load Control; and
3. High and Higher Energy Efficiency Scenarios.

Supply Side Alternatives:⁸⁷

1. 100 MW Wind Farm;

⁸⁶ Appendix K 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 EnCompass.

⁸⁷ In the higher load scenarios, to improve the efficiency of the EnCompass model's Capacity Expansion Analysis, Minnesota Power increased the minimum block size of renewables and storage (i.e., increase wind from 100 MW to 200 MW) that could be selected.

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2. 100 MW Solar Farm;
 3. 110 MW Natural Gas-Fired Reciprocating Internal Combustion Engine (“RICE”);
 4. 228 MW Natural Gas-Fired Simple-Cycle Gas Turbine;
 5. 414 MW Natural Gas-Fired Simple-Cycle Gas Turbine;
 6. 636 MW Natural Gas-Fired 1x1 Combined-Cycle;
 7. 719 MW Natural Gas-Fired 1x1 Combined-Cycle;
 8. 100 MW Lithium-Ion Battery with 4 hours of Storage;
 9. 100 MW Lithium-Ion Battery with 8 hours of Storage;
 10. 100 MW Non-Lithium-Ion Battery with 12 hours of Storage;⁸⁸
 11. 100 MW Non-Lithium-Ion Battery with 100 hours of Storage; and
 12. 50 MW Biomass.

For Step 4, the Emerging Technology Analysis, the following technologies were made available to be selected during the study period:

1. 541 MW Natural Gas-Fired 1x1 Combined-Cycle with Carbon Capture;
2. 611 MW Natural Gas-Fired 1x1 Combined-Cycle with Carbon Capture;
3. 200 MW Pumped Hydro with 20 hours of Storage;
4. 391 MW Supercritical Pulverized Coal with Carbon Capture in North Dakota;
5. 442 MW Advanced Nuclear SMR;
6. 30 MW Deep Enhanced Geothermal in North Dakota; and
7. 30 MW Deep Enhanced Geothermal in Minnesota.

Minnesota Power modeled the benefits from production tax credits and investment tax credits made available through the Inflation Reduction Act of 2022 for technologies that met the eligibility requirements.

Note that more than one of each resource alternative mentioned above can be chosen during the Capacity Expansion Analysis. Also, the capacity listed is the installed capacity value for each resource. For information on capital costs, please refer to Appendix J.

D. Environmental Futures Considered in the IRP Analysis

The Capacity Expansion Analysis and 2025 IRP analysis was conducted for the four Commission-ordered environmental cost scenarios and the Reference Case scenario with mid-carbon regulatory costs starting in 2028.⁸⁹ At the request of engagement participants, Minnesota

⁸⁸ Several of the non-li-ion battery technology with 12 to 100 hours of storage capability is still in development or considered “emerging technology”. Minnesota Power modeled these technologies as part of the Step 1-3 because the Company believes these technologies will reach commercial maturity within the study period.

⁸⁹ *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06* and *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*, Docket Nos. E-999/CI-07-1199 and E-999/DI-22-236, Order Addressing Environmental and Regulatory Costs (Dec. 19, 2023).

Power included a “no carbon regulation cost and no environmental cost” scenario to clearly identify customer cost impacts, given carbon regulation cost and other environmental cost adders are currently not included in rates. Reflected in Table 4 are the futures included in the 2025 IRP analysis, in total, there were five environmental futures and approximately 20 sensitivities that were evaluated. The insights gathered from the 2025 IRP analysis assisted in the Company’s development of the 2025 Plan.

Table 4. Six Futures Considered in 2025 IRP Analysis

		Carbon Dioxide (CO ₂) ⁹⁰				Other Criteria Pollutants
		Prior to 2028		2028 and Thereafter		
Futures	EnCompass Case Name	Environmental Cost	Regulation Cost	Environmental Cost	Regulation Cost (2025)	Environmental Costs
Low Environmental Cost	CLE1S	\$143		\$160		Low
High Environmental Cost	CHE1S	\$397		\$438		High
Low Environmental Cost and Low Carbon Regulation Cost	CLER1S	\$143		\$155	\$5	Low
High Environmental Cost and High Carbon Regulation Cost	CHER1S	\$397		\$363	\$75	High
Reference Case	CREF1S	\$270		\$259	\$40	Mid
“Customer Look”: no carbon regulation cost and no environmental cost	CCUST1S	-	-	-	-	-

⁹⁰ Carbon cost are shown in dollars per ton.

V. 2025 PLAN DEVELOPMENT

Minnesota Power's 2025 Plan outlines additional actions to further reduce carbon emissions, identifies steps required to reliably replace its coal-fired generation, and augments its portfolio with additional clean energy to meet the Minnesota CFS 90 percent carbon-free milestone by 2035. Since the submission of the 2021 Plan, Minnesota Power has refined and updated its key assumptions, modeling practices, and conducted the Hibbard Retirement Study (found in Appendix O) to evaluate feasible scenarios for potential retirement of the HREC, but the 2025 Plan ultimately supports continuing operation of HREC. Through its broad engagement process, the Company gathered insights into the issues most important to the participants and incorporated the feedback received during the IRP engagement meetings. The 2025 Plan is the next phase of Minnesota Power's *EnergyForward* strategy and was created using core resource planning principles that address reliability, customer costs, environmental regulations, new Minnesota planning requirements, technology evolution, and consideration of host community impacts.

This section covers the following topics:

- Key Planning Principles;
- Handling Uncertainty with a Flexible Plan;
- Steps 1-4: Capacity Expansion Analysis;
- Step 5: 2025 Plan Selection;
- Step 6: 2025 Plan Reliability Criteria Evaluation; and
- Step 7: 2025 Plan Energy and Capacity Outlook.

A. Key Planning Principles

Key Principles

Minnesota Power takes a principled approach to its analysis to ensure the resulting strategy is robust, sustainable, and in the best interest of customers. The principles below helped shape the resulting 2025 Plan, which embodies the Company's *EnergyForward* strategy, is forward looking to the future needs of customers, and incorporates the key insights participants identified through the IRP engagement process:

1. Remaining a Trusted, Reliable Electric Service Provider – Our customers receive energy service that is 99.99 percent reliable today and expect it to continue as Minnesota Power transitions toward providing increasingly cleaner energy. The Company has the responsibility to plan and bring forward a resource strategy and accompanying grid improvements that provide adequate energy resources that can be available during extreme conditions, such as a polar vortex or heat wave, and under varying levels of renewable production and system conditions. This IRP introduces reliability criteria that are integrated into the plan development and analysis to ensure a reliable power supply system as Minnesota Power reaches new levels in reducing carbon and integrating significant amounts of renewable energy. Furthermore, it is becoming evident that with the retirement action taken to date on Minnesota Power's system and in the broader MISO region, that utilities must remain disciplined and diligent to protect the integrity of the power supply it utilizes to serve customers. Becoming over-reliant on regional markets increases exposure that has system reliability and customer cost consequences. Minnesota Power will not recommend ceasing operation of an energy supply asset until an adequate replacement(s) are

operating to ensure no loss or gap in our ability to provide reliable service. The permitting, procurement, and implementation processes of new resources can no longer be trusted to be timely, and the consequences are too significant if action on existing generation is taken too early. This 2025 Plan will demonstrate how the Company plans to cease all coal operations for its customers and bring forward an action plan that is realistic and reasonable for meeting the reliability requirements over the planning period.

2. Advance Sustainability – Minnesota Power is committed to climate action and working towards a sustainable future for both its customers and communities. The resource planning evaluation considered scenarios that continue the carbon reduction journey that began in prior IRPs and aligns with Minnesota Power’s long-term vision to provide increasingly clean energy and meet the 90 percent carbon-free electricity CFS requirement by 2035. Minnesota Power is a clean energy leader, already delivering more than 50 percent renewable energy to its customers and will be 70 percent renewable after the wind and solar identified in the 2021 IRP goes into service. A successful plan also needs to be sufficiently robust and flexible to adapt to changing customer demand, leave room for advancements and innovation in existing and new carbon-free technologies, leverage existing infrastructure to minimize cost impacts, and be informed by our customers and host communities.
3. Transparency with Planning Insights – An IRP is designed to deliver several planning insights that will help build trust with employees, customers, regulators, communities, advocates, and Tribal Nations on the recommended 2025 Plan. Minnesota Power has developed the 2025 Plan based on a sound IRP analysis that manages customer costs and reliability from multiple perspectives and outcomes, while incorporating Minnesota’s environmental planning criteria and new carbon-free requirements. Minnesota Power is committed to being transparent with the impacts of the 2025 Plan from retirements and required federal and state laws in the IRP process.
4. Preparing for Load Growth – A robust IRP will bring forward planning that meets the needs of tomorrow’s system, requiring flexible plans and insights that can efficiently be used to adapt to changes in the demand forecast as required. Minnesota Power’s customers are communicating that their demand will grow rapidly in the next five to ten years, potentially doubling the size of Minnesota Power’s energy demand, resulting in economic benefits for the region, communities, and all customers. Minnesota Power is requesting approval for both a Base Plan and a Growth Plan that meets this moment, more efficiently utilizes the existing system, and identifies additional needs to meet reliability requirements along with achieving the Minnesota CFS requirements for these new outlooks. The Growth Plan provides a key planning foundation and will be augmented as more information becomes known from individual customers while also demonstrating benefits to our broad customer base. Allowing flexibility within an approved plan gives Minnesota Power the capability to act on a prudent plan designed to meet changing demand using least cost planning.

B. Handling Uncertainty with a Flexible Plan

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

Minnesota Power endeavored to create a 2025 Plan that contains power supply options to position its customers for a sustainable carbon-free future, while working to mitigate unnecessary reliability and cost risk. The Company's planning process evaluates the 2025 Plan with a series of sensitivities, including additional resources to meet the increasing energy needs. There are three key areas of uncertainty the Company identified for the 2025 Plan: (1) system adequacy and strength of the transmission grid, (2) customer demand outlooks, and (3) technology advancements.

MISO Resource Adequacy and Strength of Transmission

Resource Adequacy

Minnesota has an established history of robust resource planning processes that ensure reliable energy service, while at the same time positioning for a future of less carbon-intensive resources. The backdrop for the 2025 IRP study period includes significant energy system transformation. As older coal generation retires in the region, the system is becoming more reliant on wind and solar resources that are only available when the wind is blowing, or the sun is shining. Along with traditional resource adequacy planning methods, Minnesota Power has incorporated additional reliability criteria into its IRP development process for its 2025 IRP. Incorporating reliability criteria will create additional transparency and clarity on planning that includes the development of a reliable power supply across operating conditions and position the Company to have sufficient capacity to meet MISO's evolving resource adequacy requirements. This section focuses on planning uncertainties at MISO that pertain to resource adequacy. Minnesota Power further discusses its reliability criteria later in this section and in Appendix K.

Minnesota Power is monitoring two key areas of uncertainty at MISO during the study period: (1) MISO resource adequacy construct changes; and (2) the timing on when the transmission system can accommodate new renewable and dispatchable generation resources as additional coal generation is retired and new transmission is built.

The core tenets of the MISO resource adequacy construct in place at the time of Minnesota Power's last IRP were formed when MISO's energy mix contained mostly dispatchable coal and gas generation. As the power supply transitioned and accommodated the addition of more renewable energy, MISO's resource adequacy construct had to also adapt, such as enhancing requirements for demand response and more detailed evaluation of storage and renewable contributions to resource adequacy. MISO, along with Minnesota Power, recognizes that the resource adequacy construct needs to continue to adapt for even higher levels of renewable energy penetration, and to ensure there can be energy coverage for all hours and extreme system conditions to ensure reliability. Since the 2021 IRP, MISO worked with stakeholders on several changes to the MISO resource adequacy construct that better capture availability of generation resources when needed by the system during stressed periods. MISO refers to these changes as the SAC and DLOL resource adequacy methodologies.⁹¹

The SAC methodology started in MISO Planning Year 2023-2024 and the DLOL methodology will start in MISO Planning Year 2028-2029. Another change to MISO's resource adequacy construct is the implementation of the Reliability-Based Demand Curve ("RBDC") for MISO Planning Year 2025-2026, which is intended to more accurately reflect the value of capacity and contribution to reliability. Lastly, MISO has proposed material changes to the requirements for demand response to qualify as a capacity resource. These proposed changes could impact the

⁹¹ FERC approved the supply side methodology for DLOL on October 25, 2024. MISO is working with stakeholders on developing how the Load Serving Entity allocation of system demand requirements will be calculated under the DLOL methodology. This is expected to be filed with FERC in 2025.

quantity of demand response industrial customers make available to Minnesota Power, because the requirements could prove to be too onerous for customers. The aggregate of these changes is a drastic shift away from MISO's more traditional resource adequacy construct where capacity value and reserve margin were based on system peak conditions. With the volume of significant changes to MISO's resource adequacy construct over the last couple of years, Minnesota Power will continue monitoring the following key areas to better understand the impacts to Minnesota Power's plans for the capacity and energy needs in future IRPs:

- Variability of accredited capacity values of supply side and demand side resources;
- Quantity of available demand resources customers make available;
- Impact of RBDC on the final Planning Reserve Margin ("PRM") and the market clearing price and associated bilateral capacity markets; and
- Impact of resource portfolio transformation and the DLOL methodology on portfolio level resource accreditation values and planning reserve margin.

Minnesota Power will continue to actively participate and provide feedback to MISO on resource adequacy reform and the Reliability Imperative⁹² to ensure Minnesota Power's generation and demand response is properly valued for its reliability contribution.

Strength of Transmission Grid

An important component of a successful transition to a decarbonized future is having a robust transmission system. The grid must be ready to integrate increasing variable renewable energy, while allowing for the retirement of baseload generation and delivering energy from where it is created to where it is needed on a 24/7 basis. It will take the coordination and collaboration of all regulatory entities to help ensure we can meet needs for this infrastructure.

MISO has started answering the call and looking to these futures and acting through the LRTP process. To date, two tranches of regional transmission projects have been brought forward that improve reliability and support the changing capacity profile on the system. A number of these projects support Minnesota Power's system and the broader region to help enable the Company's continued transition.

The Tranche 1 portfolio consists of 18 projects that traverse the MISO Midwest subregion. The double-circuit 345 kV Northland Reliability Project, which is a collaboration between Great River Energy and Minnesota Power, is included in Tranche 1 and targeted to be in-service by 2030. The Northland Reliability Project is an example of transmission that will improve reliability, strengthen voltage support, and improve the capability to transfer energy to northeastern Minnesota. The Tranche 2.1 portfolio consists of 24 projects across the MISO Midwest subregion. There are several projects included in MISO Tranche 2.1 that will improve reliability and energy transfer in and around Minnesota Power's service territory. These projects are targeted to go into service from 2032 to 2034 if they are able to stay on track with permitting and implementation.

Lastly, and as part of the modernization of the grid that is underway, Minnesota Power received Commission approval for its HVDC Modernization Project.⁹³ The HVDC Modernization

⁹² In 2020, MISO developed the Reliability Imperative framework to address the urgent and complex challenges facing the grid. MISO defines the Reliability Imperative as the shared responsibility that MISO, its members, and states have to address the urgent and complex challenges facing the MISO grid.

⁹³ *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County and In the*

Project which will replace and upgrade the existing HVDC Line converter stations that are beyond their anticipated operational lives. The upgraded converter stations will make it possible to continue to delivery of high-capacity factor wind located in North Dakota directly to Duluth, Minnesota. This transmission project, along with new transmission projects identified by Minnesota Power and through the MISO LRTP process, will be needed to continue to pursue compliance with the 100 percent CFS in Minnesota. For this IRP planning period, the uncertainty Minnesota Power will need to monitor is the timing of the transmission projects that will enable additional capability and reliability to meet the interim CFS and reliability requirements. These transmission projects must efficiently work through permitting and local regulatory approval to meet the anticipated in-service dates.

A real-time indication of this system-wide complication of timing of new transmission is seen in the MISO interconnection queue, where the addition of large volumes of new renewable energy is already requiring significant upgrades to the transmission system and resulting in project implementation delays.

Minnesota Power, along with Minnesota regulators, policymakers, and MISO, must continue to address this challenge to maintain system reliability during the rapid decarbonization and transition of the regional power supply. Identifying the problems and finding solutions to ensure reliability during this transition will take time, and maximizing critical infrastructure is key to an efficient transition. To the extent possible, the resource planning analysis and resulting plans must try to anticipate changes in the future resource availability as a central part of a plan and adapt as the rules and requirements for a reliable system evolve to accommodate a future with less carbon and more variability in resource availability.

Customer Demand Outlook

There is inherent uncertainty in any customer demand outlook used in the IRP analysis. An IRP plan should be robust and flexible to adjust to customer needs across multiple outcomes. In this IRP, Minnesota Power is planning for a future where customer demand could more than double based on customer information and plans. Also, with Minnesota Power's uniquely large industrial customer mix, there will be swings in industrial customer demand depending on the health of customers' respective industries (see Figure 3 in Section III to see how industrial demand has varied since 1990). In the Company's last IRP, Minnesota Power experienced a declining load caused by idling of industrial customers and lasting effects from the economic recession caused by the COVID-19 pandemic. In this IRP, Minnesota Power has industrial customers preparing for significant load growth over the study period. Minnesota Power has not experienced this magnitude of load growth potential for several decades, but the Company is well positioned to serve the expanding industrial sector given its history serving energy intensive industries. To capture the variety of possible future demand scenarios and prepare a robust set of near- and long-term actions, the IRP analysis included a range of load sensitivities for planning the system that increase current industrial demand up to 1500 MW and decrease it by 200 MW.

Advancements in Technology

The advancement in carbon minimizing technologies will be a key driver of how quickly and cost effectively Minnesota Power can meet the requirements of the Minnesota CFS. Minnesota Power recognizes that currently, the technology does not exist to cost-effectively achieve a 100 percent carbon-free system but believes the industry will continue to make advancements in

Matter of the Application of Minnesota Power for a Route Permit for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County, Docket Nos. E-015/CN-22-607 and E-015/TL-22-611, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

gaining additional commercial alternatives in the coming years through pilots and demonstration projects. Similar to the last IRP, there remains uncertainty as to how quickly commercialization will occur and supporting reductions in costs are realized for critical technologies needed to achieve 100 percent carbon-free. Emerging technologies like LDES batteries, carbon capture, advanced nuclear, (i.e., SMRs) and carbon-free fuels (i.e., hydrogen and biofuels) will need to advance so that they can be implemented as part of a cost effective, reliable energy solution for customers. These technologies, in addition to a suite of demand response and energy efficiency efforts, could be important complements to the Company's growing renewable portfolio.

Minnesota Power's analysis took into consideration the potential for declining capital costs for renewables, energy storage, and emerging dispatchable technologies like advanced nuclear and carbon capture. Furthermore, Minnesota Power is recommending that a new R&D fund of \$30 million be established to better understand, develop, and pilot emerging technologies. Minnesota Power will use these funds to partner with interested customers to advance development of emerging technologies needed to meet the CFS that support reliability and the 24/7 energy needs of our customers. A flexible plan should create opportunity for these innovative technologies to be included as future actions, which is the intent of the emerging technology development fund being proposed.

It is difficult to develop a plan that can hedge against all uncertainties over a 15-year study period. The Company's commitment and *EnergyForward* strategy has already reduced carbon emissions by over 50 percent by leveraging existing infrastructure and maintaining a dispatchable generation portfolio to meet energy needs, while putting the Company on a path to meet the Minnesota CFS. The 2025 Plan, as described below, will take further action on carbon reduction while modernizing the dispatchable generation portfolio that is responsible for ensuring reliability in all 24/7 operating conditions. The Company will continue to monitor and take measured actions to manage uncertainties in the coming years.

C. Steps 1-4: Capacity Expansion Analysis

Minnesota Power arrived at its 2025 Plan using an innovative multi-step planning process that is described in further detail in Section IV. This section discusses the analytical results from the evaluation process. The analysis is broken into two important planning phases: (1) the Capacity Expansion Analysis (Steps 1-5); and (2) detailed evaluation of the 2025 Plan (Steps 6 and 7). The analysis also included Step 8, a retirement study for HREC, the results of which are discussed further in Appendix O.

The objective of the first phase is to identify the least cost supply side and demand side alternatives to replace the energy and capacity needed as BEC3 and BEC4 cease coal operations and to meet the latest customer demand outlooks. The second phase is a detailed evaluation of the performance of the proposed 2025 Plan including how the plan performs when stressed.

Three BEC operational scenarios were included in the Capacity Expansion Analysis, along with a "Status Quo" scenario, which was used as a reference case to evaluate changes in plan costs:⁹⁴

1. 2025 Plan: BEC3 refuels with natural gas by the end of 2029; BEC4 refuels with 40 percent natural gas by end of 2029 and ceases coal operations by the end of 2034;⁹⁵

⁹⁴ For all retirement scenarios, reference to a year indicates retirement on December 31 of that year.

⁹⁵ In the 2025 Plan, BEC4 is removed from the power supply at the end of 2034 when coal operations cease.

-
2. Full Retirement: Retirement of BEC3 and BEC4: BEC3 retires by the end of 2029 and BEC4 retires by the end of 2034;
 3. Full Biomass/Gas Refuel: BEC3 cofires with biomass and natural gas by the end of 2029; BEC4 cofires with biomass and natural gas by the end of 2034;
 4. Continue Coal Operations (“Status Quo”): No ceasing coal action is taken for BEC3 and BEC4 during the study period.

The Capacity Expansion Analysis was broken into multiple steps to transparently evaluate the impacts load and implementation of the CFS have on the resources selected by EnCompass. The analysis was designed to evaluate the impact to the Plan when industrial demand changes (Step 2), when the Minnesota CFS is enforced (Step 3), and if commercial availability of emerging technologies accelerates faster than expected (Step 4). By having multiple steps in the analysis process, Minnesota Power could see and measure the impacts these changes have on the plan, which assisted in the development of a robust and flexible plan, including identifying the preferred BEC pathway.

The preferred 2025 Plan for transitioning BEC operations is to refuel BEC3 with natural gas by end of 2029 and prepare to meet required environmental rules by adding natural gas capability to BEC4 for a 40 percent refuel by end of 2029 and cease coal operations for customers by end of 2034, referred to as the “2025 Plan.” Minnesota Power selected its preferred plan for BEC operations after completing Steps 1 and 2 of the analysis, by comparing plan costs for each BEC option and what can realistically be accomplished in the planning timeframe. In the following sections for Steps 1 through 4, the results and associated figures shown are for the “2025 Plan,” unless noted otherwise. The Capacity Expansion Analysis results for the other options considered at BEC are shown in Appendix K.

Step 1: Traditional Capacity Expansion Analysis – Base Case Forecast

The following includes the results from Step 1, the Traditional Capacity Expansion Analysis, where resources are selected using the EnCompass planning model under the Base Case forecast and the Minnesota environmental futures – making up the “Traditional Planning” look. The Minnesota CFS is not enforced during this step in the analysis; that occurs in Step 3 which is discussed later. Using this look, the Company is able to identify the pre-policy enforcement actions that are needed to serve its customer outlook. There are more details on the modeling process and results included in Appendix K. The following results informed the recommended path for BEC3 and BEC4 and initial resources to be included in the 2025 Plan. Following this section is a discussion on how Minnesota Power further developed the 2025 Plan using results from Steps 1-4.

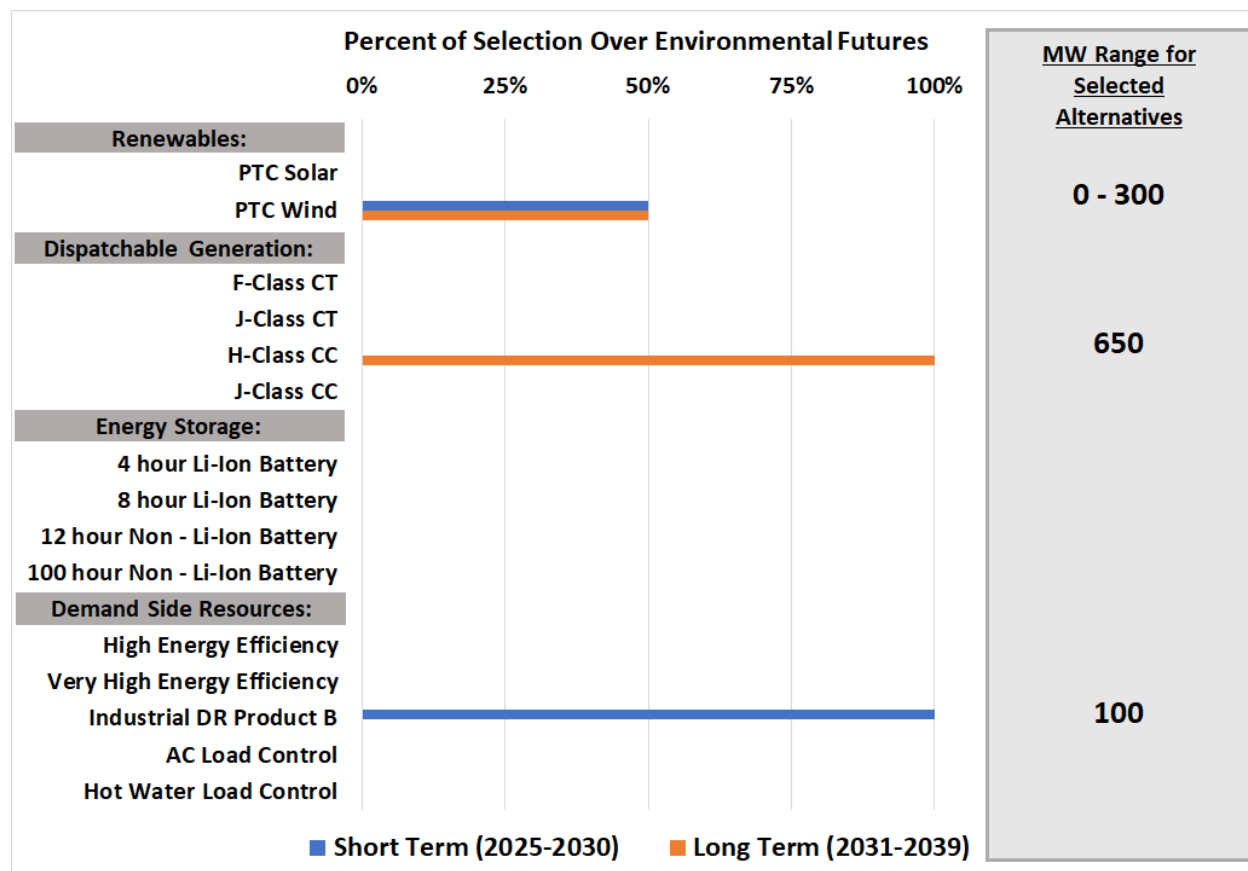
A summary of the results of the EnCompass Capacity Expansion Analysis for the proposed 2025 Plan that includes the recommended BEC outcome under the Base Case forecast is shown in Figure 8. Recall that this includes BEC3 refueled with natural gas by end of 2029 and BEC4 refueled with 40 percent natural gas by the end of 2029 and ceases coal operations in the power supply portfolio by end of 2034.⁹⁶ The figure also demonstrates the robustness of the IRP analysis that includes diverse supply and demand side technology alternatives that Minnesota Power considered in the EnCompass Capacity Expansion Analysis. This is also the first time Minnesota Power included emerging technologies to be selected in the EnCompass model. Above and

⁹⁶ Minnesota Power focused on the “2025 Plan” BEC scenario because it was identified as a least cost action in the 2025 Plan.

beyond this list were additional resource alternatives that were evaluated in the pre-screening process that are discussed in Appendix K.

The resource selections shown below are based on an expansion analysis that was done on the following environmental futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, Low Carbon Regulation Cost and Low Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs as required for integrated resource planning in Minnesota.⁹⁷

Figure 8. Capacity Expansion Analysis Results for 2025 Plan with Base Case Forecast



The Capacity Expansion Analysis clearly indicates that wind, industrial demand response, and combined cycle generation are the least cost resources to reduce carbon on the system and replace the capacity and energy when BEC4 ceases coal operations. The higher the carbon regulation cost that is modeled, the more wind that is selected, with 200 MW selected in the Reference Case for Environmental Cost (mid-carbon regulation cost). In general, wind is being selected over solar because of the lower cost and the higher energy output of wind is a better fit

⁹⁷ The Reference Case and High Carbon Regulation Cost and High Environmental Cost are required to be evaluated as part of the IRP process consistent with the Commission’s decision *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation under Minn. Stat. § 216H.06*, Docket Nos. E999/CI-07-1199 and E999/DI-22-236, Order Addressing Environmental and Regulatory Costs (Dec. 19, 2023). Minnesota Power chose to include a “no carbon regulation cost and no environmental cost” scenario to provide an additional perspective that captures a market without a carbon tax.

with Minnesota Power's high load factor. Minnesota Power's Base Case has already incorporated the outcome of the last IRP which added nearly 300 MW of solar prior to 2030. The existing 300 MW of solar in the model appear to be sufficient to meet the solar needs under Base Case forecast conditions.

Due to the magnitude of alternatives being considered and the size of the capacity and energy need in the optimization of the expansion plan, Minnesota Power had to innovate with additional modeling steps for how natural gas was included in the Capacity Expansion Analysis in order to allow the model to complete the Capacity Expansion Analysis runs required (see Appendix K for additional details).

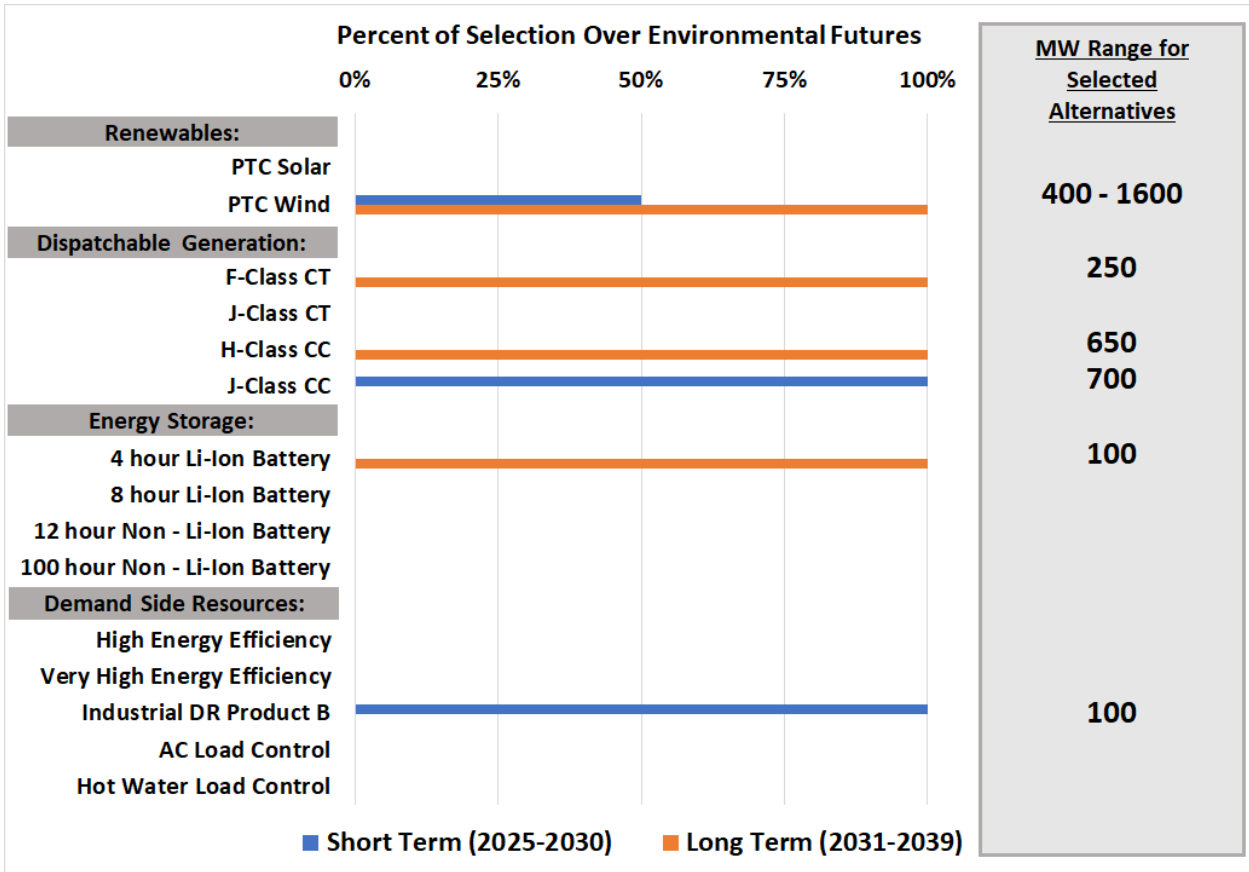
Step 2: "Pathways for Industrial Demand Scenarios" Capacity Expansion Analysis

New to this IRP, Minnesota Power introduced a Step 2 that focused on evaluating pathways to serve multiple load outlooks that increase and decrease customer demand. As discussed earlier, customers have expectations for a significant increase in energy needs over the study period for this IRP. The study includes four load sensitivities ranging from -200 MW to +1500 MW, and when combined with cease coal scenarios, there is a significant energy and capacity need created that must be addressed by the Capacity Expansion Analysis. This section focuses on the Capacity Expansion Analysis results for the +1100 MW Growth Scenario used to develop the Growth Plan as it is the expected customer growth outlook. The Capacity Expansion Analysis results for the other load growth scenarios are provided in Appendix K. A summary of the EnCompass Capacity Expansion Analysis results with the "2025 Plan" for BEC under the +1100 MW Growth Scenario is shown in Figure 9.⁹⁸ The results demonstrate the significant increased need for renewable energy and dispatchable generation to meet the higher load scenario. The energy requirements for this case more than double, as additional high capacity factor load comes onto the system.

More wind is added due to the increased carbon regulation cost. In the Reference Case for Environmental Cost, 1400 MW of wind was selected. There is also a significant increase in the need for capacity and dispatchable generation to meet the higher demand and fill the energy gaps when wind and solar are not generating. Results identify the need for 1500 MW of gas generation under this load growth outlook, with most of it being lower carbon emitting and more efficient combined cycle technology to meet the energy intensive customer growth. The results also included an increase in additional storage to help manage the renewable generation.

⁹⁸ The resource selections shown in Figure 9 are based on the following futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, Low Carbon Regulation Cost and Low Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs.

Figure 9. Capacity Expansion Analysis Results for 2025 Plan with +1100 MW Growth Scenario



After the analysis was complete for Steps 1 and 2, Minnesota Power performed a cost performance comparison between the different BEC operational scenarios evaluated in the IRP. Table 5 below illustrates how the scenarios performed over the Base Case and +1100 MW Growth Scenario, the two load scenarios used to develop the Base Plan and Growth Plan recommendations. The results of this analysis clearly indicate how close the costs are, and the influence federal PTCs have on the value proposition for biomass. The two lowest cost BEC plans were the 2025 Plan and Full Biomass/Gas Refuel (with 100 percent PTC for biomass).

Both plans performed well across the Base Case and +1100 MW Growth Scenario. The Full Biomass/Gas Refuel did not perform as well when the PTC benefit was removed, indicating the importance of biomass being recognized as a net carbon-free resource through a life-cycle analysis. There currently exists uncertainty if biomass will qualify for PTCs, since there has been no Internal Revenue Service (“IRS”) guidance issued yet on how to demonstrate biomass is a net carbon-free resource. It is recognized by the IRS as a potential fuel option to qualify for a PTC, but instructions on how to demonstrate it are forthcoming. We assume some form of a life-cycle analysis will be required to qualify for a PTC, but what form that will take is unknown. Minnesota Power’s position is biomass is a net carbon-free renewable resource based on performing a life-cycle analysis, and believe, given how well it performs, it warrants further investigation as an action item for this IRP.

Table 5. Comparison of Plan Costs

15-year Net Present Value (2025-2039) \$Billions	Environmental Future: Reference Case ⁹⁹	
	Base Case	+1100 MW Growth Scenario
BEC Operational Scenario		
2025 Plan	\$8.4	\$11.7
Full Biomass/Gas Refuel 100% PTC for Biomass	\$8.2	\$11.6
Full Biomass/Gas Refuel No PTC for Biomass	\$8.5	\$11.9
Full Retirement	\$8.6	\$12.0

As Minnesota Power transitions away from coal generation, Minnesota Power is forecasting an increase in power supply cost for replacement energy and capacity. Figures 10 and 11 show the change in power supply cost of the BEC operational scenarios from the “status quo.” This figure can be useful in informing where customer costs could directionally go if the actions in that scenario are taken and are not meant to be an indication of specific electric rates. The figure demonstrates that the 2025 Plan for BEC has one of the lowest cost impacts when compared to the other scenarios studied under Base Case and +1100 MW Growth Scenario.

The figures also highlight the benefit increasing industrial demand could have for all customers as the power supply additions are utilized more efficiently. This optimization creates a smaller cost increase profile in the +1100 MW Growth Scenario. It is important to note, however, that actual electric rates are decided by the Commission through a formal rate case proceeding once projects and plans are in the implementation phase, and those outcomes will be reflected on the customer bill. This planning exercise assists in supporting IRP decision making as the Company works across many scenarios and alternatives. Furthermore, Minnesota Power is actively engaged in identifying opportunities to mitigate customer rates, and those future efforts are not directly captured in a resource planning analysis.

⁹⁹ The costs shown in this table include power supply cost and carbon regulation cost but exclude the environmental cost. In Docket No. E-999/CI-22-236, the Commission ordered carbon regulation cost to be included in the Capacity Expansion Analysis to influence resource selection and environmental cost are an “add-on” in the post-processing. The table reflects the cost used by EnCompass to optimize the plan because that best reflects how well a plan performed given the model set-up. Please refer to Appendix K for the results with the environmental cost included.

Figure 10. 2025 Plan for BEC Power Supply Cost Compared to Alternatives – Base Demand Outlook

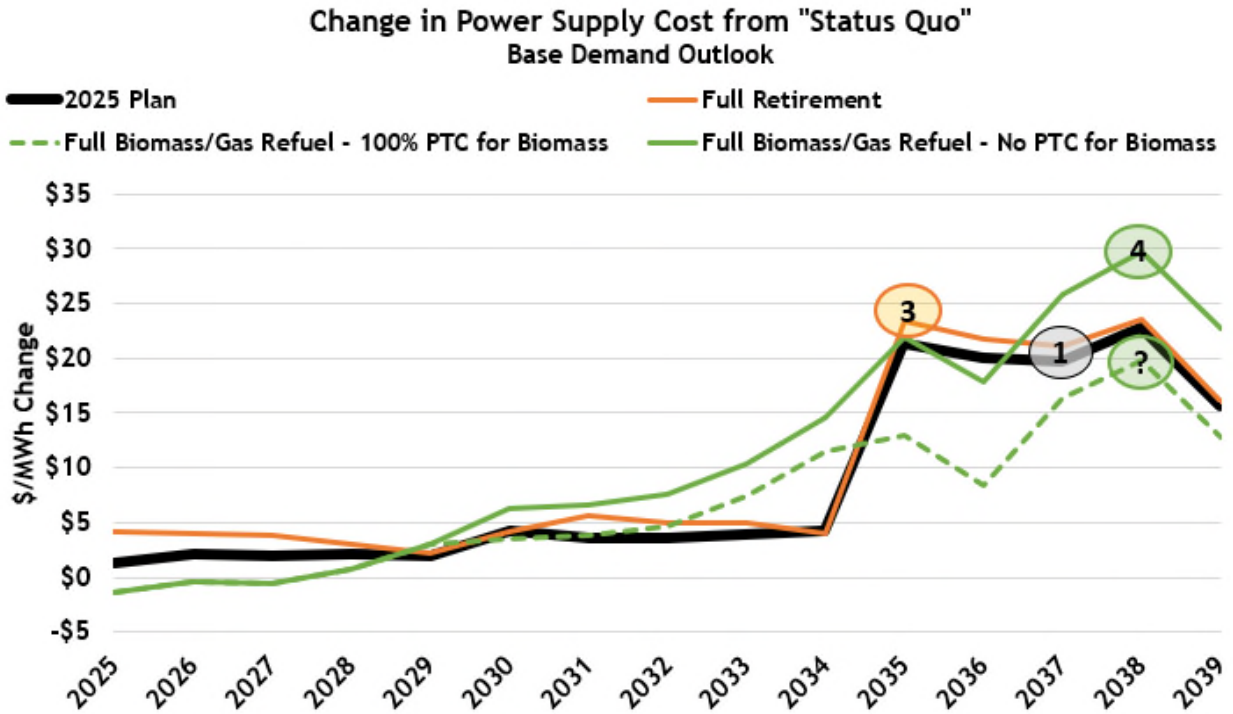
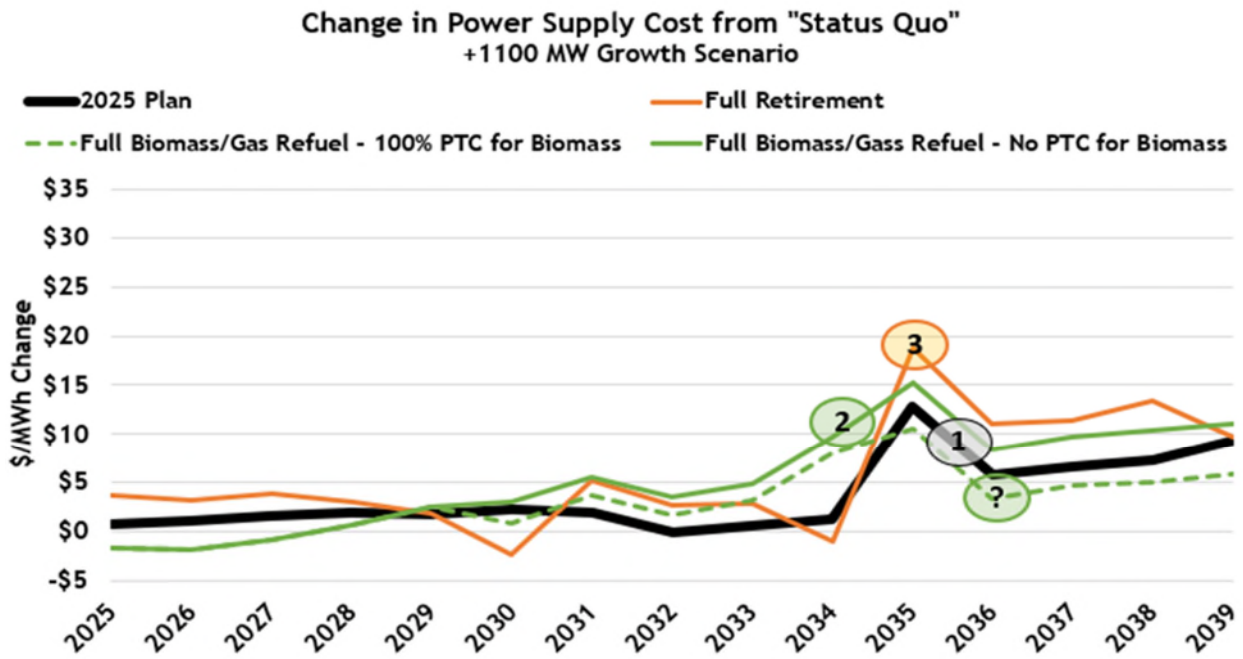


Figure 11. 2025 Plan for BEC Power Supply Cost Compared to Alternatives – +1100 MW Growth Scenario



Based on the analysis from Steps 1 and 2, and the performance across the two key load scenarios, Minnesota Power selected the “BEC3 refuel with natural gas by end of 2029; BEC4

refuels with 40 percent natural gas by end of 2029 and ceases coal operations by end of 2034” as the BEC operational scenario to include in the 2025 Base Plan and Growth Plan. These actions provide the opportunity to leverage existing assets to advance carbon reduction, meet current environmental rules in place, and position the power supply for modernization while at the same time leaving the flexibility to add on additional carbon neutral or minimizing technology in the future. Next, the preferred plan for BEC operations was moved into Step 3 to evaluate if additional carbon-free resources were needed to meet the Minnesota CFS.

Step 3: “Pathways to Minnesota Carbon Free Standard Analysis” Capacity Expansion Analysis

After Step 2 was complete, the least cost operational plan for BEC3 and BEC4 along with necessary capacity and energy additions were moved to the Step 3: “Pathways to Minnesota CFS Analysis.” A Capacity Expansion Analysis was performed where carbon-free energy was allowed to be re-selected to meet the CFS. A constraint was added to the EnCompass model that forced the model to select the least cost plan to meet the CFS milestone requirements of 80 percent in 2030 and 90 percent in 2035. The results were evaluated to see how the volume and timing of new resources being selected changed with the CFS enforced. In general, more renewables were selected and the timing of the additions were accelerated to meet the CFS milestones when compared to results from the traditional capacity expansion planning in Steps 1 and 2.

For example, in the Base Case scenario with the 2025 Plan for BEC, in Step 1 there was 100 MW of wind selected in 2030 and 2031, totaling 200 MW. With the CFS enforced, there was 200 MW of wind selected in 2030 and 2035, totaling 400 MW of wind. In the Base Case scenario, the enforcement of the CFS resulted in doubling the volume of wind. We also observed an increase in energy storage and solar being selected in cases where the CFS was required. Table 6 below summarizes the additional carbon-free resources selected to meet the Minnesota CFS with the 2025 Plan for BEC, the Reference Case environmental future, under the Base Case and +1100 MW Growth Scenario. Note that in the table “TRD” are the results from Step 1 and Step 2, and “CFS” are the results from Step 3. Also, this figure only includes the resource types that were affected by enforcement of the CFS in the EnCompass model, these scenarios also include natural gas generation and industrial demand response that was selected in Steps 1 and 2.

Table 6. Capacity Expansion Analysis Results with CFS Enforced

	Customer Demand Scenarios	
	<i>Base Case</i>	<i>+1100 MW Growth Scenario</i>
Wind	TRD: 200 MW CFS: 200 MW	TRD: 1400 MW CFS: 800 MW
Solar		CFS: 200 MW
Storage		TRD: 100 MW CFS: 300 MW

	Customer Demand Scenarios	
	Base Case	+1100 MW Growth Scenario
Total Additions for CFS Affected Resources	TRD: 200 MW CFS: 200 MW Total: 400 MW	TRD: 1500 MW CFS: 1300 MW Total: 2800 MW

It is important to note that Minn. Stat. § 216B.2422, subd. 2(c) requires, “As a part of its resource filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable resource.” Since the 2025 Plan meets the Minnesota CFS requirement, this 2025 Plan meets these requirements such that no further analysis of the requirement is needed.

Next Minnesota Power will discuss how the results from the Capacity Expansion Analysis, along with Minnesota policy, host community impacts, and insights from the engagement process, help inform the recommended actions in the 2025 Plan.

D. Step 5: Preferred Plan Selection

The Capacity Expansion Analysis clearly indicates that new dispatchable gas generation, wind, solar, storage, and enhanced industrial demand response are the least cost resources to replace coal operations at BEC4, to meet the incremental demand in the +1100 MW Growth Scenario, and to comply with the Minnesota CFS. The timing of the gas additions aligns with when retiring or ceasing coal occur at BEC3 or BEC4 and with the increase in demand in the +1100 MW Growth Scenario. Renewables follow a similar timeframe with additions being driven by action at BEC3 and BEC4 and the timing of load growth, although to meet the CFS, we see significant renewable additions in 2030 and 2035 at the 80 percent and 90 percent milestones, respectively. Industrial demand response and storage have a similar role, both help manage a large renewable portfolio to operate more efficiently, with demand response being selected prior to storage additions. No other resource technologies or demand side resources were directly selected by EnCompass in Steps 1-3. The following sections provide additional insights into how Minnesota Power used the Capacity Expansion Analysis to determine the new resources utilized in the 2025 Base Plan and Growth Plan. Note that the results are referring to the resource selections for the BEC operational scenario recommended in the 2025 Plan.

Wind

Minnesota Power has over 850 MW of wind generation in its current power supply, located in Minnesota and North Dakota. Minnesota Power issued an RFP for up to 400 MW of wind on February 15, 2024. Bids from the RFP were received on April 11, 2024, and Minnesota Power is in discussions with several wind projects that were shortlisted after a detailed review of bids. Minnesota Power plans to file the petition requesting approval later in 2025. After these wind projects are operational, Minnesota Power’s wind portfolio is projected to increase by 1.7 million MWh, resulting in nearly 4.7 million MWh of total wind generation in its energy mix.

The Capacity Expansion Analysis included the 100 percent PTC for wind projects throughout the entire study period. Minnesota Power customers benefit from the PTC and it keeps costs lower for compliance with the Minnesota CFS. If the PTC benefit were no longer available, the cost to meet the CFS would materially increase for customers.

In the Base Case scenario, the Capacity Expansion Analysis selected 200 MW of PTC-qualified wind in the early 2030s. To meet the CFS, another 200 MW of wind was selected in the mid-2030s. In the +1100 MW Growth Scenario, 1400 MW of wind was selected and another 800 MW of wind is added to meet the CFS, totaling 2200 MW of wind. This demonstrates that wind is part of a robust least cost option for replacing coal generation at BEC4, to meet incremental demand in the +1100 MW Growth Scenario, and to comply with the Minnesota CFS. Typically, Minnesota Power has seen more wind selected than solar due to the high load factor of Minnesota Power's system.

Wind clearly continues to be a cost-effective resource for customers, and the volume that is needed is significant. It could be challenging to bring this volume of wind online prior to the requirements in the CFS due to potential delays in interconnection, permitting, procurement of key components, and/or labor availability. Renewable Energy Credits ("RECs") might be needed in the interim to manage the potential gap between when wind projects are brought online and milestone dates in the CFS. Minnesota Power is recommending the following wind additions for the 2025 Plan:

1. Base Plan: Add 400 MW of wind energy by 2035. Minnesota Power will make best efforts to procure wind in time to meet the CFS but may need to use RECs to address any gaps in compliance.
2. Growth Plan: Increase the addition of wind energy by another 1800 MW of wind to meet the needs of incremental load growth and the CFS. Minnesota Power will make best efforts to procure wind in time to meet the CFS but might need to use RECs to address any gaps in compliance.

Solar

Minnesota Power is making great progress in building out a solar portfolio across its service territory. The Company's last IRP included the next phase in the Company's solar strategy to meet the SES and RES requirements. Since the 2021 IRP, Minnesota Power added 22 MW of solar across three projects (Laskin, Sylvan, and Duluth solar projects) in 2023 to support economic development and recovery within the Company's service territory following the COVID-19 pandemic. Minnesota Power's solar portfolio to meet the SES also includes the 10 MW solar array located at Camp Ripley, a 1.04 MW Community Solar Garden ("CSG") program, along with approximately 4 MW of DG solar from which Minnesota Power receives solar renewable credits.

In the 2021 IRP, Minnesota Power was ordered to add up to 300 MW of solar by 2030. Since then, the Minnesota legislature passed the DSES requiring three percent of retail sales (excluding industrial customers) to be met by DG solar projects by 2030. Minnesota Power issued an RFP seeking up to 300 MW of solar on November 15, 2023. Minnesota Power reviewed bids and selected two solar projects, the 85 MW Boswell Solar Project and the 119.5 MW Regal Solar Project. Both solar projects are expected to be operational by 2029. The Boswell Solar Project is located at BEC in Cohasset and shares interconnection service with BEC3. BEC3 and the solar project will co-dispatch, resulting in BEC3 reducing energy production during the day, displacing coal generation and carbon emissions, to allow the solar energy onto the grid. This interaction between the Boswell Solar Project and BEC3 is captured in the EnCompass modeling. Minnesota Power is currently requesting Commission approval to pursue the Boswell and Regal solar

projects. The Company also recently released the first phase of its DSES RFPs in which it is seeking between 65 and 85 MW of new DG solar within its region and communities.

The Capacity Expansion Analysis included the 100 percent PTC for solar projects throughout the entire study period. A solar project qualifies for an ITC or PTC under the Inflation Reduction Act (“IRA”). For the generic solar modeling in the IRP, based on the capital cost and energy profile, the cost of solar with an ITC or PTC was nearly identical. Given the costs were close, the solar was modeled with a PTC similar to wind. Minnesota Power customers benefit from the PTC and it keeps cost for compliance with the Minnesota CFS lower. If the PTC benefit were no longer available, the cost to meet the CFS would materially increase for customers.

In the Capacity Expansion Analysis, solar was selected less often than wind, by a sizable margin. This can be explained by its higher cost profile and Minnesota Power’s high load factor. The high concentration of industrial demand results in a 24/7 need for energy, which wind does a better job providing than solar. With Minnesota Power already having plans to add nearly 300 MW of utility and DG solar to the power supply, that addition appears to be sufficient to meet the needs in our Base Plan. In the +1100 MW Growth Scenario, there was 200 MW of solar selected to meet the CFS. As discussed earlier, there are benefits within the power supply to diversify the energy portfolio by adding solar to augment the large wind portfolio proposed in the +1100 MW Growth Plan. It will be important for Minnesota Power to continue monitoring the cost of solar and advancements in the technology to see how those advancements impact the economics for customers in future IRPs.

Minnesota Power is recommending the following solar additions for the 2025 Plan:

1. Base Plan: Take no additional action on solar.
2. Growth Plan: Add 200 MW of solar to meet the needs of incremental load growth and the CFS. Similar to the wind recommendation, Minnesota Power will make best efforts to procure solar in time to meet the CFS but might need to use RECs to address any gaps in compliance.

Demand Response

Minnesota Power currently has approximately 250 MW of interruptible demand response capability with industrial customers on its system, which it utilizes for limited peak market price shaving and emergency operations. Existing demand response programs include close coordination with large industrial customers and their manufacturing processes and dual fuel rate programs with residential and commercial customers. These existing programs are a valuable component of Minnesota Power’s power supply mix and help to ensure reliability for the region. Included in the IRP analysis as alternatives are new demand response programs for both industrial customers and residential/commercial customers.

The industrial demand response alternative modeled in the IRP expands Minnesota Power’s program for industrial customers to include energy curtailment and longer contract commitments, along with emergency curtailment. The enhanced demand response program is referred to as Product B. This capacity is available in 2028, when the Product C demand response program subscription ends. The Product C program was approved by the Commission in 2021.¹⁰⁰

Product B includes long-term capacity commitment with economic energy curtailment. This product would offer meaningful demand payments to customers for the opportunity to utilize their industrial capability for meeting the broader system needs. For purposes of the IRP evaluation,

¹⁰⁰ *In the Matter of the Petition by Minnesota Power for Approval of its Industrial Demand Response Product C Contracts*, Docket No. E-015/M-21-28, Order Establishing Pilot Program (Oct. 29, 2021).

this proxy program included a \$7 per kW-month capacity credit and a \$30 per MWh energy credit for curtailed energy. These provisions would be refined further when an actual tariff is brought forward with customers.

The multi-year commitment is important to Minnesota Power because it allows us to plan the system with confidence knowing the demand response will be available over a long period of time, in comparison to the one-year commitments customers make today. The addition of economic energy curtailments is needed to better align customer demand when renewables are available to more efficiently use such resources to meet the CFS.

The Company also continues to investigate additional demand response opportunities for residential and commercial customers through the evaluation of two peak-shaving programs for central air conditioning (“CAC”) customers and electric hot water (“HW”) 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, both types of demand response programs could benefit customers, and both programs were available for the EnCompass model to select in the IRP.

In the Capacity Expansion Analysis, the enhanced industrial response program with economic energy curtailment, “Product B,” was selected consistently as a valuable program for customers. The HW and CAC demand response programs were selected infrequently, demonstrating that these programs could have value and should continue to be evaluated in future IRPs. As discussed earlier in Section V, MISO is proposing changes to the requirements to receive capacity accreditation in the MISO Resource Adequacy Construct. The proposed changes by MISO could impact the level of demand response industrial customers make available due to overly onerous requirements. For example, to meet the proposed requirements, a customer might have to curtail demand at a speed that could jeopardize the safety of the customer’s facility and workers. Minnesota Power took into consideration the risk of the availability of industrial demand response in its recommendation. Minnesota Power is recommending the following Demand Response actions for the 2025 Plan:

1. Base Plan: Create a new tariff mechanism and acquire at least 100 MW of industrial demand response capacity by 2028 that includes an annual economic energy requirement.
2. Growth Plan: Execute the Base Plan, along with working with new industrial customers on incorporating demand response into their operations where it is feasible and economic to do so.

Natural Gas

Minnesota Power has a minimal level of natural gas generation in its power supply. The 100 MW Laskin Energy Center, a coal unit refueled with natural gas in 2015, is the sole peaking gas unit on Minnesota Power’s system today. The Company’s share of NTEC and associated contracts are still in effect but given the desire from engagement participants in the last IRP wanting NTEC to be restudied, NTEC was removed from the Capacity Expansion Analysis to restudy the wholistic need for new natural gas generation on the Company’s system.

New, modern, and efficient gas generation can serve an important role on the system as a bridge energy resource to a carbon-free future. A typical characteristic of gas generation is flexibility, the ability to quickly generate energy when needed by the system when renewables are unavailable, or storage is depleted. It can fit well with variable generation like wind and solar, especially with a utility with a high load factor like Minnesota Power. Furthermore, over the long term the natural gas generation industry has begun to build a sustainable future as vendors

finalize plans and develop flexible options for lower carbon operations through hydrogen or biofuels as a fuel source or with carbon capture technologies. Natural gas brings an immediate reduction in carbon profiles (50 to 65 percent) when it is used to replace coal and also has the modern features to be adapted to even lower carbon technology in the future.

The IRP evaluated several different natural gas technologies ranging from small peakers (RICE and aeroderivatives), large peakers (frame combustion turbine), and efficient combined cycle units with carbon capture as an option. Furthermore, gas generation could be considered for co-location at BEC to utilize existing infrastructure. With Minnesota Power's need for additional capacity, the Capacity Expansion Analysis strongly showed that gas generation was the least cost resource to meet these combined needs.¹⁰¹ Minnesota Power saw in the modeling that combined cycle was the first selected gas technology. Furthermore, in the "Step 4: Emerging Technology Capacity Expansion Analysis" the combined cycle with carbon capture was the first emerging technology to be selected when capital cost was decreased by 50 percent for all emerging technologies. This shows that carbon capture could be a promising technology in the future for converting a traditional combined cycle generator to a carbon-free resource if costs can decline further. Minnesota Power will continue to evaluate carbon minimizing options for gas turbines and other technologies in future IRPs as these needed technologies develop further.

Minnesota Power is monitoring the capacity factor on the natural gas generation recommended in the 2025 Plan to measure against compliance with the EPA's Section 111(b) carbon regulations. The carbon emission limits, and associated capacity factors observed in the 2025 Plan are at or below the requirements in most scenarios. Minnesota Power did observe for a handful of years in some scenarios a gas generator exceeding the capacity factor limit, although there were other gas generation resources in the portfolio that are well below the capacity factor limit. Minnesota Power anticipates that if the gas generation that exceeded the capacity factor limit was forced to decrease generation, other gas generation in the fleet would replace that energy and still be below the capacity factor limit. Therefore, Minnesota Power concluded that in aggregate the gas generation portfolio in the 2025 Plan will meet the EPA Section 111(b) carbon regulations.

Natural gas generation also has a critical role in meeting Minnesota Power's reliability criteria, especially for reliability support during a system event or to minimize the risk of loss of load. This is more evident when evaluating generator performance during an event, such as Winter Storm Uri, where the gas generation has the capability to dispatch all week. In comparison, when Minnesota Power studied how the system would operate if gas generation was replaced with longer duration energy storage, the storage was unable to keep up with demand because of the charge and discharge cycling required. A challenge with storage during a multi-day event with lower renewable generation available is that there is not sufficient renewable generation for serving load and charging batteries. The Capacity Expansion Analysis and Reliability Criteria showed that natural gas was the least cost option to meet customer needs as Minnesota Power transitions away from coal as a fuel source and plans for additional load.

When developing the recommendation for the dispatchable need, Minnesota Power took into consideration future needs beyond what was modeled in the IRP. Part of a robust and flexible plan is to look beyond the current need in anticipation of future actions in upcoming IRPs. To replace the coal capacity and energy at BEC4, the modeling showed an initial base need for one

¹⁰¹ Refer to Appendix K for additional information regarding how Minnesota Power approached evaluating natural gas generation in the Capacity Expansion Analysis. Due to the complexity of modeling large energy and capacity needs in a system with a high concentration of renewables, a multi-step process was used to determine the economic level of new gas generation needed.

combined cycle generator (approximately 650 MW – 700 MW). Minnesota Power’s existing dispatchable generation fleet is aging, and key PPAs are reaching the end of their terms. At the same time, there is load growth emerging that requires long-lead time assets to provide reliable service. Lastly, there is uncertainty on how MISO’s resource adequacy reform, and the impacts to renewable and energy storage accreditation (which Minnesota Power relies on), will change the capacity needs. Minnesota Power anticipates capacity needs for dispatchable generation will increase as resource adequacy requirements are modernized for a high renewable future. The potential cumulative impact of all these factors led Minnesota Power to recommend a slightly higher need for gas generation than what the Capacity Expansion Analysis was showing. Approving the need for 750 MW of gas generation in the Base Plan would give Minnesota Power certainty that a robust pathway is being pursued in its Base Plan for firm and reliable generation to support its transition, as we will need this optionality and flexibility to address several decisions that will be evaluated in future IRPs.

Minnesota Power cannot cease all coal operations in its portfolio without addressing the large capacity and energy deficits and the degradation of power supply and system reliability. A new combined cycle generation addition is required to be operational before taking the last of the cease coal actions at BEC4 to ensure reliability is restored and energy needs are met.

Minnesota Power is recommending the following natural gas additions for the 2025 Plan to meet the needs of customers:

1. Base Plan: Add 750 MW of combined cycle natural gas generation by 2035 to modernize and prepare Minnesota Power’s system to enable ceasing coal-fired generation.
2. Growth Plan: Increase natural gas additions to 1500 MW to meet the needs of incremental load growth.

Energy Storage

Energy storage is a dispatchable technology area that continues to develop and expand its capability. Energy storage options continue to mature and technology costs decline, specifically for technologies with longer duration storage capabilities that can support significant time periods when other renewable resources are not available. Furthermore, energy storage is needed to manage renewables to more efficiently integrate them into the power supply and grid. The IRP evaluated several storage technologies, including lithium-ion batteries, several LDES technologies, and pumped hydro energy storage. For LDES, technologies with 12 to 100 hours of storage were studied. There are several emerging storage technologies that are promising approximately 12 hours of storage. Minnesota Power modeled in EnCompass a generic 12-hour battery that represented several types of designs in the 12-hour range. However, Minnesota Power recognizes that any of these technologies can evolve in the near future with technological changes that would impact their cost trajectory. The Company will continue to monitor storage technology alternatives and the expanded role they can play as a dispatchable resource in its power supply as technology to help Minnesota Power meet the CFS.

Minnesota Power applied a technology curve that assumed improvements in technology advancements in energy storage results in declining capital costs in real dollars (Appendix K). The modeling assumed that storage received a 30 percent ITC. If the ITC benefit were no longer available, the cost to add energy storage to the power supply would increase for customers.

In the Capacity Expansion Analysis, energy storage was selected to manage excess renewables in Minnesota Power’s power supply. Minnesota Power’s growing renewable portfolio has the capability in some cases to produce more carbon-free energy in an hour than customers

need. Energy storage can act as a load during these periods and store excess energy. When renewable energy production declines, the renewable energy stored can be used to serve customers for a defined period of time before it must be recharged. This can be an efficient way to manage renewable volatility over a short period, but as discussed earlier, is not an efficient solution to maintain a reliable grid 24/7. Storage has a key role in augmenting a reliable system, and is useful during a short duration system event, but it needs the support of other dispatchable resources to enable the caliber of reliable service customers receive today. To meet the Minnesota CFS, storage technology will have a critical role in ensuring that the wind and solar portfolio is optimized by storing excess energy instead of curtailing as renewable penetration on the system increases. Minnesota Power reviewed the reliability attributes of a system that only contained solar, wind, and storage to gain insights into the characteristics of this portfolio. The combination of 24/7 generation technology along with storage performed markedly better under the reliability criteria and cost efficiency. When reviewing capacity expansion results across the BEC operational scenarios, energy storage was selected in some of the scenarios – demonstrating storage has economic value for customers. Typically, energy storage was selected by the model more consistently in scenarios with higher demand and where the CFS requirements were included. Storage has benefits that the modeling might not fully capture, such as storing surplus renewables to preserve the carbon-free attribute by reducing the risk of curtailments. For these reasons, Minnesota Power believes that including some additional energy storage in the Base Plan and Growth Plan will benefit customers as it is growing its renewable energy portfolio.

Minnesota Power is recommending the following energy storage additions for the 2025 Plan to meet the needs of customers:

1. Base Plan: Add 100 MW of energy storage by 2035. As Minnesota Power's energy intensive system sees value in the longer duration of storage, it will install the most reasonable duration storage that is cost effective for customers.
2. Growth Plan: Add up to another 200 MW of energy storage to meet the needs of incremental load growth and the diverse system that will be required to serve customers.

Transmission

Strengthening and expanding the local and regional transmission system is a critical aspect of the transformation to a more sustainable and increasingly cleaner energy future. There has been meaningful progress in advancing grid enhancement to support the new generation patterns emerging and maintaining a reliable system. Since the last IRP, several projects have been identified and are in various stages of early project development, regulatory review, and implementation. To date, Minnesota Power has already seen the need for additional transmission to transition its small baseload resources as BEC Units 1 and 2 and THEC were retired. Further, the 500 kV GNTL project, that went into service in 2020, facilitates the delivery of nearly 1.5 million MWh of carbon-free hydro energy into Minnesota Power's service territory, accessing large volumes of renewable energy sources. More recently, Minnesota Power began the process of modernizing its aging HVDC system that will strengthen and increase the capability to deliver energy from North Dakota to Duluth, Minnesota. Minnesota Power and Great River Energy are jointly developing the Northland Reliability Project, a 180-mile double-circuit 345 kV line identified and approved as part of MISO LRTP Tranche 1. Both projects anticipate being online by the end of this decade. Most recently, in December 2024, MISO approved its second tranche of regionally-beneficial LRTP projects, which includes additional 345 kV transmission development in Northern Minnesota, including the Bison – Alexandria 345 kV Project, the Maple River – Cuyuna 345 kV Project, and the Iron Range – Arrowhead 345 kV Project. All of these LRTP Tranche 2.1 projects

are targeted for in-service dates in 2032-2033. Minnesota Power recognizes that utilizing new transmission to support transitioning the fleet to a carbon-free power supply is necessary and will grow in complexity as higher levels of decarbonization occur.

In the 2021 IRP, Minnesota Power identified several reliability transmission projects that would be needed to enable the transmission system to handle a retirement of BEC3 and/or BEC4.¹⁰² These grid evaluations were designed to identify what additional transmission would be needed to support reliable electric service in the region if no generating resources were located at the BEC facility. These studies helped guide Minnesota Power in identifying projects that were proposed to MISO for evaluation and ultimately selected in MISO's LRTP Tranche 1 and 2.1 to prepare the region for ceasing coal operations. This is a great example of how integrated planning is occurring at Minnesota Power between transmission and generation. Minnesota Power is making great progress on early project development, seeking regulatory approvals, and preparing for construction on several transmission projects that once in place between 2030-2033, will be major milestones in preparing the system for ceasing coal operations at BEC3 and BEC4. Apart from these projects already planned and in progress, there is one additional voltage support and system strength project required to facilitate retirement of BEC4 to maintain an acceptable level of voltage support in northeast Minnesota. The IRP analysis included the cost for this project in the operational scenarios where BEC4 was retired. With Minnesota Power re-affirming cease coal operations at BEC4 by 2035 in the 2025 Plan, the recommendation is to continue evaluating voltage support needs in the region and how those might change with the addition of new gas generation that is recommended in the 2025 Plan.

Minnesota Power followed a similar approach to prior IRPs where transmission studies were performed as part of a retirement study. For this IRP, transmission studies were performed to better understand the impacts of early retirement of HREC. The study results show that there are local network upgrades required in the Duluth area that are required before retirement of HREC can occur. The results of those studies and projects required to facilitate a retirement is discussed further in Appendix F and in the Appendix O.

New transmission that connects Minnesota Power to other regions, such as the Southwest Power Pool ("SPP") and the Western Electricity Coordinating Council ("WECC"), creates an opportunity to co-optimize the Company's energy portfolio with other entities. For example, Minnesota Power could diversify its renewable portfolio by purchasing wind energy from the Pacific Northwest. When wind energy is not available in Minnesota and North Dakota, Minnesota Power could purchase wind energy from Oregon instead of dispatching batteries or carbon-based generation. To access these renewables, long distance high voltage transmission must be built to connect to new regions.

Energy Conservation

Additional energy efficiency above Minnesota Power's state leading ECO programs was also evaluated in the Capacity Expansion Analysis, but were not selected by the EnCompass model. While not being prominent in the 2025 Plan, these may be necessary to manage customer costs as the Company continues to move forward to meet the CFS.

Minnesota Power will continue its strong performance in energy efficiency programs with a planned 2.9 percent average annual savings target, well above the state goal of 1.75 percent annual savings. The Company is also exploring opportunities to expand its ECO program to include efficient fuel-switching and load management opportunities through program modifications and future Triennial filings. The Company anticipates that as power supply

¹⁰² Appendix F provides a status update on these transmission solutions.

transitions and electrification continues, energy efficiency will have a prominent role to help customers control rising energy costs and adapt behavior for new Time of Day pricing models. Please refer to Appendix B for more detail on the additional energy efficiency programs evaluated in the EnCompass IRP analysis. The analysis indicates additional energy efficiency was not selected because of the rising cost to achieve higher levels of energy efficiency and the model preferring lower cost wind and storage with the PTC/ITC to meet the energy and capacity need during the same period energy efficiency was available. Additional information on how the cost of additional energy efficiency is compared to the cost of wind can be found in the busbar analysis in Appendix K.

Emerging Technologies

The industry is preparing for the transition to carbon-free energy with several companies planning to supply technologies to meet this need. Often referred to as “emerging technologies,” this is a category of resources that are still in various stages of development and federal approval processes, but not commercially available. In the IRP analysis there are several emerging technologies included in the EnCompass analysis, including LDES, advanced nuclear, carbon capture on gas and coal generators, and enhanced geothermal. Minnesota Power engaged with the Electric Power Research Institute (“EPRI”) to develop a more in-depth understanding of proven milestones of any new development for the specific emerging technology options being considered. EPRI participated in an IRP engagement meeting to present on “Energy Technology Deployment Timelines,” where participants had an opportunity to discuss and ask questions about the timing and state of emerging technology readiness for inclusion in the plan. Minnesota Power leveraged this third-party study work to help develop a perspective on when emerging technologies can realistically be included in an IRP. The review concludes that only LDES will likely be commercially available at a scale that is sustainable before 2040. All other options are not considered viable resource options during this IRP study period. With many of these technologies in various stages of development, there is uncertainty on project cost, operating cost, permitting requirements, supply chain support, and actual operational characteristics. Furthermore, many of these technologies have not been permitted before in Minnesota or there are moratoriums in place, such as the case with nuclear in Minnesota. These considerations could result in a longer timeline to implement such resources compared to a traditional generation resource.

To better understand the impact potential emerging technologies could have in a future power supply, in Step 4 of the Capacity Expansion Analysis, all emerging technologies were made available in 2030, at the earliest retirement date studied for a BEC unit. The Company wanted to study whether, if emerging technologies were available today, it would impact the recommendations in the 2025 Plan. The key takeaway from the analysis was emerging technologies were not as cost effective as the resource portfolio proposed in the 2025 Plan to meet power supply needs and the CFS. Appendix K offers additional insight into the costs modeled for emerging technologies. This analysis did include tax incentives for all carbon-free emerging technologies, including ITC for advanced nuclear and the 45Q tax credit for capture and storage of carbon dioxide. As part of this analysis, the capital cost for emerging technologies was decreased by 50 percent and the Capacity Expansion Analysis was re-run. When cost dropped by 50 percent, the EnCompass model did select a small amount of combined cycle generation with carbon capture, along with other traditional resources like gas generation, wind, solar, demand response, and energy storage. Given the current development state of emerging technologies where capital declines will likely not be constant across technologies, it is a challenge to draw too much from these results other than capital cost will need to decrease by at

least 50 percent before some technologies become economical for customers. The results from Step 4 are discussed further in Appendix K.

Minnesota Power believes that continued support of emerging technologies is important for achieving a carbon-free future that is reliable and affordable. This will require the right policies, incentives, and research to achieve. For utilities, such as Minnesota Power, additional funding is needed to engage in these activities to research, develop, and become more familiar with these emerging technologies. The Company can pilot and select the best technologies to comply with the CFS at a reasonable cost and meet the reliability expectations customers have. Furthermore, Minnesota Power customers are also interested in advancing development of emerging technologies that support their climate goals along with Minnesota Power and the State of Minnesota. To support these activities, Minnesota Power is recommending that a new development fund of initially \$30 million be established with an annual cost recovery mechanism. Minnesota Power will use these funds to partner with interested customers to advance development of emerging technologies needed to meet the CFS that support reliability and the 24/7 energy needs of our customers.

As emerging technologies advance, there are several carbon-free technologies that exist today such as wind, solar, storage, demand response, and biomass that Minnesota Power can act on in the 2025 Plan. This IRP is reducing carbon by utilizing technologies that can be implemented in the timeframe coal is being removed, while positioning the Company to make further advancements towards the CFS by requesting an initial \$30 million fund to start development efforts on emerging technologies.

Market Purchases

An important component of a utility's power supply is contracted purchases and sales, conducted to optimize the energy surpluses and deficits that occur due to load and supply changes in the shorter-term. These agreements are called bilateral transactions, and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources. Often, bilateral purchases are a cost-effective tool to meet a power need that exists over shorter periods of time, when compared to adding a new generation resource. See Appendix C, Part 2 for a list of the Company's current bilateral transactions, which were included in the Base Case. Minnesota Power included bridge energy purchases in the load growth scenarios to bridge the energy need gap between when customers are anticipating load growth and when resources could be selected in EnCompass. The bridge purchases were modeled before 2030, prior to when new resources could be selected at the beginning of 2030.

The Company continues to use bilateral transactions to manage its short-term energy position, for example to replace energy during planned outages or during periods of lower renewable production. Although, purchasing energy in the market is becoming more difficult and costly as low-cost baseload coal generation continues to be retired in the upper Midwest. Minnesota Power is seeing fewer counterparties willing to sell energy in our region due to price volatility and the lack of new dispatchable generation being built to replace coal generation. In the long-term, this is signaling that new dispatchable generation must be built because relying on the energy market could result in volatile costs for customers and a decline in reliability.

BEC3

BEC3 is an economic capacity and energy resource for customers, is well controlled for pollution, and transitioned its operations to economic dispatch back in 2021. Minnesota Power has worked diligently to maintain and improve the flexibility of all of its thermal units, including BEC3, to maximize customer benefits as renewable energy penetration continues to increase.

Since 2015, through operational optimization and capital investments, the minimum dispatch level on BEC3 and BEC4 have been reduced. Since the last IRP, Minnesota Power implemented a project at BEC3 that reduced the minimum dispatch level from 175 MW down to 75 MW. These actions to improve the flexibility of the fleet have opened new opportunities for utilizing existing assets at BEC3 to co-locate solar. Minnesota Power is requesting approval from the Commission to add 85 MW of solar that will share interconnection service with BEC3, requiring the unit to decrease generation during the day to make room for solar energy to go onto the grid. This is a great example of Minnesota Power's foresight to invest in improving flexibility, creating an opportunity to add cost effective solar to meet the CFS, and directly reducing carbon emissions by allowing for additional renewable energy to flow onto the system.

In the IRP analysis, Minnesota Power screened two alternative fuel options at BEC3 to continue producing energy after ceasing coal operations by 2030, along with a retirement scenario. This included refueling the boiler with 100 percent natural gas or co-firing with biomass and natural gas. Both refueling alternatives would require a capital investment to install the natural gas capability or retrofit the existing coal handling system to handle biomass. The capital investment for the biomass option also includes costs for a biomass palletization facility on site that would take regional biomass and convert it to pellets that can be used in the boiler. The 100 percent gas refuel option also included a reduction in O&M due to fewer staff needed to operate a natural gas fired steam unit. A concern with refuel is that the large peaking asset would have long lead time startup operations in comparison to modern combustion turbines, although the Company believes that is manageable with the recommendation to refuel one BEC unit on 100 percent natural gas in the 2025 Plan. The need for flexible and dispatchable generation will continue to be evaluated in future IRPs as Minnesota Power prepares to meet the CFS.

The Capacity Expansion Analysis demonstrates that refueling BEC3 is a least cost option for customers versus retirement and replacing BEC3 with new gas generation. Furthermore, with Minnesota Power showing a growing capacity need with ceasing coal operations and in the +1100 MW Growth Scenario, BEC3 cannot be retired prior to replacement generation with similar operational characteristics being brought online. With a commitment to cease coal by 2030, it would be challenging or impossible to have replacement generation online given the Company's recent experience with permitting the NTEC project. Refueling by co-firing with biomass and natural gas shows economic promise, especially if biomass receives net carbon-free treatment through a life-cycle analysis to qualify for the PTC and CFS. Unfortunately, the requirements for performing a life-cycle analysis on biomass have not been finalized at the federal and state level, creating uncertainty on the viability of biomass in the future.

There are regional environmental benefits accompanying ceasing coal operation and refueling BEC3 with natural gas. With coal no longer needed to operate BEC3, there will be less coal handling occurring onsite, along with less rail cars delivering coal to the facility. The trickle-down impact to operations will also affect ash handling, where the transportation activities and storage of ash will cease. Although there are environmental benefits to the reduced coal and ash handling, the jobs associated with these activities will be negatively impacted. Minnesota Power will work with any affected employees and the union on a transition plan if the refueling of BEC3 with natural gas is approved.

For the reasons stated above, Minnesota Power is recommending in the 2025 Plan additional investigation, including submitting a life-cycle analysis for biomass to be utilized as a net-carbon free source to meet the Minnesota CFS. If net-carbon free status is achieved for biomass and this refuel option continues to show economic benefits for customers, Minnesota Power will submit necessary permitting to advance the ability to co-fire biomass at BEC3. In the short-term action plan, the 2025 Plan recommends the Company begin engineering and acquisition of necessary

materials for a 100 percent natural gas refuel of BEC3. Note that this 100 percent natural gas refuel recommendation meets the requirements of the EPA's Section 111(d) carbon regulations.

An outcome of the 2021 IRP was a requirement for Minnesota Power to evaluate the conversion of BEC3 to a synchronous condenser upon retirement. A study was performed to determine the feasibility of converting BEC3 to a synchronous condenser, for both seasonal operation and following unit retirement. The study found it is technically feasible to convert the unit to synchronous condenser operation. However, the length of time needed to switch between generating and synchronous condenser operating modes makes conversion infeasible until unit retirement. Because the 2025 Plan includes a BEC3 refuel with natural gas, Minnesota Power recommends taking no action on converting BEC3 to a synchronous condenser and will continue to consider the option in future IRPs. Appendix F contains additional information on the synchronous condenser conversion study.

BEC4

BEC4 will be one of the last baseload operating units in northern Minnesota after BEC3 ceases coal operations in 2030. As approved in the 2021 IRP, the Company continues to be committed to ceasing coal-fired operations for its customers in 2035. Like BEC3, BEC4 is an economic capacity and energy resource for customers and is well controlled for emissions. The Company continues to take actions as needed to prepare a transition to economic dispatch in a similar manner as BEC3 operates today. Action can be taken if it is economical for customers and regional reliability of the system can be maintained with no dispatchable generation online in northern Minnesota. BEC4 is jointly owned with WPPI Energy and any changes will be coordinated with this co-owner, including moving to economic dispatch, re-issuance, or retirement. Minnesota Power will continue to work closely with its partner on future plans at BEC4.

The IRP analysis evaluated multiple refuel options and retirement at the 2035 cease coal date for BEC4. The refuel options evaluated are a 40 percent natural gas refuel by 2030 or co-firing with biomass and natural gas by 2035. Per the EPA Section 111(d) carbon regulation requirements, BEC4 cannot continue to operate exclusively on coal through 2035 and additional action is required for Section 111(d) compliance. One option per the EPA regulation is to refuel BEC4 to 40 percent natural gas by 2030. Given the demonstrated need for capacity and energy in 2030, and the inability to feasibly add new generation in this timeframe, Minnesota Power is recommending in the 2025 Plan to take action at BEC4 to prepare the unit for compliance with Section 111(d) by starting the engineering and acquisition of necessary materials for a 40 percent natural gas refuel by 2030. The Company is monitoring litigation of the final Section 111 rules, which is proceeding in federal court. Outcomes from ongoing litigation may impact both the timing of rule effectiveness and the ultimate compliance obligations required by the rule. If this rule is vacated through legal proceedings, remanded by the new federal administration, or replaced with a new federal carbon regulation, Minnesota Power will re-evaluate this recommendation and provide an update in the next IRP.

In the 2021 IRP, the Commission ordered Minnesota Power in its next IRP to "...continue to evaluate additional transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030." Minnesota Power continues to make progress on transmission system upgrades to strengthen the system for considering a BEC retirement. Please refer to Appendix F for further discussions on the significant projects that are in progress. The limiting constraint on potentially removing BEC4 as early as 2030 is a power supply reliability concern along with the infeasibility to add new generation in that timeframe to replace such a large component of capacity and dispatchable energy for customers. Therefore, this IRP studied an earliest retirement date for customers of 2035 for BEC4.

HREC

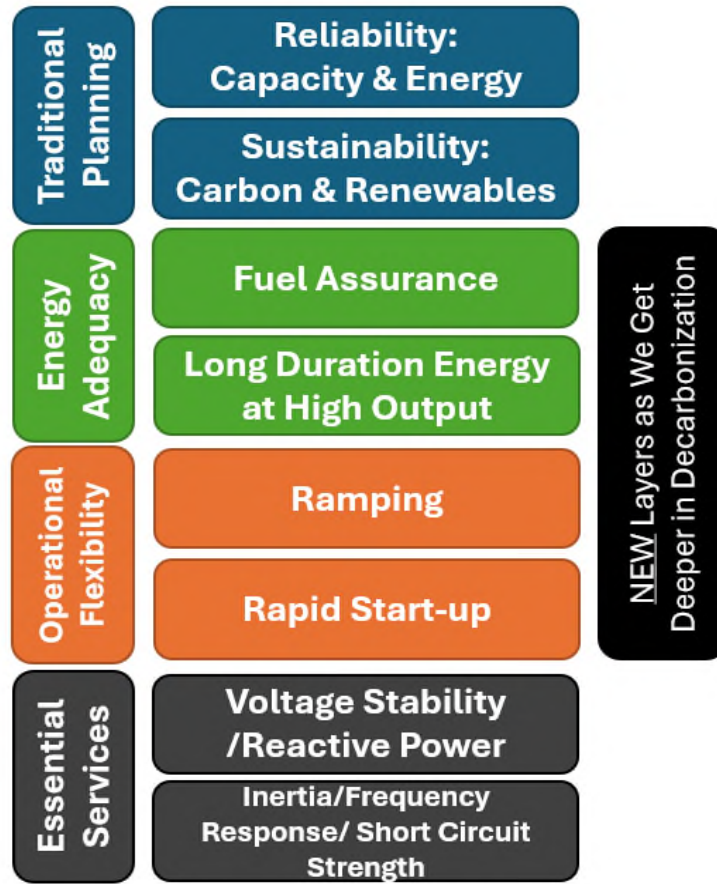
HREC is a dispatchable and renewable energy and capacity source that uses biomass to produce energy when other forms of renewable energy are unavailable. Furthermore, HREC provides an important outlet for unmerchantable roundwood affected by emerald ash borer, spruce budworm, and other pests. HREC is the only biomass facility north of the Twin Cities within an emerald ash borer quarantine zone, allowing it to receive infested wood for combustion without a compliance agreement. In the 2021 IRP, Minnesota Power was ordered to include a societal cost-benefit analysis of HREC, which must include impacts on host communities, workforce, economics, health, system reliability, the environment, and customer costs – results are shown in Appendix O. Minnesota Power also performed a retirement study of HREC, similar to the prior study performed for BEC3 and BEC4 in the last IRP, where the Company evaluated the impact of removing HREC from the power supply. This study included, for example, evaluating impacts to the host community, energy and capacity needs, transmission system, and environmental impacts. The results of that study work are discussed in Appendix O.

HREC is a valuable generation asset for customers that provides renewable energy when it is needed by the system, versus other renewable sources that provide energy when available. That dispatchable operational characteristic of HREC results in delivering higher levels of accredited capacity, contributes to meeting Minnesota Power’s reliability criteria, and is used to relieve local reliability issues in the Duluth region – all important attributes when there is declining dispatchable capacity on the system while customers are requesting more energy from Minnesota Power. For these reasons, Minnesota Power recommends in the 2025 Plan to continue operating HREC and restudy the retirement decision in the next IRP. Please refer to Appendix O for additional discussion and a more detailed evaluation that support the recommendation.

E. Step 6: 2025 Plan Reliability Criteria Evaluation

The Company has developed a MPRC process that provides additional insights into the selection and implementation of the 2025 Plan. The MPRC has four categories including: (1) Traditional Planning, (2) Energy Adequacy, (3) Operational Flexibility, and (4) Grid Essential Services, as shown in Figure 12 below. Each of these categories have sub criteria for a complete review of total system reliability. Details on the MPRC are included in Appendix K.

Figure 12. Minnesota Power Reliability Criteria



Application of the MPRC is an innovative approach to quantifiably defining and applying a set of reliability criteria to a preferred plan. The MPRC allows Minnesota Power to establish a baseline of system performance across several of the reliability criteria. As Minnesota Power ceases coal operations and brings forward replacement plans to meet the Minnesota CFS, the Company can measure if reliability is improving or declining against a baseline where the system operates reliably today. This is valuable information to incorporate into an IRP evaluation to ensure the planning considers the important aspect that customers should receive the same reliable service as they do today.

Traditional Planning

Minnesota Power continues to use Traditional Planning mechanisms as in previous IRPs using the core data elements of the load and capability, system load forecast, and resource assessments as outlined in Steps 1-4. The plan must have sufficient capacity to serve all four seasons with physical generation resources. Also, the plan must have sufficient energy to minimize unserved energy and market price risk, while also meeting the Minnesota CFS requirements and other state sustainability requirements/goals. Minnesota Power performed the Traditional Planning evaluation by using the EnCompass model to assess and develop the most reasonable plan for customers to meet the capacity, energy, and sustainability requirements. Traditional Planning is the minimum requirement for ensuring an adequate resource plan.

Minnesota Power includes additional processes for a more encompassing assessment of reliability.

Energy Adequacy

The Energy Adequacy component of the MPRC takes the Traditional Planning components one layer deeper by performing a more granular evaluation. For the 2025 IRP, Minnesota Power pursued two specific analytical constructs to evaluate the Energy Adequacy of the Base Plan and Growth Plan. The first was having a third-party perform a loss of load evaluation and the second is hourly extreme event reliability analysis.

Minnesota Power outsourced a Loss of Load Expectation (“LOLE”) modeling effort using Astrape Consulting. The intent of the LOLE study is to gain insights and develop a benchmarking tool into Minnesota Power’s unserved energy risk. The model has provided comparative benchmarking analysis for the current portfolio, the 2025 Plan, and a scenario where only wind, solar, and storage was allowed to meet Company’s incremental energy need. Each case was evaluated for its standalone capabilities using the LOLE metric as well as additional metrics looking at the depth and distribution of events across the 43 weather years and five load sensitivities. Minnesota Power views the LOLE analysis as being an effort that will be a benchmark to be reviewed and compared to in this IRP and for future planning analysis.

The LOLE analysis showed that the proposed Base Plan and Growth Plan has equal to or higher level of energy adequacy reliability compared to the existing portfolio today. Minnesota Power also performed a LOLE study where only storage, wind, and solar was allowed to replace coal energy at BEC3 and BEC4. That study showed a decline in energy adequacy reliability, there were several loss of load events for customers identified that lasted for more than a day due to the limited dispatch duration of energy storage. Note that in this scenario there was 1200 MW of energy storage, including 600 MW with 100 hours of storage capability, replacing the 800 MW of dispatchable generation at BEC.

Major event analysis is another means that Minnesota Power has applied the MPRC Energy Adequacy category, looking at the actual hourly information of specific events such as Winter Storm Uri and Winter Storm Elliot. Minnesota Power has also looked at events known as wind droughts, where there is not a major storm event, but a lower level of wind output that typically extends for up to 4-5 days. Event analysis provides insights on resource availability and the ability for serving load from Minnesota Power resources under the profiles of these real-world events that have occurred. The performance of the Base Plan and Growth Plan during Winter Storm Uri like event is discussed in more detail in the Step 7: 2025 Plan Energy and Capacity Outlook.

Minnesota Power is continuing to refine the components of the energy adequacy area in collaboration with MISO and the electric industry sector as it is a critical arena for the broader transition underway in the nation.

Operational Flexibility

Operational Flexibility needs must be understood to reliably integrate and optimize renewables by having a generation portfolio with sufficient flexibility characteristics. These operational flexibility characteristics include ramp rate and duration, cycling on and off, and rapid start up capabilities. Minnesota Power will monitor the operational flexibility need and 2025 Plan capabilities, and plan to use it to evaluate the characteristic needs of the recommended dispatchable generation in the 2025 Plan. Also, MISO included a conclusion from the January

2025 Regional Resource Assessment (“RRA”)¹⁰³ indicating a three-fold increase in the need for system ramping capabilities, supporting the need to include Operational Flexibility in the MPRC.

Grid Essential Services

Grid Essential Services is one of the key areas where integrated planning occurs between resource planning and transmission/distribution planning. Minnesota Power coordinates internally among resource, transmission, and distribution system planners on study work needed when significant action (i.e., baseload retirement) is taken that could impact the reliability of the grid. A Grid Essential Services evaluation could include transmission studies that evaluate local and regional aspects of any of the following depending on the need: steady state power flow and voltage regulation, voltage stability, transient stability, inertia, frequency response, and short circuit strength. Many of these types of studies are also occurring on a regional level in MISO’s LRTP process, which Minnesota Power is a participant in and has brought forward regionally beneficial solutions to address system issues that were identified in prior IRPs. There is also coordination on how future transmission projects could impact the capability of integrating new generation onto the system, which is factored into the 2025 Plan. Please refer to Appendix F for more on areas where integrated planning occurred between resource and transmission planners in this IRP, such as the Hibbard Retirement Study.

F. Step 7: 2025 Plan Energy and Capacity Outlook

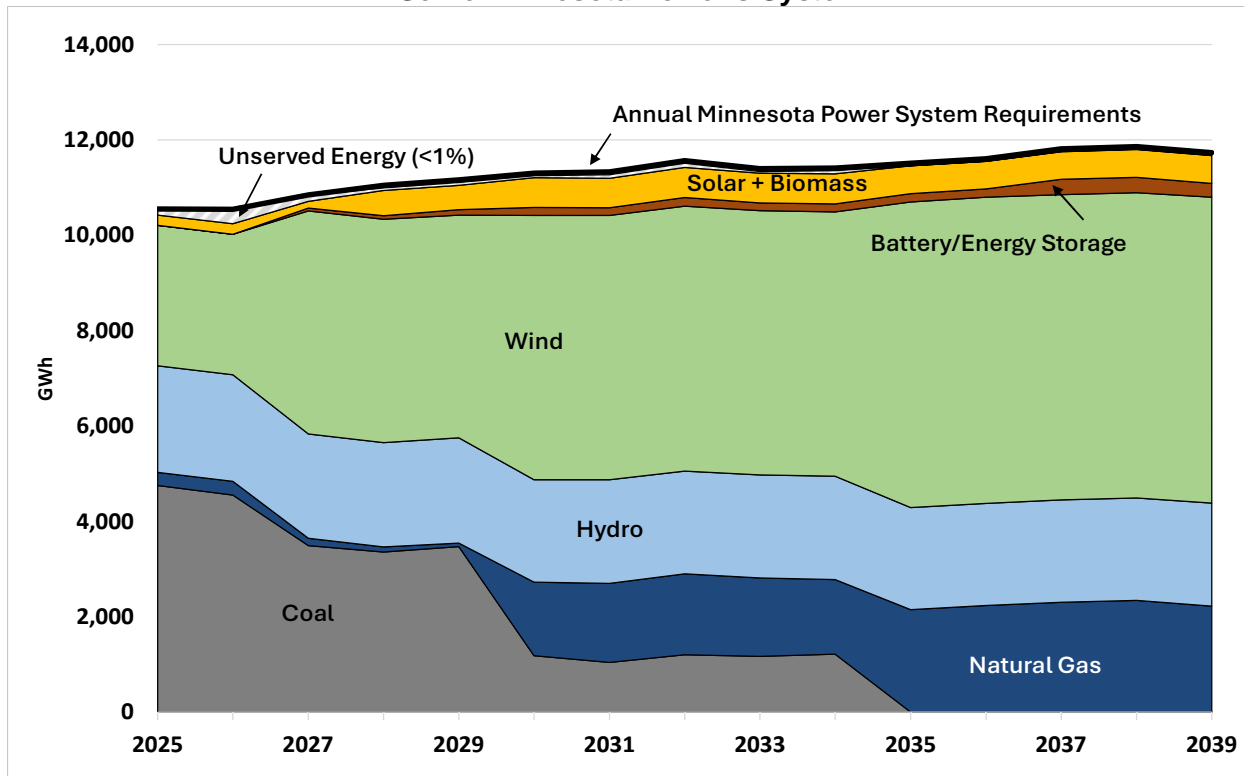
The 2025 Plan proposed by the Company continues the transition of Minnesota Power’s fleet through the next chapter of the *EnergyForward* strategy by strengthening the electric grid, preparing for customer expectations for increasing energy demand, continue to enhance the generation portfolio to meet the CFS, and optimizing existing assets for customers. In this IRP Minnesota Power is bringing forward two distinct and strategic plans for the Commission to approve that meet the needs of the current system, the Base Plan, and prepares for significant increase in energy sales that customers today are anticipating, the Growth Plan. Both plans advance clean energy and meet the Minnesota CFS requirements and also address maintaining the reliability needs of the system by taking measured steps to cease utilizing coal in the Company’s portfolio by utilizing cleaner natural gas as a replacement fuel through a refuel at BEC3 and replacing BEC4 coal generation with efficient combined cycle generation. The 2025 Plan will move Minnesota Power towards a power supply that is 80 percent renewable in 2030 and 90 percent renewable generation in 2035 while preserving the reliability of the power supply at a reasonable cost for customers.

Energy Outlook

The most significant change in Minnesota Power’s recent history is demonstrated by looking at the resulting energy profile for customers. By removing coal-fired energy, a transformational shift will be enabled with the proposed 2025 Plan. Reducing reliance on coal and making room for more flexible natural gas reduces carbon and enables a diverse portfolio that is 90 percent renewable by 2035. Figure 13 and 14 further provides a long-term look at Minnesota Power’s expected energy position. The 2025 Plan provides sufficient energy resources to serve customer requirements in both the Base Plan and Growth Plan, the result is a power supply that maximizes renewable energy, while keeping unserved energy to less than 1 percent over the study period by utilizing the dispatchable generation portfolio – see Figures 13 and 14.

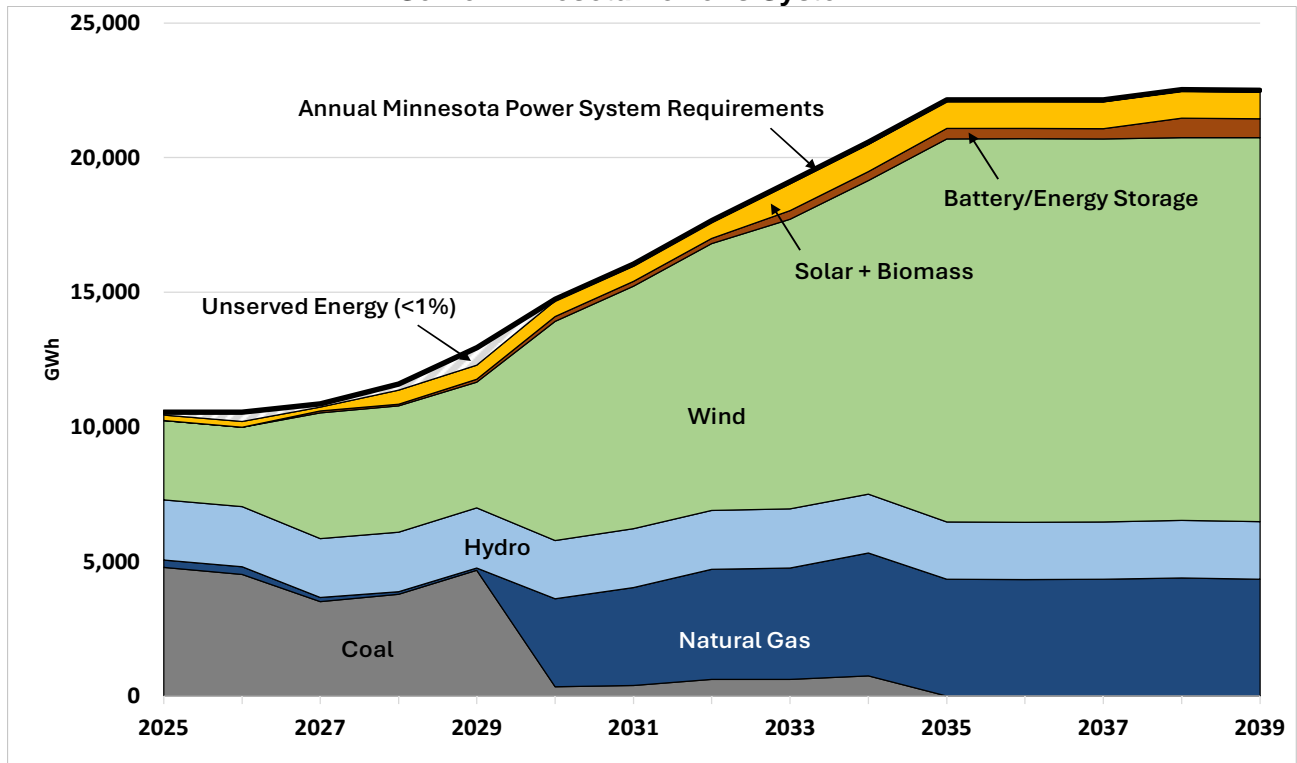
¹⁰³ MISO 2024 Regional Resource Assessment (Jan. 2025), available at https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf

Figure 13. 2025 Base Plan Energy Resources Needed to Serve Minnesota Power's System



Like the Base Plan shown above, the Growth Plan's power supply maximizes renewable energy and energy storage to meet growing customer demand, while keeping unserved energy to less than 1 percent over the study period by utilizing the recommended dispatchable generation portfolio – see Figure 14. The Growth Plan provides sufficient energy resources to serve customer requirements as Minnesota Power transitions away from utilizing coal in its portfolio.

Figure 14. 2025 Growth Plan Energy Resources Needed to Serve Minnesota Power's System



Capacity Considerations

Tables 7 through 10 on the following pages demonstrate the resulting summer and winter capacity position outlooks for the proposed Base Plan and Growth Plan. Due to ceasing coal starting in 2029, there is an identified need for additional capacity resources. In the Growth Plan, the need for capacity increases significantly when combining ceasing coal with a higher customer demand forecast. Incorporating the proposed additions of wind, solar, energy storage, industrial demand response, and new gas generation, combined with continued investment in conservation and DG solar, the Company's capacity position is brought back into an acceptable range. This is especially the case given upcoming changes in MISO resource adequacy requirements (DLOL in 2028) and to meet Minnesota Power's reliability criteria.

Minnesota Power anticipates that when DLOL changes are incorporated into the resource adequacy program, there will be a significant shift in its capacity position starting in Planning Year 2028-2029. Based on preliminary snapshots of Minnesota Power's system under DLOL that MISO provided, Minnesota Power is anticipating a significant decrease in accredited capacity. For example, in the 2035 winter of the Base Plan, the Company is expecting the accredited capacity value of the portfolio will decrease several hundred MWs. The decrease is partly driven by renewables and energy storage having lower capacity value under DLOL. With the new program there will also be reductions in reserve margin requirements, however, for Minnesota Power, the decrease in accredited capacity is expected to be larger than the decline in demand requirements, resulting in a net decrease in the capacity position. The more significant decrease in accredited capacity is occurring mostly across Minnesota Power's renewable portfolio. With wind and solar unable to dispatch when the system is in stressed conditions, these resources receive lower

accredited capacity value in the DLOL construct. To capture this planned implementation, there is an adjustment for DLOL in the Load and Capability tables shown on the following pages.

The Base Plan and Growth Plan are projected to have sufficient capacity resources for the transition to DLOL in most Planning Years. Although, there are remaining uncertainties on what the final impact of DLOL will be given the limited information provided so far and how accredited capacity values will change as the power supply transforms in the MISO region. Minnesota Power will continue to monitor the impact DLOL has to the 2025 Plan and provide updates in future IRPs as more information becomes available from MISO. More on the potential impact from DLOL to Minnesota Power's capacity position in fall and spring is discussed and shown in Appendix K.

Table 7. 2025 Base Plan Capacity Outlook - Summer

	2025	2030	2035
System Needs: Summer			
Forecasted Gross Load	1615	1655	1660
FAC/FERC System Coincidence	95.02%	95.02%	95.02%
Coincident Load	1535	1573	1577
MISO Planning Reserve Margin (UCAP)	9%	9%	9%
MP Obligation (Summer)	1673	1714	1719
Existing 2021 Plan & Approved Resources (Seasonal Accredited Capacity, Summer)			
Demand Response, Existing	173	56	56
Coal	666	238	0
Natural Gas	98	259	101
Biomass	53	52	52
Energy Storage	0	77	77
Hydro	332	333	333
Wind	192	245	242
Solar	21	40	36
Distributed Solar Energy Standard (DSES)	0	16	14
Customer Distributed Generation	153	153	153
Existing Resources	1689	1469	1064
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	16	(245)	(655)
2025 Plan Incremental Distributed Resources (Season Accredited Capacity, Summer)			
Incremental Distributed Resources Brought Forth in This Plan	0	109	109
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	16	(136)	(546)
2025 Plan Resource Additions (Seasonal Accredited Capacity, Summer)			
Energy Storage	0	0	0
BEC3 Gas Conversion	0	330	330
Natural Gas	0	0	605
Wind	0	36	64
Solar	0	0	0
Preferred Plan Resource Additions	0	366	999
Projected Net Position (Need)/Surplus	16	230	453
DLOL Projected Impact to 2025 Plan Net Position (Direct Loss Of Load (DLOL) Capacity, Summer)			
DLOL Resource Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	(326)	(370)
Planning Reserve Margin System Adjustment (+ Increase Obligation / - Decrease Obligation)	0	(98)	(98)
Projected Change In Capacity Position	0	(228)	(272)
DLOL Projected Net Position (Need)/Surplus	16	2	181

Table 8. 2025 Base Plan Capacity Outlook - Winter

	2025	2030	2035
System Needs: Winter			
Forecasted Gross Load	1626	1675	1705
FAC/FERC System Coincidence	96.33%	96.33%	96.33%
Coincident Load	1566	1613	1642
MISO Planning Reserve Margin (UCAP)	27%	27%	27%
MP Obligation (Winter)	1995	2055	2092
Existing 2021 Plan & Approved Resources (Seasonal Accredited Capacity, Winter)			
Demand Response, Existing	70	66	66
Coal	944	308	0
Natural Gas	71	267	62
Biomass	54	57	57
Energy Storage	0	77	77
Hydro	357	361	361
Wind	493	706	638
Solar	1	0	0
Distributed Solar Energy Standard (DSES)	0	0	0
Customer Distributed Generation	146	146	146
Existing Resources	2134	1989	1408
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	139	(67)	(684)
2025 Plan Incremental Distributed Resources (Season Accredited Capacity, Winter)			
Incremental Distributed Resources Brought Forth in This Plan	0	127	127
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	139	61	(557)
2025 Plan Resource Additions (Seasonal Accredited Capacity, Winter)			
Energy Storage	0	0	0
BEC3 Gas Conversion	0	380	380
Natural Gas	0	0	622
Wind	0	74	148
Solar	0	0	0
Preferred Plan Resource Additions	0	454	1151
Projected Net Position (Need)/Surplus	139	515	594
DLOL Projected Impact to 2025 Plan Net Position (Direct Loss Of Load (DLOL) Capacity, Winter)			
DLOL Resource Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	(808)	(813)
Planning Reserve Margin System Adjustment (+ Increase Obligation / - Decrease Obligation)	0	(442)	(450)
Projected Change In Capacity Position	0	(366)	(363)
DLOL Projected Net Position (Need)/Surplus	139	149	231

Table 9. 2025 Growth Plan Capacity Outlook - Summer

	2025	2030	2035
System Needs: Summer			
Forecasted Gross Load	1615	2031	2765
FAC/FERC System Coincidence	95.02%	95.02%	95.02%
Coincident Load	1535	1930	2627
MISO Planning Reserve Margin (UCAP)	9%	9%	9%
MP Obligation (Summer)	1673	2104	2864
Existing 2021 Plan & Approved Resources (Seasonal Accredited Capacity, Summer)			
Demand Response, Existing	173	56	56
Coal	666	238	0
Natural Gas	98	259	101
Biomass	53	52	52
Energy Storage	0	77	77
Hydro	332	333	333
Wind	192	245	242
Solar	21	40	36
Distributed Solar Energy Standard (DSES)	0	16	14
Customer Distributed Generation	153	153	153
Existing Resources	1689	1469	1064
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	16	(634)	(1799)
2025 Plan Incremental Distributed Resources (Season Accredited Capacity, Summer)			
Incremental Distributed Resources Brought Forth in This Plan	0	109	109
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	16	(525)	(1690)
2025 Plan Resource Additions (Seasonal Accredited Capacity, Summer)			
Energy Storage	0	0	98
BEC3 Gas Conversion	0	330	330
Natural Gas	0	697	1517
Wind	0	144	352
Solar	0	0	46
Preferred Plan Resource Additions	0	1171	2343
Projected Net Position (Need)/Surplus	16	645	653
DLOL Projected Impact to 2025 Plan Net Position (Direct Loss Of Load (DLOL) Capacity, Summer)			
DLOL Resource Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	(456)	(667)
Planning Reserve Margin System Adjustment (+ Increase Obligation / - Decrease Obligation)	0	(120)	(163)
Projected Change In Capacity Position	0	(337)	(504)
DLOL Projected Net Position (Need)/Surplus	16	309	149

Table 10. 2025 Growth Plan Capacity Outlook - Winter

	2025	2030	2035
System Needs: Winter			
Forecasted Gross Load	1626	2051	2810
FAC/FERC System Coincidence	96.33%	96.33%	96.33%
Coincident Load	1566	1975	2707
MISO Planning Reserve Margin (UCAP)	27%	27%	27%
MP Obligation (Winter)	1995	2517	3448
Existing 2021 Plan & Approved Resources (Seasonal Accredited Capacity, Winter)			
Demand Response, Existing	70	66	66
Coal	944	308	0
Natural Gas	71	292	62
Biomass	54	57	57
Energy Storage	0	77	77
Hydro	357	361	361
Wind	493	706	638
Solar	1	0	0
Distributed Solar Energy Standard (DSES)	0	0	0
Customer Distributed Generation	146	146	146
Existing Resources	2134	2013	1408
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	139	(503)	(2040)
2025 Plan Incremental Distributed Resources (Season Accredited Capacity, Winter)			
Incremental Distributed Resources Brought Forth in This Plan	0	127	127
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	139	(376)	(1913)
2025 Plan Resource Additions (Seasonal Accredited Capacity, Winter)			
Energy Storage	0	0	98
BEC3 Gas Conversion	0	380	380
Natural Gas	0	698	1526
Wind	0	296	814
Solar	0	0	0
Preferred Plan Resource Additions	0	1375	2819
Projected Net Position (Need)/Surplus	139	998	906
DLOL Projected Impact to 2025 Plan Net Position (Direct Loss Of Load (DLOL) Capacity, Winter)			
DLOL Resource Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	(1069)	(1417)
Planning Reserve Margin System Adjustment (+ Increase Obligation / - Decrease Obligation)	0	(541)	(742)
Projected Change In Capacity Position	0	(528)	(675)
DLOL Projected Net Position (Need)/Surplus	139	471	231

Event Analysis – Winter Storm Uri Performance

The actions proposed in the 2025 Plan will change how Minnesota Power provides a reliable power supply to its customers by transitioning away from coal to relying on natural gas generation and energy storage during periods when renewable energy is unavailable. As discussed earlier, Minnesota Power applied reliability criteria to ensure that this transition to decarbonize the power supply does not result in a decline in the quality-of-service customers receive today. One of the criteria that gives the Company comfort in its proposed actions is performing an event analysis, where a detailed evaluation is performed of a portfolio’s performance during a period when the system is stressed.

One event Minnesota Power looked at is the Winter Storm Uri event that occurred from February 13 – 17, 2021. This was a multi-day event of high demand due to extreme cold combined with stretches of low renewable production and higher forced outages of traditional resources. This is becoming a common tool for planners to evaluate system performance during historical stressed periods to help augment the traditional energy and capacity modeling performed with a tool like EnCompass. For this plan, this additional insight into system performance was also used to affirm the recommendation for dispatchable generation. The proposed energy portfolio in the Base Plan and Growth Plan optimizes a diverse and flexible generation mix of wind, solar, hydro, energy storage, demand response, biomass, and natural gas generation to meet the customer needs during winter the Winter Storm Uri – shown in Figures 15 and 16 below.

Figure 15. Energy Supply Performance During Winter Storm Uri with Base Plan

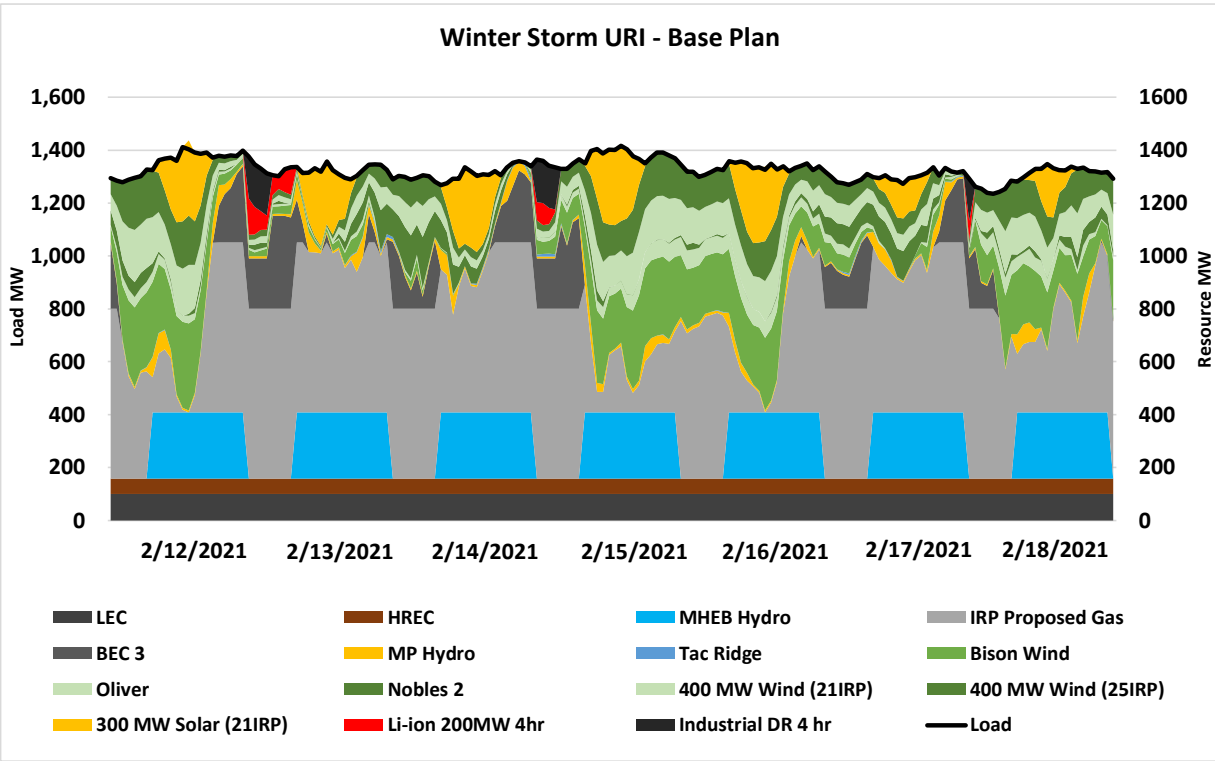
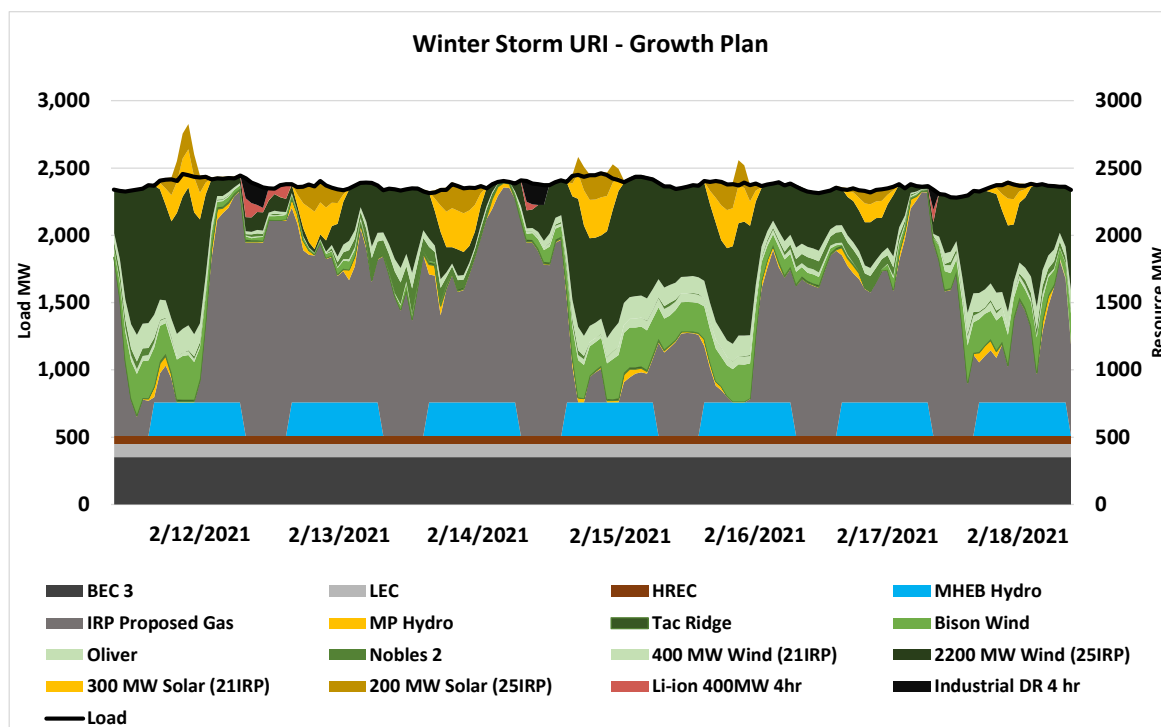


Figure 16. Energy Supply Performance During Winter Storm Uri with Growth Plan



The event analysis above is an example of how Minnesota Power’s Base Plan and Growth Plan have the capability to dispatch during a Winter Storm Uri like event. Actual performance and what generation resources are dispatched will vary depending on unit availability, price of fuel, and state of charge for batteries, for example. This analysis demonstrates that with the proposed power supply fully operational and available the Company can reliably serve customers during a similar type of event.

Socioeconomic Impacts of the 2025 Plan

The actions proposed in the 2025 Plan will have socioeconomic impacts to northeastern Minnesota that will result in changes to jobs and gross domestic product (“GDP”). Minnesota Power is performing a socioeconomic impact study using the industry accepted model built by Regional Economic Model, Inc. Not all actions in the 2025 Plan will have direct economic impacts on the region and for this study, only the resource actions that are expected to have direct impacts were included:

Base Plan

1. BEC3 natural gas refuel and BEC4 40 percent natural gas refuel;
2. Construction of 100 MW of energy storage; and
3. Construction of 750 MW natural gas fired combined cycle.

Growth Plan

1. BEC3 natural gas refuel and BEC4 40 percent natural gas refuel;
2. Construction of 1500 MW of natural gas fired combined cycle and combustion turbines;
3. Construction of 200 MW of solar;

4. Construction of 300 MW of energy storage.

The socioeconomic impact assessment is included in Appendix M.

Carbon Reduction Progress

The 2025 Plan identifies Minnesota Power's near-term plan to further reduce carbon emissions by adding renewable energy, energy storage, enhanced industrial demand response, and ceasing utilization of coal in its portfolio completely by 2035 and replacing with more efficient and lower carbon emitting natural gas combined cycle. These actions increase the renewable portfolio to 90 percent renewable and achieve CFS requirements by 2035 in both the Base Plan and Growth Plan, while ensuring cost-effective rates for customers. How Minnesota Power will meet the CFS is discussed further in Appendix I. Furthermore, in the Base Plan carbon emissions are reduced by 95 percent and in the Growth Plan reduced by more than 90 percent from 2005 levels, demonstrating even with load growth Minnesota Power continues to be a leader in serving increasing demand while still making significant progress on carbon reductions.

Sensitivity Risk Analysis

For the 2025 Plan, Minnesota Power stressed the Base Plan and Growth Plan by putting them through a series of approximately 20 sensitivities that stressed the main drivers for resource decisions. These drivers include fuel costs, technology cost, market prices, and renewable performance. This sensitivity analysis helped determine whether the 2025 Plan and its resource actions is a robust plan for customers. The sensitivity analysis results are discussed further in Appendix K.

Key Contingencies

The planning process and resource plan analysis discussed in this IRP allowed Minnesota Power to consider several contingencies that address the uncertainty that is present with the business environment, customer cost impacts, and climate compliance policy. Each gave the Company the insight needed to be prepared for the potential paths each of these can take in the near term. The key contingencies and their anticipated implications that Minnesota Power will continue to monitor are:

Uncertainty in Customer Demand due to Business Climate: Customers are anticipating large increases in their energy demand and expect Minnesota Power to have flexible plans to serve this energy. Depending how quickly this demand ramps up and the size, Minnesota Power could have capacity and energy deficits and will need to consider making market purchases to mitigate the gap period between customer needs and when new generation can be brought online. On the contrary, if a recession re-emerges or customers are forced under additional economic pressure impacting Minnesota Power's demand, the Company will have excess capacity and will consider making commitments for power sales to mitigate the effect of the reduced customer load.

Availability of Federal Tax Incentives: The affordability of the 2025 plan relies on federal tax incentives for carbon free resources needed to meet the Minnesota CFS. If there are changes to the availability of tax incentives, Minnesota Power will monitor the impact and communicate those impacts to the Commission in future IRPs or as necessary.

EPA Section 111 Carbon Regulation: If there are changes to the EPA Section 111 Carbon Regulation requirements, Minnesota Power would re-evaluate its long-term actions that are impacted and bring forward a revised plan.

Technology Advancements: If advancements in carbon-free energy technologies occur quicker and costs decline at a faster rate than expected, Minnesota Power would re-evaluate its long-term actions to reduce carbon quicker and consider the addition of more carbon minimizing technologies.

Implementation of New Generation in 2025 Plan: With the significant demand for new generation that the industry is planning for during this IRP study period there is the potential for cost and timing to shift due to availability of transmission, permitting and regulatory bottlenecks, constrained supply chains, and skilled labor shortages. Minnesota Power will monitor these risks during the execution of the IRP 2025 Plan and provide updates in future IRPs or as necessary through individual project updates.

MISO Resource Adequacy and Availability of Transmission: MISO is preparing to transition its resource adequacy requirements to implement changes to its capacity accreditation construct. Minnesota Power will continue to monitor the cost of interconnecting new resources as Minnesota Power seeks to implement its short and long-term action plans and incorporate additional renewables into the system.

Minnesota Power will also continue to closely monitor the business environment, affordability of the plan, and potential changes to other climate compliance policy outlooks and evaluate its short-term action plan as the landscape unfolds to ensure that customers and communities are served in a reliable and forward-looking way during the planning period.

Conclusion

The 2025 Plan analysis identified actions for customers that meet the current and future growth needs of the system, resulting in flexible short- and long-term action plans that include the most reasonable cost actions and meet the Minnesota CFS for the study period through 2039. The evaluations resulted in definitive plans for replacing coal generation at BEC3 and BEC4 with a mix of wind, solar, natural gas, energy storage, and enhanced demand response. This portfolio of additional renewables and dispatchable generation is supported through the Capacity Expansion Analysis. Continued leadership in conservation programs, distributed generation, and grid strengthening implementation puts Minnesota Power on a sustainable path to 90 percent renewable generation by 2035, in compliance with the milestones outlined in the CFS, as customers are expecting higher levels of energy demand. The 2025 Plan, in its entirety, is a flexible, innovative, bold, and reasonable cost plan that reflects Minnesota Power's commitment to our customers, communities, and climate action.

VI. SHORT-TERM ACTION PLAN

Minnesota Power's short-term action plan communicates the Company's vision for a sustainable energy future and outlines bold next steps in the Company's *EnergyForward* resource strategy that are centered on a commitment to providing safe, reliable, and increasingly clean energy at a reasonable cost.

Steps to Meet Short-Term Action Plan (2025 through 2030)

Minnesota Power's short-term action plan during the near term period of 2025 through 2030 is comprised of action items that will immediately reduce carbon emissions in the near term and continue the addition of renewable energy, conservation, and other demand side resources to the Company's resource portfolio.

1. Complete the 2021 IRP actions already in progress, including finalizing the Company's implementation plan for 400 MW of new wind energy by 2028 as practicable and completing the implementation of the Regal and Boswell Solar Projects, which will result in approximately 200 MW of additional utility-scale solar resources. The Company will also bring forward a filing outlining the Company's plan for up to 500 MWh of new energy storage in 2026 and progress on Integrated Distribution Plan non-wires alternatives.
2. Maximize demand side management and customer options by continuing the Company's ECO and energy efficiency programs and creating the necessary tariff mechanisms to acquire at least 100 MW of new long term demand response capacity by 2028 that includes an annual energy curtailment requirement. The Company will also work to complete the addition of 65 to 85 MW of new DG solar resources and implement an EV MDU program to further support customers' electrification needs.
3. Add new renewable energy to the Company's portfolio by releasing an RFP for 400 MW of additional wind energy and 100 MW of energy storage for implementation by 2035.
4. Advance the Company's plan to cease coal at BEC3 by the end of 2029. Begin the engineering and acquisition of materials required for a natural gas refuel of the unit. Pending the outcome of state and federal regulatory processes and economic evaluations related to biomass as a net carbon-free resource, Minnesota Power will conduct additional investigation into the economic prospects of co-firing biomass as part of the refuel plan at BEC. The Company will cease coal at BEC3 once new gas refuel capability is in service. This refueling will result in immediate carbon emissions reduction while supporting reliability in the region and continuing to provide economic benefits for the local host community.
5. In order to comply with the current EPA Section 111(d) carbon regulations, begin engineering and development required for at least 40 percent natural gas capability for BEC4 in coordination with WPPI Energy.
6. Continue operations at HREC to support regional reliability needs and ensure all environmental requirements are met for this renewable facility.
7. Work with customers to identify and integrate emerging clean firm technology with a proposal requesting \$30 million to pursue R&D projects that will be rider recoverable.

VII. LONG-TERM ACTION PLAN

Minnesota Power's long-term action plan communicates the Company's vision for transitioning to a sustainable clean energy future and outlines bold next steps in the Company's *EnergyForward* resource strategy that are centered on a commitment to providing safe, reliable, and increasingly clean energy at a reasonable cost.

Plans to Meet Long-Term Need (2030 through 2039)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix after it ceases utilizing coal. This long-term strategy will continue resource diversification and position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining reliable service to its customers at a reasonable cost. Each component of this long-term plan has been proven through the planning analysis to be flexible and robust to keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. Planned components include:

- To ensure Minnesota Power has dispatchable reliability resources to meet expected customer needs, immediately begin to develop 750 MW of combined cycle natural gas generation to be in service by 2035 to enable ceasing coal on Minnesota Power's system. BEC infrastructure reinvestment will be prioritized in siting activities.
 1. On receipt of final local permits for NTEC, and if available to meet IRP needs, the Company will refile with the Commission as required.
 2. Any new natural gas resource additions will position for minimizing carbon emissions with alternative fuel or technology as it becomes available.
- Cease utilizing coal in Minnesota Power's supply portfolio once new combined cycle generation replacement is complete to ensure reliability is not degraded. To ensure Minnesota Power meets the latest GHG requirements including EPA Section 111(d) carbon regulations by 2030, Minnesota Power will develop, along with WPPI Energy, a refueling alternative of BEC4 for operating capability of at least 40 percent natural gas, which will create additional emission reductions for the facility five years ahead of the Company's cease coal plan.
- Continue developing and implementing transmission solutions to address reliability issues related to the Company's cease coal plan, including working with regional partners to complete three approved MISO LRTP Tranche 2.1 projects and continued work with MISO to determine if additional transmission solutions are necessary for regional reliability needs as decarbonization of the electricity system continues.

As additional load growth emerges, Minnesota Power will need to be flexible and nimble and will add the following actions under the Growth Plan as necessary:

- Increase natural gas additions to 1500 MW to meet system requirements.
- Increase renewable implementation to include up to 2200 MW of wind and 200 MW of solar resources to position the Company for compliance with the CFS.
- Increase energy storage to 300 MW to ensure economic management of Minnesota Power's renewable portfolio.

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- New supply additions identified in the Growth Plan will be brought forward for Commission consideration and approval as part of a power supply agreement that outlines customer responsibility for the additions required and benefits provided to existing customers.
 - If additional load emerges above the Growth Scenario planning level, Minnesota Power will increase these initial activities with a dedicated power supply plan brought to the Commission as needed prior to submission of the Company's next IRP.

IRPs offer an iterative planning process, and Minnesota Power will continue to evaluate carbon-free technology adoption and economic pathways for CFS compliance in 2040. In its next IRP, Minnesota Power will:

1. Evaluate the economic prospects of biomass as an additional fuel source if state and federal policy indicates biomass is a net-carbon free resource based on a life-cycle analysis;
2. Review its Manitoba Hydro contract and other renewable PPA terms, as well as alternatives for replacement if necessary;
3. Evaluate additional transmission alternatives for accessing broader regional capacity and optimization;
4. Clarify the cease coal plan for BEC4 and action being taken at the facility; and
5. Continue to prioritize reliability needs of the system as it continues to transform.

In the Matter of Minnesota Power's
Application for Approval of its 2025-2039
Integrated Resource Plan

MPUC Docket No. E-015/RP-25-127

CERTIFICATE OF SERVICE

I, Kristin M. Stastny, hereby certify that on the 3rd day of March, 2025, on behalf of Minnesota Power, I electronically filed a true and correct copy of the Company's **2025-2039 Integrated Resource Plan** 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.

/s/ Kristin M. Stastny
Kristin M. Stastny

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