Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENTS
NOT-PUBLIC DATA HAS BEEN REDACTED

February 1, 2024

Will Seuffert **—Via Electronic Filing—**
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2024-2040 UPPER MIDWEST INTEGRATED RESOURCE PLAN
DOCKET NO. E002/RP-24-67

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, is pleased to submit this 2024-2040 Upper Midwest Integrated Resource Plan (2024 Plan) to the Minnesota Public Utilities Commission. The 2024 Plan identifies the resources we will need to reliably serve our customers over the next 15 years and charts a path toward achieving Minnesota's newly enacted "100 by 2040" law.

The Company's Preferred Plan is designed to build upon the substantial progress already made through prior resource plans, and we are grateful to all of our stakeholders and the Commission for their input, leadership, and collaboration as we continue to transition to a cleaner—and ultimately carbon-free—energy future. In our 2019 Plan, the Commission approved a number of key decisions in what promises to be an historic transformation of our energy system to one that will be dramatically cleaner, while remaining safe, affordable, and reliable for our customers. As the Commission directed in that proceeding, we will retire all of our baseload coal units in the coming years, replacing them with thousands of megawatts (MWs) of new renewable resources, supported by firm dispatchable resources to ensure reliability.

It's worth pausing to reflect on the progress we have already made together. Among other things, it includes the construction of multiple gigawatts of new wind resources across our region; the ongoing construction of the largest solar farm in the Midwest at our Sherco site; and the recent decommissioning of our Sherco 2 coal plant, which is the first in the series of carefully planned coal retirements that will occur throughout the 2020s. As a result of these and other achievements, our total energy mix in 2023 was 63 percent carbon-free.

In this 2024 Plan, we are proposing a Preferred Plan that will allow us to take the next step in decarbonizing our system while maintaining critical reliability and affordability for our customers at less than a one percent average annual increase in rates—less than half the national average. Key elements of that plan include:

- Extending the lives of both our nuclear plants—over 1,700 MWs of carbon-free baseload generation—into the 2050s;
- Adding nearly 10,000 MWs of renewable resources and over 2,100 MWs of energy storage to our system by 2040;
- Supporting the integration of nearly 6,000 MWs of demand-side resources, including energy efficiency, demand response, and distributed solar, on our distribution system by 2040; and
- Adding the necessary firm dispatchable resources to ensure reliability and facilitate renewable integration while generating less than 5 percent of the energy on our system.

The State of Minnesota and Xcel Energy have led the clean energy transition for decades, and this plan continues that leadership. We share the state's vision to deliver 100 percent clean energy in Minnesota by 2040, and we are well-positioned and steadfast in our commitment to achieving that target.

We look forward to discussing our 2024 Plan with the Commission, stakeholders, and the community.

Request for Protection of Confidential Information

The Company recognizes and supports the need for transparency in review of our 2024 Plan. We also take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers.

Appendix D1: 2023 Inertial Floor Study Report

Appendix D1 is marked as "Not-Public" and is provided with Critical Energy Infrastructure Information (CEII) redacted. The appendix contains contingency information related to or proposed to critical electric infrastructure, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters. Xcel Energy protects CEII as confidential Security Information as defined by Minn. Stat. § 13.37(1)(a), as its disclosure would be likely to substantially jeopardize the security of vital system information, and property against trespass, or physical injury or otherwise cause financial harm from its disclosure. Xcel Energy maintains this information as a confidential pursuant to Minn. Rule 7829.0500, subp 2.

Appendix E: Load and Distributed Energy Resource Forecasting

Appendix E is marked "Not-Public" as a portion of Section VI.E. contains information designated as Trade Secret data pursuant to Minn. Stat. § 13.37(1)(b). The information contains sensitive forecasted production and load location data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 2.

Appendix F: EnCompass Modeling Assumptions and Inputs

Appendix F is marked "Not-Public" as Table F-14: Nuclear Leave Behind Costs contains information designated as Trade Secret pursuant to Minn. Stat. § 13.37, subd. 1(b). Table F-14 includes cost data that could provide an unfair economic advantage to other persons considering constructing projects or performing upgrades in the vicinity of the Company's nuclear plants. This information derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 2.

Appendix M1: Nuclear Leave Behind Study Report

Appendix M1 is marked as "Not-Public" and is provided with Critical Energy Infrastructure Information (CEII) redacted. The appendix contains contingency information related to or proposed to critical electric infrastructure, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters. Xcel Energy protects CEII as confidential Security Information as defined by Minn. Stat. § 13.37(1)(a), as its disclosure would be likely to substantially jeopardize the security of vital system information, and property against trespass, or physical injury or otherwise cause financial harm from its disclosure. Xcel Energy maintains this information as a confidential pursuant to Minn. Rule 7829.0500, subp 2.

Appendix N1: 2021 REO-RES-SES Report
Appendix N2: 2022 REO-RES-SES Report

Appendices N1 and N2 are marked as "Not-Public" as certain portions of Attachment A to the reports are designated as Trade Secret information pursuant to Minn. Stat. § 13.37, subd. 1(b). In particular, the information pertains to specific Commission-approved Purchase Power Agreements (PPAs), the terms of which require the information be protected as not-public. Other information marked as Trade Secret relates to specific production from specific customer facilities. Xcel Energy protects this information as private customer data pursuant to the Minnesota Data Practices Act and a trade secret pursuant to Minn. Stat. § 13.37, subd. 1(b), as it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 2.

Appendix T: MISO Grid Congestion

Attachment T is marked "Not-Public" as portions of the appendix contain data designated as Trade Secret pursuant to Minn. Stat. §13.37(1)(b). The information includes wind facility curtailment and congestion costs Xcel Energy treats as confidential pursuant to purchase power agreements with facility owners. This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 2.

Copies of the filing will be served on Commission staff, the Department of Commerce, and the Office of the Attorney General – Residential Utilities Division. We will also provide a copy to the Minnesota Environmental Quality Board. Interested parties will be able to obtain copies from our web site at xcelenergy.com/UpperMidwestEnergyPlan.

Please contact Bria Shea at (612) 330-6064 or bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

RYAN LONG
PRESIDENT
NORTHERN STATES POWER COMPANY

Enclosures
c: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. Rule 7843.0300, subp. 5, we have served copies of this filing on the Department of Commerce, Office of the Attorney General, Minnesota Environmental Quality Board and parties on the enclosed service lists.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ian M. Dobson
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 330-7641

C. Date of Filing and Proposed Effective Date of Rate Factors

The date of this filing is February 1, 2024. The Company is not proposing rate factors in this filing.

D. Statute Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.2422 governs the Company's submission of a resource plan periodically in accordance with rules adopted by the Commission.

E. Utility Employee Responsible for Filing

Bria E. Shea
Regional Vice President, Regulatory Policy
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 330-6064

IV. MISCELLANEOUS INFORMATION

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

Ian M. Dobson
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
ian.m.dobson@xcelenergy.commailto:

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Christine Schwartz at the Regulatory Records email address above.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Commissioner
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
John Tuma	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2024-2040 UPPER MIDWEST INTEGRATED RESOURCE PLAN

Docket No. E002/RP-24-67

XCEL ENERGY'S INTEGRATED RESOURCE PLAN SUMMARY OF PROPOSAL

SUMMARY

On February 1, 2024, Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission its 2024-2040 Upper Midwest Integrated Resource Plan (2024 Plan).

The 2024 Plan builds on the strong foundation of cost-effective carbon reduction that we have been working toward since the Commission approved our 2019 Plan. The 2024 Plan identifies the resources we will need to reliably serve our customers over the next 15 years and charts a path toward achieving Minnesota's newly enacted "100 by 2040" law. It is comprised of a portfolio of forward-looking projects and resources designed to continue providing safe, reliable, and affordable service to our customers while continuing our ambitious carbon-reduction strategy, even as we forecast significant increases in customer load from electrification and other sources.

Copies of the filing will be served on Commission staff, the Department of Commerce, and the Office of the Attorney General – Residential Utilities Division. We will also provide a copy to the Minnesota Environmental Quality Board. Interested parties will be able to obtain copies from our web site at xcelenergy.com/UpperMidwestEnergyPlan.

Xcel Energy®

UPPER MIDWEST INTEGRATED RESOURCE PLAN 2024-2040

NORTHERN STATES POWER COMPANY
MPUC DOCKET NO. E002/RP-24-67
FEBRUARY 1, 2024

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2024-2040 Upper Midwest Integrated Resource Plan

CHAPTER 1 - EXECUTIVE SUMMARY

I. INTRODUCTION

Northern States Power Company, a Minnesota Corporation, doing business as Xcel Energy (the Company), is pleased to present this 2024-2040 Upper Midwest Integrated Resource Plan. Our plan will allow the Company to continue providing safe, reliable, and affordable service to our customers while further accelerating our ambitious carbon-reduction strategy, even as we forecast significant increases in customer load from electrification and other sources. Specifically, the Company's Preferred Plan (the 2024 Plan or Preferred Plan) in this proceeding is designed to achieve the following:

- Greater carbon emissions reductions by 2030 than projected in our last plan, and compliance with Minnesota's new "100 x 2040" law;
- $464 million in Present Value of Revenue Requirements (PVRR) savings by 2040;
- $785 million in Present Value of Societal Cost (PVSC) savings by 2040 and over $1 billion by 2050;
- Sufficient firm dispatchable resource additions to ensure reliability; and
- Less than a one percent average annual increase in rates based on generic market pricing of new generation.

These benefits build off the progress made in our last resource plan (2019 Plan). In that proceeding, the Commission approved a number of key decisions in what promises to be a historic transformation of our energy system to one that will be dramatically cleaner, while remaining affordable and reliable for our customers. As the Commission directed, we are working to close all of our baseload coal units in the coming years, replacing them with thousands of megawatts (MWs) of new renewable resources, supported by firm dispatchable resources to ensure reliability. Toward that end, we have already made great progress on our carbon emission reduction efforts to date thanks to the support from and alignment with the Commission, the Legislature, and Governor Walz and his administration.

Following Commission approval of the 2019 Plan, the Company has taken a number of steps needed to transform our energy system into one that will provide cleaner energy to our customers, while remaining safe, reliable, and affordable. Several notable accomplishments since approval of the 2019 Plan include the following:

- The closure of Sherco Unit 2 at the end of 2023, the first of our four remaining coal units that we intend to close by the end of 2030;
- Commission approval of our Certificate of Need for additional dry cask storage at our Monticello Nuclear Generating Plant, which will allow that facility to continue providing carbon-free, reliable baseload power through 2040;
- Commission approval and the start of construction for Sherco Solar, which will add 710 MWs of solar generation to our system and fill the valuable interconnection rights made available by the closure of Sherco Unit 2; and
- Commission approval of a first of its kind long-duration energy storage pilot project that will test a new 10 MW iron-air storage technology that will provide up to 100 hours of storage capability.

The Company has also initiated proceedings to construct transmission lines for replacement generation at both Sherco (the Minnesota Energy Connection) and King (the King Gen-Tie), which will allow for the cost-effective integration of thousands of megawatts of additional renewable resources on our existing system. We have also initiated a bidding process to obtain the first 1,200 MWs of new wind energy that will utilize the Minnesota Energy Connection and preserve our valuable interconnection rights when Sherco Units 1 and 3 permanently close.

The 2024 Plan builds on these achievements and actions and increases the pace of our carbon-reduction efforts even further, while continuing to ensure our system maintains robust reliability. Under our 2024 Plan, our modeling in this IRP shows potential reduction of carbon emissions by 88 percent by 2030, as compared to 2005 levels—up from a goal of 80 percent emissions reduction in our 2019 Plan.[1] In addition, our 2024 Plan positions the Company to comply with Minnesota's newly enacted "100 x 2040" law,[2] which requires utilities to generate an amount of carbon-free electricity equivalent to their Minnesota retail sales by 2040. Finally, we continue to plan on generating 100 percent carbon-free energy by 2050, consistent with the industry-leading commitment we made in 2018.

[1] We note these are only modeled results and that our actual emissions reductions over time likely will differ from the modeling. One notable example is that, consistent with prior IRPs, this carbon reduction forecast is based on modeling that dispatches units to optimize PVSC. While we have not historically applied a carbon cost adder across our generation fleet when offering our units in the MISO market (which would mimic such modeling results), we are open to further consideration of our dispatch strategy as we manage the transition of our resources.
[2] Codified as Minn. Stat. § 216B.1691 Subd. 2g.

While some of the resources included in our near-term and long-term plan have naturally changed from our 2019 Plan given the passage of time, the overall direction is the same. Our five-year action plan is expected to see 3,200 MWs of wind resources added to our system and over 1,000 MWs of distributed solar and community solar gardens, consistent with newly-passed state law. We will have new opportunities to maximize the value of these and other intermittent resources as we project adding 600 MWs of stand-alone storage during this time. Also, we plan to achieve an average annual level of 780 gigawatt hours (GWh) of energy efficiency as ordered at the conclusion of the 2019 Plan, using a combination of utility-sponsored programs and growth of "naturally occurring" savings.

As we add these clean and low-cost intermittent and short-duration resources to replace our retiring baseload coal, we are increasingly focused on ensuring that our system remains reliable, so that we can deliver the power our customers' demand at all times and responsibly meet the State's carbon reduction goals. Our focus on reliability is particularly important because, at the same time we are planning to retire our entire coal fleet (over 2,000 MWs of baseload generation), we also have nearly 1,700 MWs of power purchase agreements (PPAs) with other capacity resources set to expire between 2025 and 2028. This need to ensure an adequate low-carbon power supply during this transition drives several of the additions we are proposing. First, we plan to extend the lives of existing facilities. We plan to extend the lives of both of our nuclear plants into the early 2050s to match 20-year life-extensions we are working to obtain from the Nuclear Regulatory Commission. This will ensure that the Company continues to have available more than 1,700 MWs of carbon-free baseload power into the foreseeable future. We are also planning to extend the lives of our Company owned Refuse Derived Fuel (RDF) waste to energy generating facilities. Second, to ensure our system remains reliable through this transition, our modeling analysis shows that we need to add over 2,200 MWs of firm peaking capacity—emergency resources intended to operate only at times of peak demand, some of which could be extensions of existing PPAs—during our five-year action plan.

Collectively, these changes will result in a resource mix that continues to be diverse but that will rely much more heavily on carbon-free resources going forward, as shown in Figures 1-1 and 1-2 below.

Figure 1-1: NSP System 2024 and 2040 Preferred Plan Capacity Mix

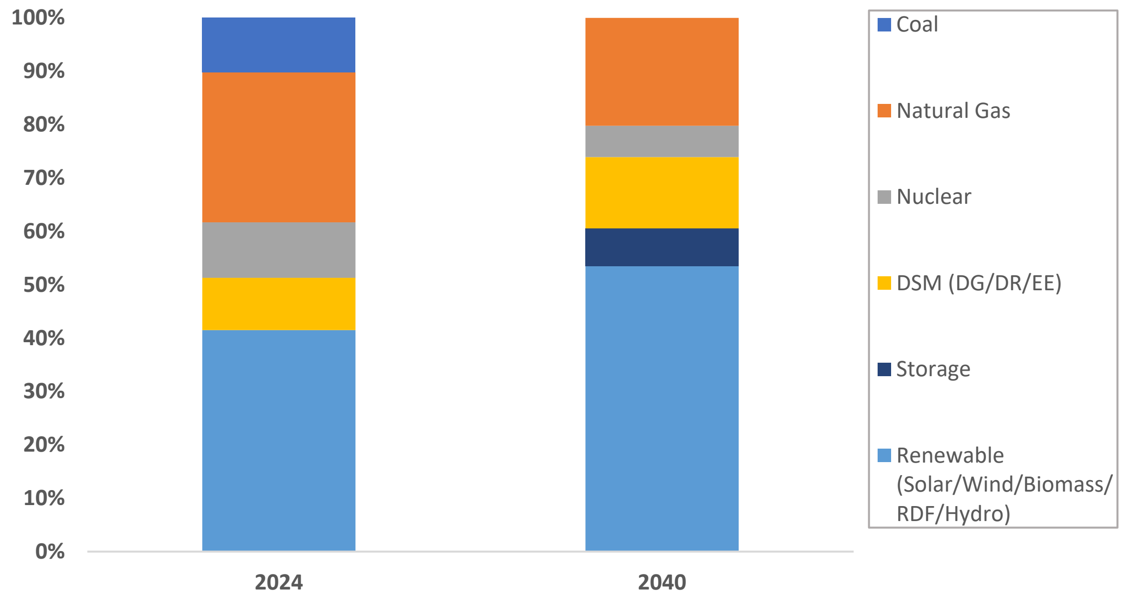
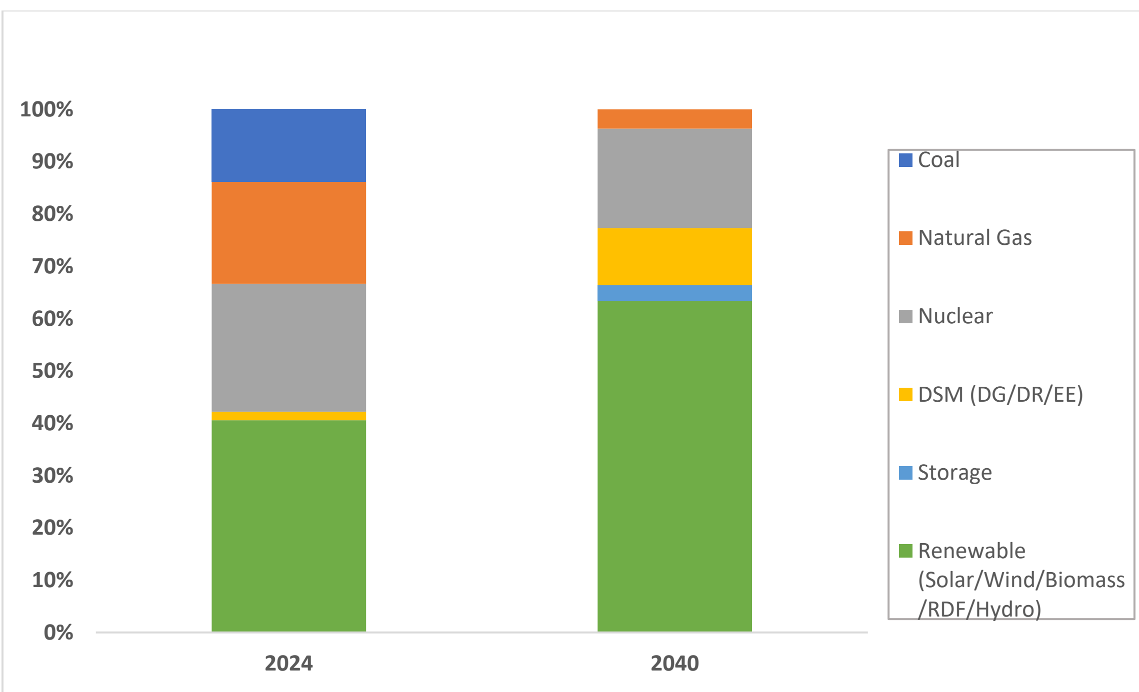


Figure 1-2: NSP System 2024 and 2040 Preferred Plan Energy Mix[3]



[3] These results are based on the modeled dispatch of resources added pursuant to our Preferred Plan. We note that the market dispatch of resources will ultimately determine the energy mix of the Preferred Plan.

Our 2024 Plan is also impacted by and consistent with state and federal energy policy, which are increasingly incentivizing utilities to accelerate their carbon-reduction strategies. As referred to above, this past year, the State of Minnesota passed the groundbreaking "100 x 2040" law, which requires that, by 2040, utilities generate or procure an amount of carbon-free energy equivalent to their Minnesota load. Likewise, the State also passed a new law requiring that at least three percent of the Company's retail sales be generated by new distributed solar generating systems. As discussed in greater detail below, we developed our 2024 Plan to ensure compliance with these and other applicable laws.

Changes in federal policy also make increasing investments in renewable resources more cost effective, and our 2024 Plan reflects this change. The Inflation Reduction Act (IRA) provides for enhanced tax incentives for new clean energy projects, making our planned renewable additions more affordable for our customers. In addition, the EPA's proposed "Good Neighbor Plan" would increase the per mega-watt hour (MWh) cost of operating carbon-emitting resources. The combination of these policies, in addition to the new State statutes reflected above, support a more rapid transition of our system to a clean energy future, consistent with the plan we lay out here.

Our 2024 Plan provides substantial economic benefits for our customers and communities. As noted above, our 2024 Plan results in $464 million in PVRR savings by 2040; $785 million in PVSC savings by 2040 and over $1 billion in PVSC by 2050. Our 2024 Plan leverages $5.7 billion in IRA tax credits through incremental renewable additions over the course of the planning period. Finally, our 2024 Plan is designed to exceed 80 percent reduction in carbon emissions (with actual results up to 88 percent by 2030) leading to continued carbon reductions while leading to less than a one percent average annual increase in rates.

Our 2024 Plan reflects a careful balancing of State and Federal policy, Commission guidance, and stakeholder input. Although there is still significant work to do to fully decarbonize our system, including developing and integrating new technologies such as standalone storage, this plan represents another critical step in that direction. We are examining advanced technologies such as new battery chemistries, advanced nuclear reactors and hydrogen, which may contribute further to our clean energy objectives. As new technologies mature, we will include them in our resource planning analyses. We are charting a path to decrease our carbon emissions even more than we had planned just a few years ago, in a responsible way that ensures our customers will have the power they need, when they need it, at an affordable cost.

II. 2024-2040 UPPER MIDWEST RESOURCE PLAN

Our 2019 Plan set us on an ambitious path to decarbonize our energy system, primarily by retiring all of our coal units in the next six years and replacing the bulk of the energy those plants provide with renewable resources. In bringing forward the 2024 Plan, we are accelerating our path toward decarbonization while remaining focused on ensuring that the core needs of our customers and stakeholders are met during this dynamic period of transition and growth. Our customers demand and deserve reliable electric service at affordable rates, and they—along with our regulators, stakeholders, and communities—have increasingly demanded that this service be provided by clean resources. In addition, our customers are beginning to use the electric service we provide to meet different needs. The growth of transportation and other beneficial electrification, along with other potential electric load increases, presents new challenges and opportunities as we plan to meet our customers' needs.

We believe that the robust planning process we have used to develop our 2024 Plan results in a portfolio that can serve the accelerating growth in energy demand in a way that is sustainable, reliable, and cost-effective. Our 2024 Plan relies on longstanding technologies with which we are deeply familiar, while integrating new and emerging technologies such as energy storage that can enhance the benefits of our system resources. We also continue our strategy of implementing a phased-in transition to a cleaner future, in which renewables and renewable-supporting resources are added over time—albeit on an ambitious but achievable timeline. This allows us to maintain the reliability of our system during this transition, while providing us with the flexibility to respond to changing market dynamics, technology advancements, and evolving regulatory policies.

Below, we discuss the major priorities and considerations we faced in developing our 2024 Plan and the overall resource mix we propose.

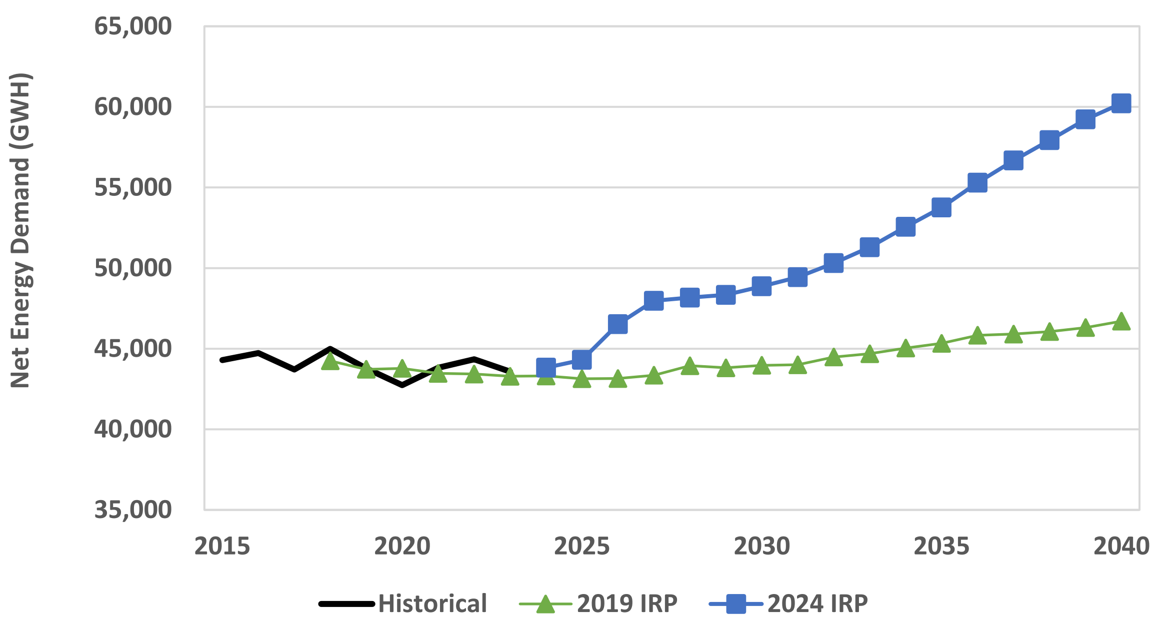
A. Planning Priorities and Characteristics

1. *Load Growth*

The last several decades of our industry can be characterized as a period of relatively flat annual growth for electric consumption. Conservation programs offered by utilities, coupled with efficiency gains in appliances and other naturally occurring energy savings from our customers, provided a significant offset to the energy growth attributable to new customer additions. For instance, after adjusting for weather, electric energy requirements of our system increased at an average of only 0.2 percent from 2019 to 2022. As a result, while utilities have needed to plan for some growth, the amount of that growth was quite small.

We now, however, anticipate that this period of ultra-slow consumption growth is ending, and we expect to see the demand for our service increase at a greater pace. While further improvements in energy efficiency and demand response capabilities will continue to provide substantial value to our customers, we anticipate that emerging uses of electricity will result in greater consumption growth than we have needed to plan for in the recent past. Specifically, our base case forecasts now anticipate average annual growth rates of 1.8 percent in our peak demand, and 2 percent for our energy forecast over the 2024-2040 planning period. This is a marked divergence from what we have anticipated in the past, as demonstrated in the Figure 1-3 below:

Figure 1-3: Forecasted Net Energy Requirements After Energy Efficiency Adjustments (GWh)



The primary factors leading to this increased growth in our forecast are new anticipated load coming from large new data centers and accelerating adoption of electric vehicles. Other forms of beneficial electrification, such as the emerging transition in space and water heating from fossil sources to electricity, will provide additional sources of new growth.

Despite our projections for accelerating growth, we anticipate decarbonizing our energy system even faster than we thought just a few years ago. This means that we can better support the decarbonization of the other industries, such as transportation and space and water heating, that we project will drive our growing sales through electrification.

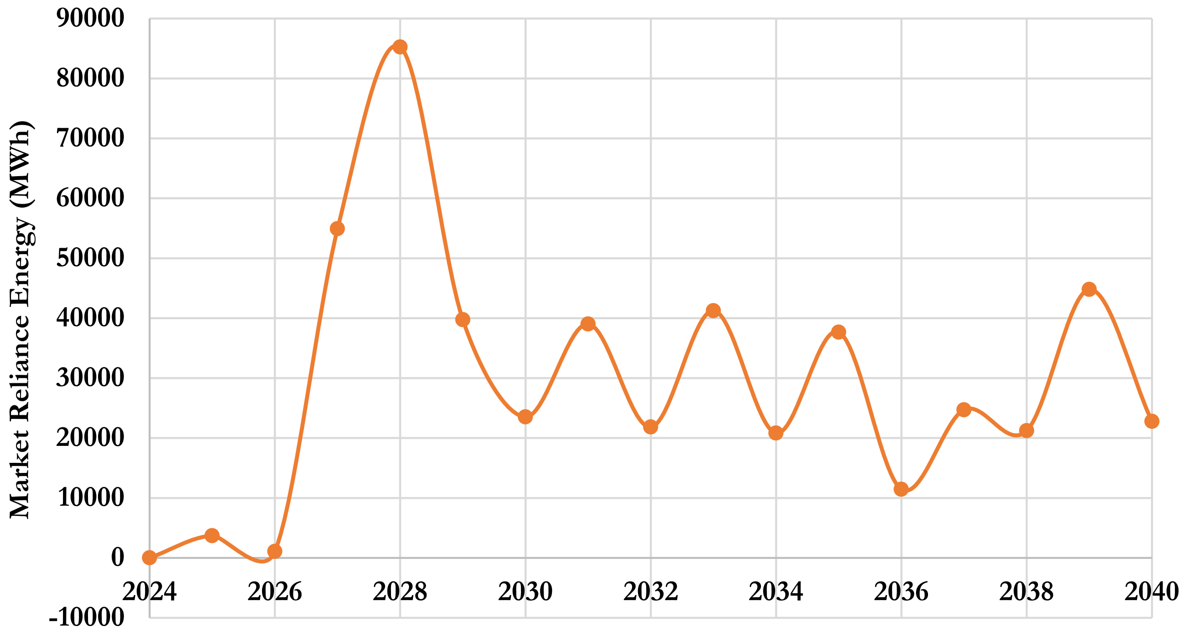
2. *Reliability*

The anticipated increase in the growth of electricity consumption discussed above comes amid renewed attention to the reliability of the electric system. The foundational service we provide to our customers is safe and reliable electricity, and we must be prepared to meet our customers' energy demands twenty-four hours a day, 365 days a year. The closing of our (and other utilities') baseload coal units and the substantial additions of intermittent renewable resources has and will continue to provide many benefits to our customers and communities. At the same time, however, it also means that we must develop our plans thoughtfully to ensure that we continue to have the resources to meet our customers' needs at all times.

As the resource mix in the region has changed, there is also less excess capacity in the MISO footprint. In fact, MISO's 2022-23 Planning Resource Auction (PRA) resulted in a capacity shortfall for the MISO North/Central Regions, leading to the price of capacity clearing at the Cost of New Entry (CONE). As a result of these developments, among other things, MISO has changed its reliability construct to a seasonal Resource Adequacy (RA) construct with capacity requirements for each season. This new seasonal RA construct establishes planning reserve margin (PRM) and resource capacity contributions for each season (spring, summer, fall, winter). Additional changes to the RA construct are also under consideration and will impact the resources needed in the MISO region to meet reliability requirements. These changes are intended to ensure that MISO's members maintain adequate supplies of generation at all times. This is especially important for us, since our Upper Midwest system constitutes approximately half of the load in MISO Zone 1 and approximately seven percent of the load in the entire MISO footprint from Manitoba to Louisiana, making our system a major part of the broader MISO market.

The planning process we used to develop our 2024 Plan reflects and responds to these changes and the need for additional focus on ensuring an adequate resource mix. In past resource plans, our modeling analysis allowed a portion of our resource needs to be fulfilled by the MISO market. When we performed the same analysis for the 2024 Plan, however, the models produced an expansion plan that would be unable to serve our load during a significant number of hours each year. This reflects the changing resource mix on our system. To illustrate this point, the orange line in the Figure 1-4 below shows the expected market reliance , which represents the total MWh in each year in which the Market Access Optimization expansion plan resources are unable to serve our load and must rely on the market purchases.

Figure 1-4: Market Access Optimization Expected Market Reliance



This analysis demonstrates that an overreliance on the market creates substantial risk of high prices and, possibly, that sufficient resources simply will not be available when they are needed.

To address this risk while continuing to optimize the cost-effectiveness of our fleet, we used a modified analysis to develop our 2024 Plan, and we did not allow our model to rely on the MISO market when optimizing our capacity expansion plan. We did, however, set those capacity obligations using MISO's coincident peak and PRM, and we allowed the model to benefit from access to the MISO market to dispatch of resources to serve our customers. This two-step analysis results in an expansion plan that takes advantage of the potential cost savings of participating in the MISO market, while not being reliant on the MISO market to meet our resource needs. In addition, by continuing to plan to MISO's coincident peak and PRM, our analytical approach ensures that we are not adding resources that are not necessary to meet our customers' needs.

In addition to planning our resource additions to limit reliance on MISO market purchases, we have taken steps to further refine our energy adequacy analysis. We conducted an energy adequacy back casting analysis to ensure our system has the reliable energy it needs to serve all customers at every hour of every day. We used historical data on scenarios, including our Preferred Plan and Market Access Optimization sensitivity discussed above, which was developed assuming 2,300 MW of hourly market access.[4] The analysis allowed us to assess the capacity and energy adequacy of our plans. We evaluated these plans on six different measures:

1. Native Capacity Shortfall: Hours of insufficient system capacity in each year.
2. Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
3. Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.
4. Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
5. MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

The Preferred Plan performs well across all of these energy adequacy metrics. There are only two hours of native capacity shortfall in 2030 across the seven historic years tested and applied to our Preferred Plan, resulting in limited dependence on the market. There are also only four hours across the seven historical test years where the Preferred Plan requires market purchases in order to meet load serving needs. In contrast, the Market Access Optimization sensitivity showed significant vulnerabilities across the energy adequacy metrics, supporting our approach in the Preferred Plan to ensuring reliability.

3. Cost-Effectiveness

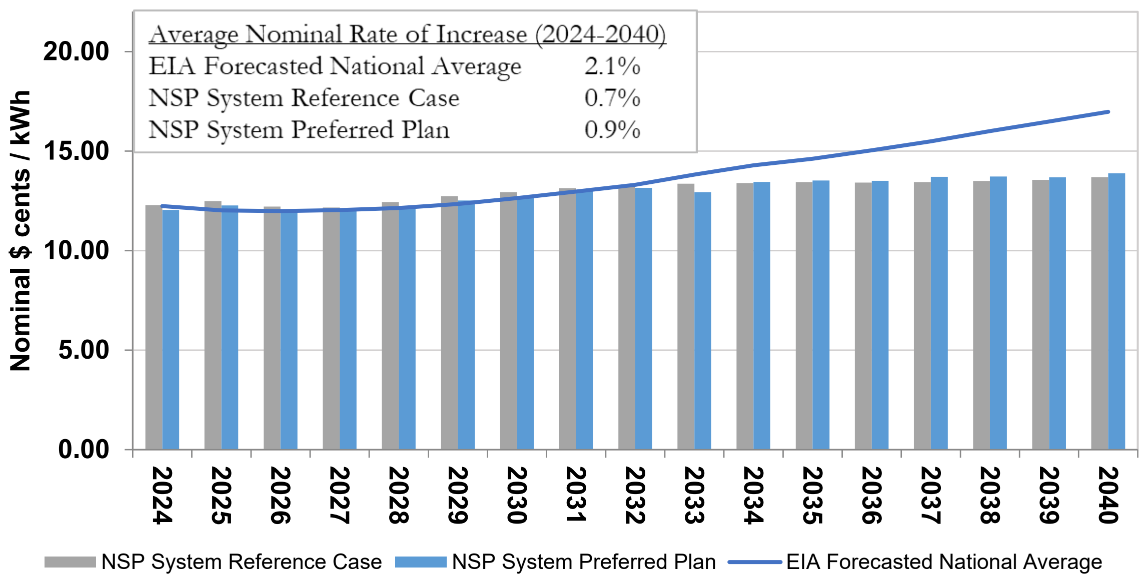
We understand the importance of keeping the cost of our service reasonable for our customers. Some of our customers truly struggle to afford their energy bills. We have developed and continue to improve upon a variety of programs designed to target and

[4] As discussed in Appendix D: Energy Adequacy Analysis, which also analyzed the Reference Case and Low Load Scenario.

assist those individuals. But regardless of whether our service is affordable for an individual or business, all of our customers rightfully expect that their energy bills will not be more than is necessary to meet their needs and public policy goals.

Our average residential customer's electricity bill has remained below the national average, and our goal continues to be that our customers will experience average annual bill increases that are below the rate of inflation. Our Preferred Plan remains broadly in line with these goals. In fact, our Preferred Plan achieves a higher level of carbon reductions than the approved 2019 Plan for a customer cost of less than one percent compound annual growth rate over the planning period. Figure 1-5 below shows the relative cost growth of our Preferred Plan in comparison to the national average:

Figure 1-5: Preferred Plan Average Rate Impact for the NSP System



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2023, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[5] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

The low cost forecast to implement our Preferred Plan is aided by additional policy incentives that will benefit our customers. In particular, the passage of the Inflation Reduction Act (IRA) unlocked a projected $5.7 billion in additional federal tax incentives for our Preferred Plan's utility-scale renewable and storage resource

[5] *See* U.S. Energy Information Administration - EIA - Independent Statistics and Analysis The EIA's Annual Energy Outlook was published in 2023.

additions. We recognize additional cost savings from the IRA for our existing renewable and nuclear resources. The value of these tax benefits were incorporated in our modeling, lowering the levelized cost of these resources significantly. These tax benefits will have a meaningful impact for our customers, since our Preferred Plan includes additions of 3,200 MWs of additional wind generation, 400 MWs of additional utility-scale solar generation, and 600 MWs of standalone storage through 2030.

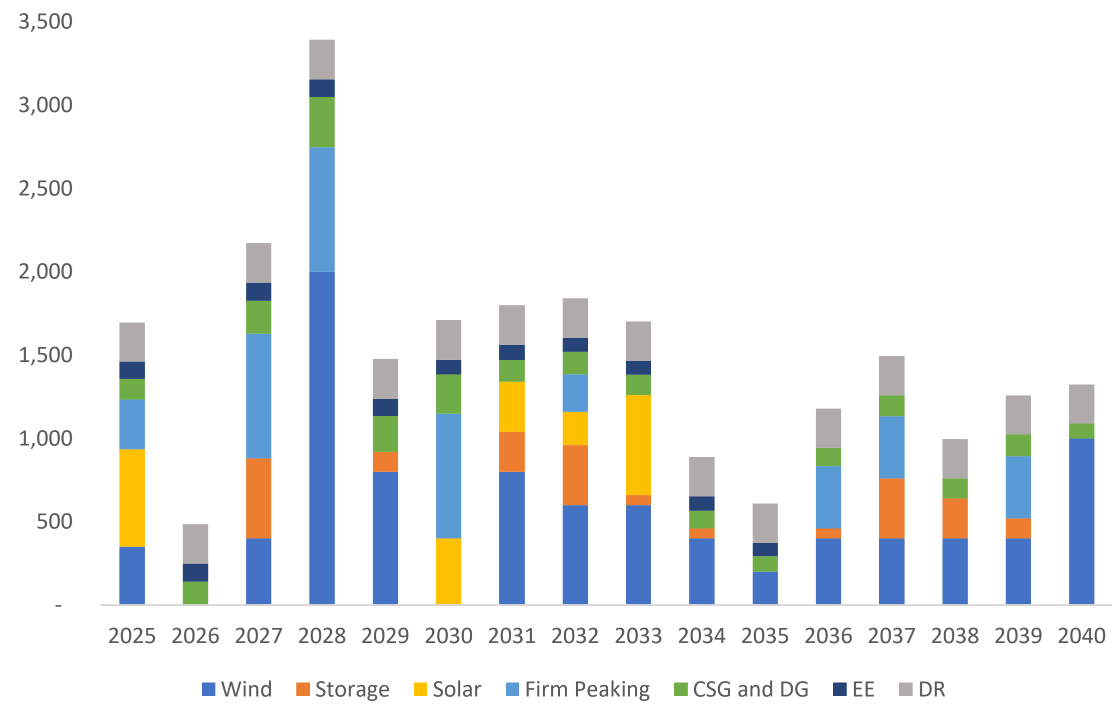
B. Proposed Resource Mix

Our Preferred Plan continues our strategy of transitioning our resource fleet to more sustainable energy sources while preserving our fundamental commitment to maintaining safe, reliable, and affordable service. Our proposed resource mix maintains the path approved in our 2019 Plan to retire all of our remaining coal generators by the end of 2030 – a reduction of approximately 2,400 MWs of baseload units. In that same time, 1,700 MWs of PPAs, the majority of which are for natural gas generation, are set to expire between 2025 and 2028.

To replace these resources and meet our customers' needs, we developed a diverse generation portfolio that relies predominantly on renewable and carbon-free resources, supported by necessary firm dispatchable resources, which are designed to operate only 5-10 percent of the year, to ensure reliability. By the end of 2030, we will add approximately 4,300 MWs of new wind and solar facilities—including the additions from community solar gardens and distributed solar, along with 600 MWs of standalone storage to optimize our system. The limited amount of carbon generation that remains on our system will largely be seldom-used peaking units that are needed to support the substantial increase in intermittent renewables.

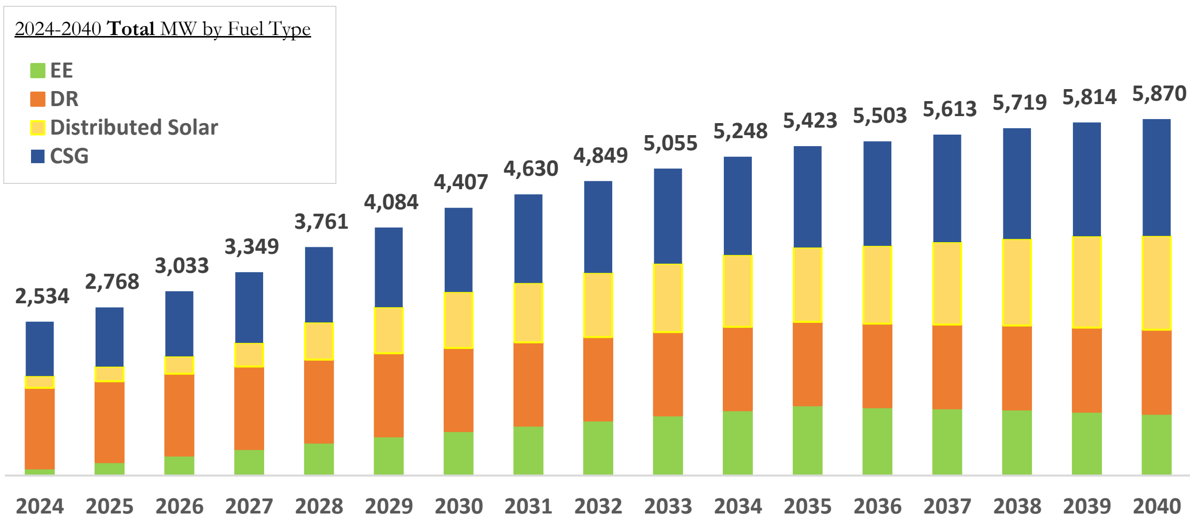
Our Preferred Plan is set forth below in Figures 1-6 and 1-7 below:

Figure 1-6: 2024-2040 Preferred Plan Resource Additions (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	350	0	400	2,000	800	0	800	600	600	400	200	400	400	400	400	1,000
Storage	0	0	480	0	120	0	240	360	60	60	0	60	360	240	120	0
Solar	585	0	0	0	0	400	300	200	600	0	0	0	0	0	0	0
Firm Peaking	298	0	748	748	0	748	0	225	0	0	0	374	374	0	374	0
CSG and DG	124	140	198	301	215	237	131	134	123	106	94	110	125	121	130	90
EE	103	108	108	105	103	87	91	85	82	86	80	0	0	0	0	0
DR	234	237	238	239	239	239	238	237	237	236	236	235	235	235	234	234

Figure 1-7 Preferred Plan Cumulative Capacity for Demand Side Resources and Community Solar Gardens (MW)



Our Preferred Plan is consistent with the path the Commission ordered in our last case. Specifically, we continue to plan to retire all of our coal units by 2030, with Sherco Unit 1 retiring in 2026, King retiring in 2028, and Sherco Unit 3 retiring in 2030. The closing of these facilities will open valuable interconnection rights, which we will use to add thousands of MWs of wind, solar, and standalone storage. We will also add substantial amounts of new wind generation and standalone storage that do not reuse these interconnection rights. In total, we envision adding nearly 10,000 MWs of utility-scale renewable energy and over 2,000 MWs of standalone storage during the entire planning period. In addition, we anticipate the capacity of community solar gardens and standalone distributed solar on our system will more than triple over the course of our planning period—growing from under 1,100 MWs of capacity in 2024 to nearly 3,500 MWs by 2040. The majority of this growth is the result of new legislation that requires at least three percent of the Company's total retail electric sales to be generated from distributed solar.

Our modeling shows that replacing these baseload coal units with this level of renewable additions will also require supporting resources that can operate for long durations. Our analysis demonstrates two steps that we must take to cost-effectively maintain a reliable system during this transition. First, our modeling shows that we will need to add a substantial amount of firm dispatchable capacity over the life of our plan. In addition to integrating our new renewables, these resources are needed to replace the 1,700 MWs of firm dispatchable PPAs that we will lose over the next few years. We have modeled these firm dispatchable additions as combustion turbine resources that are relatively low-cost to build, do not operate for much of the year, and in the future, could run at least partially on clean fuels like hydrogen. Second, we plan to extend the lives of our nuclear and RDF generating facilities. Specifically, we will extend operation of the two Prairie Island Generating Plant units for 20 years past the current license expirations, to 2053/2054, and extend operation of the Monticello Nuclear Generating Plant to 2050, which aligns with our Subsequent License Renewal application pending at the Nuclear Regulatory Commission. Additionally, we are extending the lives of our RDF plants, recognizing the value they provide to their local communities. Extending these resources are vital for our system because, with the loss of our coal fleet, our nuclear and RDF facilities constitute the only remaining baseload units on our system. If we did not extend these resources, our EnCompass modeling results show that we would need to build or acquire more than 4,600 MWs of incremental generation and storage capacity, including almost 900 MWs of additional peaking resources for the planning period.

III. CONCLUSION

We are pleased to present this 2024 Plan, which capitalizes on recent federal and state policy changes to reduce our carbon emissions more aggressively than we had previously planned. We will continue to eliminate coal, add renewables, and expand our EE and DR programs. By also adding stand-alone storage and firm dispatchable resources, we will continue to maintain a diverse fleet of resources that is cost-effective for our customers and continuing to ensure that our system is reliable.
For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and should be approved by the Commission.

CHAPTER 2 – PLANNING LANDSCAPE

I. INTRODUCTION

The Company's Preferred Plan (the 2024 Plan or Preferred Plan) continues to chart the path toward achieving some of the most ambitious carbon reduction goals of any utility in the United States by focusing on reliable, responsible decarbonization of our system. The 2024 Plan digs deeper than previous plans in the impacts and challenges of carbon-reduction on the reliability of our system, analyzing numerous assumptions to identify the plan that best meets our obligations and goals, while still ensuring that we can meet customer needs at all times.

In this Chapter, we discuss some of the key internal and external market contexts that affect how we have developed, and plan to execute on, our 2024 Plan. Specifically in this section we examine:

- Market Constructs & Renewable Integration
- Jurisdictional Updates
- Federal Incentives & Environmental Regulations
- Community & Employee Considerations
- Customer Preferences
- Supply & Technology Trends

Each of these factors affected how we developed our 2024 Plan. However, a few factors stand out above others as being particularly influential in this 2024 Plan cycle: namely, market constructs and state and federal policy. Our regional system operator's new seasonal construct allows for more precise planning and resource allocation based on each season. It also introduces new levels of complexity and concern about reliability that our 2024 Plan is tailored to address. State and federal policy has also changed significantly since 2019. In Minnesota in particular, the cost of carbon, the distributed solar and renewable energy standards, and the new carbon-free energy standard each influenced our 2024 Plan's design. The same is true of federal law, which created both significant financial incentives for renewables along with new areas of uncertainty related to the Clean Air Act.

These and other factors all affect how we developed the 2024 Plan presented in this filing—and the issues we anticipate encountering as we pursue our goals to lead the clean energy transition while ensuring reliable and affordable grid services.

II. MARKET CONSTRUCTS AND RENEWABLE INTEGRATION

The Company's Upper Midwest system is part of the Midcontinent Independent System Operator (MISO) market. MISO's primary responsibilities are overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). MISO's operations thus affect how we conduct resource planning. Here we focus on system reliability constructs and renewable integration challenges that impact how we designed our 2024 Plan.

A. New Resource Adequacy Construct

MISO's resource adequacy construct has historically been centered on an annual planning reserve margin (PRM) based on a summer peak. This approach was based on the assumption that resource needs and availability were relatively stable throughout the year, and consistently peaking in the early evening in summer months when air conditioning use is highest. However, recognizing the increasing variability in reliability needs and resource availability throughout the year, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to move to seasonal resource adequacy requirements. This new MISO construct began with the 2023 – 2024 planning year, which spans from June 1, 2023, through May 31, 2024, and will also be in place for subsequent planning years. The planned seasons are: (1) Summer: June through August; (2) Fall: September through November; (3) Winter: December through February; and (4) Spring: March through May.

This new construct is designed to address increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, seasonal variations, outages resulting from extreme weather events, and declining excess reserve margins. By planning for resource adequacy on a seasonal basis, utilities can better prepare for seasonal variations in demand and supply, leading to improved reliability of the power system.

Our 2024 Plan has incorporated the seasonal construct into the planning process and modeling, allowing for more precise planning and resource allocation based on the specific needs and resource availability of each season. Modeling tools have been adjusted, and our models have become more complex because they now have to ensure sufficient capacity across all four seasons as opposed to a single year. We have also adjusted our long-term planning assumptions because our models use trends or averages from several years of data in order to accurately predict what will happen in the future. However, we only have one year of data for existing generation assets under the seasonal construct to use when figuring out how much capacity we will need for each season. Appendix F: EnCompass Modeling Assumptions and Inputs discusses our short- and long-term capacity accreditation assumptions in more detail.

Overall, MISO's seasonal resource adequacy construct adds complexity to resource modeling but also provides a more detailed and potentially more reliable approach to ensuring grid reliability throughout the year.

B. MISO Reforms on the Horizon

MISO is actively engaged in developing and refining additional reforms to improve resource adequacy and reliability of the electric power grid. Two reforms of note—Reliability-Based Demand Curve (RBDC) and Direct Loss of Load (DLOL)—aim to better align the value of reliability, provide investment signals for future resource needs and ensure stability in resource adequacy modeling, while considering the impacts on load serving entities and various resource classes.

Due to the growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, MISO determined that its existing accreditation methods for resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during periods of highest reliability risk. In response, MISO has developed a proposal that contains a new two-step process for accreditation. At a high level, MISO's proposal calculates accreditation based on modeled and historical performance of resources during tight margin hours. More specifically, the first step in the process determines how resources receive capacity credit at a class level and the second step contains a process for class-level megawatts to be allocated amongst specific resources. The class-level step utilizes a DLOL method which averages the availability of each resource during loss-of-load hours within the Loss-of-Load Expectation model and aggregates by resource class. The second step of the proposed process allocates each resource class level megawatts (determined by the DLOL method) among the individual resources in the class using the individual resources' performance during tight margin hours based on the prior three years of operational experience.

MISO's proposal would add significant complexity to the resource adequacy construct. Based on initial information provided by MISO, the proposed approach is likely to decrease the accreditation granted to resources but may also decrease the reserve margin in certain seasons due to the increased focus on tight margin hours which can occur outside peak demand periods.

MISO and stakeholders have continued to discuss in the Resource Adequacy Subcommittee details related to MISO's proposal as well as information that will be needed to integrate MISO's proposed changes into member resource planning processes. MISO is planning to file the proposal with FERC in the first quarter of 2024. MISO has proposed implementation in the 2028/2029 Planning Year.

The RBDC is a proposed design for MISO's Planning Resource Auction (PRA). It aims to reflect the reliability value of capacity and produce more efficient and stable capacity prices. Historically, the MISO region has maintained reserves significantly exceeding the required reserve margins. However, as experienced in the 2022-23 PRA, excess reserves can no longer be expected. MISO's proposed RBDC endeavors to address the limitations associated with the use of a vertical demand curve to clear the PRA. The RBDC proposal is currently under consideration by FERC. Pending FERC approval, the RBDC reform is expected to be implemented in PY 2025-2026.

The RBDC has not been approved by FERC and the proposed DLOL accreditation reform has not been filed with FERC. Chapter 5: Economic Modeling Framework, discusses a special reliability study evaluating a higher PRM as an RBDC opt-out proxy and Appendix D: Energy Adequacy Analysis includes the assumptions used in our analysis for future capacity accreditation.

C. Renewable Integration Challenges

The challenges of integrating new clean generation into the system continue due to delayed interconnection studies and limited open transmission availability. The MISO Generator Interconnection Process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has seen significant delays.

Delay impacts are particularly evident in the Definitive Planning Process, where MISO undertakes generation interconnection studies. Current studies are several months to years behind due to the considerable number of projects in the queue, and due to a generator interconnection process, that allows late withdrawals from the queue. With the intention of addressing some limitations in processing generation interconnection queues, FERC issued Order 2023 in July of 2023,[1] which is discussed in more detail in Appendix L: System Planning Integration.

[1] https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements.

In response to direction from FERC and in recognition of the challenges described above, MISO is beginning to undertake several actions that could serve to mitigate challenges to bringing new, clean resources online. Appendix L discusses these potentially helpful initiatives in more detail, which could allow generation owners to leverage existing interconnection agreements to maximize utilization and fit renewable additions into the existing open spaces on the grid. As such, the Company is engaging in Long Range Transmission Projects and looking for ways to preserve and reutilize interconnection rights we already have, which influenced the location, size, and type of resources proposed in our 2024 Plan.

III. JURISDICTIONAL UPDATES

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states, and we have historically planned this system as an integrated whole. Each resource on the Upper Midwest bulk energy system—whether generation or transmission—is developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. In the next section, we explain how differing policies in our multi state service territories is impacting our resource planning process.

A. New Carbon-Free Energy Requirements

In December 2018, the Company announced our goal to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels companywide, and to serve customers with 100 percent carbon-free electricity by 2050. Since the Company made this announcement, we have seen multiple states across our Upper Midwest service territory adopt similar carbon free goals.

In particular, in 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (see Minn. Laws 2023, chp. 7). The new legislation requires utilities to generate or procure carbon-free energy equivalent to 100 percent of their Minnesota retail sales by 2040. The law also requires utilities to achieve interim carbon-free energy standards of 80 percent by 2030 and 90 percent by 2035, and a renewable energy standard of 55 percent by 2035. Based on our current understanding of the law, our 2024 Plan is modeled to meet the requirements of this new legislation, as set forth in more detail in Appendix N: Standard Obligations. The details of how the carbon-free standards are calculated will be important in informing the implementation of these state policies. To that end, the Minnesota

Commission has opened an Investigation docket[2] into the Carbon-Free Standard. Parties and the Commission will weigh in on a number of topics in that docket over the next couple of years, including clarification of new and amended terms such as carbon-free, partial compliance, and environmental justice areas. Determining the appropriate calculation methodology will help ensure that utilities are on track to meet their targets and that progress can be accurately measured and reported. The Company's current compliance efforts, including how we are applying those terms to its system in this 2024 Plan, are also documented in Appendix N.

Further, as discussed below, this move towards carbon-free energy requirements is not exclusive to Minnesota; other states we serve are moving towards similar goals. We will continue to track those developments.

B. Minnesota

In addition to the new carbon-free goal, Minnesota has seen other significant legislative developments since our 2019 Plan that impact how we conduct our resource planning, such as the updated cost of carbon and how Distributed Energy Resources (DER) are addressed.

1. Cost of Carbon

A recent Commission Order Addressing Environmental and Regulatory Costs (Environmental and Regulatory Costs Order)[3] requires utilities to continue to analyze potential resources under a range of assumptions about environmental values and future regulatory costs, including the five modeling scenarios previously outlined in 2020, and altered the cost range utilities must apply to any fossil generation resource. Additionally, pursuant to Minn. Stat. § 216B.2422, Subd. 3, the Commission provisionally adopted and applied the cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's (EPA) November 2023 Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advance.[4] Consistent with the Commission's Order, our 2024 Plan includes sensitivities addressing these valuations, which is discussed in detail in Appendix K: Environmental Regulations Review and Appendix F.

[2] Docket No. E999/CI-23-151.
[3] Order in Docket Nos. E-999CI-07-1199, E-999/DI-22-236, E-999/CI-14-463, December 19, 2023, Order Point 2.
[4] Available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

2. *Distributed Energy Resources*

In another recent development, Minnesota's distributed solar energy standard was amended at subdivision 2h of Minn. Stat. § 216B.1691. This amendment mandates that at least three percent of the Company's retail electric sales in Minnesota be generated from qualifying solar energy generating systems. To be counted towards this standard, the solar generating system must have a capacity of 10 megawatts or less, be connected to the distribution system, be located in our Minnesota service territory, and be constructed or procured after August 1, 2023. Additionally, subdivision 7 now sets an annual capacity limit on community solar gardens, which decreases over time, from 100 megawatts in 2024, 2025, and 2026, to 60 megawatts in 2031 and each year thereafter. To-date, community solar gardens still make up the clear majority of the DER on our system in the Upper Midwest. DERs are also coming onto our grid, in the form of electric transportation options—enabling not only flexible load opportunities but also broader economy-wide emissions reduction.

Minnesota's Energy Conservation and Optimization Act (ECO Act) has also impacted how we approach DER in the 2024 Plan. The ECO Act changed how we approach demand side management by broadening the approaches a utility may take in achieving energy efficiency (EE) and demand response (DR). In particular, it allows for inclusion of both traditional DR efforts aiming to reduce peak reduction during hot summer days as well as non-traditional efforts to shift load based on the time of day. These efforts are part of our 2024 Plan, as set forth in Appendix J: Distributed Energy Resources.

Our 2024 Plan is substantially dependent on forecasted customer load, which incorporates our best estimates about customer adoption of DER and robust statistical forecasting methods. Our Integrated Distribution Plan and grid modernization efforts help us leverage DER and new load to enable more flexible demand management, improve reliability and enable better decision-making about large-scale investments. That said, it is difficult to predict new technologies, the pace of their adoption, and thus how the DER landscape could affect our generation needs in the future. Our 2024 Plan modeling includes various sensitivities to account for these uncertainties related to the impact of DER, as set forth in Appendix J. However, we still often do not have visibility into which technologies, and at what pace, customers will adopt and thus, how that changing load will affect our grid needs in the future.

C. Wisconsin

In Wisconsin, the Company is subject to a Renewable Portfolio Standard (RPS) equal to 12.89 percent of its three-year average in-state retail energy sales. In 2022, excluding renewable energy used for voluntary renewable programs, NSPW provided 44.05 percent of its retail energy sales from RPS-eligible renewable-based energy sources, therefore exceeding the state's 2022 RPS requirements.[5]

In May 2023, the State's Governor issued a Clean Energy Plan that includes a 100 percent carbon reduction goal for the state's electric sector that is broadly consistent with our objectives to reduce emissions 80 percent from 2005 levels by 2030, and 100 percent by 2050. Therefore, the Clean Energy Plan should not impact our 2024 Plan. The Governor's climate goals have not yet resulted in additional mandates for the electric sector. Similarly, the Company continues to engage with Public Service Commission of Wisconsin (PSCW) staff and interested stakeholder as several investigatory proceedings move forward. For instance, the PSCW has opened investigation to evaluate the impact of MISO's proposed reliability-based demand curve and capacity accreditation reforms (Docket 5-EI-161), a Roadmap to Zero Carbon (Docket 5-EI-158), and an evaluation of net energy metering programs (Docket 5-EI-157). None of these proceedings have resulted in Commission orders requiring utility action as of January 2024.

D. Michigan

In Michigan, the Company is subject to a Renewable Energy Standard (RES) equal to 15 percent of retail sales through 2029, pursuant to Michigan Public Act 235 of 2023.[6] The new legislation increased the RES to 50 percent for the period 2030-2034 and 60 percent for 2035 and beyond. In addition, the legislation establishes a Clean Energy Standard (CES) requiring 80 percent of retail electricity from qualifying resources during the period 2035-2039 and 100 percent in 2040 and beyond. We do not yet know the details of how compliance with the legislation will be calculated, but based on our current calculations, our Preferred Plan is modeled to be ahead of schedule on both RES and CES requirements through 2040 by nature of our 80 percent by 2030 carbon reduction plan.

[5] *See* Docket 5-RF-*NSPW Renewable Portfolio Compliance Plan for CY 2022. Northern States Power Company, a Wisconsin Corporation.*
[6] Act No. 235. Public Acts of 2023. Enrolled Senate Bill No. 271. 2023-PA-0235.pdf (mi.gov)

E. South Dakota

In South Dakota, the Company faces challenges to its decarbonization goals. For example, it has historically faced challenges in cost recovery for certain resources. The South Dakota Public Utilities Commission suspended the fuel clause adjustment in 2016 to investigate disputed resource costs. A Settlement Stipulation approved in 2017 resolved the recovery of cost associated with the Aurora solar resource and several biomass resources. The Settlement required proxy prices for the remaining disputed resources, including the Marshall and North Star solar Power Purchase Agreements (PPAs),C-BED PPAs, and Renewable Development Fund PPAs. The Company currently recovers costs associated with these resources based on a proxy price.[7]

More recently, the South Dakota Commission disagreed with the Company's plans to retire the King and Sherco 3 units in 2028 and 2030, respectively. In June of 2023, the South Dakota Commission approved a rate case settlement that assumes the current depreciable lives of King and Sherco 3 in June 2037 and December 2034. In opposing the Company's request for accelerated depreciation of those units, Commission Staff specifically cited the impact those retirements would have on MISO's seasonal resource adequacy construct and the Company's ability to provide reliable electricity.[8] The South Dakota Commission reiterated its reliability concerns over early plant closures in a January 4, 2024 letter to the Company.

F. North Dakota

As part of the 2021 North Dakota legislative session, the North Dakota Legislature enacted Senate Bill (SB) No. 2313, which added new sections regarding integrated resource planning to Chapter 49-05 of the North Dakota Century Code (NDCC). To further guide the process of resource planning and provide clarification on the implementation of SB 2313, Section 69-09-12 of the North Dakota Administrative Code was enacted effective January 1, 2023. With this new legislation and administrative rules, the North Dakota Commission has new oversight into utility resource planning; historically, the Commission did not have a formal vehicle to review resource acquisitions outside an advance determination of prudence proceeding.

The new resource planning legislation and rules re-emphasizes that a North Dakota preferred resource plan may not select resources based on externalities representing

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[7] Docket EL18-004. https://puc.sd.gov/Dockets/Electric/2018/EL18-004.aspx.
[8] Docket EL22-017. https://puc.sd.gov/Dockets/Electric/2022/EL22-017.aspx.

environmental costs or future environmental laws or regulations that have not yet been enacted. The preferred plan must instead describe and select resources representing the least-cost plan for providing reliable service to ratepayers, consistent with North Dakota energy policy. Additional rules regarding resource plan filings are found at 69-09-12 of the North Dakota Administrative Code, which requires that:

- The resource plan must provide a North Dakota preferred plan,
- Except as otherwise required by law or by order of the commission, the North Dakota preferred plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities,
- The resource plan must include reliability and resource adequacy assessments using quantitative metrics, and
- The resource plan must include information on how the electric public utility intends to reconcile potential jurisdictional differences in resource selection.

As noted in our comments in Case No. PU-22-163 via a June 16, 2022 letter to the North Dakota Commission, the new planning process should be beneficial for all parties:

> Xcel Energy plans and operates an integrated Upper Midwest system that serves customers in five states. While we believe the integrated system provides benefits to our customers across the states we serve, in some instances we have procured resources that have not been accepted in all jurisdictions. We are hopeful that a North Dakota resource planning process will not only provide the Commission with information about our future plans, but also provide a forum to better identify and address Commission concerns in advance of resource acquisition decisions. Our resource plans provide a critical guide to achieving Company goals, procuring resources, and meeting our customers' needs safely and reliably.

We plan on filing our North Dakota Resource Plan with the Minnesota Commission and providing updates on how that proceeding progresses. The resource planning process in North Dakota may identify jurisdictional differences that could pose a challenge to the implementation of our Preferred Plan. We will engage with both the North Dakota and Minnesota Commissions to address these differences.

IV. FEDERAL INCENTIVES AND ENVIRONMENTAL REGULATIONS

In addition to state policy, federal incentives, such as the Inflation Reduction Act (IRA), and environmental regulations, such as the EPA's New Source Performance Standards 111(b) and (d) and Good Neighbor Plan, are impacting utility resource planning by incentivizing clean energy and increasing the cost of emitting resources. As described below, the IRA, with its substantial funding for clean energy, is accelerating the transition towards renewable power generation and advancing policy goals such as decreasing energy burdens for low-income consumers. EPA 111(b) and (d), and the Good Neighbor Plan, on the other hand will potentially increase the cost of operating emitting resources, thereby incentivizing the shift towards cleaner energy sources.

A. Inflation Reduction Act

The IRA was signed into law on August 16, 2022, and includes an estimated $369 billion in energy and climate spending. The IRA puts the United States on track to reduce emissions 32-42 percent below 2005 levels by 2030 through grant and loan programs, tax credits and emissions fees that touch nearly every corner of the economy. Of particular interest for this 2024 Plan, the IRA contains roughly $161 billion in clean electricity tax credits, $37 billion in clean fuel and vehicle tax credits, and $27 billion in building efficiency, electrification, transmission, and Department of Energy (DOE) grants and loans.

The IRA provides the opportunity to transfer production tax credits (PTCs) and investment tax credits (ITCs) to unrelated taxpayers for cash. Eligible credits include clean energy PTCs and ITCs earned after 2022, including PTCs from projects placed in service before 2022. However, tax credits carrying forward from years prior to 2022 are not eligible for transferability. Consideration paid in exchange for transferred tax credits cannot be included in gross income and is not deductible by the transferee. In addition to transferability, the IRA expands the availability of tax incentives across a wider variety of technologies.

The IRA presents significant opportunity to accelerate the growth of renewable and carbon-free power generation and the reduction of greenhouse-gas emissions while mitigating rate impacts. For example, for this 2024 Plan, we project anticipated benefits totaling over $5.7 billion stemming from the IRA tax credits for new renewable additions in the Preferred Plan over the course of the planning period. We will also recognize additional savings from our existing renewable and nuclear generation. In addition to these incentives, the IRA provides significant opportunities to advance policy goals such as decreasing energy burdens for low-income consumers; supporting communities affected by the energy transition; promoting environmental justice; increasing diversity, equity, and inclusion in the energy sector; and fostering workforce development.

More detail concerning the IRA can be found in Appendix U: Inflation Reduction Act, including a discussion of how our 2024 Plan leverages the IRA's significant incentives and resulted in significant estimated savings for our customers in our 2024 Plan.

B. EPA New Source Performance Standards (NSPS) 111(b) and (d)

On May 11, 2023 the EPA released a four-part proposal under their Clean Air Act authorities to regulate CO2 emissions from the power sector. The proposal included:

1) Repeal of the Affordable Clean Energy rule;
2) Regulations for new natural gas generating units pursuant to Clean Air Act section 111(b), hereafter referred to as 111(b);
3) Regulations for existing natural gas generation pursuant to Clean Air Act section 111(d), hereafter referred to as 111(d); and
4) Regulations for existing coal generation pursuant to section 111(d).

Since the rule is in a proposed state and has not yet been finalized, it is uncertain how the rule will ultimately impact operation of our facilities. We have taken into consideration the potential impacts of this rule for our 2024 Plan through a sensitivity analysis, recognizing potential impacts on existing gas Combined Cycle units and PPAs, as detailed in Appendix K.

C. Good Neighbor Plan

The "Good Neighbor" provision of the Clean Air Act for the 2015 Ozone National Ambient Air Quality Standards (NAAQS) addresses the interstate transport of air pollution, ensuring that one state's pollution does not interfere with the air quality in other, downwind states.

On February 13, 2023, the EPA finalized a rule that partially approved and partially disapproved the State Implementation (SIP) submissions from Minnesota and Wisconsin. This led to the creation of a Federal Implementation Plan (FIP), which included Minnesota and Wisconsin in the Group 3 ozone nitrogen oxides (NOx) allowance trading program, starting with the 2023 Ozone NOx season (May-September 2023). On April 14, 2023, an industry coalition, including Northern States Power-MN, filed a petition for review of the partial disapproval of Minnesota's SIP. On July 5, 2023, the 8th Circuit granted a Stay of the SIP Disapproval for Minnesota, which effectively stayed the Good Neighbor Plan requirements. This means that the Good Neighbor Plan is not in effect for Minnesota during the litigation and its future depends on the outcome.

In Wisconsin, the Good Neighbor Plan applied to sources from August 4 – September 30, 2023, and will apply in future ozone seasons. NSPW will comply through operational changes and the potential purchase of allowances.

How these regulations have been incorporated into our 2024 Plan modeling based upon estimated allowance allocations through 2029, and how market dynamics could impact costs are further discussed in Appendix F and Appendix K.

V. COMMUNITY & EMPLOYEE CONSIDERATIONS

We know that our planning and decarbonization goals impact the communities we work in and serve. The Company has made significant efforts to engage and elicit community and stakeholder feedback and incorporate that feedback into how we do business. We are also committed to transitioning our system while proactively working with the communities where plants are located and the employees who work in those plants.

A. Equity Considerations

The Company has taken a number of interrelated actions to enhance equitable outcomes and broaden participation in energy decision-making by the communities we serve. We recognize voices of minority, low-income, and protected populations are often not present in conversations regarding grid planning and resource allocation and that marginalized groups need to access, participate in, and benefit from energy markets regardless of ability, race, or socioeconomic status. To that end, we have established an Equity Stakeholder Advisory Group (ESAG), engaged in community outreach, and plan to form an Environmental Justice Advisory Board (EJAB) to advise the Company on incorporating equity into our core business efforts. Although our equity work does not directly impact the size, timing, and type of generation resources that are the focus of our 2024 Plan, our community engagement more broadly impacts and informs how we provide service to our customers. This community engagement has included, for example, outreach to ESAG; interested stakeholders including state and local governmental representatives, the Clean Energy Organizations, developers, and business representatives, among others, the Prairie

Island Indian Community; and communities regarding remediation efforts at the Allen S. King and Sherburne County Generating Plants. More information on this outreach can be found in Appendix P and P1: 2023 Sherco Remediation Report, Appendix Q and Q1: 2023 King Remediation Report, Appendix R: Equity, and Appendix S: Stakeholder Engagement Summary.

Ultimately, we remain committed to considering environmental justice (EJ) in our energy, climate, and environmental initiatives, and to providing meaningful opportunities for impacted communities to participate in the process. As further detailed in Appendix R, we have incorporated EJ into our work through: our efforts with ESAG and the future formation of EJAB, the development of a Workforce Diversification Plan, our Request for Proposals process, the development of supplier diversity goals, our corporate giving and community involvement efforts, Electric Vehicle programs, our Energy Conservation and Optimization plans, our Natural Gas Innovation Act programs, federal initiatives such as the IRA and Investment and Infrastructure Jobs Act, our Resilient Minneapolis Project, and Tribal outreach efforts. We continue to evaluate and look for other ways we can incorporate equity into our efforts.

B. Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. For our coal facilities, the plants are prominent places of employment and contributors to the property tax base in the community. This is why we have and continue to make efforts to spur economic development in locations where our current units will eventually be phased out.

For example, since we proposed to retire the Sherco coal units in Becker, Minnesota, we have worked extensively with local units of government, community stakeholders, and the State to draw new development to the site to support the local economy. This includes working with the City of Becker and Sherburne County to attract new economic development to the Becker area that meets the needs of both the community and the Company. This effort led to the approval of the sale of 348 acres of land at Sherco to Elk River Technologies for the development of a data center, on April 6, 2023. The Company expects that similar outcomes in 2024, will bring more economic opportunities and tax revenues to the community.

Relatedly, we participated in a study overseen by Center for Energy and Environment (CEE) that examined the impacts of the large baseload generation plants in Minnesota on host communities. The other participants in the study included the Coalition of Utility Cities, Minnesota Power, and the Prairie Island Indian Community. The study resulted in four main findings:

1) Power plant closures will undoubtedly have a strong economic and financial impact on the communities that host them, and potentially, other Minnesota communities as well.
2) Host communities are currently pursuing a variety of strategies to plan and prepare for power plant closures and the economic transition that they will require. None of those preparation strategies are expected to fully offset the economic impact of a plant closure, but they may help mitigate the negative effects.
3) Workers, labor unions, and host communities may benefit from close coordination and communication in plant closure transition planning and preparation efforts.
4) Not all of Minnesota's host communities receive benefits from the power plant they host.

Overall, the study reinforced that host communities are not a monolith, and that preparing for plant closures and the corresponding economic transition takes significant time, planning, and communication and outreach efforts. The Company is engaged with our host communities and our workers, as detailed in Appendix O and O1: 2023 Workforce Transition Plan, Appendix P and P1, and Appendix Q and Q1.

In addition to community impacts, we are also aware that these plant closures impact our employees and their families. With this in mind, and consistent with our past practices, we are working with these impacted employees to transition them to other Xcel Energy plants or areas of the Company. In the past, when plants have been closed or converted (and impacted headcount) we have provided resume writing services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job relocations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to-date. More details about our efforts to help our workers transition to new positions within the Company can be found in Appendix O1, which was also filed in Docket No. E002/M-22-265.

Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

VI. CUSTOMER PREFERENCES

Our Upper Midwest system continues to serve a diverse mix of customers with varied interests and preferences. While most customers continue to prioritize affordability, we have seen increasing interest in customer choice around how and from where they consume energy, sustainability, carbon reduction, and other clean energy objectives. We have taken these interests into consideration in planning our resource mix for the future. Below, we outline the energy preferences our municipal, commercial and industrial, and residential customers have expressed, as well as overall interest in DER, and what the Company is doing to help them achieve their goals through partnerships and programs. Although customer interests and preferences do not ultimately impact the type, timing, or size of resources in our resource plan, they do influence our overall program development so that we can create programs and services that best serve all of our customers' needs.

A. Municipal Customers

Cities and municipalities are increasingly setting and developing strategies around sustainability and climate goals. In fact, there are at least 32 cities in our Upper Midwest jurisdiction that have set carbon reduction or renewable energy goals, according to our Community Energy Goals Survey. We work with many of these communities through our Partners in Energy programs to support achievement of these goals. Minneapolis is the most prominent example, as evidenced by the Clean Energy Partnership that had just started when we filed our 2015 Plan. Since then, the partnership has flourished and advanced, helping to achieve progress toward the city's sustainability goals.

Other municipalities and communities are also developing goals and action plans around renewable energy and climate goals. The Company has a long history of supporting the communities we serve, and we always want to work with our customers and our communities in support of their energy goals. In addition to our Partners in Energy Program, the Company offers the following partnerships and programs:

- Community Relations Managers and Account Managers;
- Community Energy Reports;

- Renewable Energy Programs;
- Electric Vehicle Programs;
- Certified Renewable Percentage; and
- Customized Support for Sustainability Initiatives.

More can be read about these programs and our Community Energy Goals Survey in Appendix V: Community Goals.

B. Commercial and Industrial Customers

Our commercial and industrial customers place a high priority on keeping costs low to remain competitive in their own markets. This is particularly true of large industrial customers, where energy costs can make up a substantial portion of their operating expenses. However, corporate efforts to achieve sustainability goals are also increasing, both in the US broadly and within our system. As the cost of renewable energy declines, affordability and sustainability goals increasingly go hand in hand. Within our system, several of our corporate customers are co-members of the Minnesota Sustainable Growth Coalition, which is a business-led public-private partnership working to advance clean energy and other sustainability and circular economy objectives. We hear from these and other corporate customers across our Upper Midwest system that sustainability and clean energy are important to them, and they want us to offer products that meet these needs. Renewable*Connect is one such product.

In 2015, we worked with customers to develop Renewable*Connect. The program achieved full subscription in its first year. In January 2019, we filed for an expansion of this program, and included an option for high load factor customers (i.e. those that operate continuously during the day) to be served primarily with competitively priced wind and a smaller portion of solar.[9] In 2023, the Commission approved the Company's proposed expansion of this program.[10] The expansion of Renewable*Connect advances the sustainability goals of the participating companies without creating additional costs that must be carried by other, non-participating customers. We are continually evaluating the need for potential expansion of Renewable*Connect. Should there be sufficient customer interest, the Company would look to solicit the necessary resources through an RFP process.

[9] In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for the Approval of a Renewable*Connect Program. Docket No. E002/M-19-33.
[10] In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for the Approval of a Renewable*Connect Program Modification, Order, May 18, 2023.

In 2019, we also developed a new program called Certified Renewable Percentage (CRP), which is ongoing. The CRP is Renewable Energy Certificate (REC)-based accounting methodology that clarifies the percentage of our system energy delivered to customers that is renewable. The CRP is not a subscription service or program customers need to enroll in. Instead, the Company calculates, certifies, and annually reports a CRP for Minnesota.[11] With the CRP, we retire sufficient RECs on behalf of all our retail customers, such that the total RECs retired annually reflects the portion of delivered energy that is renewable. This allows all retail customers to claim the percentage of renewable energy on the system as the starting point towards their sustainability goals.

C. Residential Customers

Residential customers likewise tell us that they value both opportunities to save energy and to have access to clean, affordable and reliable energy. In response, we have developed programs that offer more convenient payment options, rebates for energy efficiency upgrades, and the chance to reduce the environmental impact of their consumption by choosing renewable energy. Customers are taking advantage of these programs in large numbers—and they have expressed strong satisfaction with their ability to select programs that best meet their individual energy needs. In fact, customers who participate in these programs tend to be more satisfied than customers who are not enrolled in a program.

Programs that we account for in our modeling include EE programs and Beneficial Electrification (BE) of space and water heating. The 2024 Plan marks the first time the Company has included BE assumptions in our electrical sales forecast. More information about how EE and BE impact our modeling can be found in Appendix E: Load and Distributed Energy Resource Forecasting.

VII. SUPPLY & TECHNOLOGY TRENDS

Trends around the supply of equipment for generation and energy storage needed to fulfill our 2024 Plan had a significant impact on the mix and timing of our resource proposals.

Wind, solar, and battery energy storage systems technology costs are expected to continue to improve. While photovoltaic (PV) module costs did increase as a result of

[11] Our most recent report was submitted on June 1, 2023 in Docket No. E999/PR-23-12. The report is filed on June 1 of each year in a reserved docket, which is xx-12, where "xx" is the last two digits of the year.

the AD/CVD and UFLPA policies that were put in place in 2021 and 2022 among other factors, they are trending downward again.[12] Overall, however, commercial solar in particular has experienced significant cost declines, with median installed costs falling over 78 percent since 2010.[13] Consistent with past years, our 2024 Plan assumes that wind and solar capital costs will continue to decline, although at perhaps a slower pace as these technologies advance on their respective maturity curves and as the industry continues to be challenged with supply chain constraints. We also expect technological advancements to continue to improve capacity factors, as tracking and PV module technologies have continued to improve and inverter loading ratios have increased with falling capital costs. These factors continue to improve the cost competitiveness of wind and solar resources in real terms–changes to incentive policies notwithstanding—relative to the other resource options we considered.

We also continue to examine the role energy storage can play in meeting our system needs. Technologically, we expect grid-scale energy storage will support our clean energy goals in the future, by helping us maintain grid stability and supporting peak management while integrating the higher quantities of intermittent renewable generation we envision on our system. From a cost perspective, battery energy storage systems have experienced significant improvements over the last few years, and we expect costs to further decline going forward. We are committed to pursuing this technology, recognizing that challenges remain to our ability to manage seasonal renewable energy variability and longer duration demand-shifting needs. More discussion of our consideration of this technology can be found in Appendix I: Minnesota Energy Storage Systems Assessment

Finally, as we have noted, achieving our corporate decarbonization goals will require further development of technologies that have not yet been identified and commercialized, as discussed in Appendix X: Advanced Technologies. We continue to monitor industry activity around other emerging technologies that may contribute to achievement of our goals. In addition to potential new battery chemistries, potential emerging clean energy technologies include advanced nuclear reactors, hydrogen, types of energy storage technologies beyond batteries, and others. We will continue to evaluate new technologies and take advantage of advancements that will meet our goal and benefit our customers.

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[12] Domestic PV supply is constrained into 2027, but many suppliers have indicated plans to pursue US based production. The AD/CVD and UFLPA policies have resulted in greater risk of modules not being admitted into the US, resulting in the need to take great care in completing detailed due diligence of module suppliers supply chain to understand risk profiles.
[13] Bolinger, Mark and Seel, Joachim. *Utility Scale Solar, 2023 Edition*. Lawrence Berkeley National Laboratory October 2023. Available at: https://emp.lbl.gov/utility-scale-solar/.

VIII. CONCLUSION

As we continue to chart the path toward achieving some of the most ambitious carbon reduction goals of any utility in the United States, we will continue to take into account key internal and external market conditions. This 2024 Plan focuses on reliable, responsible, and cost-effective decarbonization of our system, while accounting for state and federal legislation, equity for our communities and our employees, the wants and needs of our customers, and trends in the industry.

CHAPTER 3 – MINIMUM SYSTEM NEEDS

I. INTRODUCTION

Our resource planning process focuses on deep carbon reductions while serving our Upper Midwest customers reliably and affordably. In this chapter, we describe in more detail how we arrived at the minimum number of resources our system will need through the planning period. The system needs and existing resources evaluated here formulate the baseline upon which we have developed the Reference Case, our modeling scenarios, and ultimately our Preferred Plan.

We have made the following changes to aspects of our Minimum System Needs approach with this Resource Plan:

- *MISO Seasonal Resource Adequacy Requirements*. In the 2024 Plan, we are incorporating a seasonal Planning Reserve Margin to align with the approach recently adopted by MISO. Further, we are applying seasonal accredited capacity (SAC) values for each resource option. These adjustments align with MISO's ongoing effort to address the increasing variability in reliability needs and resource availability across all four seasons.
- *Market Reliance Risk*. We have optimized resource additions in the EnCompass model to ensure that the portfolio of resources developed can serve customer load across all hours by limiting access to the MISO market. The limited access is only applied to the resource optimization to avoid over reliance on MISO market purchases for reliability. We allow the model to access the MISO market to dispatch resource and take advantage of the access to economic resource in the larger MISO market.

II. MEETING CUSTOMER NEEDS

Forecasting customers' needs for electricity is a key component of any resource plan and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. The first step is forecasting the amount of electricity our customers will need over the planning period. To do this, we add a reserve margin that is prescribed by MISO for each season. We then subtract the resources we already have or expect to have (with some adjustments), to determine our net surplus or need.

We illustrate this concept in Figure 3-1 and discuss each of the components below.

Figure 3-1: Seasonal Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin

Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by seasonal accredited capacity)
Minus Generation Adjustments

Equals **Net Resource Need/Surplus**

A. Customer Needs Forecast

Forecasting our customers' energy needs starts with a capacity, or peak demand, assessment, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. In previous resource plans, planning centered on meeting the highest demand hour of a given year, which for NSP occurs in the summer. The introduction of MISO's seasonal construct shifts the focus to planning for the highest demand hour in each season.

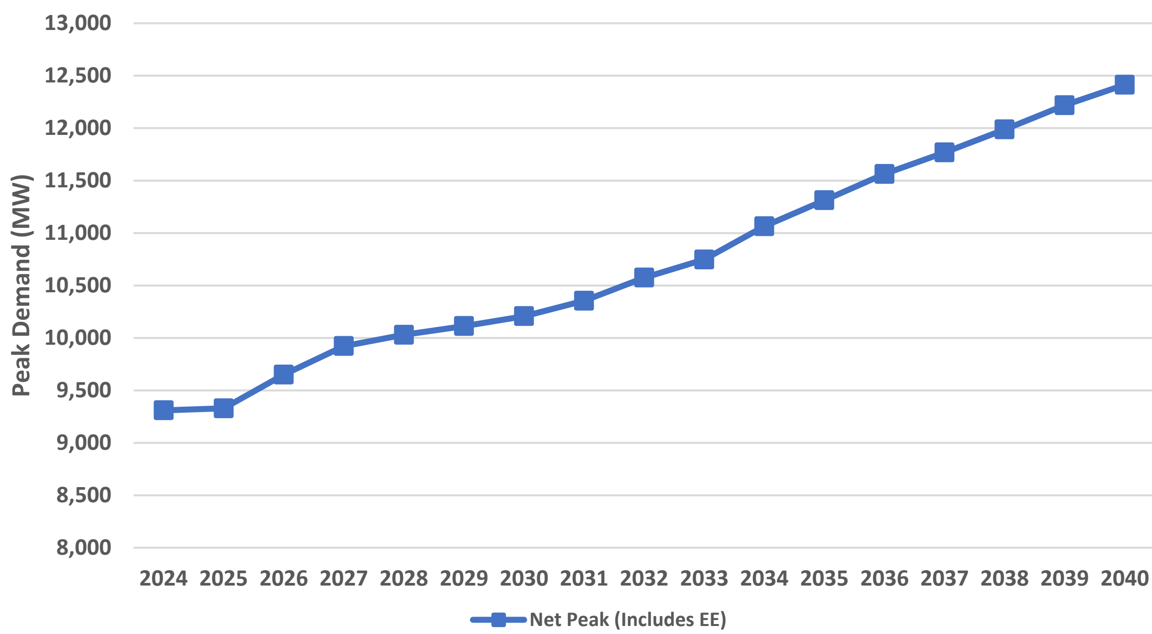
We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

1. Peak Demand Requirements

We use econometric analysis and historical actual coincident net peak demand data to determine system capacity requirements for each year. We provide a detailed discussion about our peak demand forecasting methodology in Appendix E: Load and Distributed Energy Resource Forecasting.

During the 2024 – 2040 planning period, the base case peak forecast increases at an average annual growth rate of 1.8 percent. As demonstrated in Figure 3-2 below, annual peak demand increases at an average of 194 MW each year, starting with 9,309 MWs in 2024 to 12,414 MWs in 2040.

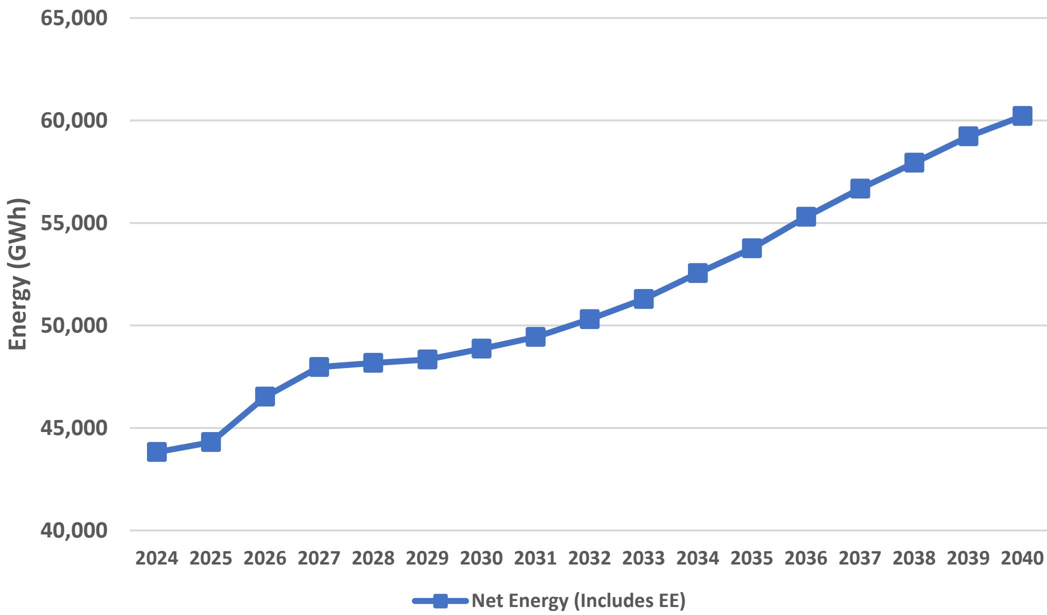
Figure 3-2: NSP System Median Base Summer Peak Demand (MW)
(Includes modeled EE Adjustment)



Additionally, the base energy forecast increases at an average annual growth rate of two percent over the 2024 – 2040 planning period, net of modeled energy savings, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements[1] are expected to increase at an annual average of 1,025 gigawatt-hours (GWh), starting with 43,823 GWhs in 2024 to 60,215 GWhs in 2040. See Figure 3-3 below.

[1] Gross of rooftop solar generation. Solar generation was modeled as a resource instead of netting against energy requirements.

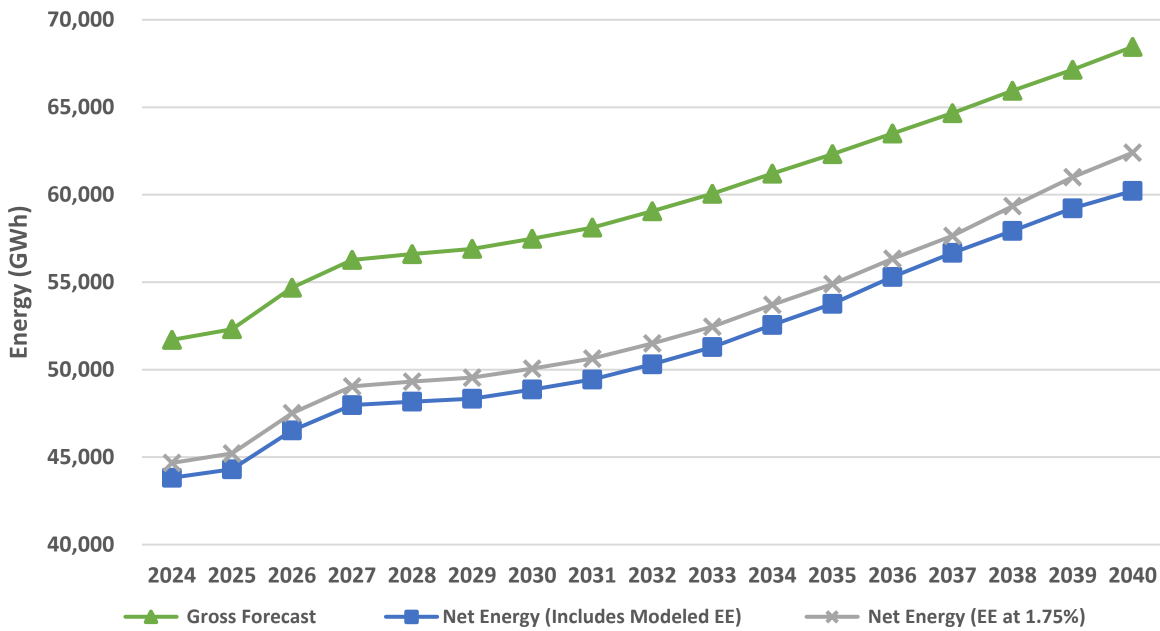
Figure 3-3: NSP System Total Median Net Energy (GWh)
(Includes modeled EE Adjustment)



The projected two percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years due, primarily, to forecasted large new data center loads and acceleration in adoption of Electric Vehicles. After adjusting for unusual weather, electric energy requirements increased at an average annual rate of 0.2 percent from 2019 to 2022.

To be consistent with the modeling approach for Energy Efficiency (EE) in our approved 2019 Plan, we continue to model EE as a supply-side resource. In a separate process, we formulated annual EE savings amounts into "Bundles" that we made available in the EnCompass model along with other supply-side resources. This required that we adjust the base energy forecast to remove the embedded EE adjustment that projects the effects of energy savings to the end of the planning period. This resulted in an NSP System Gross Energy Requirements forecast. These adjustments are shown in Figure 3-4 below.

Figure 3-4: Gross Energy Requirements Forecast Compared to Net Energy Requirements Forecast

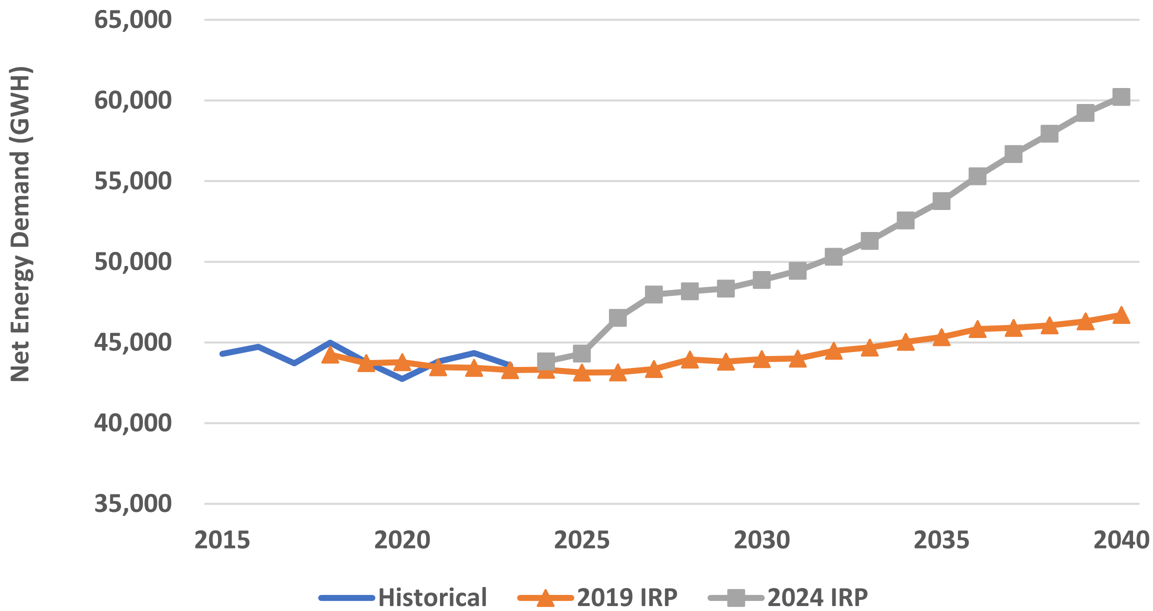


We discuss the EE Bundle modeling further in Appendix E:, Appendix F: EnCompass Modeling Assumptions and Inputs, Appendix H: Resource Options. Appendix J: Distributed Energy Resources contains detail on how the EE bundles were developed.

2. *Energy Requirements*

We forecast an approximate 35 percent increase in energy requirements over the 2024-2040 planning period, after accounting for EE included in the Base Case. As discussed above, the inclusion of two incremental EE Bundles reflects achievement of approximately 2.2 percent EE, which leaves our Net Demand substantially higher than forecast in our last Resource Plan. Figure 3-5 below compares our estimated net energy demand adjusted by the two EE Bundles, to the energy forecast in our approved 2019 Plan.

Figure 3-5: Forecasted Net Energy Requirements, After Energy Efficiency Adjustments[2] (GWh)



3. *Forecast Adjustments*

After determining the base peak capacity and energy demand forecasts, we make certain forecast adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. We summarize our key adjustments below:

DSM. Prior to our 2019 Plan, the load forecasts used in our modeling were adjusted for the expected effects of existing DSM programs. As with our 2019 Plan, in this 2024 Plan, incremental EE beyond that classified as naturally-occurring is no longer embedded in the load forecast; rather, EE is treated as a potential supply-side resource in our modeling, like Demand Response (DR). We further discuss the EE and DR (collectively, DSM) in the context of our resource planning process in Appendix J.

Rooftop solar. Projected rooftop solar is handled similarly to Energy Efficiency and is modeled as a supply-side resource in EnCompass, and is not netted from energy and peak forecasts.

[2] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a demand reduction from gross demand for purposes of the chart above.

Expected Customer Changes. We make adjustments to account for known and expected changes in load on our system. These typically reflect expected changes in specific large customers' electricity usage, either because of increased behind the meter energy generation, increased production activities by existing customers, or additional demand from new customers. This adjustment only applies to the Large Commercial/Industrial (CI) class.

Electric Vehicle Adoption. We adjust our energy and peak demand forecasts to account for increasing use of plug-in electric vehicle charging. These forecasts are based on estimates of current EV usage and future adoption (including the effect of financial incentives to facilitate adoption), and the expected electricity consumption per vehicle.

Beneficial Electrification. Residential and Commercial/Industrial energy as well as our peak demand outlooks are adjusted to account for growth in beneficial electrification from converted space and water heating.

We discuss our forecasting process, inputs, assumptions, adjustments, and results in more detail in Appendix E.

III. MISO RESOURCE ADEQUACY REQUIREMENTS

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSE) like the Company to maintain resources or secure capacity to cover their level of demand by a specific margin (planning reserve margin or PRM) to cover potential uncertainty in the availability of resources or level of demand.[3] The RA requirements are fundamental to the resource planning process and inform the level of capacity we need in our portfolio to adequately serve customers.

MISO's resource adequacy construct has historically been centered on an annual PRM. However, recognizing the increasing variability in reliability needs and resource availability throughout the year, MISO has implemented a seasonal RA construct beginning with the 2023 – 2024 planning year (PY), which spans June 1, 2023 through May 31, 2024 (and will be in place for subsequent PYs). The planning seasons are delineated as follows:

Summer: June through August
Fall: September through November
Winter: December through February
Spring: March through May

[3] The factors affecting availability and demand include: planned maintenance, unplanned or forced outages of generating facilities, deratings in resource capabilities, variations in weather, and load forecasting uncertainty.

We describe the various aspects of the seasonal PRM calculation and note that the seasonal MISO PRM and average NSP Coincidence Factor[4] in Table 3-1 below.

Table 3-1: MISO Seasonal Planning Reserve Margin and Average NSP Coincidence Factor[5]

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY 2024/2025	9.00%	14.20%	27.40%	26.70%
Average NSP Coincidence Factor	92.24%	92.67%	97.09%	95.61%

Prior to each planning year, MISO determines two different sets of capacity obligations for each LSE; one for the entire MISO footprint as a whole, and one for the Local Resource Zone (LRZ or Zone) where the LSE has load.[6]

A. MISO Footprint Capacity Obligation

By November 1 prior to a planning period, MISO issues the finalized seasonal PRM applicable to all LSEs within its footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM for each season needed to achieve a Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2024 through May 31, 2025 the overall MISO seasonal PRM on an installed capacity (ICAP)[7] basis and on an unforced capacity rating (UCAP) basis[8] are shown in Table 3-2.

[4] NSP Coincidence Factor refers to the NSP demand at the time of the MISO footprint peak demand.
[5] The values in Table 4-1 are not static and represent a snapshot in time.
[6] Almost all of the NSP system load is located within LRZ 1, which includes almost all of Minnesota, western Wisconsin, and the Dakotas. Approximately 7 MW of load along the Minnesota-Iowa border is located in LRZ 3.
[7] ICAP refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.
[8] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "MISO Planning Year 2024-2025 Loss of Load Expectation Study Report". Available at: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

Table 3-2: MISO Footprint PY 2024-2025 Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO PRM ICAP	17.7%	25.2%	49.4%	40.8%
MISO PRM UCAP	9.0%	14.2%	27.4%	26.7%

Over the planning period MISO examined in the 2023-2024 LOLE study,[9] the summer UCAP PRM increased from 7.4 percent in 2023 to 11.2 percent in 2032. The fall UCAP PRM remained relatively constant between 14.9-16.3 percent. The winter and spring UCAP PRMs also remained relatively constant between 23.7 and 25.5 percent between 2024-2033.[10,11]

Each LSE is required to have resources sufficient to meet the forecasted demand at the time of MISO's peak demand, plus its PRM. MISO's tariff acknowledges a state regulatory body's authority to establish a PRM for LSEs within its jurisdiction, which would override the PRM otherwise determined by MISO. None of the NSP System states have established a PRM that would override the MISO PRM.

B. Zonal Capacity Obligation

Additionally, MISO makes an annual determination regarding the amount of capacity required within each of MISO's Zones, called the Local Clearing Requirement (LCR) for each season. The LCR is determined as a function of each Zone's Local Reliability Requirement (LRR) and its Capacity Import Limit (CIL) for each season. The LRR represents the necessary resource requirement in order for a Zone to achieve a LOLE of 0.1 day per year, without relying on resources outside of the Zone. Each Zone, having a smaller footprint than the overall MISO footprint does not benefit from the same level of peak load diversity as does the larger, more diverse MISO footprint. If a Zone within which the Company operates has import capacity, however, the resulting LCR is reduced from the LRR to recognize the transmission system's ability to deliver outside resources into that Zone. Accordingly, the Company plans its minimum system needs based on the MISO-wide PRM while also ensuring zonal requirement are satisfied.

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[9] *See* "MISO Planning Year 2023-2024 Loss of Load Expectation Study Report." Available at: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

[10] We note these values vary slightly from the those presented in Table 4-2, which originate from the MISO PY 2024-2025 LOLE Study. This study has not yet been updated to incorporate the analyses of outyear PRMs.

[11] These PRMs were formulated without the assumption of a Direct Loss of Load methodology, which MISO intends to file in 2024. This change will impact the PRM.

For the 2024-2025 planning year, Zone 1 was determined to require an LRR of 18.9 GW to achieve the LOLE reliability requirement of 0.1 days per year. After accounting for Zone 1's summer CIL of 5.3 GW, Zone 1's summer LCR is reduced to 13.6 GW. Among the several LSEs in LRZ 1, the Company must meet its load share of LRZ 1's LCR as identified in Table 3-3 below.

Table 3-3: MISO PY 2024-2025 Seasonal Local Reliability Requirement

Local Resource Zone 1	Summer	Fall	Winter	Spring	Formula Key
LRZ 1 LRR (GW)	18.9	15.6	22.1	19.1	[A]
LRZ 1 Capacity Import Limit (CIL) (GW)	5.3	6.5	4.9	6.2	[B]
LRZ 1 LCR (GW)	13.6	9.1	17.2	12.9	[A] - [B]
NSP's Share of LRZ 1 LCR (GW)	6.7325	5.8556	7.1288	6.3785	

C. Capacity Obligations Derived from Forecasted Demands

After MISO determines seasonal PRM and zonal LRRs, each LSE's MISO-wide and zonal capacity obligation are derived for each season from its forecast of peak demand (peak load). While LSEs typically forecast the peak demand for their individual system, the resource adequacy process requires the LSE to also forecast:

- The LSE's demand at the time of the MISO footprint's peak demand (MISO Coincident Peak Demand, or MISO CPD); and
- The LSE's demand at the time of the LRZ's peak demand (Zonal Coincident Peak Demand, or Zonal CPD).

Because each LRZ footprint is smaller than the MISO footprint, the LRZ's load diversity is lower than the load diversity of the MISO system, and an LSE's Zonal CPD is typically greater than its MISO CPD.

The NSP System CPD factor measures how closely our system peak matches the MISO system peak. A coincidence factor of 95 percent indicates that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. In other words, the timing of our peak and the MISO peak does not match exactly, so we are able to reduce the amount of reserves we are required to carry.

Our estimated obligation for all planning period years can be found in the Load and Resources table in Section VI below.

D. Capacity Accreditation of Resources

After these obligation levels have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements. MISO has recently made changes to its resource accreditation process, moving from an annual accreditation to a seasonal accreditation capacity (SAC). This change is intended to align resource accreditation with availability in the highest risk periods. Under the new system, MISO accredits resources on their SAC, which is determined by the resource's availability during seasonal RA hours and non-RA hours. MISO conducts independent auctions for all seasons in the spring to clear capacity for LSEs that are short of meeting their seasonal resource adequacy requirements.

Resources used to achieve MISO's RA requirements are referred to as "Planning Resources." Planning Resources include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e., physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO's resource accreditation represents a measure of a resource's reliable contribution to the system's resource adequacy needs. MISO's SAC value for each resource, in megawatts, accounts for various factors such as plant availability and outages during tight system margins and performance during peak hours. Therefore, instead of using installed or nameplate capacity (i.e. ICAP), MISO calculates the SAC value for each resource to determine its expected contribution to RA. These are calculated differently depending on the resource's dispatchability or variability:

- *Dispatchable thermal resources* – MISO determines the SAC value for dispatchable thermal resources pursuant to Schedule 53. The SAC calculation for these resources is primarily based on the availability of offered resources, mostly during RA hours.

- *DR and EE resources* – MISO assigns capacity accreditation for DR and EE resources based on modeled forecasts.
- *Intermittent Generation and Dispatchable Intermittent resources* – The SAC value for intermittent generation resources or dispatchable intermittent resources is determined by MISO based on historical performance, availability, and type and volume of interconnection service. For wind resources, MISO determines SAC values based on interconnection service volumes and their respective wind capacity credit established through a seasonal Effective Load Carrying Capacity (ELCC) study. Wind capacity credits are determined for individual wind resources based on their average capacity factor during MISO's top eight coincident peaks that occurred during the season for the previous three years.

  The SAC value for non-wind intermittent generation and dispatchable intermittent resources (e.g., run-of-river hydro, solar) is a function of the individual unit's historical performance during the peak hours for each season of the planning period. Specifically, these units are measured on historical performance during the operating hours of 1500 to 1700 during the Summer, Fall and Springs seasons; and the hours of 0800, 0900, 1900 and 2000 in the Winter season over the three-year most recent period.
- *Energy storage resources* – The SAC value for energy storage resources is determined by MISO based on the total net energy during a test of at least one hour, deliverability, and the historical forced outage rate of the resource.

Our modeling selects resources based on their SAC values from MISO PY 2023/2024 with a long-term trend to ELCC values for wind and solar resources, to ensure we maintain adequate capacity on our system over the planning period.

IV. DEMAND SIDE MANAGEMENT

DSM programs offer our customers opportunities to lower their energy use and manage their peak demand, in particular through EE and DR programs included in our Energy Conservation and Optimization (ECO) Triennial Plan. We base our forecasts and potential incremental additions on historic achievements through our programs, as well as external studies about expected and potentially achievable adoption rates.

As previously discussed, we adjusted the customer capacity and energy forecasts in the 2024 Plan to distinguish incremental EE from the load forecast. We modeled incremental DR and EE achievements as "Bundles" to be evaluated alongside other resource options. Each Bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost.

For EE, these Bundles include measures that work to reduce a customer's overall energy usage throughout the year. The Commission's Order in Docket No. 19-368, on June 14, 2022, requires the Company to save, on average, at least 780 gigawatt-hours via energy efficiency each year through 2034. To demonstrate compliance with that target in this Resource Plan, the Company has bifurcated naturally occurring EE[12] from energy savings claimed through our ECO programs. We included three EE Bundles in our modeling for both the Reference Case and Preferred Plan. The Company developed the EE bundles based on the filed 2024-2026 ECO Triennial.[13]

The DR Bundles, on the other hand, reflect a customer's commitment to discrete reductions in demand (e.g., on a day when peak load is expected to be high otherwise). These actions are expected to reduce the anticipated annual system peak demand, as well as smooth demand on specific days when weather or other conditions lead to high demand at a certain point in time. In the Order approving our 2019 Plan,[14] the Commission directed that the Company "shall continue to acquire no less than 400 MWs of incremental demand response by 2023 as ordered in the Company's last Resource Plan." In this 2024 Plan, we included six DR Bundles in our modeling for both the Reference Case and Preferred Plan.

[12] Naturally Occurring energy efficiency includes customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by energy efficiency programs, but in the future world would not be part of an energy efficiency program because an efficient technology is required to meet code or has become common practice.
[13] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.
[14] *See* E002/RP-19-368 Order Approving Plan with Modifications and Establishing Requirements for Future Filings (April 15, 2022), Order Point 2.A.2.

We discuss the development of the bundles, our expected EE and DR levels, our analysis, and the changing DSM landscape in more detail in Appendix J.

V. EXISTING AND APPROVED RESOURCES

Our current generating resources[15] comprise a diverse portfolio including nuclear, coal, wind, biomass, solar, hydro, natural gas, and oil-fueled facilities. Physical generating assets owned by the Company have a net capacity of approximately 9,500 MWs, including about 2,300 MWs of wind. In addition to these assets, we purchase power from additional physical generating assets representing a capacity of approximately 5,600 MWs.[16] Together, these provide approximately 15,000 MWs of generation resources, of which approximately 7,700 MWs[17] is supplied by renewables. In addition to the physical assets above, customer-owned distributed solar, demand response, and energy efficiency provide additional portfolio diversity. Counting these additional customer-facing resource types, as well as the Company's nuclear units, more than 11,400 MWs of resources[18] supply carbon-free energy for our system.

A. Renewable Resources

In total, we currently have approximately 7,700 MWs of renewable capacity serving the NSP System, including:[19]

- 4,500 MWs of wind resources;
- 2,300 MWs of solar, including community solar programs and grid-scale solar;[20]
- 800 MWs of hydroelectric power;[21] and
- 130 MWs of biomass and landfill gas.

B. Nuclear

Our Monticello and Prairie Island nuclear plants provide a total net capacity of approximately 1,650 MWs of clean energy. These units operate at high-capacity factors and provide nearly 30 percent of the total electric energy and approximately 40 percent of the carbon-free energy our customers consume. Between 2019 and 2023, we have consistently maintained production costs at approximately $31.25 per

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[15] Includes approved resources: Sherco Solar 1, 2, and 3; Louise, Fillmore and Apple River solar.
[16] This total excludes the Company's current diversity exchange contract with Manitoba Hydro.
[17] *Id.*
[18] *Id.*
[19] Note: these values are approximate.
[20] Includes solar projects anticipated to be operational in 2024.
[21] Excluding capacity associated with diversity agreement contracts with Manitoba Hydro.

megawatt-hour (MWh) or less, which is a decrease of more than 20 percent when compared to 2013 production costs.

C. Coal

Our coal fleet includes our Sherburne County Generating Station (Sherco) Units 1 and 3 in Becker, Minnesota, and the Allen S. King plant[22] in Oak Park Heights, Minnesota. This coal fleet provides almost 1,700 MW of baseload and cycling generating capacity and supports system reliability. The Commission approved our proposal to retire Sherco Coal Units 1 and 2 in 2026 and 2023, respectively, in its Order in Docket No. E-002/RP-15-21(January 11, 2017). Sherco Unit 2 was retired on December 31, 2023, resulting in a loss of 682 MW of firm dispatchable generation from the NSP system. In the last Resource Plan, the Commission approved our proposal to retire the Allen S. King Generating Station in 2028 and Sherco Unit 3 in 2030.[23] These retirements are reflected in our Reference Case.

D. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of both intermediate and peaking generation. We have five owned or contracted intermediate-type generating assets that provide over 2,000 MWs of capacity. We have peaking-type resources located at seven sites, providing nearly another 2,000 MWs of capacity. Combined, these facilities provide valuable load following capabilities for our system, cycling as necessary to provide important flexibility to our generation operations and support to our growing renewable resources.

VI. NET RESOURCE SURPLUS/DEFICIT

As described above, our forecast of customers' peak demand and MISO RA requirements are used to determine our overall total generating capacity obligation. From this we deduct our expected load management achievements and accredited capacity of the various resources we have included in our Reference Case to determine our net generation capacity surplus or deficit. We anticipate a net surplus through 2026 and a deficit thereafter, starting first in the spring and summer of 2027. Reference Case Load and Resources tables for each season are in Tables 3-4 through 3-7 below.

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[22] Asset is in seasonal operation. The identified capacity represents its maximum capacity offered during the winter season.

[23] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy,* Docket No. E-001/RP-19-368, Order (April 15, 2022), at Order Point 2.A.4.

Table 3-4: Reference Case Load and Resources,[24] 2024-2040 Planning Period, Summer Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Summer																	
Forecasted gross load	10,735	10,769	11,087	11,361	11,468	11,489	11,550	11,518	11,621	11,671	11,757	11,817	11,920	11,954	12,047	12,148	12,226
Adjustment to Load from non-bundled Energy Efficiency	(1,347)	(1,277)	(1,195)	(1,132)	(1,072)	(1,004)	(927)	(839)	(772)	(718)	(623)	(524)	(482)	(461)	(482)	(513)	(602)
Adjustment to Load from EVs and Beneficial Electrification	20	35	54	81	115	158	213	361	482	620	768	919	1,058	1,193	1,324	1,453	1,578
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%
Coincident Load	8,678	8,787	9,174	9,511	9,695	9,817	9,994	10,183	10,452	10,675	10,979	11,264	11,526	11,702	11,890	12,073	12,178
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
NSP Obligation (Summer)	**9,459**	**9,578**	**10,000**	**10,367**	**10,568**	**10,700**	**10,894**	**11,100**	**11,393**	**11,636**	**11,967**	**12,278**	**12,564**	**12,755**	**12,960**	**13,159**	**13,274**
Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response (Existing)	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997	993	989	985	982	978
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,206	649	649	649	649	649	649
Natural Gas/Oil*	4,020	3,719	3,962	3,962	3,445	3,117	2,843	2,727	2,433	2,433	2,433	2,433	2,433	2,433	2,433	2,119	2,119
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38	38	38	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	785	743	744	743	737	706	700	683	674	583	573	566	516	494	502	496	473
Solar (Utility-Scale System Resources)	147	259	464	396	362	329	296	262	256	249	242	236	207	201	195	189	183
Solar (Legacy CSGs)	438	367	341	233	214	195	176	157	153	150	147	143	170	165	160	155	150
Solar (Net Metered as of 2024)	121	84	57	52	47	40	36	33	33	32	29	28	27	28	27	26	24
Existing Resources	**10,513**	**9,641**	**10,039**	**9,268**	**8,687**	**7,845**	**7,505**	**6,852**	**6,465**	**6,357**	**5,771**	**5,169**	**5,106**	**5,067**	**5,029**	**4,694**	**4,655**
Summer Net Resource (Need)/Surplus After Existing & Approved Resources	**1,054**	**64**	**39**	**(1,099)**	**(1,881)**	**(2,855)**	**(3,388)**	**(4,248)**	**(4,927)**	**(5,279)**	**(6,195)**	**(7,109)**	**(7,458)**	**(7,688)**	**(7,930)**	**(8,465)**	**(8,619)**
Reference Case Incremental Distributed Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response (Incremental)	177	178	179	179	179	178	177	175	174	172	171	169	168	166	165	163	162
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	8	40	74	102	118	130	137	140	150	159	168	176	183	190	196	201	206
Solar (Net Metered Installed after 2024)	0	18	25	33	41	49	53	56	63	71	81	88	93	97	102	107	115
Solar (3% Distributed Solar Energy Standard)	0	0	0	21	78	107	128	114	114	114	114	113	113	112	112	111	110
Incremental Distributed Resources Brought Forth in This Plan	**299**	**451**	**598**	**761**	**944**	**1,092**	**1,208**	**1,285**	**1,383**	**1,479**	**1,580**	**1,671**	**1,651**	**1,643**	**1,634**	**1,605**	**1,581**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**1,353**	**514**	**637**	**(338)**	**(937)**	**(1,763)**	**(2,181)**	**(2,963)**	**(3,544)**	**(3,800)**	**(4,615)**	**(5,438)**	**(5,807)**	**(6,045)**	**(6,296)**	**(6,860)**	**(7,038)**

[24] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case. This includes new resources at the Wheaton Generating Station, which are currently before the Public Service Commission of Wisconsin.

Table 3-5: Reference Case Load and Resources,[25] 2024-2040 Planning Period, Fall Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Fall																	
Forecasted gross load	8,809	8,820	9,085	9,300	9,328	9,338	9,357	9,370	9,286	9,310	9,343	9,386	9,402	9,435	9,478	9,515	9,295
Adjustment to Load from non-bundled Energy Efficiency	(1,302)	(1,226)	(1,156)	(1,089)	(1,027)	(965)	(892)	(818)	(736)	(673)	(581)	(501)	(458)	(442)	(461)	(482)	(562)
Adjustment to Load from EVs and Beneficial Electrification	21	39	58	87	121	168	224	298	509	648	802	951	1,089	1,225	1,356	1,485	1,882
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%
Coincident Load	6,976	7,073	7,401	7,690	7,805	7,914	8,053	8,201	8,396	8,605	8,863	9,115	9,298	9,469	9,612	9,747	9,838
MISO Planning Reserve Margin (UCAP)	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
NSP Obligation (Fall)	**7,967**	**8,078**	**8,452**	**8,782**	**8,914**	**9,038**	**9,196**	**9,365**	**9,588**	**9,826**	**10,121**	**10,410**	**10,618**	**10,814**	**10,977**	**11,131**	**11,235**
Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response (Existing)	759	762	764	766	766	765	763	760	757	754	752	749	746	744	741	739	736
Coal	1,505	1,505	1,505	872	872	455	455	0	0	0	0	0	0	0	0	0	0
Nuclear	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,219	668	668	668	668	668	668
Natural Gas/Oil*	3,810	3,726	3,726	3,726	2,938	2,938	2,644	2,533	2,235	2,235	2,235	2,235	2,235	2,235	2,235	1,953	1,953
Biomass/RDF	90	57	57	57	57	57	57	57	57	57	57	37	37	37	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	169	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	989	925	918	904	888	841	825	794	751	696	691	649	637	616	633	633	611
Solar (Utility-Scale System Resources)	66	137	262	251	239	228	216	205	207	208	210	211	192	193	194	195	196
Solar (Legacy CSGs)	194	172	154	148	141	135	129	123	124	125	127	128	158	158	159	160	161
Solar (Net Metered as of 2024)	90	56	34	33	31	28	26	25	26	26	25	25	25	26	27	27	25
Existing Resources	**9,956**	**9,306**	**9,385**	**8,721**	**7,898**	**7,413**	**7,081**	**6,461**	**6,053**	**5,995**	**5,395**	**4,781**	**4,770**	**4,747**	**4,734**	**4,451**	**4,427**
Fall Net Resource (Need)/Surplus After Existing & Approved Resources	**1,990**	**1,228**	**933**	**(62)**	**(1,016)**	**(1,625)**	**(2,115)**	**(2,904)**	**(3,535)**	**(3,832)**	**(4,726)**	**(5,629)**	**(5,848)**	**(6,066)**	**(6,243)**	**(6,679)**	**(6,808)**
Reference Case Incremental Distributed Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response (Incremental)	97	97	97	98	97	97	96	95	94	93	92	91	90	89	88	87	86
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	4	23	45	65	78	90	101	110	121	133	145	157	169	182	195	207	220
Solar (Net Metered Installed after 2024)	0	12	15	21	27	34	39	43	50	59	69	77	84	92	98	109	120
Solar (3% Distributed Solar Energy Standard)	0	0	0	13	52	74	94	89	92	95	98	101	105	108	111	115	118
Incremental Distributed Resources Brought Forth in This Plan	**217**	**351**	**483**	**628**	**790**	**932**	**1,052**	**1,149**	**1,252**	**1,356**	**1,465**	**1,566**	**1,556**	**1,561**	**1,565**	**1,553**	**1,545**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,207**	**1,579**	**1,416**	**566**	**(226)**	**(693)**	**(1,063)**	**(1,755)**	**(2,283)**	**(2,475)**	**(3,260)**	**(4,063)**	**(4,292)**	**(4,505)**	**(4,678)**	**(5,126)**	**(5,263)**

[25] *Id.*

Table 3-6: Reference Case Load and Resources,[26] 2024-2040 Planning Period, Winter Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Winter																	
Forecasted gross load	7,660	7,791	8,047	8,156	8,177	8,208	8,243	8,275	8,252	8,308	8,101	8,126	8,129	8,427	8,464	8,534	8,256
Adjustment to Load from non-bundled Energy Efficiency	(1,067)	(958)	(903)	(880)	(805)	(782)	(727)	(671)	(599)	(541)	(446)	(383)	(350)	(360)	(380)	(388)	(439)
Adjustment to Load from EVs and Beneficial Electrification	20	56	81	101	154	171	234	309	493	661	986	1,156	1,315	1,325	1,480	1,640	1,912
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%
Coincident Load	6,420	6,689	7,015	7,163	7,307	7,375	7,524	7,683	7,909	8,183	8,390	8,640	8,829	9,119	9,286	9,501	9,445
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Winter)	**8,179**	**8,522**	**8,937**	**9,125**	**9,309**	**9,396**	**9,586**	**9,788**	**10,076**	**10,425**	**10,689**	**11,007**	**11,249**	**11,617**	**11,831**	**12,105**	**12,033**
Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response (Existing)	441	443	445	447	447	447	447	447	447	447	447	447	447	446	446	446	446
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,250	665	665	665	665	665	665
Natural Gas/Oil*	4,372	4,372	4,204	4,204	3,997	3,255	3,255	2,753	2,753	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,131
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29	29	29	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	610	169	169	169	169	169	169	100	100	80	80	72	72	70	70	70
Wind	2,146	1,641	1,685	1,596	1,573	1,488	1,470	1,426	1,392	1,193	1,154	1,109	1,073	928	923	892	831
Solar (Utility-Scale System Resources)	1	28	58	50	42	34	27	19	11	23	34	45	56	60	70	80	89
Solar (Legacy CSGs)	5	41	34	29	25	20	16	11	7	14	20	27	34	50	57	65	73
Solar (Net Metered as of 2024)	0	52	6	7	6	5	4	3	2	3	5	7	8	10	11	13	14
Existing Resources	**11,059**	**10,627**	**10,041**	**9,318**	**9,075**	**7,766**	**7,734**	**6,706**	**6,589**	**6,137**	**5,521**	**4,888**	**4,864**	**4,740**	**4,729**	**4,717**	**4,327**
Winter Net Resource (Need)/Surplus After Existing & Approved Resources	**2,880**	**2,106**	**1,104**	**193**	**(234)**	**(1,630)**	**(1,851)**	**(3,082)**	**(3,487)**	**(4,288)**	**(5,168)**	**(6,119)**	**(6,384)**	**(6,877)**	**(7,101)**	**(7,387)**	**(7,706)**
Reference Case Incremental Distributed Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response (Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	6	10	13	14	14	12	10	7	14	23	33	45	57	70	85	100
Solar (Net Metered Installed after 2024)	0	11	3	5	5	6	6	5	3	7	14	21	28	35	43	53	71
Solar (3% Distributed Solar Energy Standard)	0	0	0	3	9	11	12	8	5	10	16	22	28	34	40	47	54
Incremental Distributed Resources Brought Forth in This Plan	**130**	**260**	**375**	**503**	**625**	**741**	**835**	**927**	**1,012**	**1,119**	**1,232**	**1,341**	**1,331**	**1,337**	**1,344**	**1,335**	**1,335**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**3,010**	**2,366**	**1,480**	**696**	**392**	**(889)**	**(1,016)**	**(2,155)**	**(2,475)**	**(3,168)**	**(3,935)**	**(4,778)**	**(5,054)**	**(5,540)**	**(5,757)**	**(6,053)**	**(6,371)**

[26] *Id.*

Table 3-7: Reference Case Load and Resources,[27] 2024-2040 Planning Period, Spring Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Spring																	
Forecasted gross load	8,137	8,181	8,473	8,699	8,809	8,712	8,697	8,737	8,786	8,789	8,840	8,699	8,753	8,785	8,801	8,839	8,843
Adjustment to Load from non-bundled Energy Efficiency	(1,108)	(1,062)	(1,012)	(949)	(961)	(808)	(738)	(687)	(635)	(569)	(488)	(401)	(375)	(366)	(385)	(394)	(459)
Adjustment to Load from EVs and Beneficial Electrification	14	24	39	57	107	113	200	265	353	459	571	887	1,026	1,158	1,287	1,412	1,534
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%
Coincident Load	6,733	6,830	7,171	7,465	7,606	7,666	7,800	7,949	8,131	8,298	8,531	8,782	8,991	9,157	9,277	9,425	9,483
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Spring)	**8,531**	**8,653**	**9,085**	**9,459**	**9,637**	**9,712**	**9,883**	**10,072**	**10,302**	**10,514**	**10,809**	**11,127**	**11,392**	**11,601**	**11,754**	**11,941**	**12,015**
Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response (Existing)	811	815	819	821	822	821	820	818	816	814	813	811	809	808	806	804	803
Coal	1,229	1,229	1,229	669	669	276	276	0	0	0	0	0	0	0	0	0	0
Nuclear	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,247	664	664	664	664	664	664
Natural Gas/Oil*	4,003	4,003	3,919	3,919	3,710	3,130	3,130	2,702	2,702	2,430	2,430	2,430	2,430	2,430	2,430	2,430	2,169
Biomass/RDF	87	53	53	53	53	53	53	53	53	53	53	36	36	36	8	8	8
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	659	169	169	169	169	169	169	100	100	80	78	72	70	70	70	70
Wind	1,106	890	835	777	715	632	578	510	457	398	395	395	395	352	362	362	349
Solar (Utility-Scale System Resources)	157	90	180	182	185	187	189	191	193	186	178	171	163	141	134	127	121
Solar (Legacy CSGs)	483	112	106	107	109	111	112	114	116	112	108	104	100	116	110	105	99
Solar (Net Metered as of 2024)	119	131	53	26	25	25	25	26	27	25	24	23	21	21	21	19	17
Existing Resources	**10,476**	**9,803**	**9,185**	**8,545**	**8,279**	**7,226**	**7,174**	**6,405**	**6,285**	**5,940**	**5,328**	**4,712**	**4,692**	**4,638**	**4,605**	**4,590**	**4,300**
Spring Net Resource (Need)/Surplus After Existing & Approved Resources	**1,945**	**1,150**	**100**	**(914)**	**(1,357)**	**(2,486)**	**(2,708)**	**(3,667)**	**(4,016)**	**(4,574)**	**(5,482)**	**(6,415)**	**(6,700)**	**(6,963)**	**(7,150)**	**(7,352)**	**(7,715)**
Reference Case Incremental Distributed Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response (Incremental)	109	109	110	110	110	110	109	109	108	107	107	106	105	105	104	104	103
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	3	15	31	47	60	74	88	102	113	119	123	127	130	133	134	135	136
Solar (Net Metered Installed after 2024)	0	29	24	17	22	31	38	45	53	58	68	71	74	75	78	79	85
Solar (3% Distributed Solar Energy Standard)	0	0	0	10	40	61	82	83	86	85	84	82	80	79	77	75	73
Incremental Distributed Resources Brought Forth in This Plan	**236**	**386**	**513**	**646**	**806**	**957**	**1,091**	**1,208**	**1,319**	**1,415**	**1,518**	**1,608**	**1,578**	**1,562**	**1,544**	**1,504**	**1,470**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,181**	**1,537**	**612**	**(268)**	**(552)**	**(1,529)**	**(1,618)**	**(2,459)**	**(2,697)**	**(3,159)**	**(3,963)**	**(4,807)**	**(5,121)**	**(5,402)**	**(5,605)**	**(5,848)**	**(6,245)**

[27] *Id.*

VII. MEETING RENEWABLE ENERGY REQUIREMENTS AND GOALS

A. Minimum Compliance Requirements

Each of the states in the NSP System has a different public policy with respect to renewable energy requirements or objectives. Table 3-8 below illustrates each state's renewable energy standard (RES).

Table 3-8: Renewable Energy Requirements and Objectives by State – NSP System

State	Renewable & Recycled	Renewable	Carbon-free	Solar	Distributed Solar
Minnesota		30% by 2020* 55% by 2035	80% by 2030 90% by 2035 100% by 2040	1.5% by 2020*	3% by 2030
North Dakota	10% by 2015**				
South Dakota	10% by 2015**				
Wisconsin	12.9% by 2015*				
Michigan	50% by 2030 60% by 2035		100% by 2040		

*Goal Met
**Voluntary objective met

Of our states that have renewable standards expressed as a percentage of electric retail sales from qualifying resources by a certain date, Minnesota's RES is the highest, requiring that 30 percent of the Company's energy come from renewables, with at least 24 percent of the electricity we provide to retail customers coming from wind energy by 2020.[28] Legislation passed in the 2013 session also established a Solar Energy Standard (SES) for Minnesota that requires that investor-owned utilities in the state generate 1.5 percent of 2020 retail sales, net of customer exclusions, from solar energy resources. Of that 1.5 percent, 10 percent must come from systems with

[28] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards an overall 25 percent wind and solar requirement (amounting to 1 percent of total sales). The SES is assessed separately. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691.

capacity less than 40 kW.[29] Additionally, the Distributed Solar Energy Standard requires that three percent of solar power come from distributed energy by 2030, and the Carbon Free Standard (CFS) requires 80 percent of retail sales to come from carbon-free energy by 2030,[30] 90 percent by 2035, and 100 percent by 2040.

North Dakota and South Dakota each have a voluntary objective that includes renewable or recycled energy.[31] Further, our North Dakota regulators have indicated that compliance with the North Dakota Renewable Energy Objective should be accomplished with competitively-priced energy.

To-date we have implemented plans that result in the entire NSP System complying with, at the very least, the highest of renewable energy requirements across our jurisdictions, in this case, the Minnesota RES. This strategy also places us in compliance with the specific requirements in each of our other jurisdictions. As a result, we have been planning for renewable energy additions, and allocating their benefits, to all our jurisdictions (with certain exceptions as discussed in Chapter 2, Planning Landscape). As state energy policies continue to evolve, however, we will continue to examine whether this requires a strategy change going forward, and engage our Commissions as needed on that topic.

B. RES and SES Compliance

We project continued compliance with the renewable energy goals and standards in each of our NSP states under our Preferred Plan. The Company currently maintains a set of banked Renewable Energy Credits (RECs) for future compliance.[32] In the past, we have leveraged our REC bank to manage the size, type, and timing of renewable energy additions on our system, to ensure that we identify and acquire the renewable generation resources that provide our customers with the greatest value at the lowest

[29] The original legislation set a threshold of 20 kW, but was increased to 40 kW in 2018, per HF3232. *See* "Minnesota Renewable energy Standard: Utility Compliance." Minnesota Department of Commerce (January 2019) at 7. Available at: https://www.leg.state.mn.us/docs/2019/mandated/190330.pdf.
[30] Minn. Stat. § 216B.1691 Subd. 2h states that projects must comply with eligibility requirements to count toward the DSES. Eligibility requirements stipulate that the project must be: 10 MW or less; connected to our distribution system; located in our Minnesota service territory; and constructed/procured after August 1, 2023 using a Commission-approved competitive bidding process; etc.
[31] As defined in North Dakota Century Code, 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." South Dakota Codified Law 49-34A-94 contains a similar definition.
[32] A REC is an accounting device designed to reflect the renewable energy attributes of a particular MWh of renewable energy generation. RECs are the currency for compliance with state renewable targets.

cost. The Company currently expects to generate a sufficient number of RECs throughout the planning period to satisfy our renewable obligations. Additional information on our compliance with RES and SES is provided in Appendix N: Standard Obligations.

C. Carbon Free Standards

In 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to create new carbon-free energy standards (see Minn. Laws 2023, chp. 7). The new legislation requires Xcel Energy to generate or procure carbon-free energy equivalent to 100 percent of its Minnesota retail sales by 2040. The law, Minn. Stat. § 216B.1691, also requires Xcel Energy to achieve interim carbon-free standards of 80 percent by 2030, and 90 percent by 2035.

Further, both Wisconsin and Michigan's Governors recently put forward 100 percent by 2040 carbon reduction goals for their respective states' electric sector. Proceedings by those states' Public Utilities Commissions are still in the early stages and have not produced any final compliance requirements for electric utilities. Additional information regarding our compliance with the newly enacted carbon-free energy standard is provided in Appendix N.

VIII. ENERGY POLICY AND COMPANY GOALS

As discussed above, we believe that we are well positioned to meet minimum system needs. At least through 2026, we expect that we will be able to meet those needs with existing and already-approved resources. In December 2018, the Company announced its goals to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels company-wide, and to serve customers with 100 percent carbon-free electricity by 2050. Our 2024 Plan is informed by these internal policies, as well as the renewable energy milestones set forth in Minn. Stat. § 216B.1691, and demonstrates our commitment to a cost-effective, renewable, and carbon-free future. Additionally, our Preferred Plan will result in significant carbon reductions and keeps us on track to provide 100 percent carbon-free electricity by 2050.

IX. REFERENCE CASE

We incorporate all the aforementioned elements into the EnCompass modeling tool, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plan through sensitivity analysis and special studies by individually changing key assumptions and re-running the plans under these changed assumptions. Our analysis resulted in the following Reference Case Expansion Plan, depicted in Tables 3-9 through 3-13 below.

Table 3-9: Reference Case Annual Expansion Plan, Summer Season UCAP[33]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	29	103	46	0	0	0	0	0	0	0	0	0
Storage	0	0	0	425	0	102	0	148	151	0	0	0	437	445	284	0	0
Firm Dispatchable	0	0	0	629	629	0	629	0	314	314	0	629	0	0	0	629	0
Wind	0	0	0	72	325	72	0	216	142	70	278	172	102	67	66	98	227
Distributed Resources																	
Demand Response	177	182	187	189	189	188	182	177	171	166	160	155	150	145	140	134	129
Energy Efficiency (EE) Bundles	114	101	106	105	102	100	84	88	83	80	84	78	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	8	50	41	58	81	49	33	0	17	17	19	14	12	11	10	9	12
Total Annual Resource Additions, Summer Accredited Capacity	**299**	**333**	**333**	**1,477**	**1,326**	**540**	**1,031**	**675**	**878**	**647**	**542**	**1,048**	**700**	**668**	**500**	**871**	**368**

33 Note: This table includes EE, DR, and Distributed Solar resources that are also reflected in the Load and Resources Table.

Table 3-10: Reference Case Annual Expansion Plan, Fall Season UCAP[34]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	20	76	36	0	0	0	0	0	0	0	0	0
Storage	0	0	0	391	0	90	0	122	128	0	0	0	403	419	271	0	0
Firm Dispatchable	0	0	0	628	628	0	628	0	314	314	0	628	0	0	0	628	0
Wind	0	0	0	88	392	86	0	252	168	84	336	210	126	84	84	126	294
Distributed Resources																	
Demand Response	97	100	103	105	105	104	100	96	92	89	85	81	78	74	71	67	64
Energy Efficiency (EE) Bundles	116	102	107	107	103	101	86	89	84	81	84	78	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	4	31	24	39	58	41	35	8	21	24	26	23	23	23	23	26	28
Total Annual Resource Additions, Fall Accredited Capacity	**217**	**233**	**235**	**1,357**	**1,286**	**442**	**924**	**604**	**807**	**591**	**531**	**1,021**	**630**	**600**	**449**	**847**	**386**

[34] *Id.*

Table 3-11: Reference Case Annual Expansion Plan, Winter Season UCAP[35]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	3	9	3	0	0	0	0	0	0	0	0	0
Storage	0	0	0	433	0	104	0	151	148	0	0	0	422	430	273	0	0
Firm Dispatchable	0	0	0	598	598	0	598	0	299	299	0	598	0	0	0	598	0
Wind	0	0	0	156	696	153	0	449	296	144	557	337	196	126	122	176	395
Distributed Resources																	
Demand Response	0	2	4	5	6	6	6	6	6	6	5	5	5	5	5	5	5
Energy Efficiency (EE) Bundles	130	114	119	119	115	113	95	99	93	90	92	86	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	0	17	0	8	8	3	0	0	0	17	21	22	25	25	28	32	40
Total Annual Resource Additions, Winter Accredited Capacity	**130**	**133**	**123**	**1,320**	**1,423**	**382**	**709**	**707**	**841**	**556**	**675**	**1,049**	**648**	**586**	**427**	**811**	**439**

[35] *Id.*

Table 3-12: Reference Case Annual Expansion Plan, Spring Season UCAP[36]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	16	66	34	0	0	0	0	0	0	0	0	0
Storage	0	0	0	422	0	100	0	141	137	0	0	0	342	336	206	0	0
Firm Dispatchable	0	0	0	702	702	0	702	0	351	351	0	702	0	0	0	702	0
Wind	0	0	0	76	315	65	0	161	96	48	192	120	72	48	48	72	168
Distributed Resources																	
Demand Response	109	113	117	119	121	120	117	115	113	110	108	106	103	101	99	97	94
Energy Efficiency (EE) Bundles	124	109	115	114	111	108	92	96	90	87	91	85	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	3	41	11	19	49	43	42	22	22	9	13	6	4	2	3	0	4
Total Annual Resource Additions, Spring Accredited Capacity	**236**	**263**	**243**	**1,451**	**1,297**	**452**	**1,019**	**568**	**808**	**605**	**404**	**1,018**	**521**	**487**	**356**	**870**	**266**

[36] *Id.*

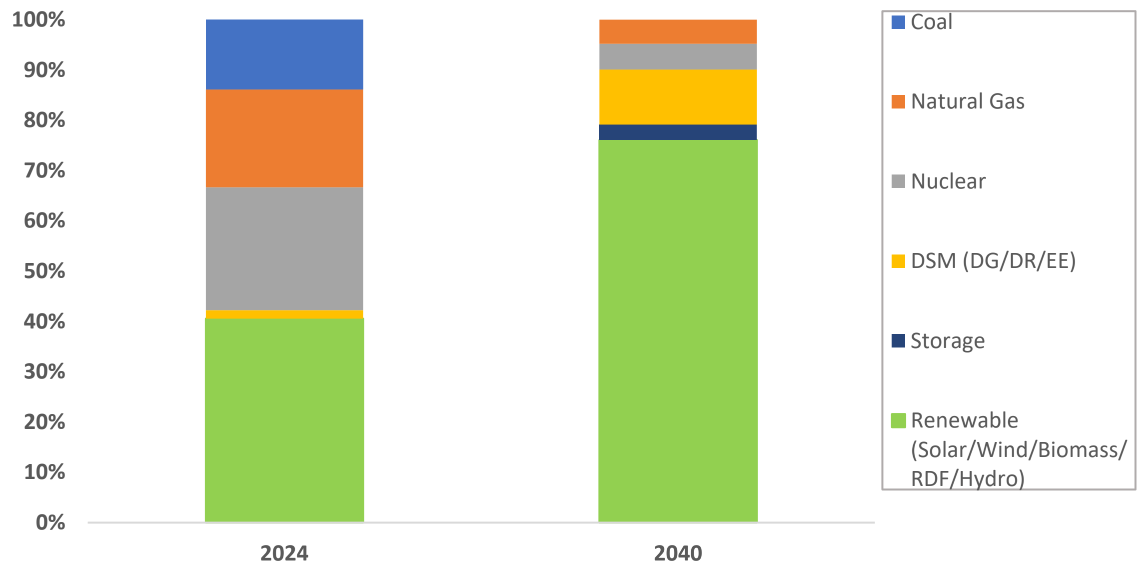
Table 3-13: Reference Case Annual Expansion Plan, ICAP[37]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	100	400	200	0	900	0	800	0	0	0	0	0
Storage	0	0	0	480	0	120	0	180	180	0	0	0	480	480	300	0	0
Firm Dispatchable	0	0	0	748	748	0	748	0	374	374	0	748	0	0	0	748	0
Wind	0	0	0	400	1,800	400	0	1,200	800	400	1,600	1,000	600	400	400	600	1,400
Distributed Resources																	
Demand Response	231	234	236	238	239	239	238	238	237	236	236	235	235	234	234	233	233
Energy Efficiency (EE) Bundles	114	101	106	105	102	100	84	88	83	80	84	78	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	18	119	138	194	306	263	245	109	107	117	169	110	114	80	96	124	174
Reference Case Total Annual Resource Additions	**363**	**453**	**480**	**2,165**	**3,195**	**1,222**	**1,716**	**2,015**	**1,781**	**2,107**	**2,089**	**2,972**	**1,429**	**1,194**	**1,030**	**1,705**	**1,807**

[37] *Id.*

The Reference Case presented here would result in the following energy mix depicted in Figure 3-6 below.

Figure 3-6: NSP System Reference Case Energy Mix in 2024 and 2040



In Chapter 4, we detail our Preferred Plan. In Chapter 5: Economic Modeling Framework, we outline and discuss the starting assumptions, scenarios, and sensitivities that formed our EnCompass modeling analysis, and resulted in our Preferred Plan.

X. CONCLUSION

Our 2024 Plan focuses on reducing carbon emissions while ensuring reliable and affordable service to our customers. The minimum number of resources required for the planning period is determined based on system needs and existing resources. The Reference Case, modeling scenarios, and Preferred Plan are developed based on this baseline. In our 2024 Plan, our minimum system needs are informed by the seasonal resource adequacy construct recently implemented by MISO and our energy adequacy analysis. These changes are intended to address the increasing variability in reliability needs and resource availability throughout the year and align resource accreditation with availability.

CHAPTER 4 - THE PREFERRED PLAN

I. INTRODUCTION

The Preferred Plan we propose here continues to deliver on our obligations to provide safe, reliable, and affordable service to our customers while further accelerating our ambitious carbon-reduction strategy. It increases the pace of the carbon-reduction efforts approved in our 2019 Plan, while continuing to ensure our system maintains robust reliability.

Building on our ongoing efforts to transform our energy system, and based on extensive collaboration with our stakeholders, the key components of our Preferred Plan include:

- Adding thousands of megawatts of additional renewable resources to our system, including customer-sited DERs;
- Integrating and investing in energy storage systems, including adding short-duration storage systems to our fleet;
- Extending the life of our nuclear fleet;
- Ensuring reliability through additional firm dispatchable generation; and
- Continuing to increase Energy Efficiency and Demand Response resources to help reduce overall system demand.

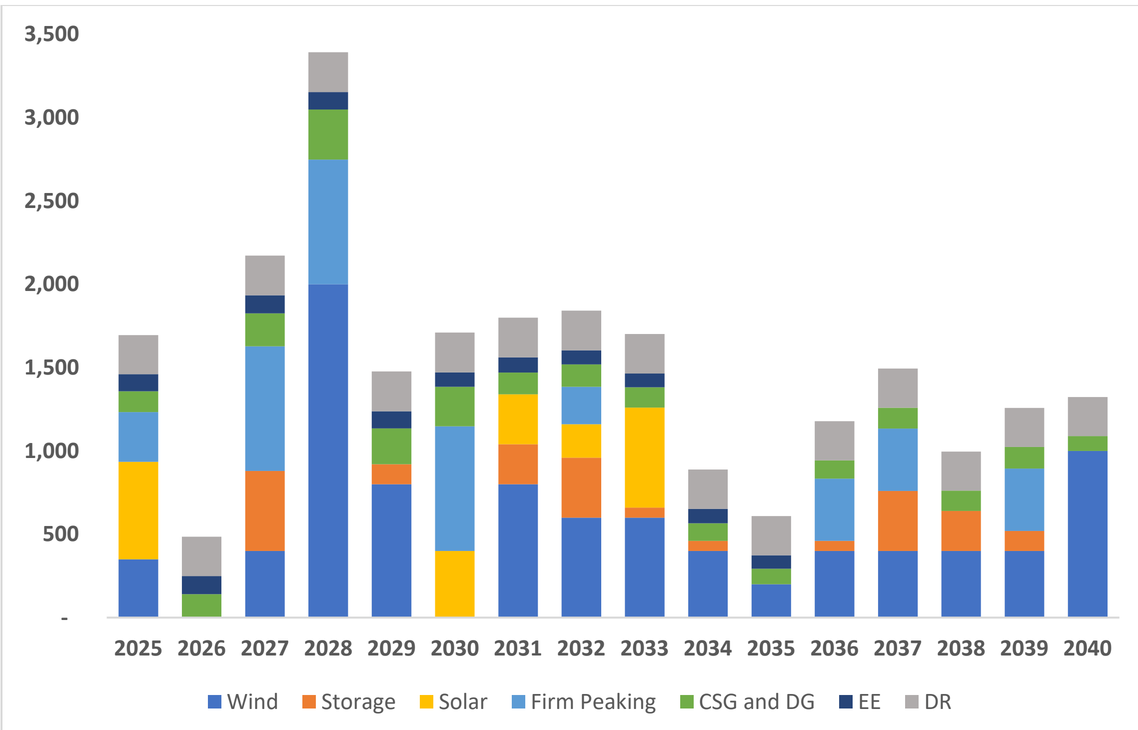
Our Preferred Plan leverages existing grid connections and proven technologies, while using emerging technologies like battery storage to provide a balanced mix of resources, at an estimated average annual increase in retail rates of less than one percent, all while preserving our fundamental commitment to reliability.

Our planning objectives center on addressing generation decarbonization and load growth while maintaining reliability, and the cost effectiveness of our Preferred Plan. Importantly, we understand and have considered the impact that our Preferred Plan will have on our customers and have engaged with stakeholders and the community to help inform and further refine our Preferred Plan. Our strategy reflects our commitment to providing clean, reliable, and affordable energy to our customers, while also leading the charge in the clean energy transition.

II. PREFERRED PLAN

Our Preferred Plan is designed to accelerate our carbon-reduction efforts while maintaining a safe, reliable, and affordable system for our customers and communities. Figures 4-1 and 4-2 below outline our Preferred Plan's modeled resource additions over the 2024 – 2040 planning period. Resource additions in 2025 include the approved Sherco Solar resources expected to achieve commercial operations in 2025, the approved Apple River solar resource, and the investments at our Wheaton and Blue Lake facilities approved in 2019 Plan.[1]

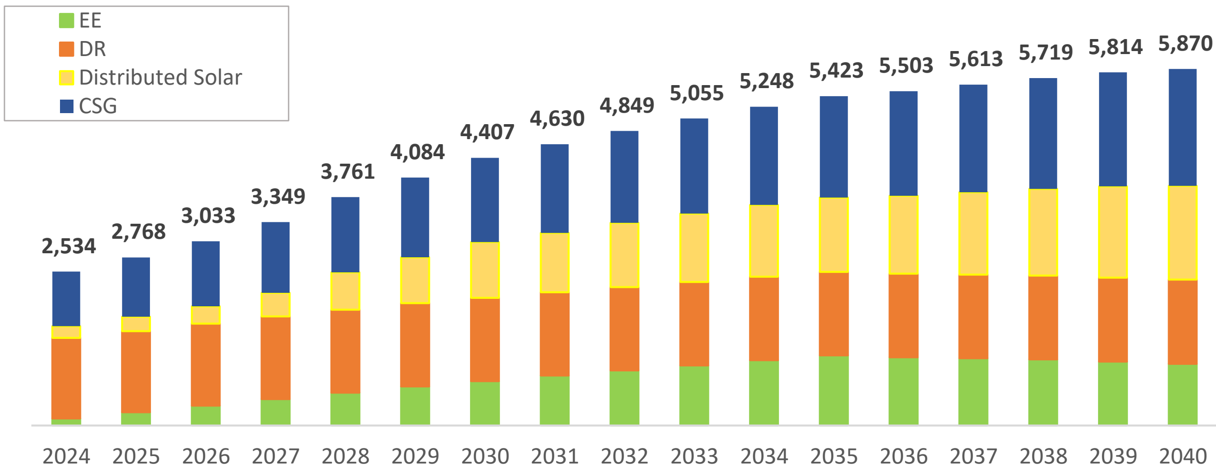
Figure 4-1: Preferred Plan Resource Additions (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	350	0	400	2,000	800	0	800	600	600	400	200	400	400	400	400	1,000
Storage	0	0	480	0	120	0	240	360	60	60	0	60	360	240	120	0
Solar	585	0	0	0	0	400	300	200	600	0	0	0	0	0	0	0
Firm Peaking	298	0	748	748	0	748	0	225	0	0	0	374	374	0	374	0
CSG and DG	124	140	198	301	215	237	131	134	123	106	94	110	125	121	130	90
EE	103	108	108	105	103	87	91	85	82	86	80	0	0	0	0	0
DR	234	237	238	239	239	239	238	237	237	236	236	235	235	235	234	234

[1] The Wheaton repowering is currently under review by the Wisconsin Public Service Commission.

Figure 4-2: Preferred Plan Cumulative Capacity Demand Side Resources and Community Solar Gardens (MW)



The figures illustrate our Preferred Plan's aim to maximize cost-effective renewable resources. This is in addition to the significant distributed resources projected, which align with state law and policy. The Preferred Plan is supported by firm dispatchable generation, enhancing renewable integration and system reliability, in an effort to reduce market exposure and risk.

With this diverse mix of resources, our system will not be overly reliant on any one fuel source, and we will continue to ensure reliability, while retaining the flexibility to consider the economics of new resources as our baseload plants retire. Our projected capacity and energy mix for 2040 under our Preferred Plan can be seen in Figures 4-3 and 4-4 below.

Figure 4-3: NSP System 2024 and 2040 Preferred Plan Capacity Mix

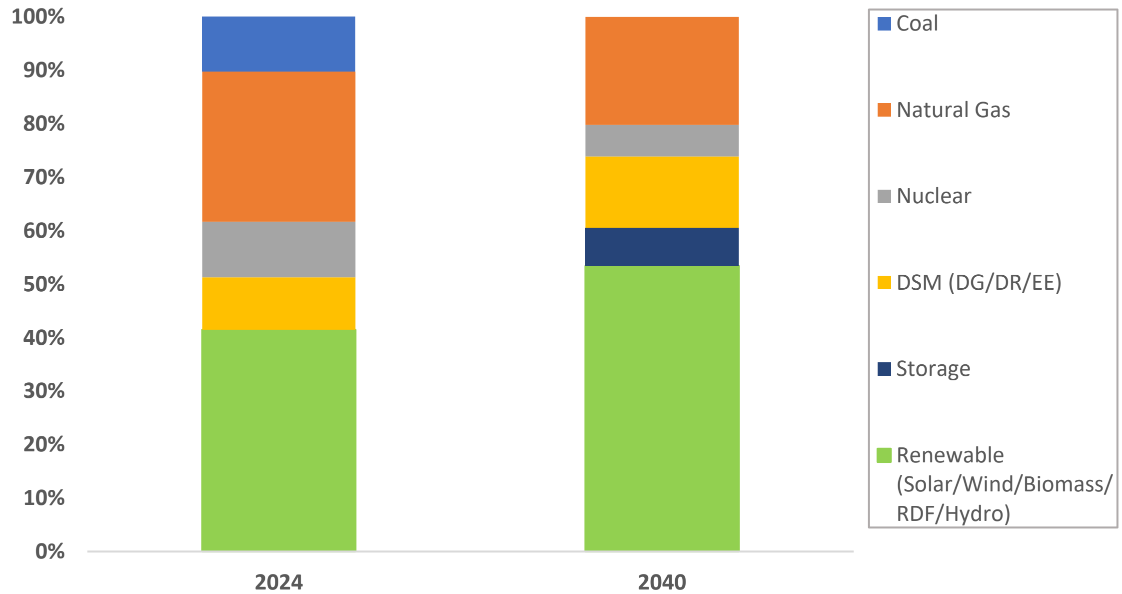
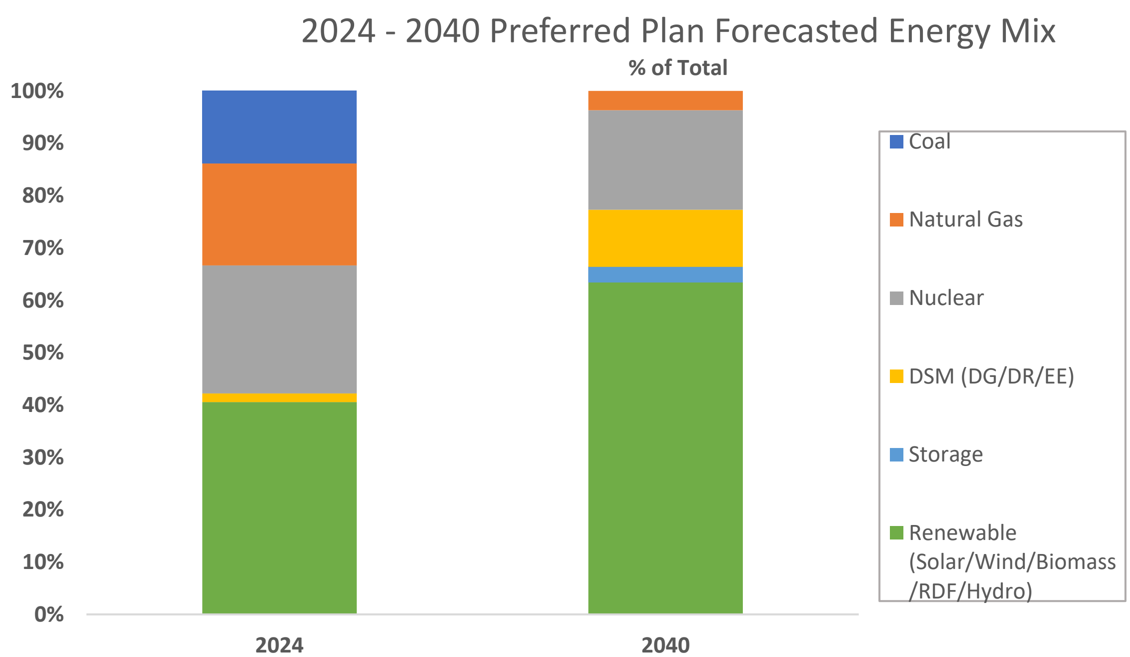


Figure 4-4: NSP System 2024 and 2040 Preferred Plan Energy Mix



Below, we discuss our Preferred Plan's anticipated resource mix in more detail.

A. Coal Resources

Our Preferred Plan continues along the path that the Commission set in our 2019 Plan when it approved our proposal to close all of our coal units by 2030. We retired Sherco Unit 2 at the end of 2023, removing approximately 700 MWs of baseload coal from our fleet. We continue to plan for retiring Sherco Unit 1 in 2026, King in 2028, and Sherco Unit 3 in 2030, bringing our total coal reductions to 2,400 MWs.

Closing our coal units aligns with our sustainability goals and makes economic sense due to changes in federal policy that makes replacing coal generation with cleaner energy sources more cost-effective. Regardless, these coal units have been a cornerstone of our fleet for decades, operating at high load-factors to provide reliable power to our customers. We therefore need to retire these resources responsibly by giving ourselves sufficient time to build the necessary replacement resources, help transition our workforce, and maintain a reliable system. Our Preferred Plan is designed to allow us to do just that.

B. Renewable Resources

As part of our Preferred Plan, we plan to add significant wind and solar resources. Robust renewable additions continue to be a critical component of our vision to achieving our clean energy commitments. In addition to helping to achieve our renewable energy goals, wind and solar do not have any fuel costs and act to insulate the Company against rising fuel prices. Our Preferred Plan reflects a modeled expansion need of nearly 9,900 MWs of utility-scale renewable resources by 2040, with new resource additions beginning in 2027.

We have long been one of the nation's leading providers of wind energy and expect this to continue. Our Preferred Plan reflects the need for an incremental 8,400 MWs of wind capacity through 2040. We note that the MISO accreditation for wind is higher than the assumption used in our 2019 Plan, and the assumption coupled with the lower levelized cost of energy from IRA production tax credits is driving the wind additions.

In addition to this substantial increase in wind generation, our Preferred Plan reflects a modeled expansion need for 1,500 MWs of solar through 2040. Further, our Preferred Plan includes nearly 2,000 MWs of Community Solar Gardens and nearly 1,600 MWs of distributed solar resources in compliance with state law.

C. Firm and Dispatchable Resources

We plan to add essential firm dispatchable capacity to our resource mix. As we transition from a system built off of baseload coal to one that is made up primarily of clean, intermittent, and short duration resources, we remain committed to ensuring that we can still meet our customers' energy demands at all times. This reliability is a fundamental obligation of our service and one that our customers expect. Unlike intermittent renewable resources, firm dispatchable resources can be relied on to deliver power on-demand for extended periods of time due to their primary characteristics: dispatchability and consistent fuel supply. Our focus on reliability is particularly important because at the same time we are planning to retire our entire coal fleet (approximately 2,400 MWs of baseload generation), we also have nearly 1,700 MWs of power purchase agreements (PPAs) with other capacity resources set to expire between 2025 and 2028.

As shown in our energy adequacy analysis in Appendix D: Energy Adequacy Analysis, additional firm dispatchable resources help maintain reliability amid retiring base load generation. Our 2024 Plan therefore includes the addition of approximately 3500 MW of cumulative firm dispatchable between 2027 and 2040 to ensure long-duration, affordable energy when our intermittent renewables are not able to fully meet our customers' needs.

D. Battery Energy Storage Systems

We plan to add Battery Energy Storage Systems (BESS) to help meet some of our dispatchable needs. In addition to firm dispatchable resources, our modeling shows an incremental need for approximately 2,100 MW of storage between 2027 and 2040. The BESS modeled as part of our 2024 Plan are short-duration storage systems. Although valuable, short-duration BESS cannot currently meet the longer duration dispatch needed from firm dispatchable resources.[2] Instead, the primary value to our system that short-duration BESS provides is in aiding renewable integration, providing grid support, deferring some, but not all, traditional grid investments, and improving power quality. We provide additional information on the uses of BESS, and its limitations, as part of the Appendix I: Minnesota Energy Storage Systems Assessment.

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[2] Recently, we partnered with Form Energy to deploy and test a multi-day, iron-air battery system at the Sherco site, but the project is a pilot, to allow for further study. We anticipate that advancements in long-duration storage and grid-forming technologies will continue, and that long-duration storage, together with other grid investments to ensure system stability, will have the potential to address firm dispatchable needs in the future.

E. Nuclear Resources

We plan to extend operations at both of our nuclear plants. Combined, this will provide approximately 1,650 MW of net dispatchable generation. We propose to extend operation of the two Prairie Island Nuclear Generating Plant units for 20 years past the current license expirations, to 2053/2054, and to extend operation of the Monticello Nuclear Generating Plant by 10 years to 2050, which aligns with our Subsequent License Renewal application for Monticello pending review by the Nuclear Regulatory Commission.

To accommodate more intermittent renewable resources on the grid, we work with the MISO Day-Ahead market to allow for flexible power operations capabilities at all three nuclear units. Our nuclear plants can safely and efficiently accommodate power changes of approximately 280 MW—or over 15 percent—of our nuclear capacity in response to the market. Our nuclear fleet is also a critical component of our reliability and stability strategy, particularly during the winter months, when MISO's seasonal resource adequacy construct reduces the accredited capacity of renewables. We discuss the benefits of nuclear, as well as the performance of our nuclear fleet, in greater detail in Appendix M: Nuclear.

By continuing the operation of these plants to at least 2050, customers will continue to benefit from the carbon-free, baseload power that our nuclear fleet provides, while helping to keep costs low as we leverage existing, reliable resources on our system. Nuclear is central to achieving our carbon reduction goals and maintain reliability.

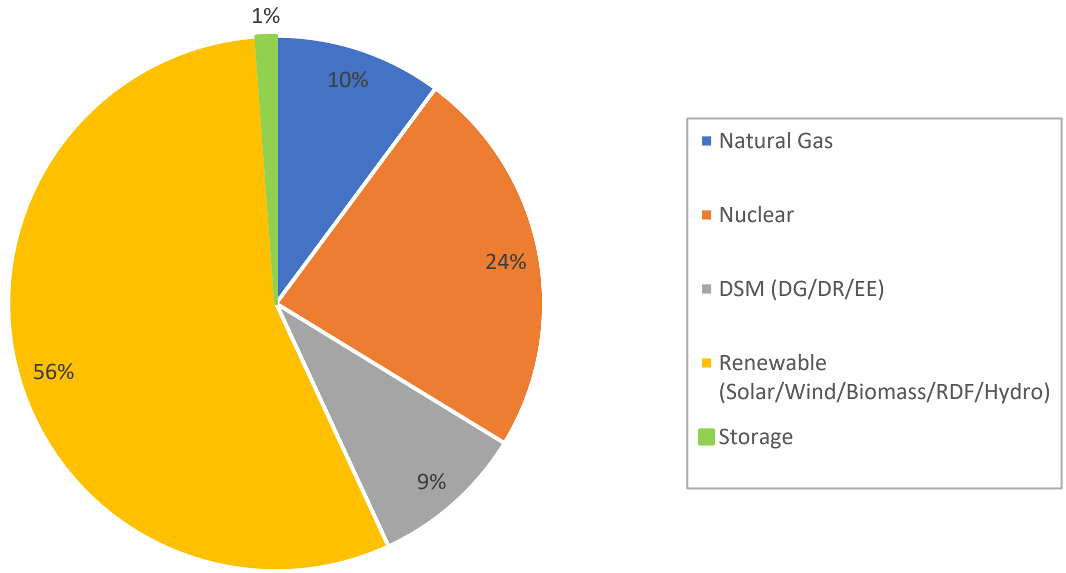
III. ACTION PLANS

A. Five-Year Plan (2024-2030)

Our 2024 Plan does not identify any incremental capacity needs until 2027. However, from 2027 through 2030, our Preferred Plan contemplates adding over 6,000 MWs of incremental generation. Below, we discuss the near-term actions by resource type that underly our long-term plan, recognizing that the resource additions may need to be smoothed during the implementation process to create a portfolio of projects that can be constructed effectively within the constraints of the market for equipment and labor.

With our 2024 Plan, we are taking steps to transform our energy resource portfolio to include a robust mix of renewable resources, supported by firm dispatchable resources. We anticipate that by 2030, our forecasted energy mix, would match that displayed in Figure 4-5, and models a nearly 88 percent reduction in CO_2 emissions from 2005 levels by 2030.

Figure 4-5: NSP System 2030 Preferred Plan Energy Mix



The details of this near-term resource mix and related action plan are provided below.

1. Wind

Our 2024 Plan proposes to add 3,200 MWs of wind additions through 2030. 2,800 MWs of the 3,200 MWs near-term wind total is assumed to utilize the MN Energy Connection Sherco Generation tie line. The remaining 400 MWs of generation is generic and non-location specific. We are pursuing 1,200 MWs of this wind through the recently approved MN Development Transfer Resource Acquisition Process to utilize the MN Energy Connection tie line. We would expect to begin further procurement activities and the proceedings for regulatory approval in the next year to ensure we have the necessary wind generation online before the capacity is needed through a Commission approved bidding process. To the extent we encounter opportunities to economically repower existing resources or if specific customer programs require specific procurements, we expect to pursue them and submit the plans for approval in separate proceedings.

2. Solar

Our 2024 Plan adds 400 MWs of solar using the King Interconnection in 2030. Beyond these additions, we do not include any new utility scale solar projects between 2024 through 2030, other than those already approved by the Commission and included in our Base Case.

One of the key components of our 2019 Plan was the Sherco Solar project. We are currently working on completing the Sherco Solar project, which will be constructed in two separate 230 MW AC blocks. The first block is scheduled to be completed in October 2024, and the second block in October 2025.

On the distributed solar side, we have incorporated forecasted growth into our 2024 Plan. We recognize the potential of distributed solar capacity and are committed to harnessing this potential to further our clean energy objectives. As measures of this, we have used as model assumptions the maximum possible level of non-legacy community solar gardens and levels of 3 percent distributed solar energy standard (DSES) solar that attain full compliance with the DSES by the 2030 requirement. Additionally, we also understand that the actual additions to customer-owned, behind the meter distributed solar capacity may exceed the forecasted amount included in our Preferred Plan and have thus included additional modeling examining higher levels of this resource.

3. Firm Dispatchable

Our 2024 Plan calls for 2,244 MWs of firm dispatchable resources by 2030. These resources are split between 748 MWs in 2027, 748 MWs in 2028, and 748 MWs in 2030. Approximately 374 MWs of the 2028 need is located on our re-optimized Sherco Generation tie line and is pending regulatory approvals from the Commission. The rest of the firm dispatchable additions are not location specific.

We have already opened a proceeding before the Minnesota Commission to consider up to 800 MWs of firm dispatchable resources.[3] The 800 MWs are included in the 2,244 MWs proposed in our Plan. However, our modeling for our 2024 Plan confirms a need exceeding 800 MWs of firm dispatchable resources. As part of the 800 MW proceeding, the Company has submitted three proposals totaling in excess of 800 MWs. Third party providers have also submitted their own proposals.

[3] Docket No. E002/CN-23-212

4. Battery Energy Storage Systems

We plan to add approximately 600 MWs of BESS by 2030. The 600 MWs of BESS is comprised of a modeled 480 MWs of generic storage in 2027, and 120 MWs as part of our re-optimized Sherco Generation tie line in 2029. We expect to solicit these resources as part of a request for proposals under a commission approved bidding process.

5. Nuclear Extension

In order to support our nuclear extensions to at least 2050, steps will need to be taken in the near future. We plan on filing a Certificate of Need with the Commission on February 7, 2024, for additional dry fuel storage to support continued operation of Prairie Island through 2053/2054. The concrete pad construction would occur over a 9–12-month period between 2027 and 2029 to support license extension and future dry fuel storage needs. By the end of 2026, we anticipate submitting our application for license renewal with the Nuclear Regulatory Commission to extend the Prairie Island Nuclear Generating Plant operating license from 2033/2034 to 2053/2054.

With respect to Monticello, the Commission recently approved, in August 2023, dry fuel storage expansion in support of a Subsequent License Renewal, which is currently pending review by the Nuclear Regulatory Commission. The concrete pad construction at Monticello would occur in 2026 over a 9-12-month duration with spent fuel loading occurring in 2028 to support license extension and future dry fuel storage needs. Shortly after a Commission decision on this 2024 Plan, we will also seek another Certificate of Need to support the additional 10-year life extension.

Throughout the planning process, we continue to collaborate with the Prairie Island Indian Community, the City of Red Wing, the City of Monticello, Goodhue County, Wright County, and other community interests to ensure transparency and continuous partnership.

6. Refuse Derived Fuel Waste to Energy Extension

Finally, all three of our renewable Refuse Derived Fuel (RDF) waste to energy generating plants are slated for retirement in 2027 and we plan to extend the life and operations of our Red Wing, Mankato, and French Island RDF plants to 2037, 2037, and 2040 respectively. These plants not only add significant value to our system and help us achieve our renewable energy goals with reliable power, but also provide value to the local communities they serve. We plan to address the extension of these plants in our upcoming annual remaining lives filings. More about these plants, and the value they provide to their community is included in Appendix W: RDF Plants.

B. Long-Term Plan

In addition to our immediate five-year action plan, our long-term 2024 Plan relies on model-selected resources in the 2031-2040 planning period that we envision could be part of our energy future including:

- Adding an additional 1,100 MWs of incremental utility-scale solar;
- Adding an additional 5,200 MWs of incremental wind and repowering existing wind resources when economical;
- Adding an additional 1,500 MWs of incremental Battery Energy Storage Systems;
- Adding approximately 1,347 MWs of incremental firm dispatchable resources;
- Developing additional regional transmission infrastructure;
- Growing our DR portfolio to approximately 1,385 MW by 2040; and
- Continuing plans to achieve average annual energy savings, through our energy efficiency programs between 2031-2040.

Our 2024 Plan presents a pathway to 2040 to meet Minnesota's 100 percent carbon free by 2040 law. While these modeled additions project what our system would look like in 2040, we note that ingenuity, new technologies, and transmission will be necessary in order to ensure we can achieve our longer-term goals of 100 percent carbon-free electricity across the NSP system by 2050.

While our 2024 Plan examines the generation side of the equation, the Company is working on creating a long-term Vision study to examine the 2040 and 2050 timeframes to determine what transmission investments might be needed to achieve a 100 percent carbon-free energy plan. The study will include a comprehensive look at load growth, including varying electrification and adoption rates, generation profiles and locational data, and finally transmission needed to accommodate the future carbon goals. We look forward to leveraging these studies to inform our planning as they become available.

IV. PUBLIC INTEREST ANALYSIS

Based on our detailed analysis, we conclude that the 2024 Plan is in the public interest. We believe it best balances our goals to ensure reliability, achieve significant carbon reduction, and maintain reasonable costs to customers.

The Commission's rules identify the factors that the Commission must consider when determining if the 2024 Plan is in the public interest.[4] Specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

- Maintain or improve the adequacy and reliability of utility service;
- Keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints;
- Minimize adverse socioeconomic effects and adverse effects upon the environment;
- Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
- Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

By planning ahead and charting an orderly, gradual transition of our generation fleet, we believe our 2024 Plan achieves all of these goals while managing the impacts to our communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. As set forth in more detail below, we believe our 2024 Plan is in the public interest and merits Commission approval.

A. Reliability

The 2024 Plan aims to provide safe and reliable service amidst the retirement of baseload units and the addition of variable renewable generation capacity. Challenges in planning for reliability are presented by the new seasonal MISO Resource Adequacy construct, the increase in intermittent resources, and the uncertainty in future capacity accreditation and Planning Reserve Margins. The future accreditation of resources, crucial for investments in solar and storage resources, is particularly challenging due to its dependence on the installed capacity of all resource types across the MISO system.

In this 2024 Plan, we used an updated analytical approach to design a plan that addresses these challenges. It both ensures we have sufficient resources to meet our customers' needs and positions us to be able to comply with future changes to the MISO Resource Adequacy construct. We plan to meet customer needs with very limited reliance on neighboring systems and the broader MISO market. At the same time, we benefit from participation in the MISO market by incorporating the current planning assumptions and allowing for the economic dispatch of our resources within

[4] Minn. R. 7843.0500, subp. 3.

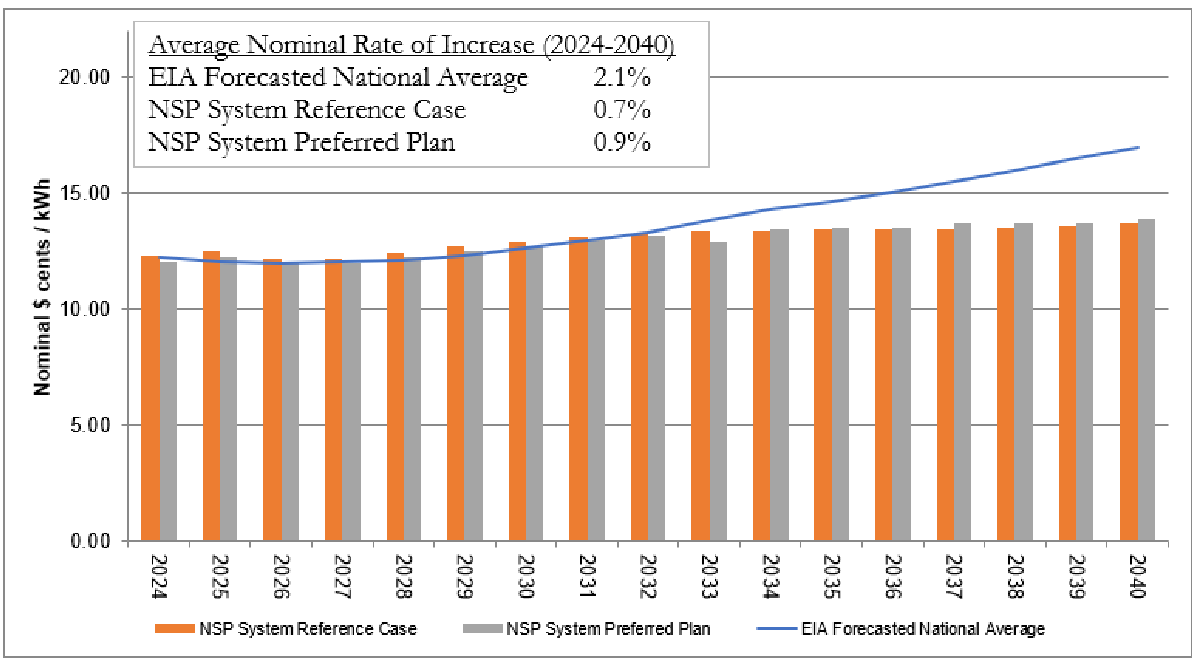
the broader region. As a result, our 2024 Plan is robust under changing assumptions and provides a path to transition our system while maintaining the reliable system our customers expect. For further detail on our reliability stress tests, see Appendix D: Energy Adequacy Analysis.

B. Impact to Customer Bills

The opportunity to achieve significant reductions in our carbon emissions for a nominal increase in cost is one of the principal benefits of our 2024 Plan. By leveraging technological advancements and financial savings from recent policies such as the IRA, we are able to present a 2024 Plan that achieves significant carbon reductions at a nominal customer cost of less than one percent annual increase in retail rates compared to the EIA forecasted national average electricity rate increase of over two percent. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are less than half of the expected national average increase in electricity prices.

Figure 4-6 shows the relative cost growth of our 2024 Plan in comparison to the national average.

Figure 4-6: Preferred Plan Average Rate Impact for the NSP System



While there is a cost to add the resources the Company needs over the next 15 years to continue providing safe and reliable service, to comply with state energy requirements, and to address plant retirements and PPA expirations, the cost is modest and appropriate in light of the benefits. For further details about the rate impact analysis, please see Chapter 6: Customer Rate and Cost Impacts.

C. Environmental Effects

Minimizing and addressing environmental effects is foundational to our 2024 Plan. In particular, our 2024 Plan increases the share of clean generating resources which can significantly and cost-effectively reduce the negative impacts like air and water pollution, land use, and associated environmental compliance cost. All NSP coal units are scheduled to cease operation by December 31, 2030, and we are replacing those resources primarily with new renewable resources and extended nuclear generation resources. This will lead to an increased share of clean energy supply, including utility-scale renewables and energy storage, and clean DERs, resulting in environmental and health benefits for the communities in which we work and that we serve. Our 2024 Plan also charts a path to meet Minnesota's 100 x 2040 law, to meet our own aggressive decarbonization goals, and to comply with EPA standards. A full discussion of the environmental regulations impacting planning can be found in Appendix K: Environmental Regulations Review.

D. Socioeconomic Impacts

We acknowledge that phasing out some of our legacy generation assets has a significant impact on the economies of the communities where those plants are located and the employees who work in those facilities. We will continue to make efforts to draw new development to locations where our current units have been or will be retired and to support our employees, consistent with our past practices, by working with those impacted to transition to new positions. Additional details of these efforts can be found in Appendix O and O1: 2023 Workforce Transition Plan.

Our plan to promote clean and distributed resources generates socioeconomic benefits, by preserving jobs with our nuclear fleet and creating jobs throughout renewable development and construction. We are also committed to working with our communities and stakeholders to ensure meaningful opportunities for them to participate in the process. Additional details can be found in Appendix R: Equity.

E. Flexibility to Respond to Change

Our 2024 Plan positions the Company to meet near-term needs and create flexibility for the future. Planning constructs, federal and state policy changes, and technology development, cost, and adoption all create uncertainty, which led us to prioritize strategic flexibility in our 2024 Plan. With this diverse mix of resources, our system will not be overly reliant on any one fuel source, and we will continue to ensure reliability, while retaining the flexibility to consider the economics of new resources as our baseload plants retire. For example, we have left open our firm and dispatchable capacity needs in our long-term plan, recognizing that the technology landscape is rapidly changing, and new options may be more economically favorable than natural gas at that time. This flexibility enhances our ability to respond to changes in our planning landscape that could affect our operations during the planning period and preserves some agility for us to respond and adapt.

F. Limiting Risks

The Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The Plan incorporates significant capacity additions to replace retiring resources and expiring PPAs, consisting of a diverse portfolio of DSM, nuclear and RDF extension, solar, wind, and firm dispatchable resource additions. Further, ensuring we do not become too dependent on a single fuel source mitigates risk.

We also have evaluated factors such as energy market exposure and portfolio length. All of our baseload scenarios show high levels of market interaction but are not overly reliant on the market to serve customer load.

V. CONCLUSION

Our Preferred Plan builds upon the efforts approved in our 2019 Plan and aligns with state and federal energy policies. The plan includes significant additions of renewable resources, investments in energy storage systems, extension of our nuclear fleet's life, and an increase in Energy Efficiency and Demand Response resources. It also includes the necessary firm dispatchable resources—modeled to provide less than 5 percent of our system's energy by 2040—necessary to maintain reliability as we continue to pursue the clean energy transition. By leveraging existing grid connections, proven technologies, and emerging technologies like battery storage, we aim to provide a balanced mix of resources.

We have considered the average annual rate impact on our customers and engaged with stakeholders and the community to refine our Plan. Our planning objectives are centered on balancing service reliability, affordability, environmental impacts, and equitable community investment. This strategy reflects our commitment to leading the charge in the clean energy transition while ensuring that our energy remains clean, reliable, and affordable for our customers. Our 2024 Plan presents the best path forward for the Company, our customers, and the energy future of our Upper Midwest system, and is thus in the public interest. We look forward to the implementation of the 2024 Plan and the positive impacts it will have on our energy system and the broader community.

Table 4-1-Preferred Plan UCAP Load and Resources, 2024-2040 Planning Period, Summer Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Summer																	
Forecasted gross load	10,735	10,769	11,087	11,361	11,468	11,489	11,550	11,518	11,621	11,671	11,757	11,817	11,920	11,954	12,047	12,148	12,226
Adjustment to Load from non-bundled Energy Efficiency	(1,347)	(1,277)	(1,195)	(1,132)	(1,072)	(1,004)	(927)	(839)	(772)	(718)	(623)	(524)	(482)	(461)	(482)	(513)	(602)
Adjustment to Load from EVs and Beneficial Electrification	20	35	54	81	115	158	213	361	482	620	768	919	1,058	1,193	1,324	1,453	1,578
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%
Coincident Load	8,678	8,787	9,174	9,511	9,695	9,817	9,994	10,183	10,452	10,675	10,979	11,264	11,526	11,702	11,890	12,073	12,178
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
NSP Obligation (Summer)	**9,459**	**9,578**	**10,000**	**10,367**	**10,568**	**10,700**	**10,894**	**11,100**	**11,393**	**11,636**	**11,967**	**12,278**	**12,564**	**12,755**	**12,960**	**13,159**	**13,274**
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response, Existing	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997	993	989	985	982	978
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,445	3,117	2,843	2,727	2,433	2,433	2,433	2,433	2,433	2,433	2,433	2,119	2,119
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38	38	38	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	785	743	744	743	737	706	700	683	674	583	573	566	516	494	502	496	473
Solar (Utility-Scale System Resources)	147	259	464	396	362	329	296	262	256	249	242	236	207	201	195	189	183
Solar (Legacy CSGs)	438	367	341	233	214	195	176	157	153	150	147	143	170	165	160	155	150
Solar (Net Metered as of 2024)	121	84	57	52	47	40	36	33	33	32	29	28	27	28	27	26	24
Existing Resources	**10,513**	**9,641**	**10,039**	**9,268**	**8,687**	**7,845**	**7,505**	**6,852**	**6,465**	**6,357**	**6,313**	**6,267**	**6,204**	**6,165**	**6,127**	**5,792**	**5,753**
Summer Net Resource (Need)/Surplus After Existing & Approved Resources	**1,054**	**64**	**39**	**(1,099)**	**(1,881)**	**(2,855)**	**(3,388)**	**(4,248)**	**(4,927)**	**(5,279)**	**(5,654)**	**(6,011)**	**(6,360)**	**(6,590)**	**(6,832)**	**(7,367)**	**(7,521)**
Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response (Incremental)	177	178	179	179	179	178	177	175	174	172	171	169	168	166	165	163	162
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	8	40	74	102	118	130	137	140	150	159	168	176	183	190	196	201	206
Solar (Net Metered Installed after 2024)	0	18	25	33	41	49	53	56	63	71	81	88	93	97	102	107	115
Solar (3% Distributed Solar Energy Standard)	0	0	0	21	78	107	128	114	114	114	114	113	113	112	112	111	110
Incremental Distributed Resources Brought Forth in This Plan	**299**	**451**	**598**	**761**	**944**	**1,092**	**1,208**	**1,285**	**1,383**	**1,479**	**1,580**	**1,671**	**1,651**	**1,643**	**1,634**	**1,605**	**1,581**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**1,353**	**514**	**637**	**(338)**	**(937)**	**(1,763)**	**(2,181)**	**(2,963)**	**(3,544)**	**(3,800)**	**(4,074)**	**(4,340)**	**(4,709)**	**(4,947)**	**(5,198)**	**(5,762)**	**(5,940)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Summer)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	103	161	201	328	319	310	301	292	283	275	266
Storage	0	0	0	425	417	512	502	689	1,006	1,079	1,154	1,177	1,256	1,615	1,873	2,024	2,062
Firm Dispatchable	0	0	0	629	1,257	1,257	1,886	1,886	2,086	2,086	2,086	2,086	2,400	2,714	2,714	3,029	3,029
Wind	0	0	0	72	433	577	576	720	819	915	974	998	1,054	1,109	1,162	1,214	1,361
Preferred Plan Resource Additions	**0**	**0**	**0**	**1,126**	**2,107**	**2,346**	**3,067**	**3,455**	**4,111**	**4,407**	**4,533**	**4,571**	**5,011**	**5,730**	**6,033**	**6,541**	**6,718**
Projected Net Position (Need)/Surplus	**1,353**	**514**	**637**	**787**	**1,170**	**582**	**887**	**492**	**568**	**608**	**459**	**230**	**302**	**783**	**834**	**779**	**778**

Table 4-2-Preferred Plan UCAP Load and Resources, 2024-2040 Planning Period, Fall Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Fall																	
Forecasted gross load	8,809	8,820	9,085	9,300	9,328	9,338	9,357	9,370	9,286	9,310	9,343	9,386	9,402	9,435	9,478	9,515	9,295
Adjustment to Load from non-bundled Energy Efficiency	(1,302)	(1,226)	(1,156)	(1,089)	(1,027)	(965)	(892)	(818)	(736)	(673)	(581)	(501)	(458)	(442)	(461)	(482)	(562)
Adjustment to Load from EVs and Beneficial Electrification	21	39	58	87	121	168	224	298	509	648	802	951	1,089	1,225	1,356	1,485	1,882
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%	92.67%
Coincident Load	6,976	7,073	7,401	7,690	7,805	7,914	8,053	8,201	8,396	8,605	8,863	9,115	9,298	9,469	9,612	9,747	9,838
MISO Planning Reserve Margin (UCAP)	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
NSP Obligation (Fall)	**7,967**	**8,078**	**8,452**	**8,782**	**8,914**	**9,038**	**9,196**	**9,365**	**9,588**	**9,826**	**10,121**	**10,410**	**10,618**	**10,814**	**10,977**	**11,131**	**11,235**
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response, Existing	759	762	764	766	766	765	763	760	757	754	752	749	746	744	741	739	736
Coal	1,505	1,505	1,505	872	872	455	455	0	0	0	0	0	0	0	0	0	0
Nuclear	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796
Natural Gas/Oil	3,810	3,726	3,726	3,726	2,938	2,938	2,644	2,533	2,235	2,235	2,235	2,235	2,235	2,235	2,235	1,953	1,953
Biomass/RDF	90	57	57	57	57	57	57	57	57	57	57	37	37	37	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	169	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	989	925	918	904	888	841	825	794	751	696	691	649	637	616	633	633	611
Solar (Utility-Scale System Resources)	66	137	262	251	239	228	216	205	207	208	210	211	192	193	194	195	196
Solar (Legacy CSGs)	194	172	154	148	141	135	129	123	124	125	127	128	158	158	159	160	161
Solar (Net Metered as of 2024)	90	56	34	33	31	28	26	25	26	26	25	25	25	26	27	27	25
Existing Resources	**9,956**	**9,306**	**9,385**	**8,721**	**7,898**	**7,413**	**7,081**	**6,461**	**6,053**	**5,995**	**5,972**	**5,908**	**5,898**	**5,875**	**5,862**	**5,579**	**5,555**
Fall Net Resource (Need)/Surplus After Existing & Approved Resources	**1,990**	**1,228**	**933**	**(62)**	**(1,016)**	**(1,625)**	**(2,115)**	**(2,904)**	**(3,535)**	**(3,832)**	**(4,150)**	**(4,501)**	**(4,721)**	**(4,939)**	**(5,116)**	**(5,552)**	**(5,680)**
Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response (Incremental)	97	97	97	98	97	97	96	95	94	93	92	91	90	89	88	87	86
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	4	23	45	65	78	90	101	110	121	133	145	157	169	182	195	207	220
Solar (Net Metered Installed after 2024)	0	12	15	21	27	34	39	43	50	59	69	77	84	92	98	109	120
Solar (3% Distributed Solar Energy Standard)	0	0	0	13	52	74	94	89	92	95	98	101	105	108	111	115	118
Incremental Distributed Resources Brought Forth in This Plan	**217**	**351**	**483**	**628**	**790**	**932**	**1,052**	**1,149**	**1,252**	**1,356**	**1,465**	**1,566**	**1,556**	**1,561**	**1,565**	**1,553**	**1,545**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,207**	**1,579**	**1,416**	**566**	**(226)**	**(693)**	**(1,063)**	**(1,755)**	**(2,283)**	**(2,475)**	**(2,684)**	**(2,935)**	**(3,164)**	**(3,377)**	**(3,551)**	**(3,998)**	**(4,135)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Fall)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	76	126	163	274	276	277	279	280	282	283	285
Storage	0	0	0	391	375	448	428	571	854	937	1,024	1,067	1,159	1,517	1,790	1,966	2,033
Firm Dispatchable	0	0	0	628	1,255	1,255	1,883	1,883	2,075	2,075	2,075	2,075	2,388	2,702	2,702	3,016	3,016
Wind	0	0	0	88	523	689	680	840	966	1,092	1,176	1,218	1,302	1,386	1,470	1,554	1,764
Preferred Plan Resource Additions	**0**	**0**	**0**	**1,107**	**2,153**	**2,393**	**3,067**	**3,420**	**4,058**	**4,378**	**4,551**	**4,637**	**5,129**	**5,886**	**6,244**	**6,819**	**7,098**
Projected Net Position (Need)/Surplus	**2,207**	**1,579**	**1,416**	**1,673**	**1,928**	**1,699**	**2,004**	**1,665**	**1,775**	**1,903**	**1,867**	**1,701**	**1,964**	**2,509**	**2,693**	**2,821**	**2,963**

Table 4-3-Preferred Plan UCAP Load and Resources, 2024-2040 Planning Period, Winter Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Winter																	
Forecasted gross load	7,660	7,791	8,047	8,156	8,177	8,208	8,243	8,275	8,252	8,308	8,101	8,126	8,129	8,427	8,464	8,534	8,256
Adjustment to Load from non-bundled Energy Efficiency	(1,067)	(958)	(903)	(880)	(805)	(782)	(727)	(671)	(599)	(541)	(446)	(383)	(350)	(360)	(380)	(388)	(439)
Adjustment to Load from EVs and Beneficial Electrification	20	56	81	101	154	171	234	309	493	661	986	1,156	1,315	1,325	1,480	1,640	1,912
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%	97.09%
Coincident Load	6,420	6,689	7,015	7,163	7,307	7,375	7,524	7,683	7,909	8,183	8,390	8,640	8,829	9,119	9,286	9,501	9,445
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Winter)	**8,179**	**8,522**	**8,937**	**9,125**	**9,309**	**9,396**	**9,586**	**9,788**	**10,076**	**10,425**	**10,689**	**11,007**	**11,249**	**11,617**	**11,831**	**12,105**	**12,033**
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response, Existing	441	443	445	447	447	447	447	447	447	447	447	447	447	446	446	446	446
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,372	4,204	4,204	3,997	3,255	3,255	2,753	2,753	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,131
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29	29	29	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	610	169	169	169	169	169	169	100	100	80	80	72	72	70	70	70
Wind	2,146	1,641	1,685	1,596	1,573	1,488	1,470	1,426	1,392	1,193	1,154	1,109	1,073	928	923	892	831
Solar (Utility-Scale System Resources)	1	28	58	50	42	34	27	19	11	23	34	45	56	60	70	80	89
Solar (Legacy CSGs)	5	41	34	29	25	20	16	11	7	14	20	27	34	50	57	65	73
Solar (Net Metered as of 2024)	0	52	6	7	6	5	4	3	2	3	5	7	8	10	11	13	14
Existing Resources	**11,059**	**10,627**	**10,041**	**9,318**	**9,075**	**7,766**	**7,734**	**6,706**	**6,589**	**6,137**	**6,097**	**6,049**	**6,025**	**5,901**	**5,890**	**5,878**	**5,487**
Winter Net Resource (Need)/Surplus After Existing & Approved Resources	**2,880**	**2,106**	**1,104**	**193**	**(234)**	**(1,630)**	**(1,851)**	**(3,082)**	**(3,487)**	**(4,288)**	**(4,592)**	**(4,958)**	**(5,224)**	**(5,716)**	**(5,941)**	**(6,227)**	**(6,546)**
Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response (Incremental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	6	10	13	14	14	12	10	7	14	23	33	45	57	70	85	100
Solar (Net Metered Installed after 2024)	0	11	3	5	5	6	6	5	3	7	14	21	28	35	43	53	71
Solar (3% Distributed Solar Energy Standard)	0	0	0	3	9	11	12	8	5	10	16	22	28	34	40	47	54
Incremental Distributed Resources Brought Forth in This Plan	**130**	**260**	**375**	**503**	**625**	**741**	**835**	**927**	**1,012**	**1,119**	**1,232**	**1,341**	**1,331**	**1,337**	**1,344**	**1,335**	**1,335**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**3,010**	**2,366**	**1,480**	**696**	**392**	**(889)**	**(1,016)**	**(2,155)**	**(2,475)**	**(3,168)**	**(3,359)**	**(3,617)**	**(3,893)**	**(4,380)**	**(4,596)**	**(4,892)**	**(5,211)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Winter)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	9	12	9	30	44	59	73	88	102	116	129
Storage	0	0	0	433	425	521	512	702	984	1,052	1,122	1,142	1,214	1,557	1,802	1,943	1,974
Firm Dispatchable	0	0	0	598	1,197	1,197	1,795	1,795	1,976	1,976	1,976	1,976	2,275	2,574	2,574	2,873	2,873
Wind	0	0	0	156	928	1,224	1,210	1,496	1,702	1,867	1,949	1,955	2,021	2,079	2,128	2,168	2,369
Preferred Plan Resource Additions	**0**	**0**	**0**	**1,187**	**2,549**	**2,942**	**3,526**	**4,006**	**4,671**	**4,924**	**5,091**	**5,131**	**5,584**	**6,298**	**6,606**	**7,100**	**7,346**
Projected Net Position (Need)/Surplus	**3,010**	**2,366**	**1,480**	**1,883**	**2,941**	**2,053**	**2,510**	**1,851**	**2,195**	**1,756**	**1,731**	**1,514**	**1,691**	**1,918**	**2,009**	**2,207**	**2,135**

Table 4-4-Preferred Plan UCAP Load and Resources, 2024-2040 Planning Period, Spring Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Spring																	
Forecasted gross load	8,137	8,181	8,473	8,699	8,809	8,712	8,697	8,737	8,786	8,789	8,840	8,699	8,753	8,785	8,801	8,839	8,843
Adjustment to Load from non-bundled Energy Efficiency	(1,108)	(1,062)	(1,012)	(949)	(961)	(808)	(738)	(687)	(635)	(569)	(488)	(401)	(375)	(366)	(385)	(394)	(459)
Adjustment to Load from EVs and Beneficial Electrification	14	24	39	57	107	113	200	265	353	459	571	887	1,026	1,158	1,287	1,412	1,534
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%	95.61%
Coincident Load	6,733	6,830	7,171	7,465	7,606	7,666	7,800	7,949	8,131	8,298	8,531	8,782	8,991	9,157	9,277	9,425	9,483
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Spring)	**8,531**	**8,653**	**9,085**	**9,459**	**9,637**	**9,712**	**9,883**	**10,072**	**10,302**	**10,514**	**10,809**	**11,127**	**11,392**	**11,601**	**11,754**	**11,941**	**12,015**
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response, Existing	811	815	819	821	822	821	820	818	816	814	813	811	809	808	806	804	803
Coal	1,229	1,229	1,229	669	669	276	276	0	0	0	0	0	0	0	0	0	0
Nuclear	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821
Natural Gas/Oil	4,003	4,003	3,919	3,919	3,710	3,130	3,130	2,702	2,702	2,430	2,430	2,430	2,430	2,430	2,430	2,430	2,169
Biomass/RDF	87	53	53	53	53	53	53	53	53	53	53	36	36	36	8	8	8
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	659	169	169	169	169	169	169	100	100	80	78	72	70	70	70	70
Wind	1,106	890	835	777	715	632	578	510	457	398	395	395	395	352	362	362	349
Solar (Utility-Scale System Resources)	157	90	180	182	185	187	189	191	193	186	178	171	163	141	134	127	121
Solar (Legacy CSGs)	483	112	106	107	109	111	112	114	116	112	108	104	100	116	110	105	99
Solar (Net Metered as of 2024)	119	131	53	26	25	25	25	26	27	25	24	23	21	21	21	19	17
Existing Resources	**10,476**	**9,803**	**9,185**	**8,545**	**8,279**	**7,226**	**7,174**	**6,405**	**6,285**	**5,940**	**5,902**	**5,869**	**5,849**	**5,795**	**5,762**	**5,747**	**5,457**
Spring Net Resource (Need)/Surplus After Existing & Approved Resources	**1,945**	**1,150**	**100**	**(914)**	**(1,357)**	**(2,486)**	**(2,708)**	**(3,667)**	**(4,016)**	**(4,574)**	**(4,907)**	**(5,258)**	**(5,543)**	**(5,806)**	**(5,993)**	**(6,195)**	**(6,558)**
Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response (Incremental)	109	109	110	110	110	110	109	109	108	107	107	106	105	105	104	104	103
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	3	15	31	47	60	74	88	102	113	119	123	127	130	133	134	135	136
Solar (Net Metered Installed after 2024)	0	29	24	17	22	31	38	45	53	58	68	71	74	75	78	79	85
Solar (3% Distributed Solar Energy Standard)	0	0	0	10	40	61	82	83	86	85	84	82	80	79	77	75	73
Incremental Distributed Resources Brought Forth in This Plan	**236**	**386**	**513**	**646**	**806**	**957**	**1,091**	**1,208**	**1,319**	**1,415**	**1,518**	**1,608**	**1,578**	**1,562**	**1,544**	**1,504**	**1,470**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,181**	**1,537**	**612**	**(268)**	**(552)**	**(1,529)**	**(1,618)**	**(2,459)**	**(2,697)**	**(3,159)**	**(3,389)**	**(3,650)**	**(3,964)**	**(4,245)**	**(4,448)**	**(4,691)**	**(5,088)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Spring)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	66	117	152	244	234	224	214	204	195	185	176
Storage	0	0	0	422	410	499	485	658	912	942	972	956	983	1,218	1,362	1,420	1,394
Firm Dispatchable	0	0	0	702	1,403	1,403	2,105	2,105	2,319	2,319	2,319	2,319	2,669	3,020	3,020	3,371	3,371
Wind	0	0	0	76	420	516	472	535	552	624	672	696	744	792	840	888	1,008
Preferred Plan Resource Additions	**0**	**0**	**0**	**1,199**	**2,233**	**2,418**	**3,127**	**3,415**	**3,935**	**4,130**	**4,196**	**4,195**	**4,610**	**5,235**	**5,417**	**5,864**	**5,949**
Projected Net Position (Need)/Surplus	**2,181**	**1,537**	**612**	**931**	**1,682**	**889**	**1,509**	**955**	**1,238**	**970**	**808**	**545**	**646**	**990**	**969**	**1,173**	**861**

Table 4-5-Preferred Plan ICAP Load and Resources, 2024-2040 Planning Period, Summer Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
							System Needs: Summer										
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO Planning Reserve Margin (ICAP)	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Obligation (Summer)	**11,073**	**11,212**	**11,706**	**12,136**	**12,371**	**12,527**	**12,753**	**12,994**	**13,337**	**13,621**	**14,009**	**14,373**	**14,708**	**14,932**	**15,171**	**15,405**	**15,539**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	1,020	1,034	1,048	1,057	1,062	1,066	1,067	1,069	1,070	1,071	1,073	1,074	1,076	1,078	1,080	1,082	1,084
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646
Natural Gas/Oil	4,687	4,617	4,478	4,478	4,244	3,538	3,538	3,031	3,031	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,372
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	753	753	301	301	301	301	301	301	184	184	151	137	124	124	120	120	120
Wind	4,520	4,312	4,485	4,310	4,273	4,094	4,088	4,023	3,960	3,349	3,337	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,315	1,968	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	171	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,918**	**17,224**	**18,345**	**17,679**	**17,551**	**16,297**	**16,427**	**15,475**	**15,391**	**14,574**	**14,077**	**13,562**	**13,634**	**13,255**	**13,393**	**13,486**	**13,113**
Summer Existing & Approved Net Resource (Need)/Surplus	**5,845**	**6,012**	**6,639**	**5,543**	**5,180**	**3,770**	**3,674**	**2,480**	**2,054**	**952**	**68**	**(811)**	**(1,074)**	**(1,677)**	**(1,779)**	**(1,919)**	**(2,426)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	231	234	236	238	239	239	238	238	237	236	236	235	235	234	234	233	233
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	0	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**345**	**586**	**832**	**1,133**	**1,542**	**1,905**	**2,234**	**2,430**	**2,619**	**2,815**	**3,068**	**3,256**	**3,339**	**3,402**	**3,479**	**3,566**	**3,717**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**6,191**	**6,597**	**7,471**	**6,676**	**6,722**	**5,675**	**5,908**	**4,910**	**4,673**	**3,768**	**3,136**	**2,445**	**2,265**	**1,725**	**1,701**	**1,647**	**1,291**
Preferred Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	400	698	895	1,490	1,483	1,475	1,468	1,460	1,453	1,446	1,439
Storage	0	0	0	480	480	600	600	840	1,200	1,260	1,320	1,320	1,380	1,740	1,980	2,100	2,100
Firm Dispatchable	0	0	0	662	1,323	1,323	1,985	1,985	2,196	2,196	2,196	2,196	2,526	2,857	2,857	3,188	3,188
Wind	0	0	0	400	2,400	3,200	3,200	4,000	4,600	5,200	5,600	5,800	6,200	6,600	7,000	7,400	8,400
Preferred Plan Resource Adjustments	**0**	**0**	**0**	**1,542**	**4,203**	**5,123**	**6,185**	**7,523**	**8,890**	**10,146**	**10,598**	**10,791**	**11,574**	**12,658**	**13,290**	**14,134**	**15,127**
Summer Preferred Plan Net Resource (Need)/Surplus	**6,191**	**6,597**	**7,471**	**8,217**	**10,925**	**10,799**	**12,093**	**12,433**	**13,563**	**13,913**	**13,734**	**13,235**	**13,839**	**14,383**	**14,991**	**15,781**	**16,418**

Table 4-6-Preferred Plan ICAP Load and Resources, 2024-2040 Planning Period, Fall Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
							System Needs: Fall										
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO Planning Reserve Margin (ICAP)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Obligation (Fall)	**9,425**	**9,556**	**9,999**	**10,390**	**10,545**	**10,692**	**10,879**	**11,080**	**11,343**	**11,625**	**11,974**	**12,315**	**12,562**	**12,793**	**12,987**	**13,168**	**13,291**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	734	747	759	767	772	776	779	781	784	787	790	792	796	799	802	805	809
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646
Natural Gas/Oil	4,687	4,617	4,478	4,478	4,244	3,538	3,538	3,031	3,031	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,372
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	753	753	301	301	301	301	301	301	184	184	151	137	124	124	120	120	120
Wind	4,520	4,312	4,485	4,310	4,273	4,094	4,088	4,023	3,960	3,349	3,337	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,315	1,968	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	171	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,632**	**16,936**	**18,056**	**17,388**	**17,261**	**16,007**	**16,139**	**15,187**	**15,105**	**14,289**	**13,793**	**13,281**	**13,353**	**12,976**	**13,115**	**13,210**	**12,839**
Fall Existing & Approved Net Resource (Need)/Surplus	**7,206**	**7,380**	**8,057**	**6,998**	**6,715**	**5,314**	**5,259**	**4,108**	**3,762**	**2,664**	**1,820**	**966**	**791**	**183**	**128**	**42**	**(453)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	143	146	148	149	150	150	150	150	150	150	150	150	150	150	150	150	150
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	0	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**259**	**501**	**748**	**1,050**	**1,460**	**1,826**	**2,156**	**2,354**	**2,544**	**2,742**	**2,996**	**3,184**	**3,268**	**3,331**	**3,409**	**3,495**	**3,646**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**7,466**	**7,881**	**8,805**	**8,049**	**8,176**	**7,140**	**7,415**	**6,461**	**6,307**	**5,406**	**4,815**	**4,150**	**4,059**	**3,513**	**3,537**	**3,537**	**3,193**
Preferred Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	400	698	895	1,490	1,483	1,475	1,468	1,460	1,453	1,446	1,439
Storage	0	0	0	480	480	600	600	840	1,200	1,260	1,320	1,320	1,380	1,740	1,980	2,100	2,100
Firm Dispatchable	0	0	0	738	1,477	1,477	2,215	2,215	2,441	2,441	2,441	2,441	2,810	3,179	3,179	3,548	3,548
Wind	0	0	0	400	2,400	3,200	3,200	4,000	4,600	5,200	5,600	5,800	6,200	6,600	7,000	7,400	8,400
Preferred Plan Resource Adjustments	**0**	**0**	**0**	**1,618**	**4,357**	**5,277**	**6,415**	**7,753**	**9,135**	**10,391**	**10,843**	**11,036**	**11,858**	**12,980**	**13,612**	**14,494**	**15,487**
Fall Preferred Plan Net Resource (Need)/Surplus	**7,466**	**7,881**	**8,805**	**9,667**	**12,533**	**12,417**	**13,831**	**14,215**	**15,442**	**15,797**	**15,659**	**15,186**	**15,917**	**16,493**	**17,149**	**18,032**	**18,680**

Table 4-7-Preferred Plan ICAP Load and Resources, 2024-2040 Planning Period, Winter Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
							System Needs: Winter										
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO Planning Reserve Margin (ICAP)	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%
Obligation (Winter)	**9,879**	**10,293**	**10,794**	**11,022**	**11,243**	**11,348**	**11,578**	**11,822**	**12,170**	**12,591**	**12,910**	**13,295**	**13,586**	**14,032**	**14,290**	**14,620**	**14,534**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	367	379	390	401	406	411	416	421	427	432	437	443	448	454	460	466	472
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646
Natural Gas/Oil	4,687	4,617	4,478	4,478	4,244	3,538	3,538	3,031	3,031	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,372
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	753	753	301	301	301	301	301	301	184	184	151	137	124	124	120	120	120
Wind	4,520	4,312	4,485	4,310	4,273	4,094	4,088	4,023	3,960	3,349	3,337	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,315	1,968	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	171	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,265**	**16,568**	**17,687**	**17,023**	**16,895**	**15,642**	**15,776**	**14,828**	**14,748**	**13,934**	**13,441**	**12,931**	**13,006**	**12,631**	**12,773**	**12,871**	**12,501**
Winter Existing & Approved Net Resource (Need)/Surplus	**6,386**	**6,275**	**6,893**	**6,001**	**5,652**	**4,293**	**4,199**	**3,005**	**2,577**	**1,343**	**531**	**(364)**	**(580)**	**(1,401)**	**(1,517)**	**(1,750)**	**(2,033)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	41	43	45	47	48	48	49	50	51	52	53	54	55	56	57	57	58
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**171**	**424**	**683**	**998**	**1,420**	**1,797**	**2,138**	**2,346**	**2,547**	**2,754**	**3,017**	**3,214**	**3,295**	**3,357**	**3,434**	**3,517**	**3,665**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**6,557**	**6,699**	**7,576**	**6,999**	**7,072**	**6,090**	**6,336**	**5,351**	**5,124**	**4,098**	**3,548**	**2,851**	**2,715**	**1,956**	**1,917**	**1,767**	**1,632**
Preferred Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	400	698	895	1,490	1,483	1,475	1,468	1,460	1,453	1,446	1,439
Storage	0	0	0	480	480	600	600	840	1,200	1,260	1,320	1,320	1,380	1,740	1,980	2,100	2,100
Firm Dispatchable	0	0	0	748	1,496	1,496	2,244	2,244	2,470	2,470	2,470	2,470	2,844	3,218	3,218	3,592	3,592
Wind	0	0	0	400	2,400	3,200	3,200	4,000	4,600	5,200	5,600	5,800	6,200	6,600	7,000	7,400	8,400
Preferred Plan Resource Adjustments	**0**	**0**	**0**	**1,628**	**4,376**	**5,296**	**6,444**	**7,782**	**9,164**	**10,420**	**10,872**	**11,065**	**11,891**	**13,018**	**13,651**	**14,537**	**15,530**
Winter Preferred Plan Net Resource (Need)/Surplus	**6,557**	**6,699**	**7,576**	**8,627**	**11,448**	**11,386**	**12,780**	**13,133**	**14,288**	**14,517**	**14,420**	**13,916**	**14,606**	**14,974**	**15,568**	**16,304**	**17,162**

Table 4-8-Preferred Plan ICAP Load and Resources, 2024-2040 Planning Period, Spring Season

ICAP Rating - Load and Resources 2024-2040 Planning Period																	
Determination of Need	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
						System Needs: Spring											
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO Planning Reserve Margin (ICAP)	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
Obligation (Spring)	**9,916**	**10,058**	**10,560**	**10,994**	**11,201**	**11,289**	**11,487**	**11,707**	**11,974**	**12,220**	**12,564**	**12,933**	**13,241**	**13,484**	**13,662**	**13,879**	**13,965**
Existing & Approved Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response, Existing	683	696	709	719	725	729	733	737	741	745	749	753	757	761	766	770	775
Coal	1,705	1,705	1,705	1,027	1,027	517	517	0	0	0	0	0	0	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192	646	646	646	646	646	646
Natural Gas/Oil	4,687	4,617	4,478	4,478	4,244	3,538	3,538	3,031	3,031	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,372
Storage	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Biomass/RDF	128	70	70	70	70	70	70	70	70	70	70	44	44	44	12	12	12
Hydro	753	753	301	301	301	301	301	301	184	184	151	137	124	124	120	120	120
Wind	4,520	4,312	4,485	4,310	4,273	4,094	4,088	4,023	3,960	3,349	3,337	3,313	3,313	2,933	3,013	3,013	2,908
Solar (Utility-Scale System Resources)	1,315	1,968	3,487	3,671	3,814	3,956	4,096	4,236	4,336	4,432	4,529	4,627	4,725	4,729	4,826	4,923	5,019
Solar (Legacy CSGs)	881	877	872	868	864	859	855	851	846	842	838	834	830	825	821	817	813
Solar (Net Metered as of 2024)	171	151	150	149	148	148	147	146	145	145	144	143	142	142	141	140	140
Existing Resources	**16,581**	**16,886**	**18,006**	**17,341**	**17,214**	**15,960**	**16,093**	**15,143**	**15,062**	**14,247**	**13,752**	**13,241**	**13,315**	**12,938**	**13,079**	**13,175**	**12,804**
Spring Existing & Approved Net Resource (Need)/Surplus	**6,665**	**6,828**	**7,446**	**6,347**	**6,013**	**4,671**	**4,606**	**3,436**	**3,088**	**2,027**	**1,189**	**308**	**74**	**(546)**	**(584)**	**(704)**	**(1,160)**
Incremental Distributed Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Demand Response (Incremental)	136	138	140	142	143	144	144	144	145	145	145	146	146	146	147	147	148
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	0	100	199	298	377	455	533	610	667	724	780	836	892	948	1,003	1,058	1,113
Solar (Net Metered Installed after 2024)	0	37	76	109	149	210	254	288	326	375	477	520	567	580	609	667	787
Solar (3% Distributed Solar Energy Standard)	0	0	0	62	250	373	497	494	506	517	529	540	551	562	574	585	596
Incremental Distributed Resources Brought Forth in This Plan	**260**	**508**	**763**	**1,073**	**1,491**	**1,864**	**2,200**	**2,405**	**2,603**	**2,807**	**3,068**	**3,263**	**3,345**	**3,407**	**3,484**	**3,568**	**3,717**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**6,925**	**7,337**	**8,210**	**7,420**	**7,504**	**6,535**	**6,807**	**5,842**	**5,691**	**4,834**	**4,256**	**3,571**	**3,419**	**2,861**	**2,900**	**2,864**	**2,557**
Preferred Plan Resource Additions / Retirements	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	400	698	895	1,490	1,483	1,475	1,468	1,460	1,453	1,446	1,439
Storage	0	0	0	480	480	600	600	840	1,200	1,260	1,320	1,320	1,380	1,740	1,980	2,100	2,100
Firm Dispatchable	0	0	0	738	1,477	1,477	2,215	2,215	2,441	2,441	2,441	2,441	2,810	3,179	3,179	3,548	3,548
Wind	0	0	0	400	2,400	3,200	3,200	4,000	4,600	5,200	5,600	5,800	6,200	6,600	7,000	7,400	8,400
Preferred Plan Resource Adjustments	**0**	**0**	**0**	**1,618**	**4,357**	**5,277**	**6,415**	**7,753**	**9,135**	**10,391**	**10,843**	**11,036**	**11,858**	**12,980**	**13,612**	**14,494**	**15,487**
Spring Preferred Plan Net Resource (Need)/Surplus	**6,925**	**7,337**	**8,210**	**9,038**	**11,861**	**11,812**	**13,222**	**13,595**	**14,826**	**15,225**	**15,100**	**14,607**	**15,276**	**15,840**	**16,513**	**17,358**	**18,044**

CHAPTER 5 - ECONOMIC MODELING FRAMEWORK

I. INTRODUCTION

We have used the EnCompass Resource Planning model to perform our economic analysis since 2020. We use EnCompass as our primary resource planning software to estimate the costs of various resource expansion plan options, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. EnCompass results are a decision support tool to guide development and selection of a Preferred Plan and test the robustness of the plan under a variety of assumptions and sensitivities.

To ultimately identify and refine our Preferred Plan presented in Chapter 4, we created three scenarios that examined different combinations and timing of baseload nuclear unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We refer to these scenarios as "baseload study scenarios." After this analysis was completed, we used the outcomes and sensitivity tests to select and refine a Preferred Plan. Finally, we conducted special studies on the Preferred Plan for a more thorough examination of specific issues not fully covered in the plan.

We discuss our assumptions, scenarios, sensitivities and how these inputs guided selection of our Preferred Plan in more detail below. This comprehensive analysis ultimately aligns with and reinforces our Preferred Plan.

II. BASE ASSUMPTIONS IN THE REFERENCE CASE

There are several assumptions included in our baseline data inputs that are common across all scenarios studied. These factors may, in some cases, be varied within sensitivities, but are largely kept constant across the default study of each scenario.

As discussed in Chapter 2: Planning Landscape, in 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (see Minn. Laws 2023, Ch. 7). Further, Minnesota's distributed solar energy standard (DSES) was amended at subdivision 2h of Minn. Stat. § 216B.1691. This amendment mandates that at least three percent of the Company's retail electric sales in Minnesota be generated from solar energy generating systems that meet certain eligibility criteria by 2030. While we did not include constraints to meet the required renewable energy standard, solar energy standard, or carbon-free standard, we did include a modeling constraint to comply with the three percent DSES by 2030.[1]

Other important starting assumptions in our analysis include:

Load Forecast. The Company used discrete changes in assumptions for electric vehicles, large commercial and industrial customers, beneficial electrification, and rooftop solar to determine our load and energy forecasts under two alternatives to the base forecast, which is our most probable forecast of future load changes: the High and Low load sensitivities. We provide detailed descriptions of our load forecasting methodology and assumptions under each of our sensitivities in Appendix E: Load and Distributed Energy Resource Forecasting.

We also incorporated a seasonal planning reserve margin, per MISO requirements, as shown in Table 5-1. The modeled Planning Reserve Margin is based on the MISO Planning Year 2024-2025 assumptions, adjusted for the average coincidence factors in MISO Planning Year 2024-2025 and Planning Year 2023-2024. EnCompass determines an effective reserve margin based on our MISO coincident factor assumption. For summer 2024, the coincidence factor results in a reduction to net load of 730 MW.

Table 5-1: Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY24/25	9.00%	14.20%	27.40%	26.70%
Average Coincidence Factor	92.24%	92.67%	97.09%	95.61%

Existing Fleet. We develop forecasts to model our existing fleet's cost and performance assumptions (such as variable O&M, heat rate, forced outage rate, maintenance requirements, etc.) based on historical data, with adjustments for known future changes where applicable. Additional operational and performance assumptions include:

- Retirements of Sherburne County Generating Station (Sherco) Units 1 and 3 in 2026 and 2030, respectively, and retirement of the Allen S. King plant in 2028, as approved in our 2019 Plan;[2]

[1] Our plan complies with the renewable standards and the carbon-free standard as shown in Appendix N: Standard Obligations.
[2] Sherco Unit 2 was retired on December 31, 2023.

- Sherco Units 1 and King are dispatched economically through their respective retirement dates. Sherco 3 is jointly owned with Southern Municipal Power Agency (SMMPA). We are currently offering Sherco 3 as a must-run under our operating agreement with SMMPA. We will continue to work with SMMPA to identify opportunities to operate Sherco 3 more flexibly as the plant nears its end of life. Therefore, in the modeling, we have assumed Sherco 3 is offered as must-run through 2029 and offered on an economic basis in 2030.
- Retirement of all other facilities at their current expected end of life, if that is planned to occur within the resource planning period, unless we have specifically included costs of life extension (e.g. for nuclear units in scenarios that include life extension);
- Short-term PPA extensions for Mankato Energy Center and Cannon Falls, consistent with recently-executed agreements;
- Sherco and King generation tie lines reoptimized with a Combustion Turbine (CT) allowed for selection on the Sherco generation tie-line; and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Major PPA expirations include:

- Manitoba Hydro: 835 MW in 2025
- Cottage Grove: 226 MW in 2027
- Mankato Energy Center: 314 MW in 2028
- Cannon Falls: 317 MW in 2028

Additional cost–related assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Costs associated with re-licensing the nuclear plants were developed for use in the Baseload Study modeling.

Renewable Energy. The addition of Sherco Solar 1, 2, and 3, Apple River Solar, and the Louise and Fillmore solar projects are included in our baseline assumptions. We also included small solar resources in our baseline assumptions.

In addition, we have assumed:

- Accreditation of wind, solar and battery resources based on the 2023-2024 MISO Planning Year seasonal accredited capacity. For years beyond 2024, the seasonal accredited capacity trends over multiple years to meet the assumptions in MISO's November 2022 Regional Resource Assessment (RRA).
- The costs used for wind, solar, and storage assets fully incorporate the Production Tax Credit (PTC) or Investment Tax Credit (ITC) in the Inflation Reduction Act (IRA). The IRA allows the transferability of tax credits, allows utilities to elect out from normalization for storage facilities, and allows owners of solar facilities to claim a PTC in lieu of the ITC, which is subject to normalization.
- The resources on the generation tie-lines to Sherco and King were allowed to re-optimize—meaning the model selected from an updated resource mix based on updated assumptions to maximize customer and system benefits. Wind, Solar, and a firm dispatchable resource were available for selection on the Sherco tie-line. Solar additions were available for selection on the King tie-line.

Markets. We have optimized resource additions in the EnCompass model to ensure that the portfolio of resources developed is capable of serving customer load across all hours by limiting access to the MISO market. The limited access is only applied to the resource optimization to avoid over reliance on MISO market purchases for reliability or sales for wholesale revenues. We allow the model to access the MISO market to dispatch resources and take advantage of the access to economic resources in the larger MISO market.

> *Wholesale electricity price forecasts.* To derive the forecast of monthly On and Off-peak electricity prices, the Company uses a simple average of On and Off-peak power price forecasts provided by external analysts Wood Mackenzie and S&P Global. To generate hourly market prices, the Company uses the hourly energy price forecast from the Horizons Energy EnCompass National Database, specifically the energy prices at the MISO-ND-MN node and scales it to match the monthly On and Off-peak price forecasts.

Purchase and sales limits. In our EnCompass model, when we allow access to the MISO market, we include a limit on the amount of energy that we can either purchase from or sell to the MISO market. This limit was established in our 2019 Plan based on PROMOD modeling and historical transfer data. For 2024-2029, we have continued to assume a market interaction limit of 2,300 MWs. Further, we include a cap on market sales of no more than 25 percent of retail sales consistent with the assumption used in our 2019 Plan. While significant transmission expansion projects are at various stages of development, as discussed in Appendix T: MISO Grid Congestion, we believe it is prudent to limit market exposure during this period of rapid energy transition as further discussed below.

Emissions rates and costs. Emission rates for existing and planned resources are consistent with historical and expected performance. We assume the following costs and apply them to emitting resources as relevant:

- For the regulatory cost of carbon, we use the regulatory cost range of $5-$75 per ton starting in 2028 and escalating at inflation. Our base assumption uses the mid-point of the regulatory cost of carbon range. The regulatory cost of carbon impacts the dispatch of resources in the Encompass modeling. The modeling optimizes the dispatch based on cost, and therefore the dispatch of emitting resources is reduced relative to a scenario where the regulatory cost is not included. Our projected carbon reduction of 88 percent by 2030 is based on modeling that includes the mid-point of the regulatory cost of carbon range.
- Externality costs are included based on United States Environmental Protection Agency's (EPA) September 2022 *External Review Draft of Report on the Social Cost of Greenhouse Gases*[3] (EPA SC-GHG) consistent with the Commission's Order,[4] for purposes of measuring environmental and socioeconomic costs under Minn. Stat. § 216B.2422, Subd. 3, with the base assumption using the mid-range values. To avoid double counting, we adjusted the EPA SC-GHG values for modeling purposes by subtracting the Regulatory Cost of Carbon from the EPA SC-GHG value starting in 2028. Additional combinations of externality and regulatory costs were included as sensitivity cases.

Generic Resources. EnCompass uses generically defined resources to meet future demand when our already existing and approved resources are not sufficient in a given year. Generic resources are modeled as incremental units of a certain installed capacity size. The ICAP values are provided below, and the UCAP, representing the MISO seasonal accredited capacity value the units would yield, is factored into the Encompass modeling process. For example, although the generic unit size for solar is 100 MW installed capacity, the resource adequacy or MISO capacity credit value we would expect to receive for a plant of that size is as little as 6.3 MWs in the winter for

[3] We understand the EPA finalized the draft SC-GHG values in November 2023.
[4] Order in Docket Nos. E-999CI-07-1199, E-999/DI-22-236, E-999/CI-14-463. December 19, 2023.

Planning Year 2023-2024.

Generic units ICAP values included in modeling are as follows:[5]

- 374 MW gas-fired CT unit,
- 225 MW gas-fired CT unit,
- 108 MW reciprocating engine peaking unit (RICE),
- 60 MW utility scale battery,
- 200 MW wind project,
- 100 MWdc utility scale solar, and
- 130 MWdc solar + 60 MWac battery, 100 MWac inverter.

Appendix F: EnCompass Modeling Assumptions & Inputs, provides more detail on modeling assumptions. Please see Appendix H: Resource Options, for additional discussion on supply-side resource options included in the analysis.

Customer Programs. Incremental customer programs for Demand Response (DR) and Energy Efficiency (EE) were included as potential resources in the EnCompass model. The derivation of these six DR and three EE "Bundles" is described in Appendix J: Distributed Energy Resources. It is important to note that these Bundles represent generic Demand-Side Management (DSM) additions and therefore may not perfectly align with the size and timing of actual DR or EE additions to the system in the future.

III. SCENARIOS

We created three scenarios to examine combinations and timing of baseload nuclear unit retirements (our only remaining baseload units after Sherco and King retire by the end of this decade), and the resulting size, type, and timing of new resources we would need to add to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We describe key parameters of these scenarios below.

[5] The cost and performance data for these units are based on consultant's estimates, publicly available third-party data, and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction.

A. Reference Case Scenario

We describe the development of our Reference Case in Chapter 3: Minimum System Needs. The Reference Case (Scenario 1) is an extension of our approved 2019 Plan,[6] in that all of the baseload units retire at their currently scheduled retirement dates, and it serves as our starting point. The Reference Case includes the following underlying assumptions:

- Approved resources, including: Sherco Solar 1, 2, and 3; Apple River, Louise and Fillmore solar projects; Wheaton Repower.[7]
- Extension of our Refuse Derived Fuel Waste to Energy Generating Plants.
- Short-term PPA extensions include: Mankato Energy Center and Cannon Falls.
- Sherco and King Tie-Line reoptimized.
- CT allowed for selection on Sherco Tie-Line.
- Optimized without market purchases/sales.
- Dispatched with access to MISO market.

Additional resource options are evaluated and optimized in the modeling and added when economic. These resource options include wind, solar, storage, combustion turbines, and reciprocating engines, as described in Appendix F: EnCompass Modeling Assumptions & Inputs.

To determine the optimal strategy regarding the future of the baseload nuclear fleet, we developed two additional scenarios with varying combinations of nuclear retirement dates. The resulting system needs were then met with an EnCompass model-optimized portfolio of new resources. Internal finance, energy supply, and nuclear subject matter experts worked to develop a robust set of assumptions and potential retirement dates for the nuclear retirements. These input assumptions include: ongoing capital expenditures, O&M expenses, and decommissioning and/or life extension costs. We also incorporated planning level estimates from a "leave behind" study conducted by the Company to determine the transmission system impacts of the nuclear plants' retirement to inform our Preferred Plan.

[6] July 25, 2021 Reply Comments, Docket No. E002/RP-19-368.
[7] Wheaton Repower is subject to approval by the Public Service Commission of Wisconsin.

B. Prairie Island Extension Scenario

For the Prairie Island extension scenario (Scenario 2), the Prairie Island 1 and 2 retirement date extends from 2033/2034 to 2053/2054. The Monticello retirement date is unchanged. This scenario is designed to test the economics of re-licensing Prairie Island and extending the operational life by 20 years.

C. Extend All Nuclear Scenario

For the "extend all nuclear" scenario (Scenario 3), the Prairie Island 1 and 2 retirement date extends from 2033/2034 to 2053/2054, and the Monticello retirement date extends from 2040 to 2050. This scenario is designed to test the economics of re-licensing both Prairie Island 1 and 2 and Monticello, extending the operational life of Prairie Island by 20 years and Monticello by 10 years.

IV. MARKET ACCESS AND RELIABILITY

While reliability has always been a critical objective of resource planning, there has been increased focus on regional reliability in the past several years as utilities and other generation owners across the country retire significant dispatchable capacity, replacing it with significant amounts of variable renewable generation. In 2022, the North American Reliability Corporation (NERC) concluded that the MISO region was at risk of insufficient electricity supplies during peak winter conditions.[8] MISO's 2022-2023 Planning Resource Auction (PRA) resulted in a capacity shortfall for the MISO North/Central Regions resulting in the price of capacity clearing at the Cost of New Entry (CONE). More recently, NERC concluded that the supply of electricity in the MISO region "is more likely to be insufficient in the forecast period and that more firm resources are needed."[9]

Recognizing the evolving reliability challenges, MISO has proposed changes to its resource adequacy (RA) construct. The seasonal RA construct was implemented last year and provided reserve margin and resource capacity contributions tailored to each season (spring, summer, fall, winter). Additional changes to the RA construct are also under consideration and will impact the resources needed in the MISO region to meet reliability requirements.

[8] 2022-2023 NERC Winter Reliability Assessment (November 2022) at p. 4. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.
[9] 2023 NERC Long-Term Reliability Assessment (Dec. 2023) at p. 7. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

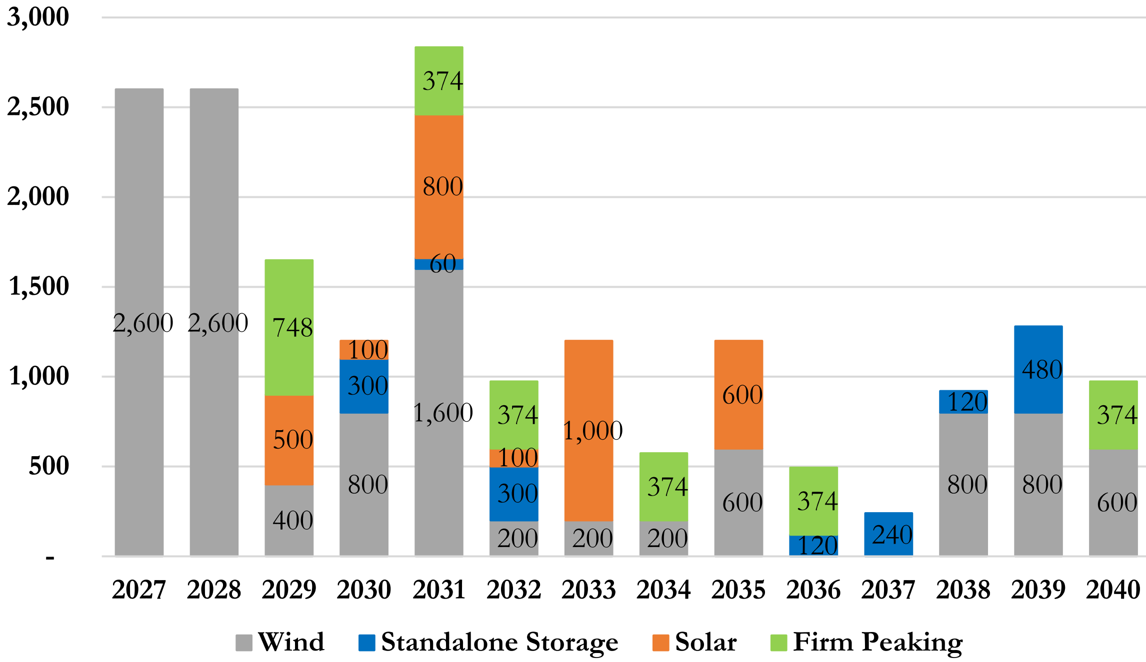
The evolving MISO RA construct creates a challenge to resource planning. Ensuring resource and energy adequacy to all our customers across our Upper Midwest System is a foundational duty of our business. The challenges facing resource planning include the change to a seasonal RA construct, a transition to a higher percentage of intermittent resources across the region, and uncertainty in accredited capacity and future Planning Reserve Margins (PRM). The future accreditation of resources presents a particularly difficult challenge for planners. Investments in solar and storage resources, like other resources, depend on the capacity value of the resources over the life of the assets, which is dependent upon the installed capacity of all resource types in the MISO system.

In this 2024 Plan, the Company used an analytical approach to develop a plan that ensures we have sufficient resources to meet our customers' needs at all times and positions us to be able to comply with future changes to the MISO RA construct, while retaining the economic benefits of the MISO market. Our 2024 Plan adds resources to be able to meet customer needs with very limited reliance on neighboring systems and the broader MISO market. At the same time, our 2024 Plan retains the benefits of participation in the MISO market by incorporating the current planning assumptions and allowing for the economic dispatch of our resources within the broader region. We have tested our Preferred Plan using historical data to analyze variations in load and renewable production. Our 2024 Plan is robust under changing assumptions and provides a path to transition our system while maintaining the reliable system our customers expect.

In our 2019 Plan, we allowed access to the MISO market, subject to an hourly limit on the amount of energy that we could buy or sell to the MISO market. This limit was developed for our 2019 Plan based on PROMOD modeling and historical transfers. We also imposed a limit on market sales of no more than 25 percent of retail sales, consistent with the assumption used in our last 2019 Plan. Given the scale and pace of change in the market at that time, this approach was reasonable for that plan.

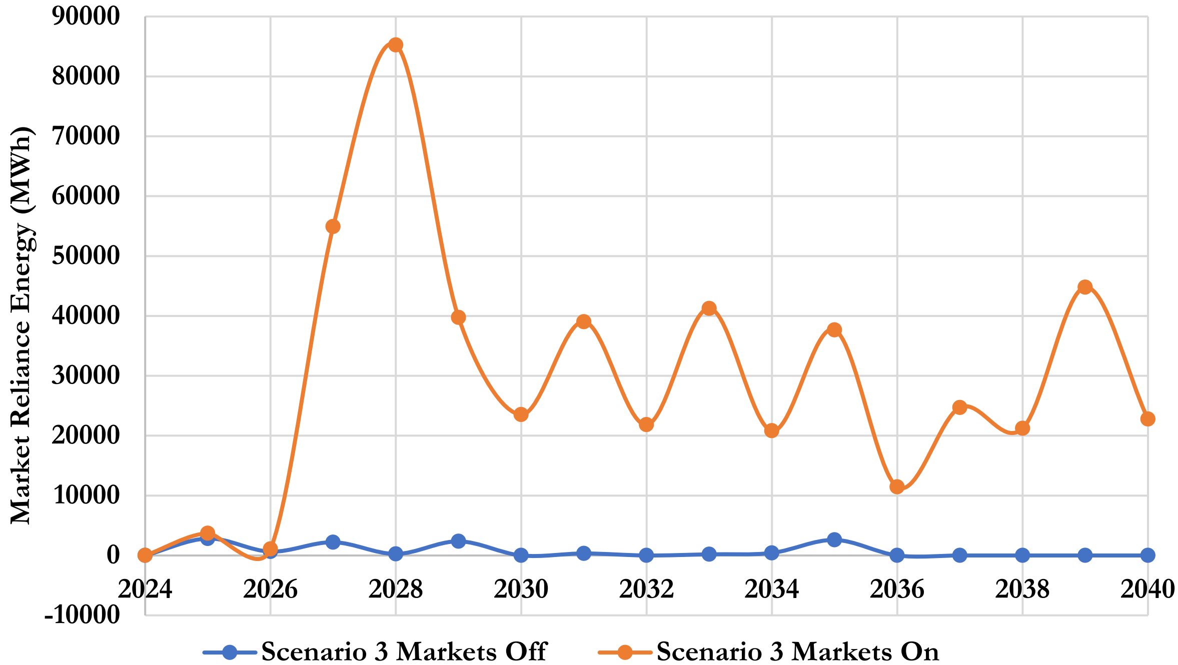
Using the same market access assumptions as those applied in the 2019 Plan now, however, results in a plan with substantial market exposure. In other words, when we allow EnCompass to optimize the resource expansion with the ability to rely on the market, the resources included in the expansion plan are unable to serve our load in a significant number of hours. The Market Access Optimization expansion plan, which represents Scenario 3 with 2,300 MW of hourly market access, is shown below in Figure 5-1.

Figure 5-1: Market Access Optimization Expansion Plan (MW)



The model makes large wind resources additions in 2027, 2028, and beyond (adding over 10,000 MW of wind alone during the planning period) to fulfill capacity needs based on accreditation assumptions and current market conditions. The model assumes excess energy is sold into the market, and the resulting wholesale revenue would make these significant wind resource additions cost-effective. The model does not select firm dispatchable resources until 2029. To assess the market exposure of this plan, we modeled a dispatch run on the expansion plan without market access. This dispatch run provides the number of hours our system relies on market purchases to serve load. The expected market reliance energy shown in Figure 5-2 below is the total megawatt-hours (MWh) in each year in which the expansion plan resources are unable to serve our load and must rely on market purchases.

**Figure 5-2: Market Access Optimization -
Expected Market Reliance**



The significant amount of market reliance results when the plan is optimized with market access. Such a plan's market exposure would be risky for multiple reasons. During the times when the plan is reliant on the market for purchases, Locational Marginal Prices (LMPs) may be unreasonable, or worse, resources may simply not be available. During times when the plan is selling into the market, if LMPs are low, the substantial amount of resources added may not be cost-effective as anticipated by the model. In addition, the resources may not be able to comply with future changes to the MISO reliability construct, if, for instance, there are significant changes to capacity accreditation in the future.

Moreover, historically, we have planned to have enough resources to meet our load serving needs. In the past, when our system relied on fewer renewable resources, this meant ensuring we had sufficient resources to meet our annual planning reserve margin. In general, having sufficient capacity to meet our annual peak resulted in sufficient capacity to meet our needs year-round. As more variable resources have been added to our system, it has become necessary to consider more hours of the year. The change to a seasonal RA construct and the use of the chronological hourly modeling tool, EnCompass, were both motivated by the changing resource mix.

While we have optimized our portfolio without access to the market, we will continue to benefit from the access to the MISO market as we have in the past. We will continue to dispatch our resources on an economic basis. We will purchase from the market when market purchases are lower cost than using our own resources, and we will sell excess generation into the market to benefit our customers. While we optimized the capacity expansion additions without market reliance, we conduct a dispatch run in the Encompass model with market access to reflect these market interaction benefits. Furthermore, as noted above, we plan for our peak needs coincident with the MISO peak. The coincidence factor allows us to procure less capacity than we would otherwise need. In addition, we plan to the MISO PRM, which is developed considering the broader MISO footprint.

By optimizing the resource expansion plan without access to the market, we ensure that our 2024 Plan can serve our customers' needs across all hours of the year and positions us to be able to comply with future changes to the MISO RA construct. Our 2024 Plan adds resources to be able to meet customer needs with very limited reliance on neighboring systems and the broader MISO market for reliability. At the same time, our 2024 Plan retains the benefits of participation in the MISO market by incorporating the current planning assumptions and allowing for the economic dispatch of our resources within the broader region. We have tested our Preferred Plan using historical data to analyze variations in load and renewable production. Our 2024 Plan is robust under changing assumptions as further described in Appendix D: Energy Adequacy Analysis and provides a path to transition our system while maintaining the reliable system our customers expect.

V. SENSITIVITIES

To determine how changes in our assumptions impact the costs or characteristics of the baseload study plans, we examine them under a number of sensitivities. This testing provides insights on potential plan performance and helps us assess the "robustness" of each scenario in the face of future uncertainty, meaning that we want to test how resilient the scenario is to changes in one or more key assumptions. Generally, if a given plan is extremely sensitive to changes in assumptions, it would not represent a prudent course of action for the Company to pursue, because it would subject our customers to excessive risk. Compared to our 2019 Plan, this 2024 Plan includes fewer scenarios, but more sensitivities to address key resource robustness and policy uncertainties as described throughout this section. A summary of sensitivities is presented in Table 5-2 with additional discussion below.

Table 5-2: Sensitivities and Special Studies

Category	Scenario Descriptions
Standard	PVSC – Base, i.e., with Mid Reg Cost ($40) >2028 + Mid Draft EPA <2028 + (Draft EPA - Reg Cost) starting in 2028
	PVRR – Base, i.e., no carbon cost and environmental externality
Sensitivities on All Three Nuclear Scenarios	
Fuel prices	High Fuel/Market Price
	Low Fuel/Market Price
Load	High Load
	Low Load
Technology cost	High Technology Cost
	Low Technology Cost
	Edison MISO Market Prices for wind and solar
Cost of carbon	High Reg Cost ($75) >2028 + High Draft EPA <2028 + (Draft EPA - Reg Cost) starting in 2028
	Low Reg Cost ($5) >2028 + Low Draft EPA <2028 + (Draft EPA - Reg Cost) starting in 2028
	Draft EPA - High ($0 Reg Cost)
	Draft EPA - Mid ($0 Reg Cost)
	Draft EPA - Low ($0 Reg Cost)
Market Access	Market access off in dispatch runs
Environmental Policy	Good Neighbor Rule applied in both Minnesota and Wisconsin + EPA Rule 111
Combination	High technology cost + high load
	Low technology cost + low load
Carbon Free 100x50	Carbon constraint to reach 100x50 carbon free goal
Special Studies on the Preferred Plan	
DG Solar Bundles	Selectable DG bundles
Advanced Technologies	Hydrogen Only
	SMRs Only
	Long-Duration Storage Only
	All three advanced technology options available for selection
Data Center Load	Data Center Load

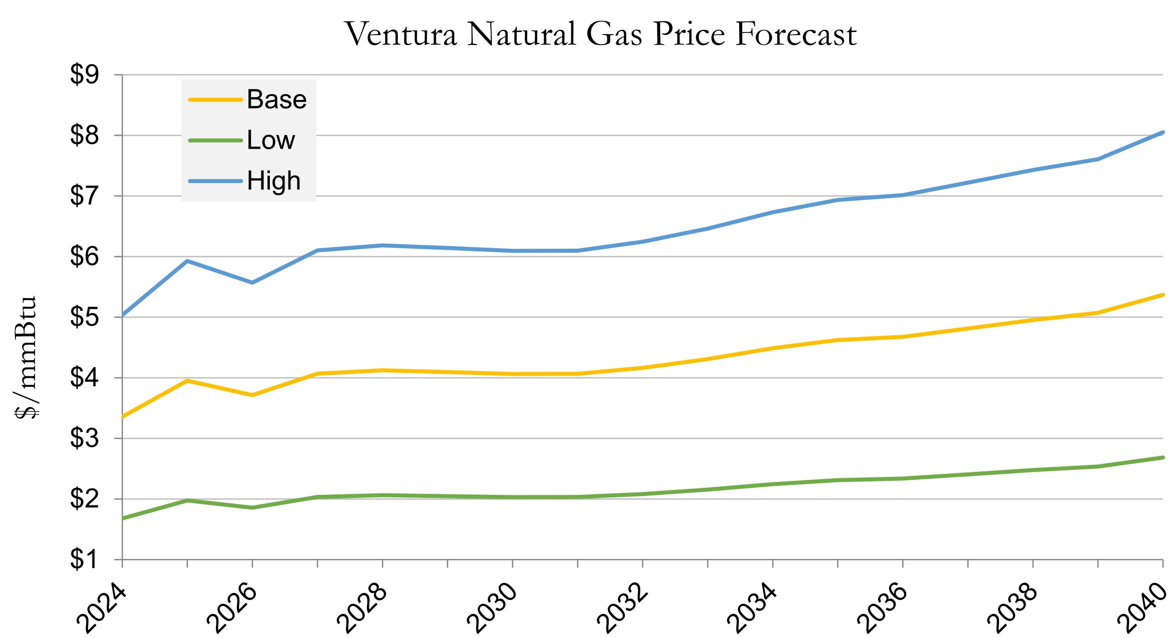
Resource Adequacy	Higher PRM (RBDC opt-out proxy)
	25% Battery ELCC
	Market Access 2,300 MW
	Wind Fleet Variability
Energy Adequacy Analysis	Scenario 3 with market access off
	Scenario 1 with market access off
	Market access 2,300 MW re-optimization for Scenario 3
	Low load scenario for Scenario 3 with market off

*Note: shaded scenarios require re-optimization of the expansion plans and redispatch of the resulting expansion plans.

Special studies on the Preferred Plan are discussed in Section VIII. A summary of the PVRR and PVSC for each sensitivity can be found in Appendix G: Scenario Sensitivity Analysis, and below we discuss additional detail for these sensitivities.

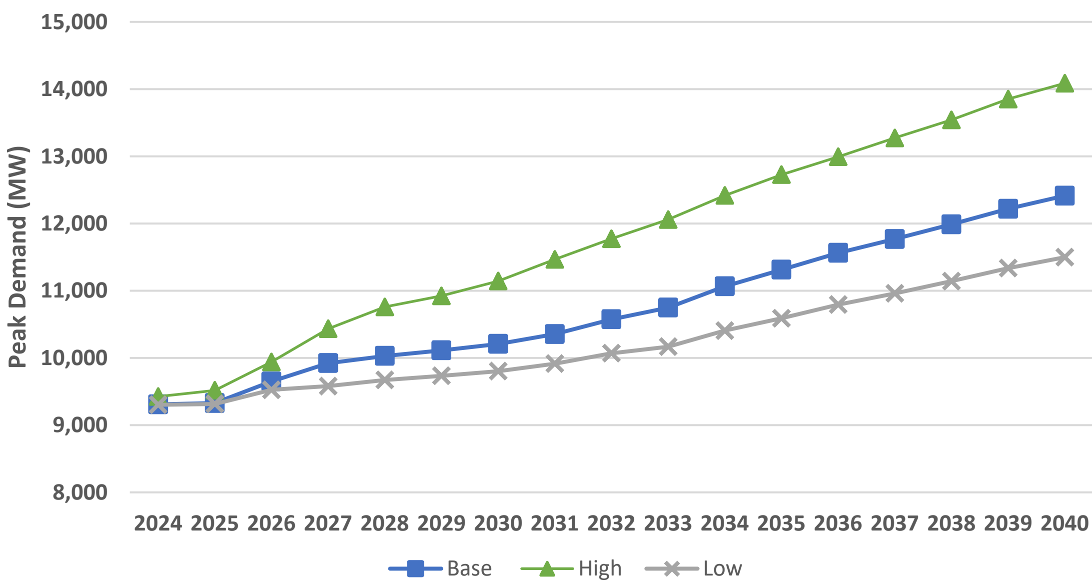
Fuel Price/Market Costs. High and low-price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast. Fuel price assumptions by base, low, and high sensitivities are depicted below in Figure 5-3.

Figure 5-3: Fuel Price Assumptions, by Base, Low, High Sensitivities



Load. The low load sensitivity includes high customer adoption-based Distributed Energy Resource (DER) growth, no beneficial electrification, slower adoption of electric vehicles (EV), and less new load from data centers. The high load sensitivity includes increased beneficial electrification, full achievement of Minnesota's "20 percent by 2030" goal for EV penetration with similar increases in EV adoption in other states served by NSP, and additional large data center loads located in Minnesota. Peak Demand, net of EE impacts, by Base, Low, and High sensitivity is shown in Figure 5-4 below.

Figure 5-4: Peak Demand, Net of EE Impacts, by Base, Low, High Sensitivities (MW)



Technology Costs. Wind, solar and battery costs, as well as battery operational characteristics such as cycle limit and Round-Trip Efficiency (RTE), are from National Renewable Energy Laboratory (NREL) 2023 *Annual Technology Baseline* (ATB) data. High and low technology cost sensitivities are created based on NREL ATB "Conservative" and "Advanced" forecasts. We also have a sensitivity where the wind, solar and solar + battery hybrid LCOEs prior to 2030 are adjusted to match the 2023 Q1-Q3 actual PPA prices in MISO, reported in the Edison Energy Global Renewable Market Update quarterly reports to align pricing with most recent market trends in MISO. We did not include any sensitivities adjusting capital costs for thermal resources such as the generic CTs or Reciprocating Engines, so all sensitivities include our base cost assumptions for those resources. New wind and solar resource cost assumptions and sensitivities with and without transmission costs are shown below in Figure 5-5 and 5-6, and new battery resource costs assumptions and sensitivities are shown below in Figure 5-7.

Figure 5-5: New Wind and Solar Resource Cost Assumptions with Transmission Cost ($/MWh)

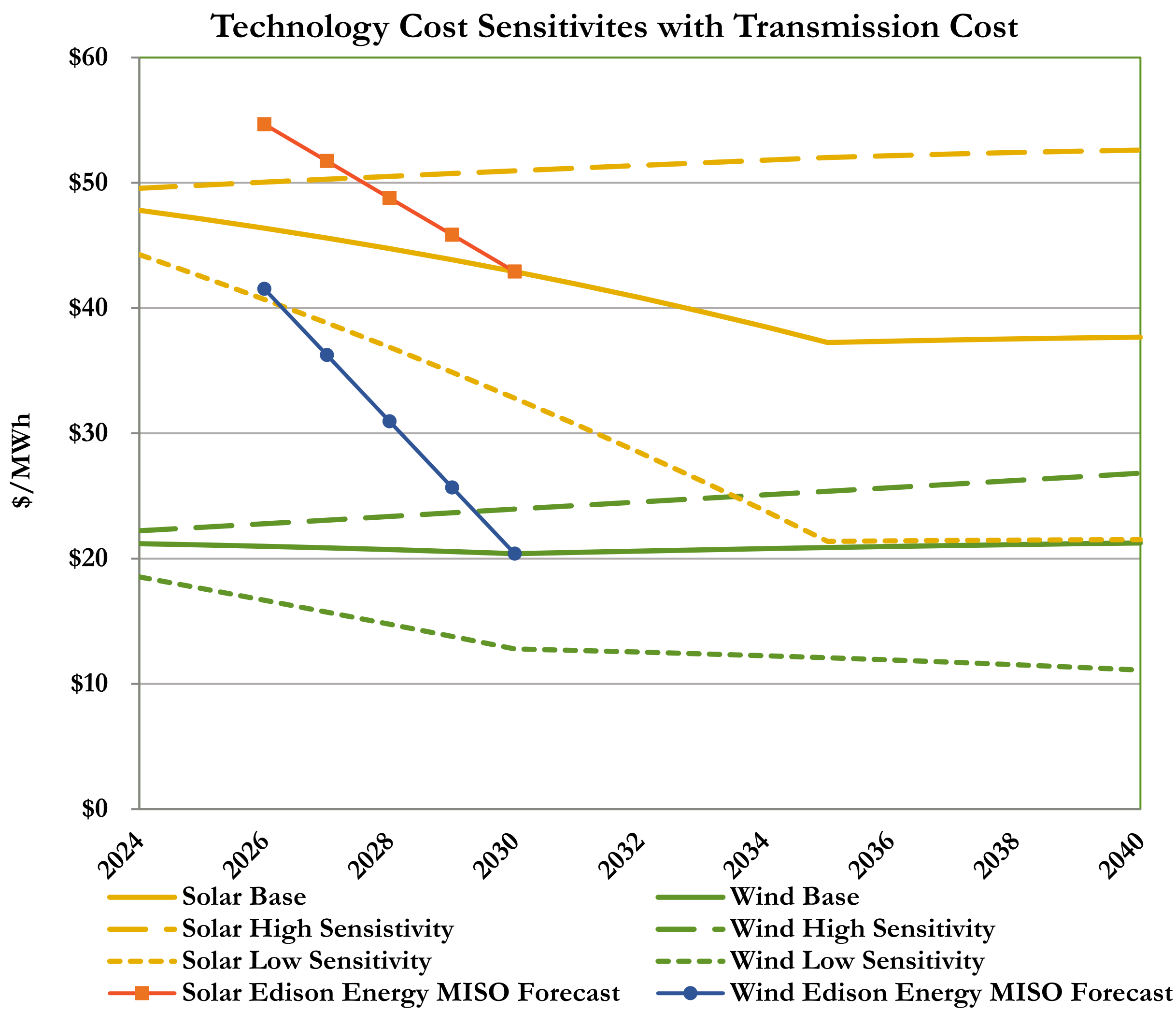


Figure 5-6: New Wind and Solar Resource Cost Assumptions without Transmission Cost($/MWh)

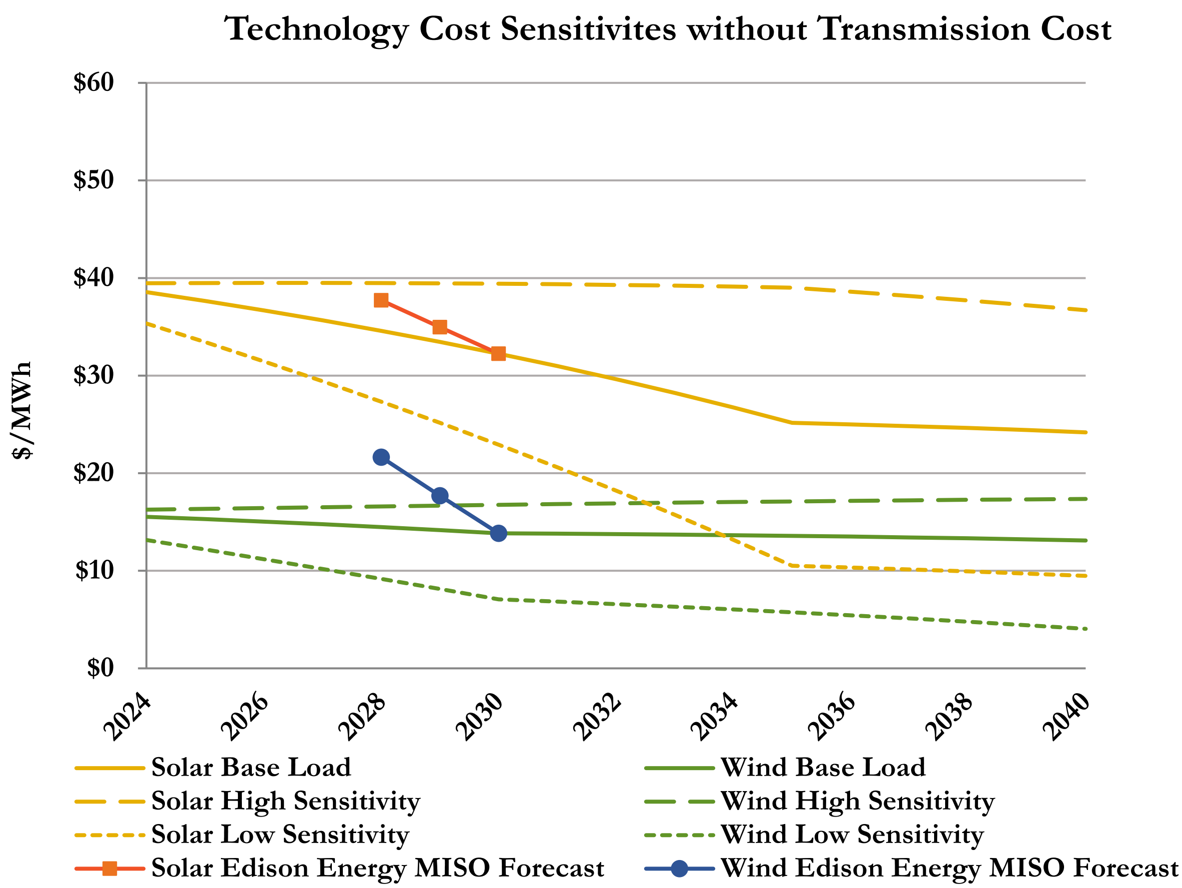
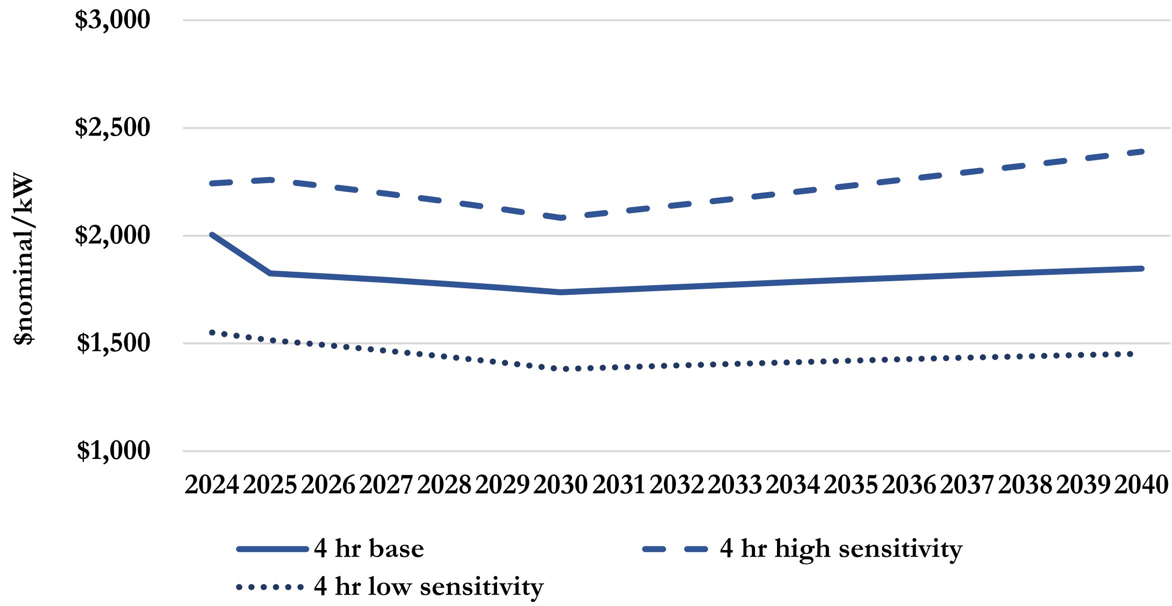


Figure 5-7: New Battery Resource Cost Assumptions with Transmission Cost (nominal $/kW)



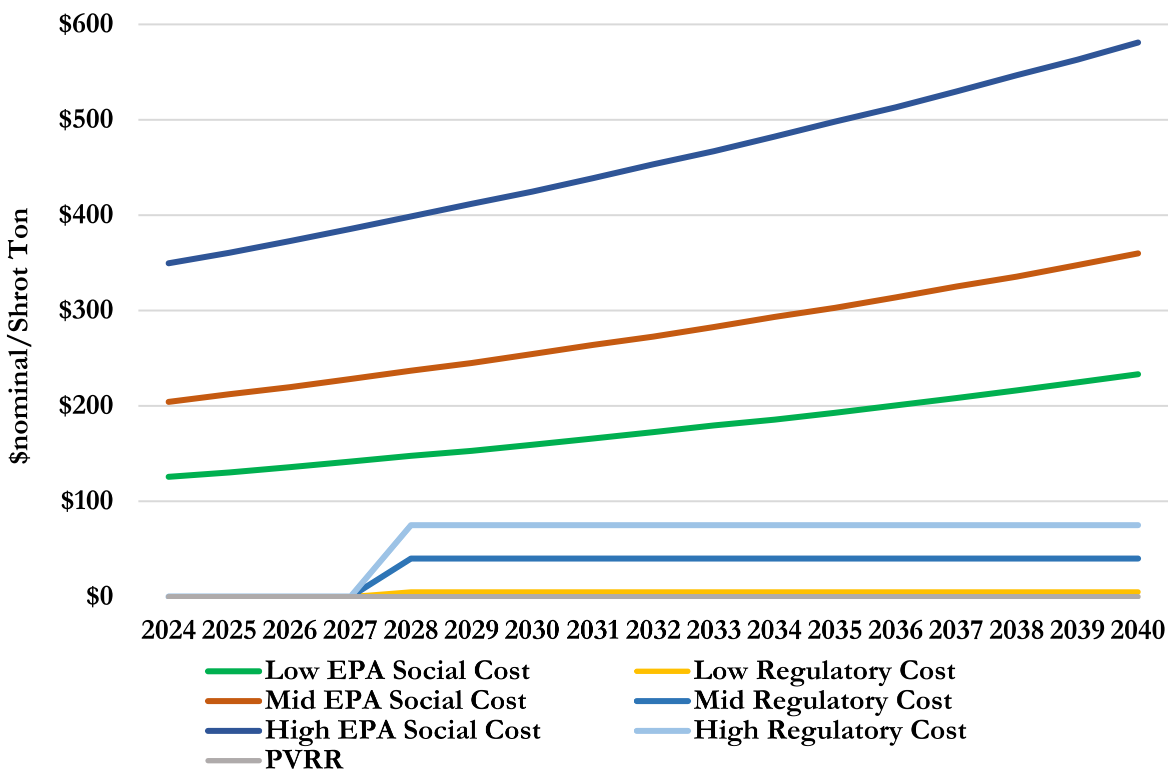
Greenhouse Gas (GHG) Costs. We applied six sensitivities to the model in compliance with the Commission's December 19, 2023 Order in Docket No. E-999/DI-22-236. In the Order, the Commission established a range of regulatory costs of carbon dioxide emissions from $5 to $75 per short ton, effective in 2028 and thereafter. The Commission also provisionally adopted and applied the draft measures of costs related to the emissions of greenhouse gasses as set forth in the EPA's External Review Draft of Report on the Social Cost of Greenhouse Gases (EPA's SC-GHG), released in September 2022,[10] and its successors, for purposes of measuring environmental and socioeconomic costs under Minn. Stat. § 216B.2422, Subd. 3. As noted above, the PVSC base value used the midpoint of the regulatory cost range of $5-$75 and the mid-range of the EPA's SC-GHG. The additional carbon sensitivities are:

High Externality, High Regulatory Cost of Carbon
Low Externality, Low Regulatory Cost of Carbon
High Externality
Mid Externality
Low Externality
PVRR, or No Externality or Regulatory Cost of Carbon

[10] We understand the EPA finalized the draft SC-GHG values in November 2023.

Both the externality and regulatory costs are applied in the regulatory cost sensitivities. To avoid double counting, in the regulatory cost sensitivity, we adjusted the EPA SC-GHG values for modeling purposes by subtracting the Regulatory Cost of Carbon from the EPA SC-GHG value (beginning in 2028). Carbon cost assumptions are depicted in Figure 5-8 below.

Figure 5-8: Carbon Cost Assumptions
($ nominal/Short Ton)



Market Access. The "all markets off" sensitivity represents a view in which we cannot access the market to sell energy outside our system.

Policy (Good Neighbor and proposed EPA Rule 111). This sensitivity requires our fleet to comply with the stayed Good Neighbor Rules and EPA Rule 111 as proposed. To address the Good Neighbor Rules implementation in both Minnesota and Wisconsin, we impose NOx allowances to all existing fossil fuel unit operations. For EPA Rule 111, we limit the annual capacity factor of existing combined cycle units to under 50 percent and any new CT annual capacity factor to under 20 percent.

Combination. For this sensitivity, we combined two different futures: (1) high technology cost and high load and (2) low technology and low load. The high/low technology and high/low load assumptions are described above.

100 Percent Carbon-Free by 2050 (100x50). For this sensitivity, we included a carbon constraint in the model to reach our 100x50 carbon free goal.

It is important to note that these sensitivities are designed to test the performance of our baseload nuclear retirement decisions under plausible future conditions. These sensitivities are not, however, intended to test which future is overall least cost for our system. We do not have full control over the level of distributed solar or electrification growth on our system and have no control over variables such as fuel prices and new resource capital costs. However, as shown in Appendix G: Scenario Sensitivity Analysis: PVRR & PVSC Summary, our Preferred Plan provides benefits under nearly all sensitivities. As demonstrated in the next section, the sensitivities analysis shows that our Preferred Plan baseload nuclear decisions to extend Prairie Island 1 and 2 and Monticello are likely to yield customer benefits relative to the Reference Case, even in a future where multiple key assumptions change.

VI. ENCOMPASS ANALYSIS RESULTS AND SELECTING THE PREFERRED PLAN

After identifying the scenarios and sensitivities for analysis, we used EnCompass to identify the expansion plans for each of the three primary scenarios, and their resulting cost and emissions impacts.

A. EnCompass Model Optimization & Challenges

In the initial round of modeling, all generic technology alternatives (wind, solar, 4-hour and 10-hour batteries, solar + battery hybrid, CTs) were made available to the model, and we developed fully-optimized expansion plans using a typical on and off-peak day per month for the optimization horizon 2027-2055. However, due to the substantial number of these alternatives, initial runs took a significant amount of time to complete (or fail completely). Furthermore, the limited dispatch duration of the 4-hour generic batteries was not evaluated due to the typical on and off-peak setting in the expansion plan. As a result, the model yielded unreliable plans with prominent levels of unserved energy. This unserved energy occurs due to the production cost runs, which are used for more granular dispatch and system cost estimates and simulate the electric system on an hourly time basis, versus the simplified time periods used during capacity expansion modeling used to determine the best mix of resources to arrive at a least-cost portfolio for a planning period. If the production cost runs associated with certain portfolio yield unserved energy, it demonstrates that resource adequacy captured in the EnCompass modeling has not been achieved due to the disconnect between modeling steps. In this case, due to this set of initial runs reflecting unserved energy and therefore deemed unreliable, we needed to address several refinements in our modeling methodology.

1. *Reduced Time Block Granularity*

On average, initial runs took over 24 hours to process, and in several instances, EnCompass ran into memory issues and was unable to "solve" the problem. This is defined as the mixed integer programming ("MIP") Stop Basis tolerance defined within EnCompass never being reached and a portfolio never being presented in the modeling output. In order to address the solve time/feasibility issue, the number of daily intervals modeled was reduced to 11 total time blocks per day versus the 24 per day (i.e., every hour) initially used for the on-peak/off-peak optimization period. This additional aggregation of hours resulted in 264 (11*2*12) intervals being solved per year versus 576 (24*2*12) intervals. It should be noted that this aggregation of hours was only applied to capacity expansion modeling for selection of resources for the portfolios and not for the production costing used to estimate overall portfolio costs, which was done using the full 8,760 hours per year granularity. This aggregation was determined based on similar modeling run-time issues experienced in the Company's other jurisdictions and has been discussed/recommended by the software vendor for EnCompass, Anchor Power. They have confirmed that the aggregation proposed would not fundamentally alter the validity of the analysis results. The reason the capacity expansion process, versus production costing, requires this additional aggregation of hours is because of the much larger problem size EnCompass must solve when determining capacity selections.

2. *Addressing Battery Storage*

In addition to the time granularity issues discussed previously, modeling the different battery storage duration options (for example, 10-hour versus 4-hour) created additional complexities that were a challenge for the model to solve. To develop reliable portfolios which did not result in the modeling reflecting unserved energy, we first removed the 10-hour batteries and solar + battery hybrid resource options to reduce the problem size in the initial step of the capacity expansion plan optimization. We specifically removed these options because doing so was expected to have a minimal impact on any resulting expansion plan for two different reasons, namely MISO's current capacity accreditation methodology for Energy Storage Resources

(ESRs) does not differentiate between ESRs of different durations. For instance, 10-hour batteries receive the same amount of capacity accreditation as 4-hour batteries. Should MISO provide updated guidance for ESR accreditation, we will incorporate it into our model to distinguish between short-duration and long-duration resources.

Second, since the battery portion of a solar + battery hybrid resource can only be charged by the paired solar instead of the grid, the solar + battery hybrid resources do not generate the same energy benefits to the system as standalone batteries. Therefore, they are unlikely to be selected over standalone solar resources or standalone batteries. Furthermore, the IRA allows standalone batteries to receive full ITC without pairing with solar, thereby removing most of the cost advantages of solar + battery hybrid. Moreover, to verify that this simplifying assumption did not result in the elimination of any 10-hour ESR or solar + storage additions, we conducted a special study to allow the Encompass model to consider these resource options. The special study confirmed that 10-hour ESR and solar + storage resources are not selected in the planning period when included as resource options. In the special study where we allow 10-hour batteries and hybrid options in the expansion plan, the 10-hour batteries are only selected in 2052 and the hybrid resource was not selected.

3. *Second step expansion plan*

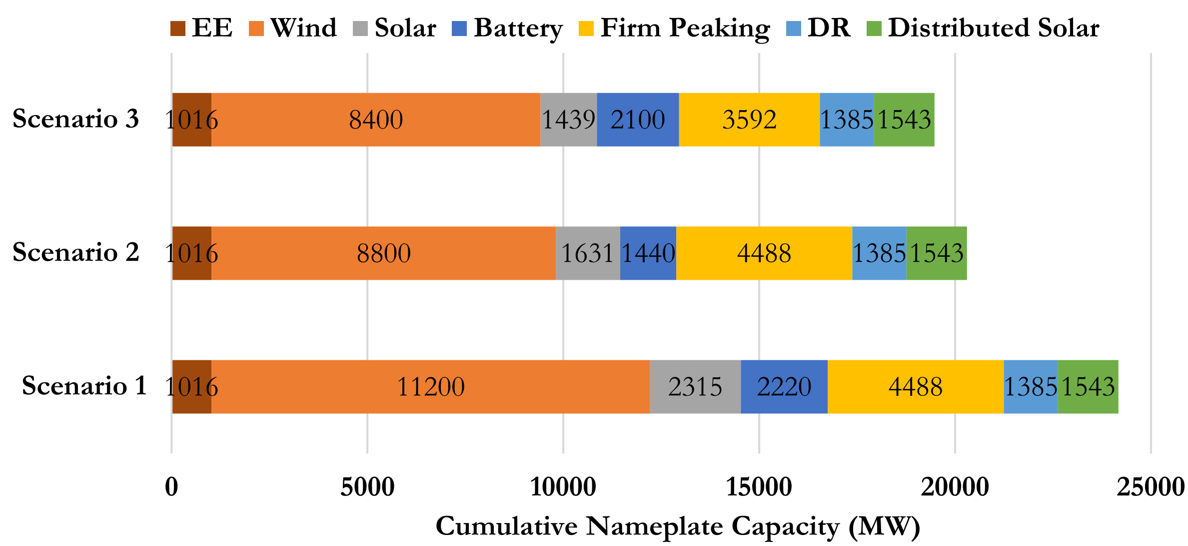
In order to address the unserved energy issue, we created a second expansion plan optimization with more granular time periods, which allowed EnCompass to better evaluate the energy adequacy of dispatchable resources (i.e. 4-hour batteries and CTs). Specifically, we used all calendar days instead of typical on- and off-peak days per month. With this increased optimization granularity, the problem size increased significantly. To allow the model to solve within a reasonable amount of time, we reduced the optimization horizon from 2024-2055 in the initial expansion plan to every four years. Further, we used the wind and solar capacity additions selected in the initial capacity expansion plan as a floor for the minimum wind and solar capacity needs. Additions of wind and solar above the floor are considered in the expansion plan developed in the second step. This second step expansion plan allows EnCompass to capture most of the hourly granularity when evaluating resource options.

B. Modeling Results and Conclusions

Completing baseload scenario runs, as described above, allows us to examine scenario outcomes side-by-side, to evaluate their benefits and drawbacks. Among other factors, we examine the resource expansion profile and carbon emissions outcomes, present value costs, and several indicators of risk for each scenario.

The cumulative expansion plan additions through the planning period for the three scenarios are shown below in Figure 5-9.

Figure 5-9: Expansion Plans by Scenario (MW, Cumulative Nameplate Capacity Resource Additions by Resource Type, 2024-2040)



As shown above in Figure 5-9, Scenario 3 results in fewer additions of firm peaking and wind capacity relative to both Scenarios 1 and 2. The extension of the nuclear units offset additions of other resources need for capacity and energy. While Scenario 2 includes the same amount of cumulative firm peaking resources through 2040, those additions are delayed by the extension of Prairie Island, and few firm peaking resources are needed over the 20-year life extension. Moreover, the nuclear extensions provide a certain and stable source of energy to our system as we transition our generation fleet.

The cost impact of the three scenarios is shown below in Table 5-3. The table shows the net present value (NPV) delta of modeled costs compared to Scenario 1 (the

Reference Scenario), with negative values representing customer savings relative to the Reference Scenario.[11]

**Table 5-3: Scenario PVSC/PVRR Deltas from Reference Case
($2024 millions)**

PVSC Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
Scenario 1 PVSC	$0	**$51,037**	$0	**$63,635**	$0	**$68,788**
Scenario 2 PVSC	($413)	**$50,624**	($437)	**$63,198**	($513)	**$68,275**
Scenario 3 PVSC	($785)	**$50,252**	($941)	**$62,695**	($1,025)	**$67,762**
PVRR Production Cost	**Delta in NPV ($m) 2024-2040**	**NPV ($m) 2024-2040**	**Delta in NPV ($m) 2024-2047**	**NPV ($m) 2024-2047**	**Delta in NPV ($m) 2024-2050**	**NPV ($m) 2024-2050**
Scenario 1 PVRR	$0	**$34,678**	$0	**$44,948**	$0	**$48,927**
Scenario 2 PVRR	($97)	**$34,581**	$291	**$45,239**	$391	**$49,317**
Scenario 3 PVRR	($464)	**$34,215**	$46	**$44,994**	$239	**$49,166**

The Scenario 3 plan was the lowest cost plan in terms of PVSC in all time periods assessed. As our nuclear plants provide a source of carbon-free energy to our system, extension of these resource results in overwhelming benefits due to the avoidance of carbon emissions from other resources. It also is the lowest cost plan in terms of PVRR through 2040, and nearly breakeven through 2047 compared to the Reference Case. The only outlier is when PVRR is assessed through 2050, which shows Scenario 3 adds $239 million in NPV compared to the Reference Case. We note, however, that the replacement capacity added at the end of the expansion plan to replace Prairie Island in Scenario 2 and Prairie Island and Monticello in Scenario 3, significantly impacts overall cost.

Given current technologies, the model makes significant additions of firm dispatchable resources in the late 2040s in anticipation of the retirement of the nuclear fleet. Under the PVRR assumptions, no cost is included on the emissions from these resource additions. We expect technological advancements will provide resource options that are not currently available when the plants near the end of their extended lives. Therefore, the significant firm dispatchable additions in the late 2040s may not provide a reliable indication of the costs that far out in time. As a result, we provide cost comparisons over three different time horizons. The most relevant of these

[11] Note that these PVRR and PVSC deltas shown depict NPV for 2024-2040.

horizons—through 2040, when resource and cost assumptions are most known—shows the extension of our nuclear fleet provides significant economic benefits even when the benefits of avoided emission are not included.

VII. PREFERRED PLAN SELECTION AND ASSESSMENT

As described previously in this chapter and in Chapter 4: Preferred Plan, we evaluated the PVRR and PVSC results of our three baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the Preferred Plan. Based on these outcomes, we selected baseload Scenario 3. Our Preferred Plan continues on the path toward achieving ambitious carbon reduction goals and regulatory requirements, reflects substantial stakeholder input and consensus, and ensures reliability and affordability for our customers on both a PVRR and PVSC basis. The baseload aspects of this Preferred Plan include extension of our Monticello nuclear facility to 2050 and Prairie Island to 2053/2054. We discuss more detail regarding how we selected and evaluated our Preferred Plan below.

A. Extend All Nuclear

From a modeling perspective, the PVSC and PVRR results are primary indicators of the various scenarios' economic favorability. Table 5-3 shown above indicates that the Prairie Island and Monticello nuclear extension scenario, Scenario 3, yields the most attractive customer value relative to the Reference Case. Further, Scenario 3 provides the best fit for our carbon goals and helps mitigate the potential for regulatory or legislative action around carbon costs or carbon reduction levels. Maintaining nuclear generation in our resource portfolio provides fuel diversity and an ongoing source of carbon-free baseload generation. From a reliability risk perspective, baseload nuclear adds value as we transition our generation fleet away from coal assets to more intermittent, renewable resources. While all of our scenarios meet the carbon goal we established, we believe cost and risk considerations elevate Scenario 3 above the rest as an appropriate path forward.

As demonstrated in our modeling analysis, the Preferred Plan achieves customer value, not only under a PVSC basis through the mid-2040s but also nearly break-even on a PVRR basis when the cost of Scenario 3 is considered through 2047.

In addition to the beneficial cost outcomes discussed above, the Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality, and effectively managing market exposure, as shown in the sensitivity analysis below. The

Preferred Plan incorporates significant capacity additions to replace retiring resources, consisting of a diverse portfolio of DSM, nuclear extension, solar, wind, and firm dispatchable resource additions. This approach mitigates the risk of becoming too dependent on a single fuel source.

B. Sensitivity Results

As previously discussed, a final step in our analysis process evaluated the performance of the baseload study plans under different sensitivities. As shown in Appendix G: Scenario Sensitivity Analysis: PVRR & PVSC Summary, the summary of the PVRR and PVSC for each sensitivity consistently shows the Preferred Plan, Scenario 3, as yielding the most customer benefits on a PVSC basis across nearly all sensitivities. We address key sensitivity assumptions and insights below.

1. *Fuel Prices*

The Preferred Plan produces savings under both High and Low Fuel Price sensitivities. Our nuclear fleet provides an effective hedge against fuel price volatility.

2. *Load*

Table 5-4 below provides a summary of the load sensitivity results under different planning periods. The Preferred Plan provides savings under both the high and low load sensitivities relative to the Reference Case, which suggests that the Preferred Plan is robust under a range of potential future conditions.

Table 5-4: Preferred Plan NPV Savings under Different Load Scenarios and Planning Periods ($2024 millions)

	Base PVSC	Base PVRR	High Load PVSC	Low Load PVSC
2024-2040 NPV Delta	($785)	($464)	($837)	($534)
2024-2047 NPV Delta	($941)	$46	($953)	($560)
2024-2050 NPV Delta	($1,025)	$239	($1,013)	($627)

3. *Technology Cost*

The Preferred Plan provides savings under the High Tech, Low Tech, Edison MISO Market Prices sensitivities conducted. While the savings are reduced under the Low

Technology cost sensitivity, the overall saving of $514 are still considerable as shown in Appendix G.

4. Cost of Carbon

As discussed above, the Preferred Plan was analyzed using six different cost of carbon assumptions. A summary of the results is shown below in Table 5-5.

Table 5-5: Preferred Plan NPV Savings under Different Environmental Regulatory Costs and Planning Periods ($2024 millions)

	PVSC	PVRR	High Reg, High SC-GHG	Low Reg Low SC-GHG	No Reg, High SC-GHG	No Reg, Mid SC-GHG	No Reg, Low SC-GHG
NPV ($m) 2024-2040							
Scenario 1	$0	$0	$0	$0	$0	$0	$0
Scenario 2	($413)	($97)	($707)	($343)	($607)	($428)	($301)
Scenario 3	($785)	($464)	($1,160)	($739)	($974)	($800)	($667)
NPV ($m) 2024-2047							
Scenario 1	$0	$0	$0	$0	$0	$0	$0
Scenario 2	($437)	$291	($1,006)	($224)	($894)	($463)	($192)
Scenario 3	($941)	$46	($1,754)	($790)	($1,565)	($982)	($612)
NPV ($m) 2024-2050							
Scenario 1	$0	$0	$0	$0	$0	$0	$0
Scenario 2	($513)	$391	($1,239)	($248)	($1,067)	($544)	($209)
Scenario 3	($1,025)	$239	($2,058)	($823)	($1,814)	($1,074)	($607)

The Preferred Plan produces the greatest level of savings under all sensitivities that consider a cost of carbon. As discussed above, costs are shown in the 2040s when a carbon cost is not considered, but even when carbon cost are not included, the Preferred Plan results in savings through 2040.

5. Market Access

As discussed above, for the Encompass dispatch runs, we allow for purchases of market energy and energy sales to market. When market interactions are not allowed, the Preferred Plan continues to show significant benefits as shown in Appendix G.

6. Environmental Policy

The Preferred Plan provides an effective hedge against potential environmental regulations, including the Good Neighbor Rule and draft EPA 111 Rule as shown in Appendix G.

7. Combination

Under the High Technology cost + high load combination sensitivity the Preferred Plan generally results in increased benefits as shown in Appendix G. The extension of the nuclear fleet avoids cost associated with replacement resources and provides a steady source of baseload power for our system. The benefits are reduced or offset under a Low Technology cost + low load sensitivity due to the lower cost of replacement resources and lower load serving needs.

8. 100 Percent Carbon-Free by 2050 (100x50)

The Company has set a goal to generate 100 percent carbon-free energy by 2050 (100x50). Advances in technology will be critical to achieving this goal reliably and cost-effectively. To assess the benefits of our Preferred Plan compared to existing technologies, we conducted a sensitivity that reoptimizes our expansion plan to achieve a 100 percent carbon-free generation fleet by 2050. The results of the analysis are shown below.

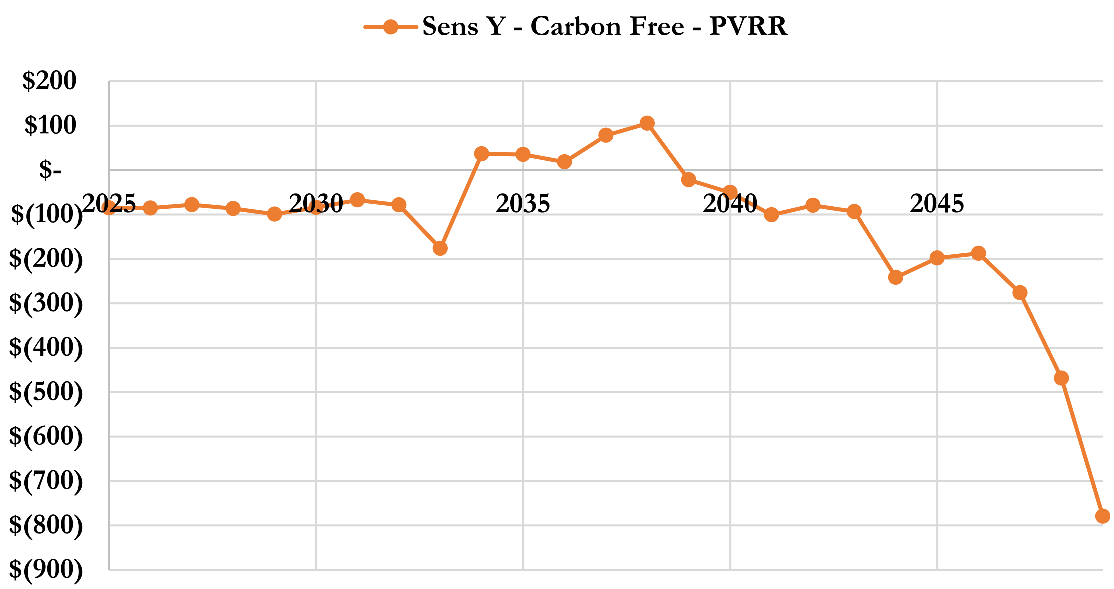
Table 5-6: NPV Savings under 100 Percent Carbon-Free by 2050 Constraint ($2024 millions)

PVSC Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
Scenario 1 - Carbon Free - PVSC	**$0**	$50,703	**$0**	$62,974	**$0**	$70,930
Scenario 2 - Carbon Free - PVSC	**($298)**	$50,406	**($385)**	$62,589	**($1,003)**	$69,927

Scenario 3 - Carbon Free - PVSC	**($662)**	$50,041	**($931)**	$62,042	**($1,850)**	$69,080
PVRR Production Cost	**Delta ($m)**	**NPV ($m) 2024-2040**	**Delta ($m)**	**NPV ($m) 2024-2047**	**Delta in NPV ($m) 2024-2050**	**NPV ($m) 2024-2050**
Scenario 1 - Carbon Free - PVRR	**$0**	$34,819	**$0**	$46,314	**$0**	$54,273
Scenario 2 - Carbon Free - PVRR	**($200)**	$34,619	**($323)**	$45,991	**($947)**	$53,326
Scenario 3 - Carbon Free - PVRR	**($612)**	$34,207	**($941)**	$45,373	**($1,865)**	$52,407

As shown in the Table 5-6 above, the Preferred Plan results in dramatic savings of nearly $2 billion on both a PVSC and PVRR basis. Compared to existing technologies, the extension of our nuclear fleet provides an overwhelmingly cost-effective source of carbon-free energy. Figure 5-10 below shows the PVRR savings over time.

Figure 5-10: Preferred Plan Annual Costs or Savings Compared to the Reference Case, 100x50 Sensitivity ($ millions)



As shown above, significant savings are achieved in the late 2040s under this analysis. Further, as noted above, we expect advancements in technology will reduce the cost of reaching our 100 percent carbon-free goal. As discussed further below, long-duration storage, hydrogen, and small-module reactors could play a role in our energy future as technology evolves. The technologies and costs of alternatives that will be available in the 2040s are very uncertain today. As a result, caution should be taken when considering expect impacts twenty years from now. However, it is clear that our nuclear fleet can play a critical role in providing a source of carbon-free generation well into the future.

C. Preferred Plan and Future Load Uncertainty

We anticipate a change in the slow load growth we have experienced over the past several years. As discussed further in Appendix E: Load Forecasting, we expect to see the demand for electricity to increase at a greater pace. While further improvements in energy efficiency and demand response capabilities will continue to provide substantial value to our customers, we anticipate that emerging uses of electricity will result in greater consumption growth than we have needed to plan for in the recent past. Specifically, our base case forecasts now anticipate average annual growth rates of 1.8 percent in our peak demand, and 2 percent for our energy forecast over the 2024-2040 planning period. As discussed above, given that there is uncertainty in any long-term forecast, primarily around the potential for data center loads and their timing, accelerated EV and DG adoption, etc., we developed High and Low load sensitivities that adjusted the base outlook using discrete adjustments for these forecast components. As shown in Table 5-7 below, under all load sensitivities, Scenario 3 – the Preferred Plan, is the most economic.

Table 5-7: NPV Savings under Base, High, and Low Loads ($2024 millions)

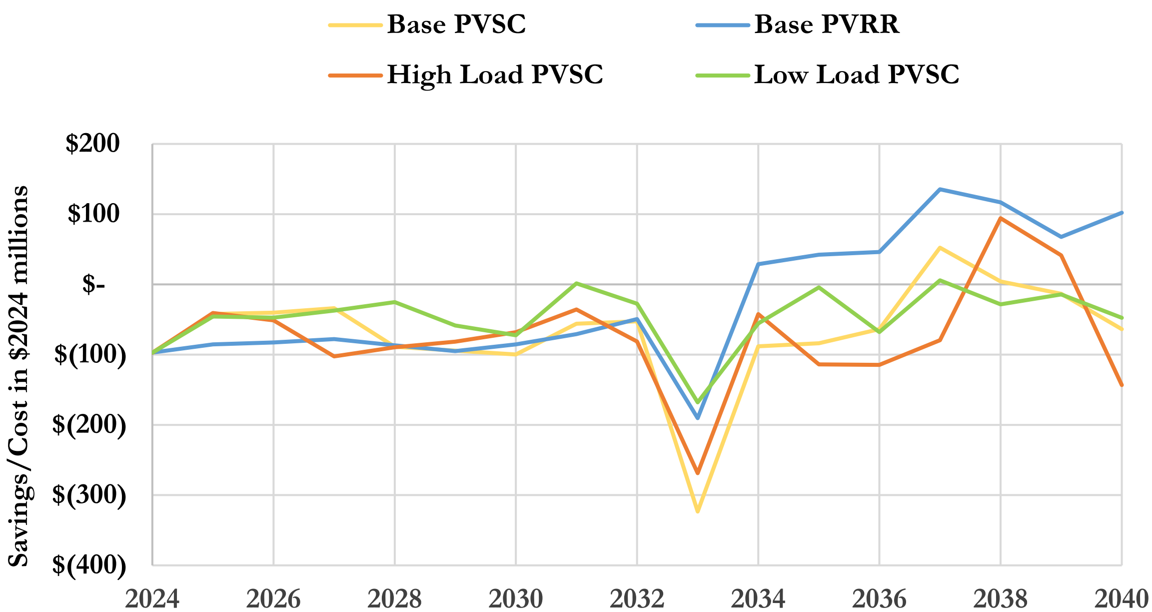
	Scenario 1	Scenario 2	Scenario 3
Delta in NPV ($m) 2024-2040 Base Load PVSC	$0	($437)	($941)
Delta in NPV ($m) 2024-2040 High Load PVSC	$0	($567)	($837)
Delta in NPV ($m) 2024-2040 Low Load PVSC	$0	($298)	($534)

	Scenario 1	Scenario 2	Scenario 3
Delta in NPV ($m) 2024-2047 Base Load PVSC	$0	($437)	($941)
Delta in NPV ($m) 2024-2047 High Load PVSC	$0	($548)	($953)
Delta in NPV ($m) 2024-2047 Low Load PVSC	$0	($143)	($560)
Delta in NPV ($m) 2024-2050 Base Load PVSC	$0	($513)	($1,025)
Delta in NPV ($m) 2024-2050 High Load PVSC	$0	($596)	($1,013)
Delta in NPV ($m) 2024-2050 Low Load PVSC	$0	($128)	($627)

As demonstrated above, the Preferred Plan offers benefits across a range of potential future scenarios. Additional analysis focused on the Preferred Plan is discussed below.

Figure 5-11 below, provides further detail on the expected savings of the Preferred Plan relative to the Reference Case through 2040. As shown, the Preferred Plan achieves customer savings through 2040 under the variations in expected load growth. In other words, load growth that is higher or lower than expected will not significantly change the benefits expected under the Preferred Plan. This demonstrates that the Preferred Plan is robust and beneficial to customers, yielding savings under a host of potential future conditions.

Figure 5-11: Preferred Plan Annual Costs or Savings Compared to the Reference Case, by Scenario ($ millions)



The detailed expansion plan for the 2027-2030 Preferred Plan is provided below.

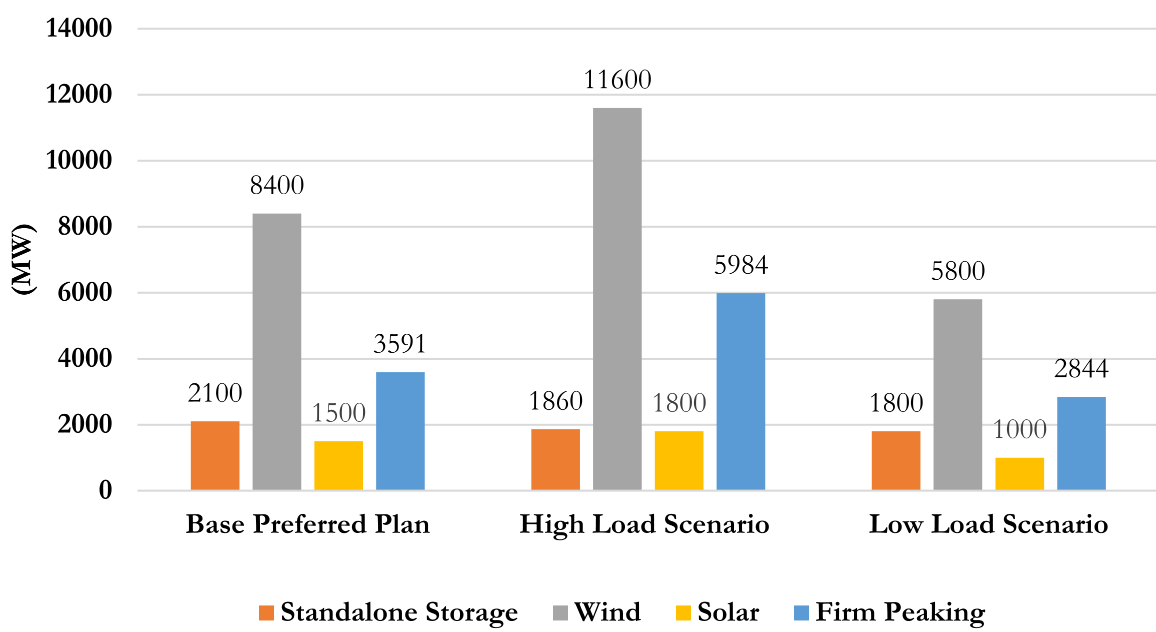
Table 5-8: Preferred Plan Expansion Plan (2027-2030) (MW)

	2027	2028	2029	2030
Standalone Storage	480	-	120	-
Wind	400	2,000	800	-
Solar	-	-	-	400
Firm Peaking	748	748	-	748
Total	**1,628**	**2,748**	**920**	**1,148**

Relative to the Preferred Plan the High Load sensitivity has the same amount of firm dispatchable added by 2030, while the Low Load sensitivity has 374 MW less. The High Load sensitivity also include more storage and wind additions in the near-term, while the Low Load sensitivity, which captures a high distributed solar assumption, includes less wind and solar in the near-term. In other words, across load sensitivities, our plans call for significant additions of renewables and firm dispatchable resources as we continue to retire units and transitions our system.

For simplicity, Figure 5-12 below shows cumulative expansion plan additions by resource type. It is important to note that while DR and EE are not reflected as separate categories, they would be considered to fill any firm dispatchable needs identified in the expansion plans. Similarly, evolving economics and value could also shift the mix of resource additions.

**Figure 5-12: Cumulative 2024-2040
Additions by Resource Type and Sensitivity (MW)**



D. Preferred Plan Benefits

We believe our analysis supports selection of Scenario 3, extension of Prairie Island to 2053/2054 and Monticello nuclear facility to 2050, as our Preferred Plan. While all of our scenarios meet the 2030 carbon goal we established and achieve compliance with the new 100 percent carbon-free energy by 2040 legislation, we believe cost and risk considerations elevate Scenario 3 above the rest as an appropriate path forward.

1. *Cost*

As demonstrated in our modeling analysis, the Preferred Plan achieves customer value under a wide variety of future conditions. The Preferred Plan achieves savings under all PVSC analysis and through the planning period on a PVRR analysis. When carbon impacts are considered, either through incorporation of a cost or an emissions constraint, our Preferred Plan results in significant savings. Further, from a customer rate impact perspective, the Preferred Plan, as modeled, results in annual rate increases of under one (1) percent, which is below the rate of inflation.[12] Altogether, we believe the Preferred Plan delivers tangible customer savings while taking industry-leading steps towards a carbon free future.

2. *Risk*

In addition to beneficial cost outcomes, the Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The 2024 Plan incorporates significant capacity additions to replace retiring resources and expiring PPAs, consisting of a diverse portfolio of DSM, nuclear extension, solar, wind, storage, and firm dispatchable resource additions. Further, ensuring we do not become too dependent on a single fuel source mitigates risk.

We also evaluate factors such as energy market exposure and portfolio length. Our Preferred Plan limits our exposure to market risk and ensures we have the resources needed to serve our customers. As discussed below, we conducted extensive analysis to confirm the energy adequacy of our plan. Further, our Preferred Plan results in a portfolio length of at least 230 MWs through the planning period. We believe our Preferred Plan's portfolio length is warranted at this time, and creates an effective hedge for our customers against two key risk factors:

Capital Investment Wind Down at Retiring Plants. The retirement of our remaining coal

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[12] As noted in Chapter 4: Preferred Plan and discussed further in Chapter 6: Customer Rate and Cost Impacts

assets, in addition to the expiration of other resources by 2030 exposes our customers to some risk as we wind down operations and reduce capital spend at these plants. In the event of an early outage, excess capacity will give us the option to adjust resource procurements as needed if we find that a capital investment needed to continue operation of a retiring plant is not in our customers' best interests at that time.

Capacity Accreditation. We expect further changes to the accreditation of resources in MISO as discussed Chapter 2: Planning Landscape. MISO's Direct Loss of Load (DLOL) proposal calculates accreditation based on modeled and historical performance of resources during tight margin hours. Our Preferred Plan additions position us to be able to manage the uncertainty of further changes to resource accreditation.

VIII. SPECIAL STUDIES ON THE PREFERRED PLAN

Special studies in resource planning allow for a more thorough examination of specific issues not fully covered in the general resource plan. In this 2024 Plan, we evaluated community energy goals and meeting renewable statute requirements as described below. We also conducted remodels to assess how distributed generation (DG) solar bundles and potential new technology options could impact the Preferred Plan as described below.

A. 50 Percent/75 Percent Renewables

Minn. Stat. § 216B.2422, subd. 2(c) requires that we "include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources." The Preferred Plan (Scenario 3) satisfies the statute's first requirement (50 percent of energy needs from conservation or renewables) because it is economically optimized and meets approximately 81 percent of energy needs with renewables and conservation. Our baseload scenario analysis satisfies this statute's second requirement (75 percent of energy needs from conservation or renewables), as Scenario 3 yields the least cost plan for meeting at least 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.

B. Remodels – DG Solar Bundles, New Technology (Hydrogen, SMRs, Long Duration Storage)

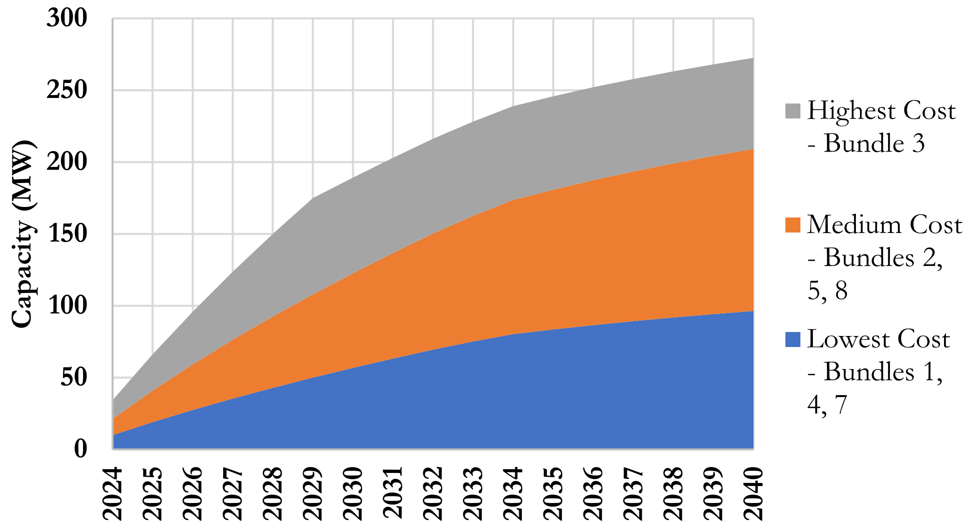
We conducted a special study on the Preferred Plan to assess the impacts of additional DG solar bundles as required by 2019 Plan, Order Point 15. Further, we conducted special studies of advanced technologies (hydrogen, SMRs, long duration storage, and a combination of the three advanced technologies), data center load, resource adequacy (higher PRM/RBDC opt-out, 25 percent battery ELCC, 2,300 MW market access, wind fleet variability), and an energy adequacy analysis—on the Preferred Plan. For each of these studies, the additional resource options are evaluated and optimized in the modeling and added when economic. The study assumptions and findings are described below. A cost analysis for these studies is not included below because the assumptions are insufficiently developed, and the current costs are too high relative to the resource options modeled in this 2024 Plan. Further, the commercial viability of some of these technologies hinders the ability to provide a detailed and reliable cost analysis.

1. DG Solar Bundles

For this special study, we created nine solar bundles as additional resource options for EnCompass to select. Appendix J: Distributed Energy Resources, contains detail on how the solar bundles were developed and about what they represent: estimates of generic customer-owned distributed solar that are economically possible, absent any 1) technical and market barriers for customers and 2) specific details about how the Company would acquire these resources.

Figure 5-13 below shows the selected DG bundle capacity by year, and the resulting cumulative capacity expansion plan is shown in Table 5-9.

Figure 5-13: Selected DG Bundles (MW)



As shown in Figure 5-13 above, solar bundle resource selection increases each year and peaks at 272 MW in 2040. Notably, half of the capacity is installed by the late 2020s. The majority of the added DG solar capacity is derived from the two lowest incentive payment bundles. As shown in Table 5-9 below, the addition of the DG solar bundle resource option results in a reduction of 900 MW of utility-scale generic solar, a slight increase in the amount of storage, and an additional 800 MW of wind. Please see Appendix J: Distributed Energy Resources, for discussion about next steps upon acceptance of each bundle.

Table 5-9: Cumulative Capacity Expansion Plan with Solar Bundle Resource Option (MW)

Resource Type	Base Preferred Plan	Selectable DG Bundles
Standalone Storage	2,100	2,160
Wind	8,400	9,200
Utility-Scale Solar (Non-Bundle)	1,500	600
Firm Peaking	3,592	3,592
Total Without Bundles	15,592	15,552
Additional DG Solar (Bundles)	0	273

Resource Type	Base Preferred Plan	Selectable DG Bundles
Total Added Capacity	15,592	15,775

2. *Advanced Technology*

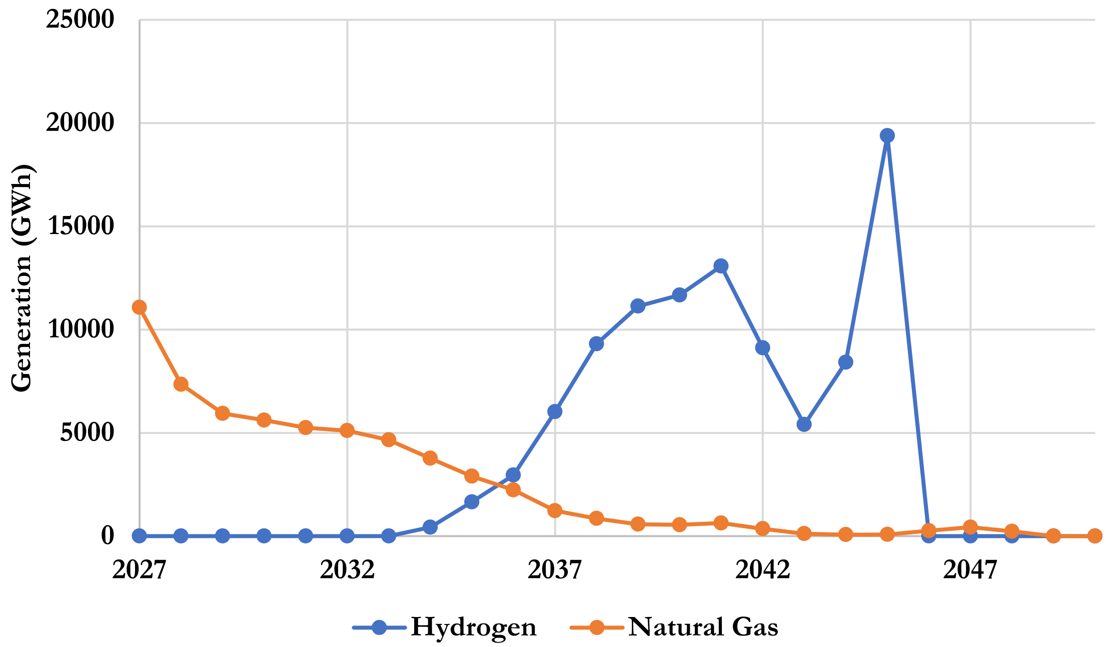
As discussed in Appendix X: Advanced Technologies, advanced and evolving technologies will play a critical role in helping us eliminate the remaining carbon emissions from our system while maintaining safe, affordable, and reliable electric service at times when renewable energy output is low. To further analyze the potential of advanced technologies to achieve our 2050 carbon-free vision, we used Encompass to perform special studies on three advanced technologies. We first study each technology—hydrogen, small modular reactors (SMRs), long duration energy storage (LDES)—individually. Finally, we conducted another study to allow EnCompass select from all three advanced technology options. For each special study, we impose a 100 percent carbon reduction by 2050 (100x50) constraint in EnCompass. We discuss our assumptions and study findings below. Additional model inputs and assumptions are included in Appendix F: EnCompass Modeling Assumptions & Inputs.

a. Hydrogen

For this study, hydrogen is the only advanced technology option available for EnCompass to select. The model allows hydrogen blending with natural gas in firm dispatchable resources (modeled as generic CTs) up to 100 percent starting in 2030 based on economic signals and the carbon constraint. The generic CT depreciation life remains at the default of 40 years due to its hydrogen blending capability.

As shown on Figure 5-14, hydrogen generation rises starting in 2034, reaching its peak in 2045, as the declining production cost and the hydrogen PTC make it a cost-effective, clean alternative to natural gas. However, the expiration of the hydrogen PTC in 2045 reduces its cost-effectiveness and the model does not rely on hydrogen after the PTC expiration based on these assumptions. Further, the use of natural gas gradually diminishes over this period.

Figure 5-14. Generation by Fuel Type in the Hydrogen Only Study (PVSC)



b. Small Modular Reactors (SMRs)

For this study, SMRs are the only available advanced technology resource option for EnCompass to select starting in 2035. The depreciation life of generic CTs is shortened to be fully depreciated in 2050.

As shown below in Table 5-10, the first SMR is selected in 2047 in anticipation of nuclear retirement and zero carbon target in 2050.

Table 5-10: Cumulative Capacity Expansion Plan in the SMR Only Study (MW)

Resource Type	2027-2035	2036-2040	2041-2045	2046-2050	2051-2055
Standalone Storage (4-hr)	1,620	900	2,040	5,640	(900)
SMRs	-	-	-	4,200	3,000
Wind	5,800	3,800	8,400	3,200	2,000
Solar	1,800	300	2,000	5,800	2,900

Resource Type	2027-2035	2036-2040	2041-2045	2046-2050	2051-2055
Firm Peaking	2,244	1,122	-	(3,366)[13]	-
Total	11,464	6,122	12,440	15,474	7,000

c. Long Duration Energy Storage (LDES)

For this study, LDES is the only advanced technology resource for EnCompass to select starting in 2035. The depreciation life of generic CTs is shortened to be fully depreciated in 2050.

The battery seasonal accreditation starts with the MISO October 2023 Resource Adequacy BPM section 4.2.9.4, which provides the five percent forced outage (95 percent accredited capacity assumptions) for new energy storage resources. The accreditation trends over several years from the 95 percent capacity accreditation to the long-term assumptions for battery storage resources in the MISO November 2022 RRA. The MISO battery accreditation is based on a four-hour battery. In the case of a 10-hour battery, we conservatively apply the same value since MISO does not provide an ELCC for a 10-hour duration.

As shown below in Table 5-11, the first LDES is selected in 2036. With significant further additions through 2050. The analysis relies on renewable additions and LDES to achieve the 100x50 goal. As shown in the table below, the model relies on LDES rather than the shorter duration standalone storage.

Table 5-11: Cumulative Capacity Expansion Plan in the LDES Only Study (MW)

Resource Type	2027-2035	2036-2040	2041-2045	2046-2050	2051-2055
Standalone Storage	1,680	-	(840)	840	-
LDES	-	3,000	1,700	7,600	5,500
Wind	6,000	2,400	8,600	-	3,000
Solar	1,800	-	-	3,700	2,100
Firm Peaking	2,244	-	-	(2,244)	-

[13] All firm peaking resources are retired by 2050 in this study.

Resource Type	2027-2035	2036-2040	2041-2045	2046-2050	2051-2055
Total	11,724	5,400	9,460	9,896	10,600

d. Three Advanced Technology Resource Options

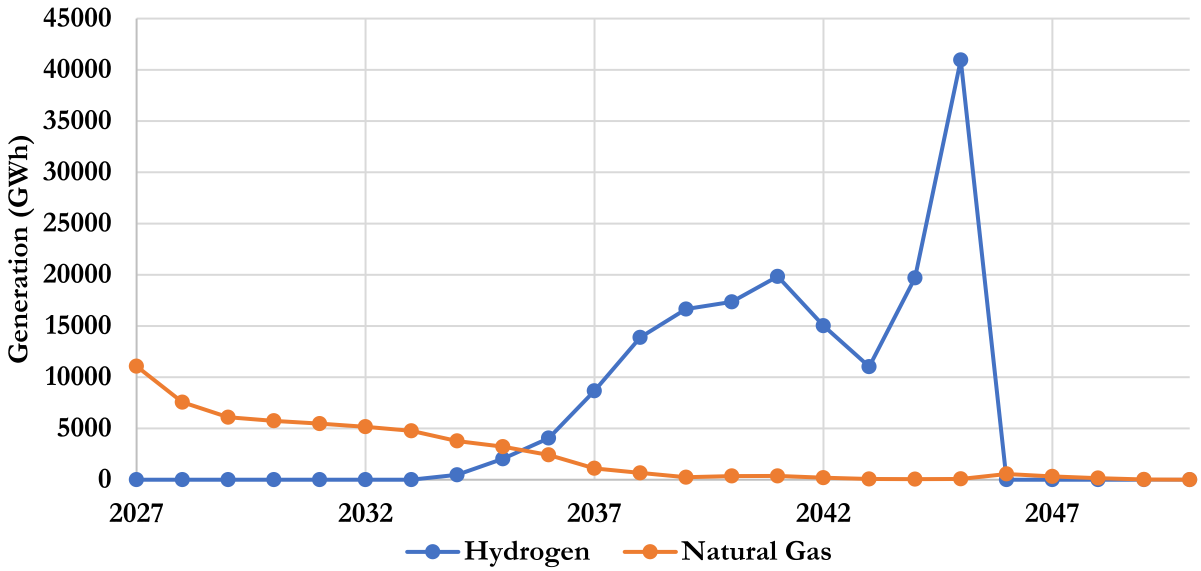
For this study, all three advanced technology resource options—hydrogen, small modular reactors (SMRs), and long duration energy storage (LDES)—were available for EnCompass to select. The SMRs and LDES resources could be selected starting in 2035. The model allows hydrogen blending with natural gas up to 100 percent in firm dispatchable resources (modeled as a CT) starting in 2030 based on economic signals and the carbon constraint. The generic CT depreciation life remains at the default of 40 years, due to its blending capability.

As shown below in Table 5-12, the first LDES resource is selected in 2036, and no SMR is selected throughout the planning period. Hydrogen blending starts in 2034 in the PVSC scenario.

Table 5-12: Cumulative Capacity Expansion Plan in the Study with Three Advanced Technology Resource Options (MW)

Resource Type	2027-2035	2036-2040	2041-2045	2046-2050	2051-2055
Standalone Storage	1,320	-	(600)	(720)	-
LDES	-	2,500	1,900	6,200	5,200
SMRs	-	-	-	-	-
Wind	6,400	800	10,000	-	3,600
Solar	1,500	-	-	3,900	2,300
Firm Peaking	2,470	-	-	-	-
Total	11,690	3,300	11,300	9,380	11,100

Figure 5-15. Generation by Fuel Type in the Scenario with Three Advanced Technology Resource Options (PVSC)



The integration of hydrogen, SMRs, and LDES onto our system has the potential to provide our customers with safe, reliable, and cost-effective benefits while helping the Company and the State of Minnesota achieve decarbonization goals. Our Preferred Plan strategically positions us to explore and integrate advanced technologies in a practical and timely manner to accelerate the clean energy transition.

3. Data Center Load

For the data center load special study, we have assumed load growth surpassing the traditional high load sensitivity to accommodate the accelerated load growth stemming from data centers. The demand for data centers has recently surged notably due to the expansion of machine learning/artificial intelligence technologies, which are more energy-intensive than traditional data processing methods. Xcel Energy's achievements in renewable energy, along with state initiatives and robust fiber connectivity, are contributing to this increased demand for data centers in our service territory. The Company is actively engaged with several hyperscale and colocation data centers, with transmission interconnection studies underway for several requests. These entities are largely seeking renewable/carbon-free energy options and are interested in forming partnerships.

The results in Table 5-13 show the impact of an increased data center load on the capacity expansion plan.

Table 5-13: Cumulative 2024-2040 Additions by Resource Type Comparison

Resource Type	Base Preferred Plan	Data Center Load
Standalone Storage	2,100	2,220
Wind	8,400	12,800
Solar	1,500	3,200
Firm Peaking	3,592	5,462
Total	15,592	23,682

4. *Resource Adequacy*

To assess resource adequacy, we conducted four special studies as further described below: (1) higher planning reserve margin (RBDC Opt-Out), (2) 25 percent battery ELCC, (3) 2,300 MW Market Access and (4) Wind Fleet Variability. The resulting capacity expansion plan for each resource adequacy study is shown in Table 5-14 and discussed below.

Table 5-14: Cumulative 2024-2040 Additions by Resource Type for Each Resource Adequacy Study

Resource Type	Base Preferred Plan	RBDC Opt-Out	25% Battery ELCC	2,300 MW Market Access	Wind Fleet Variability
Standalone Storage	2,100	2,100	1,320	1,620	2,160
Wind	8,400	8,400	9,200	11,400	8,000
Solar	1,500	1,400	1,700	3,100	1,600
Firm Peaking	3,592	3,592	4,488	2,618	3,592
Total	15,592	15,492	16,708	18,738	15,352

a. Higher Planning Reserve Margin (RBDC Opt-Out)

As discussed in Chapter 2: Planning Landscape, the Reliability Based Demand Curve (RBDC) is a proposed design for MISO's Planning Resource Auction that aims to reflect the value of capacity in excess of the MISO PRM and produce more efficient and stable capacity prices. The RBDC opt-out proxy represents the additional capacity necessary to opt-out of the RBDC. By opting out of the RBDC, we can avoid costs that would otherwise be assessed to compensate other generators in MISO. This sensitivity assesses the cost of securing the excess generation needed to opt-out. As shown in Table 5-14 above, this study results indicate that the Preferred Plan capacity additions are sufficient to meet the higher planning reserve margin in most years.

b. 25 Percent Battery Effective Load Carrying Capability (ELCC)

The 25 percent battery ELCC special study evaluates the impact of a lower ELCC for battery storage, instead of the 95 percent accreditation battery storage received in the current planning year. As shown in Table 5-14 above, in this study, standalone storage resources additions are reduced by 780 MW while over 1,000 MW of capacity is added from the other resource options. In the near term, by 2030, there is no change in firm peaking capacity additions, and battery capacity additions are reduced by 60 MW relative to the Preferred Plan.

c. 2,300 MW Market Access

For this study, we allow hourly market access of 2,300 MW. As thoroughly discussed in Section IV, the model adds over 10,000 MW of wind alone during this planning period and results in a significant market exposure.

d. Wind Fleet Variability

In the 2019 Plan, the Commission ordered that the Company analyze our likely firm dispatchable need using "corrected modeling of wind fleet variability."[14] We clarify that our generic wind profile uses the average hourly wind generation from our existing wind fleet, which inherently reflect variability of the wind generation profiles. However, to address the order point, this sensitivity uses a blended profile from three representative wind profiles in Minnesota, North Dakota and South Dakota, then allows the model to re-optimize any additions of firm dispatchable resources. We note that our existing wind facilities are modeled using resource-specific wind profiles.

The results in Table 5-14 above show that the cumulative firm peaking capacity additions by 2040 in this study is the same as the Reference Case, indicating changing the generic wind profile does not reduce the need for firm dispatchable resources. However, we intend to conduct this analysis as part of evaluation of resource options in Docket No. E-002/CN-23-212.

[14] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, Order (April 15, 2022), at p.32.

5. *10-hour battery and hybrid resource options*

In this study, a 10-hour battery is first selected in 2052 and the hybrid resource is not selected in the modeling period. This validates our decision to remove these two resource options in the base runs to speed up the run time.

6. *Energy Adequacy Analysis*

We conducted a special study to test the energy adequacy of our plans. As discussed in Appendix D: Energy Adequacy Analysis, we used historical data on four plans including our Preferred Plan and Market Access Optimization, which was developed assuming 2,300 MW of hourly market access.[15] This analysis allows us to assess the capacity and energy adequacy of our plans. We evaluated these four plans on six different measures:

1. Native Capacity Shortfall: Hours of insufficient system capacity in each year.
2. Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
3. Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.
4. Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
5. MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

A summary of the results for each scenario in 2030 and 2040 is shown in Table 5-15 below. The highest values in each category are in bold.

[15] As discussed in Appendix D, which also analyzed the Reference Case and Low Load Scenario.

Table 5-15: Summary of 2030 Energy Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2030**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
Preferred Plan (Scenario 3)	**2016 Historical**	1	83	1	83	1	83
	2017 Historical	0	0	0	0	0	0
	2018 Historical	0	0	0	0	0	0
	2019 Historical	0	0	0	0	0	0
	2020 Historical	1	219	1	219	2	590
	2021 Historical	0	0	0	0	1	204
	2022 Historical	0	0	0	0	0	0
Market Access Optimization (Scenario 3 Market On Expansion Plan)	**2016 Historical**	**54**	**484**	**7**	**1,684**	**61**	**32,204**
	2017 Historical	**48**	**272**	**5**	**953**	**69**	**25,023**
	2018 Historical	**65**	**344**	**6**	**1,312**	**102**	**40,769**
	2019 Historical	**74**	**463**	**6**	**1,368**	**94**	**45,356**
	2020 Historical	**83**	**415**	**7**	**1,479**	**109**	**57,072**
	2021 Historical	**61**	**269**	**5**	**1,082**	**100**	**41,205**
	2022 Historical	**20**	**290**	**3**	**1,144**	**24**	**7,254**
	**** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)**						

As shown in Table 5-15 above, the Preferred Plan performs well across energy adequacy metrics. There are only two hours of native capacity shortfall in 2030 across the seven historic years tested and applied to our Preferred Plan, resulting in limited dependence on the market. There are only four hours across the seven historical test years where the Preferred Plan requires market purchases in order to meet load serving needs.

In contrast, under the Market Access Optimization, assumes market access of 2,300 MW in all hours of the year, the results plan exposes our customers to excessive risk. There are 405 hours across the seven historic years where the plan has insufficient capacity to meet needs. This results in 509 hours where the plan cannot meet load serving needs and must rely on market purchases of nearly 250,000 MWh of energy.

IX. CONCLUSION

Considering the above, we believe our modeling and analysis fully supports selection of the Preferred Plan and strikes a strong balance in meeting our planning objectives, in service of our customers' needs. The Preferred Plan sets us on a path to meet both our 2030 carbon reduction objectives and longer-term carbon-free goals and achieve compliance with the new 100 percent carbon-free energy by 2040 legislation, all while providing affordable and reliable service. Further, the Preferred Plan is bolstered by comprehensive reliability and sensitivity analysis, which scrutinize a wide variety of factors and contingencies. This thorough examination provides confidence in the plan's resilience to uncertainties and its ability to meet future energy demands reliably. The combination of robust sensitivity analysis and the multifaceted advantages of nuclear plant extensions underscore the soundness of the Preferred Plan.

CHAPTER 6 – CUSTOMER RATE AND COST IMPACTS

I. INTRODUCTION

Minn. R. 7843.0500, subp. 3, requires that the Minnesota Public Utilities Commission evaluate resource plans on, among other things, their ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints." In this chapter we present rate and bill impacts of our Preferred Plan for our Residential, Commercial, and Industrial customer classes.[1] Overall, our Preferred Plan results in an estimated annual rate increase of 0.5 percent for Minnesota customers, which is less than the expected national average increase of 2.1 percent for electricity prices.

Producing a detailed analysis of rate impacts in a resource planning process with long time horizons is challenging due to the potential changes in our rates and resource needs over time. Factors that can impact the estimated rate impacts in the planning period include generation ownership structure, tax treatment, regulatory decisions, large customer load additions, changes in customer class allocations, and others. The simplifying assumptions made in both the calculation methodology and the input variables mean that these estimated impacts may not align with the actual rates set by the Commission for various customer classes in the future. We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing.

Our customer cost impact analysis shows that the Preferred Plan does not materially increase costs for our customers. The Preferred Plan results in an estimated average annual increase in retail rates of 0.9 percent across our system, compared to the Reference Case results of 0.7 percent and the EIA forecasted national average electricity rate increase of 2.1 percent. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are less than half of the expected national average increase in electricity prices. Both the Reference Case and the Preferred Plan are designed to meet the Company's clean energy goals, and state policy objectives. As shown below, our Preferred Plan maintains affordability and reliability while continuing our trend of carbon reduction benefits relative to our Reference Case.

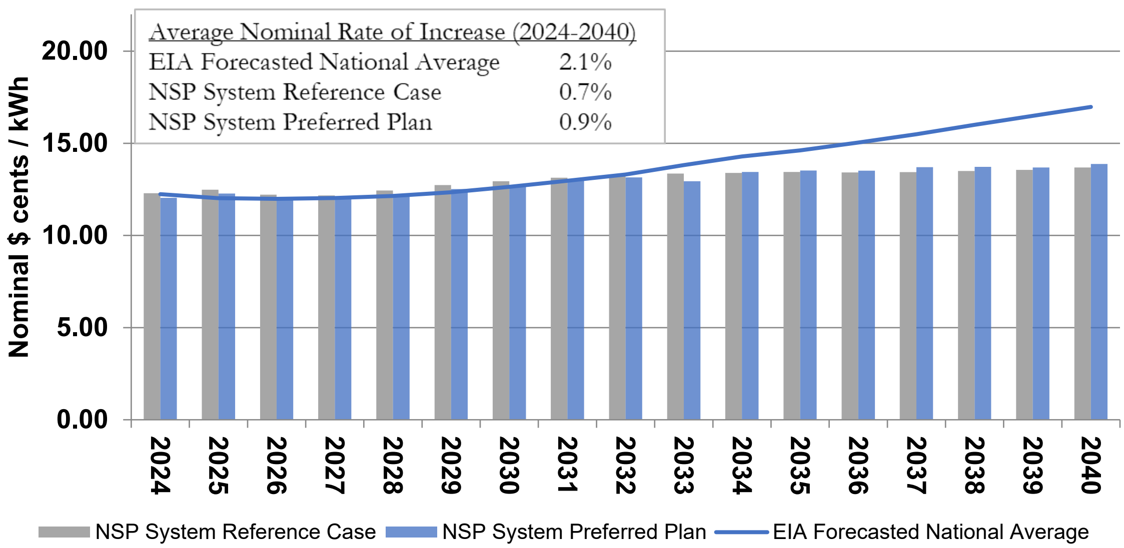
A. Preferred Plan Average Nominal Cost Comparison to National Average

We begin by showing our Reference Case and Preferred Plan's average nominal cost as compared to the national average as forecasted by the Energy Information

[1] See *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, MN PUC Docket No. E-002/RP-19-368, Order Point 18 (April 15, 2022).

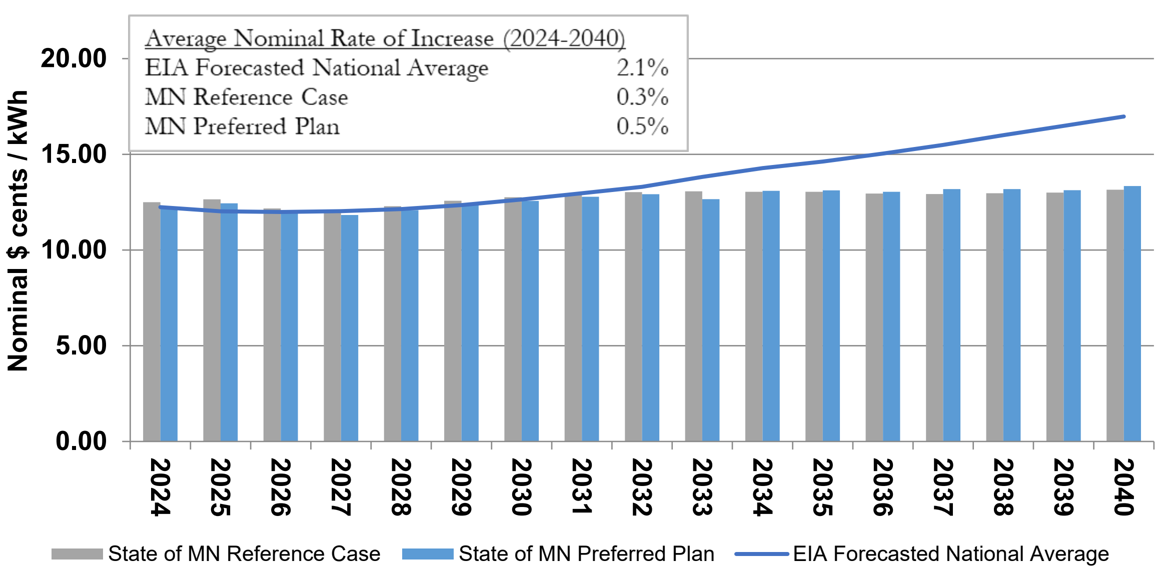
Administration. To show the cost impact of our proposal over the long-term, we provide a compound average growth rate (CAGR) comparison of our Preferred Plan compared to the national average nominal cost CAGR for the NSP System in Figure 6-1, and Minnesota in Figure 6-2, below. As can be seen in these figures, our Preferred Plan remains lower than the national average.

**Figure 6-1: Average Nominal Cost Comparison
NSP System**



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2023, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[2] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

**Figure 6-2: Average Nominal Cost Comparison
State of Minnesota**



The results above indicate that the CAGR for average rates is higher for the Preferred Plan than for the Reference Case. To be clear, however, this should not be interpreted to mean that the Reference Case is more beneficial to customers than the Preferred

Plan. The CAGR simply measures the growth rate from one end point to another, in this case the average rate in 2024 versus the average rate in 2040. The Preferred Plan average rate in 2024 begins at a slightly lower point than in the Reference Case, and ends slightly higher in 2040, resulting in a higher growth rate. In contrast, the PVRR analysis takes into account each year of the annual revenue requirement stream, and not just the end points in 2024 and 2040. As discussed earlier in this filing, the Preferred Plan results in a lower PVRR than the Reference Case, making the Preferred Plan the overall least cost option for our customers.

The results in Figures 6-1 and 6-2 also show that the Minnesota CAGR is lower than the NSP system average CAGR for the time period of 2024 through 2040. This is due to the way each CAGR is calculated. The annual NSP system average rates are calculated as the annual revenue requirement for the entire NSP system divided by NSP system sales. The annual Minnesota rates are calculated the same way using the jurisdictional revenue requirement and the jurisdictional annual sales forecast. Since Minnesota sales are forecasted to grow more quickly than the NSP average, they make up a larger portion of the total NSP sales mix in 2040 than they do in 2024. Therefore, the average rates in 2040 (and thereby the CAGR to reach those rates) for Minnesota are lower than for the NSP system as a whole.

II. REVENUE REQUIREMENTS FORECAST METHODOLOGY

To calculate the long-term rate impacts of the Preferred Plan as compared to the Reference Case, we first developed a forecast of revenue requirements for the Reference Case. This forecast leverages retail revenue requirements from the Company's most recent rate case test years approved by each Commission in our five jurisdictions: Minnesota,[3] North Dakota,[4] South Dakota,[5] Wisconsin,[6] and Michigan[7] to create an NSP System revenue requirement for 2024. We identified annual costs through the end of the planning period (2040) using the CAGR of generation and fuel costs from the EnCompass model Reference Case. This approach avoids speculation

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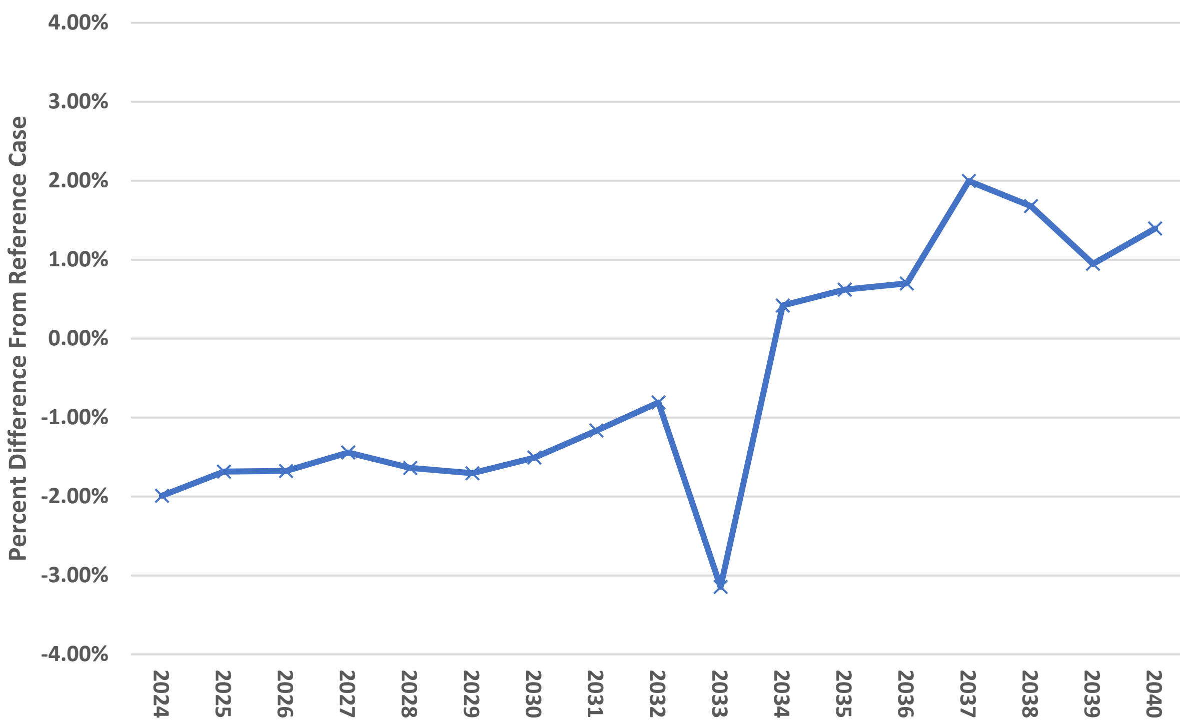
[2] *See* U.S. Energy Information Administration - EIA - Independent Statistics and Analysis The EIA's Annual Energy Outlook was published in 2023.
[3] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order, MN PUC Docket No. E-002/GR-21-630 (July 17, 2023).
[4] *Northern States Power Company 2021 Electric Rate Increase Application*, Order on Settlement, Case No. PU-20-441 (August 18, 2021).
[5] *In the Matter of the Application of Northern States Power DBA Xcel Energy for Authority to Increase Its Electric Rates*, Order Granting Joint Motion for Approval of Settlement Stipulation; Order Approving Refund Plan, Docket No. EL22-017 (June 8, 2023).
[6] *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates,* Final Decision, 4220-UR-126 (December 20, 2023).
[7] *Id.*

on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the EnCompass model to create a "business as usual" long term rate projection.

To determine the revenue requirement impact of the Preferred Plan, we identified the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case Encompass model results. This annual differential was added to the annual Reference Case revenue requirements to create the Preferred Plan annual revenue requirements.

Figure 6-3 below illustrates the estimated revenue requirement impacts of the Preferred Plan compared to the Reference Case over the planning period, while Figure 6-4 localizes the impacts to Minnesota.

**Figure 6-3: Annual Percent Change in Revenue Requirements (2024-2040)
Preferred Plan Compared to Reference Case
NSP System**

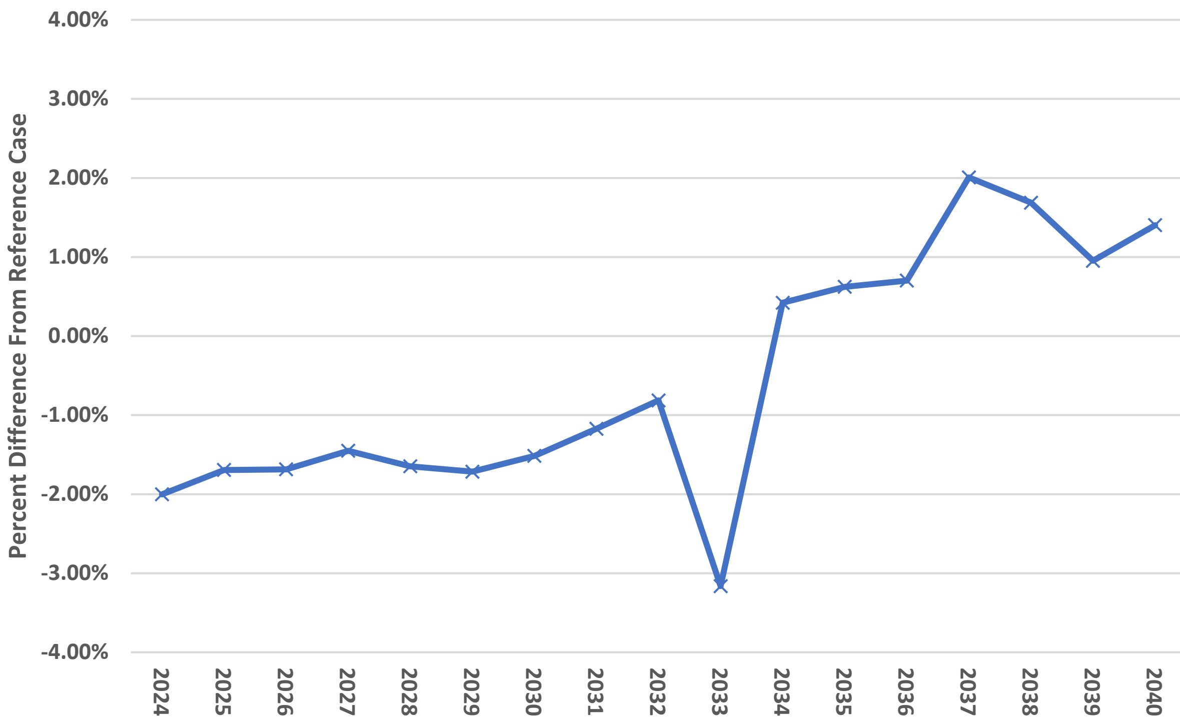


The annual revenue requirements for the Reference Case and Preferred Plan were jurisdictionalized using allocators from the Company's 2022-2024 Minnesota Electric Rate Case (Docket No. E-002/GR-21-630). Table 6-1 and Figure 6-4 below provide the estimated impact of the Preferred Plan for Minnesota.

Table 6-1: Estimated Incremental Impact of Preferred Plan
State of Minnesota – All Customers

Year	Reference Case Revenue Req ($000)	Incremental Impact of Preferred Plan ($000)	Preferred Plan Revenue Req ($000)	Incremental Impact (%)
2024	$3,537,894	-$70,821	$3,467,074	-2.00%
2025	$3,628,567	-$61,488	$3,567,079	-1.69%
2026	$3,721,563	-$62,756	$3,658,808	-1.69%
2027	$3,816,943	-$55,396	$3,761,547	-1.45%
2028	$3,914,768	-$64,499	$3,850,268	-1.65%
2029	$4,015,099	-$68,867	$3,946,232	-1.72%
2030	$4,118,002	-$62,422	$4,055,580	-1.52%
2031	$4,223,542	-$49,503	$4,174,039	-1.17%
2032	$4,331,788	-$35,259	$4,296,529	-0.81%
2033	$4,442,807	-$140,536	$4,302,271	-3.16%
2034	$4,556,672	$19,193	$4,575,865	0.42%
2035	$4,673,454	$29,110	$4,702,565	0.62%
2036	$4,793,230	$33,664	$4,826,895	0.70%
2037	$4,916,076	$98,679	$5,014,755	2.01%
2038	$5,042,070	$85,061	$5,127,131	1.69%
2039	$5,171,293	$49,226	$5,220,520	0.95%
2040	$5,303,828	$74,393	$5,378,222	1.40%

**Figure 6-4: Annual Percent Change in Revenue Requirements (2024-2040)
Preferred Plan Compared to Reference Case
State of Minnesota**



III. KEY DRIVERS

The major inflection points in the delta of revenue requirements (and rates) are driven by the differences in the set of resources that comprise the Preferred Plan and Reference Case; these points coincide with differences in the retirement dates for Prairie Island. Compared to the Reference Case, the Preferred Plan results in lower cost through 2033 due to the extension of Prairie Island and corresponding reduction in depreciation expense. The Prairie Island extension results in fewer resources added in 2033, including the offset of a firm dispatchable addition, compared to the Reference Case, and therefore lower costs reflected in the downward spike in 2033 reflected in Figures 6-3 and 6-4 above. The slightly higher costs in 2034 and beyond reflect the relative costs associated with the Prairie Island extension and the costs of resources added in the Reference Case after Prairie Island retires based on our assumptions for generic resource additions. The generic resource additions are modeled assuming a levelized cost over the life of the asset.

IV. ESTIMATED ANNUAL RATE IMPACTS

After determining the revenue requirement of the Reference Case and the incremental impacts from the Preferred Plan, we determined customer class revenue requirement impacts using cost allocation principles described below. We calculated rate impacts in $ per kWh by dividing each customer class's revenue requirement in each year by the annual forecasted sales.

Figure 6-5 and 6-6 provide the incremental rate impacts of the Preferred Plan for retail customers and by customer class, respectively.

Figure 6-5: Incremental Rate Impact of Preferred Plan State of Minnesota – All Customers

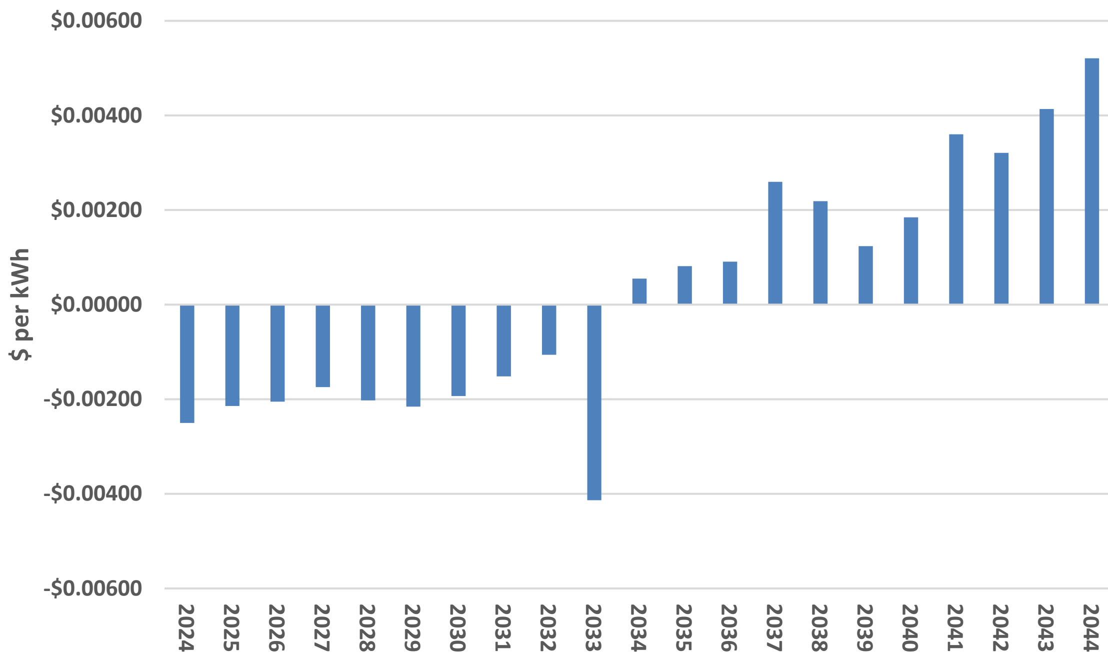
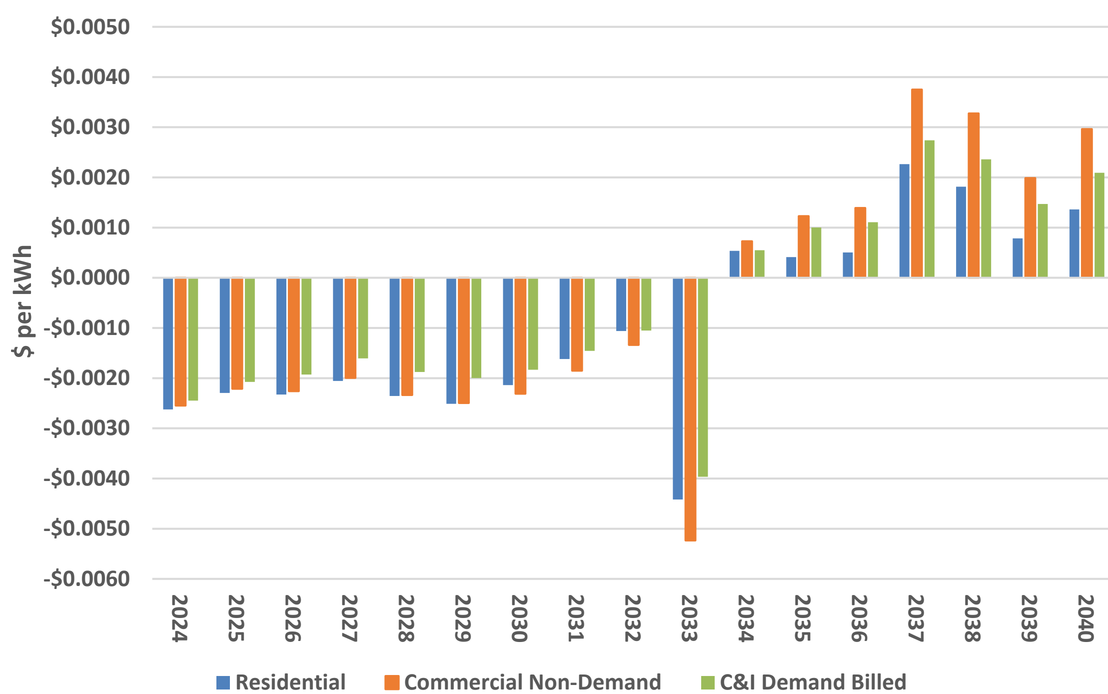


Figure 6-6: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota



As noted above, we determine customer class revenue requirement impacts of the Preferred Plan by allocating incremental costs to customer classes for each year in the planning period (2024-2040). To do this, we apply ratemaking treatments to expense items for each generation resource type that is impacted by the 2024 Plan. Items include fuel costs and purchased energy, fixed O&M, variable O&M, and the revenue requirement associated with capital investments.

Costs for fuel, purchased energy, and variable O&M are allocated to customer classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[8]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	31.69%	2.94%	65.03%	0.35%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

Fixed O&M and the revenue requirement related to capital investments are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[9] We provide the plant stratification analysis for each plant type below:

[8] See Docket No. E002/GR-21-630, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order
, (July 17, 2023).
[9] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$1,026	$1,026 / $1,026	100.0%	0.0%
Fossil	$2,458	$1,026 / $2,458	41.8%	58.2%
Nuclear	$5,109	$1,026 / $5,109	20.1%	79.9%
Wind	$11,262	$1,026 / $11,262	9.1%	90.9%
Solar	$3,736	$1,026 / $3,736	27.5%	72.5%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, nuclear, etc.) to the replacement cost of a Combustion Turbine (CT). CTs are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After fixed O&M costs and the capital-related revenue requirement originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to customer class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator utilized in our most recent rate case.[10] The D10S allocator is simply each customer class's load that is coincident with the NSP system peak load. We provide the D10S customer class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	39.55%	2.77%	57.68%	0.00%

[10] *Id.*

V. ESTIMATED NEAR-TERM RATE IMPACTS

Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Minnesota Estimated Rate Impacts by Customer Class per Year

Rate Class Impacts		2024	2025	2026	2027	2028	2029	2030	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)		15.467¢	15.248¢	15.607¢	15.961¢	16.192¢	16.456¢	15.911¢	N/A
Cumul Increase (¢/kWh)			-0.219	0.140	0.494	0.725	0.989	0.444	N/A
Cumulative Increase (%)			-1.42%	0.90%	3.19%	4.69%	6.39%	2.87%	0.47%
$ Impact/Month, @	650 kWh		($1.42)	$0.91	$3.21	$4.71	$6.43	$2.89	N/A
Sm Non-Dmd (avg rate, ¢/kWh)		14.501¢	14.301¢	14.672¢	15.122¢	15.522¢	15.949¢	16.743¢	N/A
Cumul Increase (¢/kWh)			-0.200	0.171	0.621	1.021	1.448	2.242	N/A
Cumulative Increase (%)			-1.38%	1.18%	4.28%	7.04%	9.99%	15.46%	2.43%
$ Impact/Month, @	1,000 kWh		($2.00)	$1.71	$6.21	$10.21	$14.48	$22.42	N/A
Demand (avg rate, ¢/kWh)		10.879¢	10.447¢	9.739¢	9.477¢	9.706¢	9.953¢	10.331¢	N/A
Cumul Increase (¢/kWh)			-0.432	-1.141	-1.403	-1.173	-0.927	-0.548	N/A
Cumulative Increase (%)			-3.97%	-10.48%	-12.89%	-10.79%	-8.52%	-5.04%	-0.86%
$ Impact/Month, @	37,500 kWh		($162.01)	($427.72)	($526.04)	($440.02)	($347.47)	($205.45)	N/A
Street Ltg (avg rate, ¢/kWh)		26.983¢	26.673¢	27.082¢	27.690¢	28.200¢	28.681¢	29.236¢	N/A
Cumul Increase (¢/kWh)			-0.310	0.099	0.708	1.217	1.698	2.254	N/A
Cumulative Increase (%)			-1.15%	0.37%	2.62%	4.51%	6.29%	8.35%	1.35%
$ Impact/Month, @	60 kWh		($0.19)	$0.06	$0.42	$0.73	$1.02	$1.35	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2030) for the Preferred Plan would be expected to have the following impacts:

- Residential rate increases by about 0.47 percent on a compounded annual basis through 2030, equivalent to a total increase of $2.89 per month above the current rate level;
- Commercial rate increases by about 2.43 percent on a compounded annual basis through 2030, equivalent to a total increase of $22.42 per month above the current rate level; and
- Industrial rate decreases by about 0.86 percent on a compounded annual basis through 2030, equivalent to a total decrease of $205.45 per month below the current rate level.

As noted above, this is not intended to be a prediction of what rate or bill increases will actually be over this time (which will be impacted by numerous factors, including, among other things, the specific costs of actual generation additions rather than generic assumptions used here, non-generation related costs, actual sales growth, and cost allocation decisions). Instead, this is intended to serve as an indicative look at the incremental rate and monthly bill impacts of the modeling results for the Preferred Plan.

VI. RATE IMPACTS OF STANDARD OBLIGATIONS

Each electric utility must submit to the Commission a report containing an estimation of the rate impact of activities necessary to comply with Minn. Stat. § 216B.1691, subd. 2e. The report must be updated and submitted as part of each integrated resource plan or plan modification filed under section Minn. Stat.§ 216B.2422.

We have been adding cost-effective renewable resources to our system to reduce emissions consistent with the analysis in our resource plans and acquisitions. Our analysis in the 2024 Plan considers the costs and impacts of the renewable additions but does not require any additions to meet our standard obligations. Therefore, our standard obligations do not impact our rates. For further details please see Appendix N: Standard Obligations.

VII. CONCLUSION

Based on the totality of these metrics, we believe that our Preferred Plan keeps customers' bills and rates as lows as practicable while continuing our transition to a carbon-free system. As we continue our transition to a carbon-free system, we remain committed to being the energy provider of choice for our customers, and keeping rates low is a key part of that commitment.

CERTIFICATE OF SERVICE

I, Christine Schwartz, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

or

xx electronic filing

Docket Nos. E002/RP-24-67
E002/RP-19-368
E002/GR-21-630
Xcel Energy Miscellaneous Service List

Dated this 1st day of February 2024

/s/

____

Christine Schwartz
Regulatory Administrator

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Kolbinger	brian@beckertownship.org	Becker Township Board	PO Box 248 12165 Hancock St Becker, MN 55308	Electronic Service	No	OFF_SL_19-368_19-368_Official
Kay	Kuhlmann	Teri.Swanson@ci.red-wing.mn.us	City Of Red Wing	315 West Fourth Street Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Brenda	Kyle	bkyle@stpaulchamber.com	St. Paul Area Chamber of Commerce	401 N Robert Street Suite 150 St Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_19-368_19-368_Official
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Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_19-368_19-368_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 E 7th St St Paul, MN 55106	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, MB R3C 2P4 CANADA	Electronic Service	No	OFF_SL_19-368_19-368_Official
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Melanie	Mesko Lee	Melanie.Lee@burnsvillemn.gov	City of Burnsville	100 Civic Center Parkway Burnsville, MN 55337-3867	Electronic Service	No	OFF_SL_19-368_19-368_Official
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_19-368_19-368_Official
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_19-368_19-368_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Alan	Muller	alan@greendel.org	Energy & Environmental Consulting	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
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Ric	O'Connell	ric@gridlab.org	GridLab	2120 University Ave Berkeley, CA 94704	Electronic Service	No	OFF_SL_19-368_19-368_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jessica	Palmer Denig	jessica.palmer-Denig@state.mn.us	Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul, MN 55164	Electronic Service	No	OFF_SL_19-368_19-368_Official
J. Gregory	Porter	greg.porter@nngco.com	Northern Natural Gas Company	1111 South 103rd St Omaha, NE 68124	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Greg	Pruszinske	gpruszinske@ci.becker.mn.us	City of Becker	PO Box 250 12060 Sherburne Ave Becker, MN 55308	Electronic Service	No	OFF_SL_19-368_19-368_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_19-368_19-368_Official
Nathaniel	Runke	nrunke@local49.org	International Union of Operating Engineers Local 49	611 28th St. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_19-368_19-368_Official
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jeff	Schneider	jeff.schneider@ci.red-wing.mn.us	City of Red Wing	315 West 4th Street Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
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Douglas	Seaton	doug.seaton@umwlc.org	Upper Midwest Law Center	8421 Wayzata Blvd Ste 300 Golden Valley, MN 55426	Electronic Service	No	OFF_SL_19-368_19-368_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park	5005 Minnetonka Blvd St. Louis Park, MN 55416	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_21-630_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-630_Official
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
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Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 E 7th St St Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_Official
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Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-630_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_21-630_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Christa	Moseng	christa.moseng@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 Saint Paul, MN 55164-0620	Electronic Service	No	OFF_SL_21-630_Official
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-630_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_21-630_Official
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Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_21-630_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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