APPENDIX M

Xcel Energy October 25, 2024, Comments in Support of Settlement Agreement and Appendices A-F

Lyon County Generating Station Project
Combined Application
MPUC Docket Nos. E002/CN-25-145, G002/GS-25-154,
E002/TL-25-161 & G002/GP-25-163
May 2025

414 Nicollet Mall
Minneapolis, MN 55401

October 25, 2024

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

RE: COMMENTS – SETTLEMENT AGREEMENT SUPPORT

IN THE MATTER OF XCEL ENERGY'S COMPETITIVE RESOURCE ACQUISITION PROCESS FOR UP TO 800 MEGAWATTS OF FIRM DISPATCHABLE GENERATION
DOCKET NO. E002/CN-23-212

IN THE MATTER OF XCEL ENERGY'S 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, submits these Comments in support of the Settlement Agreement filed on October 3, 2024 in the two above-named dockets. The Settlement Agreement is by and among the following parties: Xcel Energy, Minnesota Department of Commerce – Division of Energy Resources (Department), Clean Energy Organizations (CEOs),[1] Laborers' District Council of Minnesota and North Dakota (LIUNA), the International Union of Operating Engineers Local 49 (49ers), the North Central States Regional Council of Carpenters (Carpenters), National Grid Renewables Development, LLC (National Grid), DE Shaw Renewable Investments, L.L.C. (DESRI), Onward Energy Holdings, LLC (Onward), and Invenergy Renewables LLC (Invenergy) (collectively Settling Parties).

The Company respectfully requests that the Commission approve the Settlement Agreement. Xcel Energy also requests that the Commission open a comment period regarding the Settlement Agreement.

[1] For the purposes of this Settlement Agreement, the CEOs include Fresh Energy, Minnesota Center for Environmental Advocacy, and Clean Grid Alliance.

Further, Xcel Energy requests that the Commission approve the extensions of our waste-to-energy generating plants, as discussed herein. Consideration of this issue was inadvertently excluded from the settlement discussions, but no commenter objected to the proposal that was included in the initial filing of our Integrated Resource Plan.

Request for Protection of Confidential Information

Security Information

Certain passages of the Comments are marked "Not-Public" as they includes security information as defined in Minn. Stat. § 13.37, subd. 1(a). The protected information is related to system restoration plans that, if improperly released, could substantially jeopardize the security of our system and customers.

Trade Secret Information

A portion of the Comments is also marked "Not-Public" because it includes trade secret information as defined by Minn. Stat. 13.37, subd. 1(b). 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.

Onward Trade Secret Information

A portion of the Comments is also marked "Not-Public" because it includes trade secret information as defined by Minn. Stat. 13.37, subd. 1(b). The protected information was provided by Onward pursuant to the Protective Order issued in Docket 23-212. It is the subject of efforts by both Onward and Xcel Energy to maintain its secrecy and 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.

Appendix D: Project Evaluation Scores

Appendix D is marked "Not-Public" in its entirety as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The individual scoring for projects bid into Docket 23-212 is based on trade secret information provided by the bidders, and Xcel Energy's evaluation of the bids is also maintained as a trade secret. The bid evaluation methodology is the subject of efforts by Xcel Energy to maintain its secrecy and 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 the above-noted information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

1. **Nature of the Material:** The appendix includes the evaluation and scores of projects submitted to the firm dispatchable acquisition.
2. **Authors:** Xcel Energy bid evaluation personnel.
3. **Importance:** The bid evaluation information and methodology are critical to ensuring the confidentiality of future bid evaluations.
4. **Date the Information was Prepared:** June through October 2024.

Appendix H: Specific Customer Data

A portion of Appendix H is marked "Not-Public" as it includes identifying information for specific potential customers. 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.

Appendices H1 and H2: Electric Vehicle Forecasts

Appendices H1 and H2 are designated as "Not-Public" in their entirety, as they contain information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The Company considers the electric vehicles forecast models and supporting documentation to be proprietary in their design, and thus they derive an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial or otherwise competitive advantage from their use. Additionally, the files include data provided by Guidehouse that the Company treats as Not-Public pursuant to agreement with that source. Thus, Xcel Energy maintains the above-noted information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

1. **Nature of the Material:** The appendices are Excel spreadsheets that serve as the basis of the Company's ND, SD, WI and MI electric vehicles forecasts.
2. **Authors:** Xcel Energy Risk Analytics personnel.
3. **Importance:** The appendices are proprietary to the Company in their design, and they also include data the Company treats as not-public pursuant to agreement with the provider.
4. **Date the Information was Prepared:** June 2024.

Appendix H3: Nuclear Projects

Appendix H3 is marked as "Not-Public" as it includes information designated as trade secret data pursuant to Minn. Stat. § 13.37(1)(b). The nuclear project cost data 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.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact me at bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s /

BRIA E. SHEA
REGIONAL VICE PRESIDENT, REGULATORY POLICY

Encls
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF MATTER OF XCEL ENERGY'S COMPETITIVE RESOURCE ACQUISITION PROCESS FOR UP TO 800 MEGAWATTS OF FIRM DISPATCHABLE GENERATION	DOCKET NO. E002/CN-23-212
IN THE MATTER OF XCEL ENERGY'S 2024-2040 UPPER MIDWEST INTEGRATED RESOURCE PLAN	DOCKET NO. E002/RP-24-67

COMMENTS IN SUPPORT OF SETTLEMENT AGREEMENT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits these Comments in support of the comprehensive settlement agreement (Settlement Agreement) filed on October 3, 2024.[1] The Settlement Agreement is by and among the following parties: Xcel Energy, Minnesota Department of Commerce – Division of Energy Resources (Department), Clean Energy Organizations (CEOs),[2] Laborers' District Council of Minnesota and North Dakota (LIUNA), the International Union of Operating Engineers Local 49 (49ers), the North Central States Regional Council of Carpenters (Carpenters), National Grid Renewables Development, LLC (National Grid), DE Shaw Renewable Investments, L.L.C. (DESRI), Onward Energy Holdings, LLC (Onward), and Invenergy Renewables LLC (Invenergy) (collectively Settling Parties).[3]

[1] *In the Matter of Northern States Power Company d/b/a Xcel Energy's 2024-2040 Integrated Resource Plan*, Docket No. E-002/RP-24-67, Settlement Agreement (Oct. 3, 2024), eDocket No. 202410-210671-01; *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, Docket No. E-002/CN-23-212 (Oct. 3, 2024), eDocket No. 202410-210671-01.

[2] For the purposes of this Settlement Agreement, the CEOs include Fresh Energy, Minnesota Center for Environmental Advocacy, and Clean Grid Alliance.

[3] Each Settling Party is a party to either Docket No. E002/CN-23-212, Docket No. E002/CN-24-67, or both.

The Settlement Agreement addresses substantial issues among the Settling Parties in two proceedings before the Minnesota Public Utilities Commission (Commission): Xcel Energy's competitive procurement process for firm dispatchable resources (the Firm Dispatchable Docket),[4] and Xcel Energy's 2024 Integrated Resource Plan (the 2024 IRP or the IRP Docket).[5] These Comments and associated materials demonstrate that the Settlement Agreement is in the public interest, provide additional information requested during the comment period in the IRP Docket, and request approval from the Commission on one item that was inadvertently excluded from the scope of the Settlement Agreement.

EXECUTIVE SUMMARY

Xcel Energy is pleased to present the Commission with this Settlement Agreement, which represents a joint resolution of the Company's firm dispatchable acquisition efforts and its 2024 IRP.

In our 2019 IRP, the Commission approved our 2019 Preferred Plan with modifications, establishing ambitious goals for the transformation of our generation fleet. This Settlement Agreement represents the next step in achieving these goals. As we noted in our initial IRP filing, our total energy mix in 2023 was 63 percent carbon free. Following the Settlement Agreement, we anticipate that, based on our current modeling and assumptions, our total energy mix will be 88 percent carbon free by 2030, when the selected resources are in-service.

We will accomplish this change in our system by acquiring thousands of megawatts (MW) of wind, solar, and storage resources by 2030, and extending the lives of our nuclear units to provide carbon-free baseload generation. To add the resources we need to reliably serve our customers from 2027 to 2029, we will select a portfolio of renewable + storage and thermal projects—all supported by updated system-wide modeling confirming that the projects are in the public interest. These plans will be executed on an aggressive timeline to ensure that the projects are available for our customers as we retire all of our coal facilities by 2030.

We will pursue these projects with renewed commitments to equity goals and partnerships with organized labor. We also will continue to explore new methods and ideas that could benefit our customers in the future, through evaluations of clean firm resources, grid enhancing technologies, new battery storage technologies, and a Distributed Capacity Procurement program intended to maximize the benefits of

[4] Docket No. E002/CN-23-212.
[5] Docket No. E002/CN-24-67.

distributed generation on our system. These initiatives will ensure we continue to lead the clean energy transition.

The Settlement Agreement is in the public interest because it meets the needs of our customers while balancing reliability, affordability, and environmental stewardship. The Settlement Agreement will ensure that we have the firm dispatchable resources to keep our system stable and reliable in the coming years. It will also ensure that we can meet the needs of our customers every minute, every day, all year long, as shown in our energy adequacy analysis. We will be able to meet our customers' needs primarily—but not exclusively—with our system resources, protecting customers from over-reliance on regional markets.

Our analysis also shows the cost impacts of the Settlement Agreement are comparable—or even lower than—the initial Preferred Plan in our 2024 IRP. On a Present Value of Social Cost (PVSC) basis, the Settlement Agreement is $73 million lower between 2024 and 2040 compared to the updated Preferred Plan,[6] and $75 million lower over the same time period on a Present Value of Revenue Requirements (PVRR) basis. Our modeling estimates that the Settlement Agreement will have an average annual rate increase of less than one percent.

The Settlement Agreement also ensures that we are positioned to comply with Minnesota's ambitious policy goals, including the Carbon Free Standard. As we work to retire our coal fleet, the Settlement Agreement will allow us to continue our rapid transition away from carbon-emitting resources while adding significant amounts of renewable and renewable-supporting resources. As a result, modeling indicates that the Settlement Agreement will have lower carbon emissions than the reference case in every year from 2030 to 2050. Through compromise, the Settlement Agreement modifies our Preferred Plan by extending existing contracts for gas-fired units and adding one new hydrogen-capable natural gas facility in Lyon County, Minnesota. This is in place of our Preferred Plan's proposal to add four generic combustion turbines. Selection of these resources supports our environmental goals, and will allow us to comply with the Carbon Free Standard as shown in Table 1:

[6] The updated Preferred Plan is the initial Preferred Plan with updates to include an extension of the Manitoba Hydro contract, solar production profiles, and corrections for retirement dates. These updates are described in more detail in Section III.

Table 1
Settlement Agreement Carbon Free Standard Compliance

	2030	2035	2040
NSP Carbon-Free Generation (GWh)*	45,835	52,199	60,481
MN Allocated CF Generation (GWh)**	35,195	40,357	46,935
MN Elec Retail Sales (GWh)	35,726	39,669	44,625
Percentage Carbon Free Generation	98.5%	101.7%	105.2%

**NSP carbon Free generation includes biomass, hydro, utility scale solar, wind and nuclear.*

***MN Allocated CF Generation includes MN share of carbon free generation and all DG solar generation (existing and legislation required).*

The Settlement Agreement also ensures that our system is capable of integrating the new renewable resources we plan to acquire. The Lyon County Generating Station is a critical system resource that is needed to provide system stability services, and selecting it will enable us to integrate as much as 2,000 MW of renewables on the Minnesota Energy Connection transmission line in the next few years.

Developed through collaboration, careful evaluation, and reasoned compromise, the Settlement Agreement is the best path forward for Xcel Energy and our customers, and is in the public interest. For these reasons, we request that the Commission approve the Settlement Agreement.

I. DESCRIPTION OF THE SETTLEMENT AGREEMENT

A. The Settlement Process

Following the August 9 comment period in the IRP Docket, it appeared that a substantial consensus existed among parties on outstanding IRP Docket issues. The Department convened a settlement conference to explore whether a joint resolution for the Firm Dispatchable Docket and the IRP Docket could be reached. To allow for settlement discussions, Xcel Energy requested a suspension of the Firm Dispatchable Docket procedural schedule. Judge Palmer-Denig granted this request on August 27, 2024, allowing parties to engage in productive settlement negotiations. On October 3, 2024, the Settling Parties filed the comprehensive Settlement Agreement resolving outstanding issues in both the IRP Docket and the Firm Dispatchable Docket.

B. Summary of Settlement Agreement Terms

The Settlement Agreement represents a negotiated outcome across both the IRP Docket and the Firm Dispatchable Docket. The agreements related to the IRP Docket

are inextricably linked to the agreements related to the IRP docket, and the Settling Parties intend that the Settlement Agreement be approved in full without any modifications.

1. Terms Related to the IRP Docket

The Settlement Agreement includes a Five-Year Action Plan for the Company with targets for wind, solar, and storage acquisition, and nuclear facility life extensions. New resources will be procured using the Track 1 or the Modified Track 2 bidding process. Xcel Energy will file its next Integrated Resource Plan within 24 months of the Commission Order approving the Settlement Agreement. The Settlement Agreement also includes equity and labor provisions, support for a thermal battery pilot involving the Company and Rondo Energy, and requires the submission of a Distributed Capacity Procurement proposal by October 3, 2025.

2. Terms Related to the Firm Dispatchable Docket

The Settling Parties agree to an identified set of bids that will be selected in the Firm Dispatchable Docket and to specific provisions that will apply to the Power Purchase Agreement (PPA) negotiations for the selected bids.

C. Standard of Review

The Commission should evaluate the Settlement Agreement to determine whether it is in the public interest.[7]

When reviewing an IRP, the Commission's charge is to "approve, reject, or modify the plan . . . consistent with the public interest."[8] The competitive resource acquisition in the Firm Dispatchable Docket was authorized as part of the last IRP decision and, as such, is also reviewed under the public interest standard.[9]

Minnesota Rule 7843.0500, subp. 3, further provides that:

> Resource options and resource plans must be evaluated on their ability to:

[7] *See, e.g.*, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Recovery Process for Cost Impacts Due to February Extreme Gas Market Conditions*, Docket No. G011/CI-21-611, ORDER ADOPTING SETTLEMENT AGREEMENT at 8 (Oct. 19, 2022) ("The Commission is authorized to accept, reject, or modify any agreement by the parties. It can accept agreements upon finding that to do so is in the public interest and is supported by substantial evidence.").
[8] Minn. Stat. § 216B.2422, subd. 2(a).
[9] Minn. Stat. § 216B.2422, subd. 5.

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

The following sections of these Comments demonstrate that the Settlement Agreement meets these standards.

II. THE SETTLEMENT AGREEMENT RESULTS IN AN INTEGRATED RESOURCE PLAN THAT IS IN THE PUBLIC INTEREST

The Settlement Agreement establishes a reasonable IRP that is in the public interest. The settlement terms related to the IRP Docket cover five issues: the Five-Year Action Plan, resource procurement procedures, provisions related to the next IRP filing, commitments related to labor and equity, and additional program and pilot filings.

A. The Five-Year Action Plan is in the Public Interest

The Five-Year Action Plan agreed to by the Settling Parties includes the follow resource acquisition or life extension targets:

- Wind: 3,200 MWs through 2030. 2,800 MWs are projected to use the Minnesota Energy Connection transmission line submitted for a Certificate of Need and Route Permit in Dockets E-002/CN-22-131 and E-002/TL-22-132.
- Solar: 400 MWs through 2030, which are projected to use the King Interconnection.[10]
- Standalone Storage: 600 MWs by 2030. 120 MWs are projected to use the Minnesota Energy Connection.
- Nuclear: Extension of Monticello Nuclear Generating Plant to 2050, and Prairie Island Generating Plant Units 1 and 2 to 2053 and 2054, respectively, for planning purposes.

[10] The solar acquisition targets in the Settlement Agreement are in addition to forecast Community Solar Garden and Distribution Generation solar.

The reasonableness of this Action Plan is supported by the information filed in the IRP Docket, and particularly by the similar modeling results from the Company, the Department, and the CEOs (collectively, the Modeling Parties).

1. Evidence in the IRP Docket Demonstrates that Customer Needs for Energy and Capacity are Growing.

The record in the IRP Docket demonstrates that our customers' need for electricity will grow in the future. As explained in our initial IRP filing on February 1, 2024, we anticipate that customer peak demands will grow by 1.8 percent per year on average, and customer energy consumption will grow by 2.0 percent per year on average over the planning period.[11] This was a significant change from the forecasting in our 2019 IRP and is a major driver of the need to acquire substantial resources in the next few years.

There is consensus among the Modeling Parties that this forecast is reasonable. In particular, the Department conducted a detailed analysis and concluded that "Xcel's energy and capacity forecasts are reasonable pending the submission of additional information."[12] The additional information requested by the Department is discussed in Appendix H. Similarly, the CEOs conducted capacity expansion modeling based on the same forecasts used by the Company without any changes.[13] Each Modeling Party conducted a detailed review of the sales forecast, and determined that the forecast was reasonable. This growth in demand for electricity, combined with the reduction in existing resources on our system, drives the need to acquire resources that can provide the energy and capacity our customers require.

2. The Resource Targets in the Settlement Agreement are in the Public Interest.

The Settlement Agreement identifies a Five-Year Action Plan of resources to meet the customer needs in the next few years. The Settling Parties agree that the resource targets in the Five-Year Action Plan, when combined with the bids selected in the Firm Dispatchable Docket, are a reasonable way to meet customer needs for energy and capacity.

Beyond the parties' agreement, the record in the IRP Docket demonstrates that the Five-Year Action Plan in the Settlement Agreement is reasonable. As explained in our initial IRP filing on February 1, 2024, the results of our capacity expansion modeling

[11] IRP Docket, Resource Plan, Chapter 1 at 7 (Feb. 1, 2024).
[12] IRP Docket, Department Comments at 100 (Aug. 12, 2024).
[13] IRP Docket, CEO Comments at 11–13 (Aug. 9, 2024) (identifying modeling changes proposed by CEOs, which did not include any forecasting adjustments).

demonstrated the need to acquire 3,200 MWs of wind, 400 MWs of solar, and 600 MWs of standalone storage by 2030.[14] Our modeling also demonstrated that extending our nuclear facilities for planning purposes would be the most reasonable plan for our customers. The Five-Year Action Plan is consistent with this analysis, and all of the information and analysis in our initial IRP filing thus supports the outcome of the Settlement Agreement.

The Settlement Agreement also is supported by the analysis and recommendations of the Department and the CEOs in their initial comments. A comparison of the initial recommendations of the Modeling Parties is provided in Table 2:

Table 2
Initial Five-Year Action Plan Recommendations[15]

Resource	Department	Xcel Energy	Settlement	CEOs
Wind	2,400 MW	3,200 MW	3,200 MW	3,800 – 4,800 MW
Solar	600 MW	400 MW	400 MW	400 MW
Storage	N/A	600 MW	600 MW	800 – 1,200 MW
Firm Dispatchable	2,400 MW peaking resources[16]	2,244 MW	Resources from Docket 23-212	1,344 MW[17]
Nuclear	Extend for Planning	Extend for Planning	Extend for Planning	Extend for Planning

Although there are some differences between these initial recommendations, there are several major areas of convergence and the results are directionally consistent. All Modeling Parties recognized the need to obtain thousands of MW from wind and solar resources, and the reasonableness of extending the nuclear units.[18] Each modeling party also recognized the need to obtain some firm dispatchable resources during the Five-Year Action Plan.

This consensus led the Settling Parties to begin negotiations that resulted in the Settlement Agreement. The wind, solar, storage, and nuclear proposals in Xcel's Five-Year Action Plan are consistent with the results from each Modeling Party, represent a

[14] IRP Docket, Resource Plan, Chapter 4 at 10.
[15] IRP Docket, Department Comments at 62; IRP Docket, CEO Comments at 1–3.
[16] The Department proposed that the Commission should "treat battery and combustion turbine units as interchangeable for IRP purposes and defer the exact mix to the resource acquisition proceeding." IRP Docket, Department Comments at 100.
[17] This figure represents 970 MW of extended natural gas PPAs and 374 MW of new resources located on the Minnesota Energy Connection transmission line. IRP Docket, CEO Comments at 24.
[18] IRP Docket, Department Comments at 62; IRP Docket, CEO Comments at 1–3.

reasonable balance between the recommendations of the Modeling Parties, and the Settling Parties agreed that these targets for resource acquisitions would be in the public interest. The Settling Parties also agreed that with the selection of the identified bids from the Firm Dispatchable Docket, discussed in more detail in Section III, the Commission does not need to authorize the procurement of additional firm dispatchable resources in the IRP Docket. These resource targets are in the public interest because they are supported by robust modeling from each of the Modeling Parties.

There are several things that the Settlement Agreement does not do, which also are in the public interest. In particular, the Settlement Agreement does not identify a specific preferred plan for years beyond the Five-Year Action Plan or attempt to resolve complex arguments about modeling parameters. Because the recommended five-year action plans were similar among the Modeling Parties, the Settling Parties focused on reaching consensus about the actions that need to be taken in the next few years instead of spending months disputing the details of modeling parameters. The Settlement Agreement will allow us to begin all the work that must be done to acquire the thousands of MW of renewable resources our customers need. Further, conversations about detailed modeling parameters will continue in our next IRP, which will be filed in only two years.

The Settlement Agreement also does not authorize or begin procurement for any additional firm dispatchable resources beyond those selected here. The identified bids from the Firm Dispatchable Docket, combined with the resource targets in the Settlement Agreement, are sufficient to meet the needs of our customers for the next few years. Decisions about any future firm dispatchable procurements can be made in the future.

B. The Resource Procurement Provisions are in the Public Interest

The Settlement Agreement authorizes a bidding process to acquire the resources identified in the Five-Year Action Plan using the Track 1 process when Xcel Energy does not bid, and the Modified Track 2 process when Xcel Energy does bid. The Track 2 process, which was most recently used for the Firm Dispatchable Proceeding, would not be used to acquire resources selected in the Settlement Agreement.

This change is in the public interest because, as recognized by Comments in the IRP Docket, recent experiences have revealed flaws in the Track 2 process. Comments filed in the IRP Docket on August 9, 2024 by the Company, the Department,[19] and the CEOs[20] each recommended that the Track 2 process should not be used for acquisitions

[19] IRP Docket, Department Comments at 101.
[20] IRP Docket, CEO Comments at 58.

stemming from this resource plan. Each Comment recognized the challenges of conducting a competitive resource acquisition in a contested case proceeding, and concluded that the challenges outweigh the potential benefits. The length of a Track 2 proceeding makes it challenging for developers to participate. As such, it cannot be effectively used to select resources at the pace needed to meet the needs of customers.

The Settlement Agreement also includes reasonable provisions, initially proposed in the Comments of the Federal Executive Agencies,[21] that will allow the Company to efficiently acquire resources for customer-facing carbon free generation programs. While there are no such programs requiring resources at this time, this procedural step will allow us to obtain resources efficiently if programs are approved by the Commission in the future.

C. Provisions for the Next IRP are in the Public Interest

The Settlement Agreement also includes provisions related to the next IRP filing that are in the public interest.

The Company has agreed to file the next IRP within 24 months of the Commission Order approving the Settlement Agreement, which is consistent with the public interest because the timeline is based on the Commission's Rules.[22] The Company also has agreed to three components that will be included in the next IRP: a more detailed discussion of clean firm resources; a discussion about Grid Enhancing Technologies and how they could impact resource planning; and a sensitivity analysis that caps the capacity of natural gas peaking plants. These additional analyses are in the public interest because they will focus our efforts on areas that stakeholders have identified as beneficial for customers.

D. Equity and Labor Commitments are in the Public Interest

The Settlement Agreement also includes labor and equity programs that are in the public interest. In particular, the Legislature has recently passed statutes ensuring that utilities focus on local job creation and consider labor issues in selecting projects,[23] and evaluate diversity and equity in both their operation and supply chains.[24]

[21] IRP Docket, Federal Executive Agencies Comments at 7.
[22] *See* Minn. Rule 7843.0300, subp. 2.
[23] *See* Minn. Stat. § 216B.2422, subd. 4a.
[24] *See* Minn. Stat. § 216C.51.

To support these efforts, the Settlement Agreement ensures that work will continue to evaluate methods to increase participation and outcomes from our energy efficiency programs in connection with the Energy Conservation and Optimization program.

In addition, the Company has committed to working with stakeholders to explore methods to increase career opportunities for populations that are currently underrepresented in energy sector employment while implementing the resource plan, including tracking and reporting about the makeup of our workforce. The Company also has committed to working with stakeholders to maximize socioeconomic benefits to our host communities.

These provisions represent meaningful commitments from the Company to continue our efforts to support equity and labor partnerships.

E. Program and Pilot Filings are in the Public Interest

The Settlement Agreement also includes commitments for new projects and programs that are in the public interest.

The first is a commitment to continue working with Rondo Energy to explore a thermal heat battery pilot. The Company believes that, with additional time and development, a thermal heat battery concept could provide value to our customers. To that end, the Company has committed to explore a thermal heat battery pilot with Rondo Energy and make a filing by December 31, 2025. To ensure that any pilot program is targeted to maximize value, the Company has further committed that any pilot will be large enough to provide valuable information about scalability and optimization.

The Company also commits to filing a Distributed Capacity Procurement (DCP) program by October 3, 2025. The DCP program is envisioned as a way to align the growth of Distributed Energy Resources (DERs) on our system with locations which can provide the most benefit to our customers as a whole. The DCP program would actively work to procure DERs and target them to maximize the efficiency of existing infrastructure.

The Company recognizes that there is growing interest in the DCP program from developers who want to understand how they can engage and customers who are interested in learning more about their options to participate. The Five-Year Action Plan was developed with the expectation that there will be over 1,000 MW in incremental customer-driven community solar and distributed generation brought online by 2030. This growth will more than double the amount of DERs on our system

by the end of the decade,[25] and developers and customers will have many opportunities to invest in DERs through existing programs during that time. With this level of expected growth from the Company's existing DER programs, it is appropriate for the Company and stakeholders to take the time needed to develop a DCP program that can maximize benefits for customers before it is filed next year.

The Company's commitment to develop the details of the DCP program over the course of the next year is in the public interest. At this time, the DCP program is still in its early development phase, and it is too early to make any detailed programmatic decisions. Providing this time, therefore, will ensure the Company has the flexibility to design a DCP program that best serves our customers and can be implemented effectively.

Our commitment to move forward with these new programs further demonstrates that the Settlement Agreement is in the public interest.

F. Public Interest Finding

The Commission's Rules identify specific factors that must be evaluated when determining if the Settlement Agreement's resolution of the IRP Docket is in the public interest.[26] Each of these factors weighs in favor of the Settlement Agreement, particularly when incorporating the analysis in our initial IRP filing.[27]

1. Adequacy and Reliability

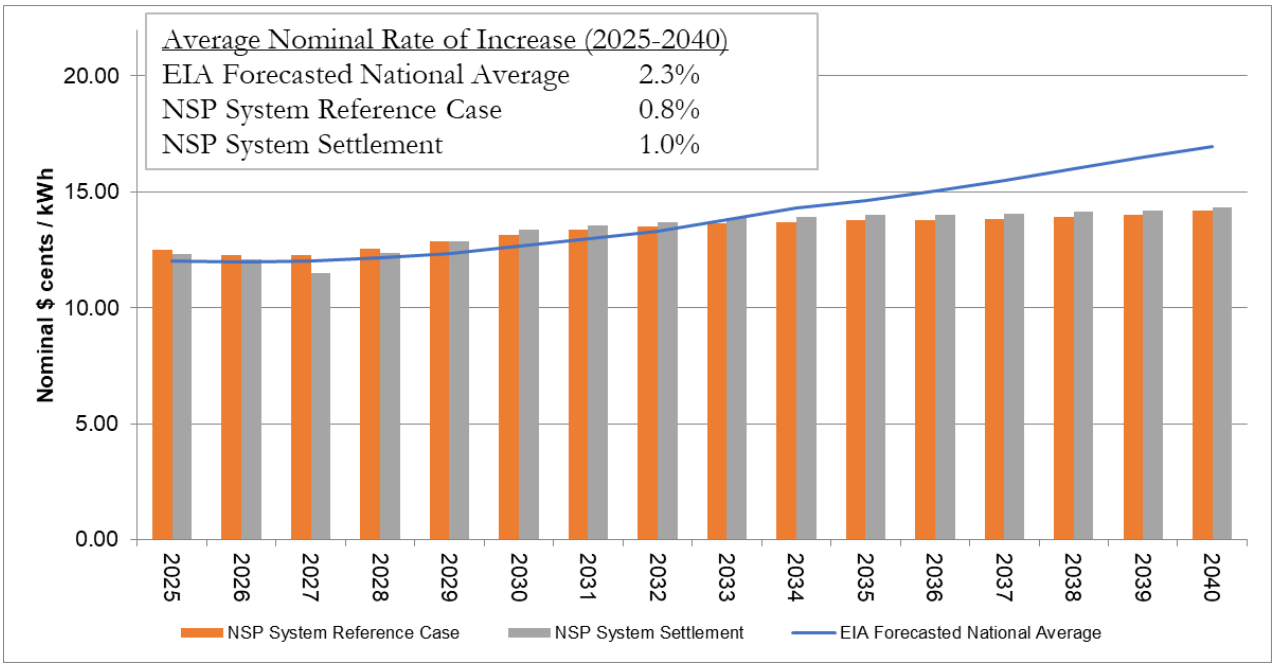
The Settlement Agreement supports Xcel Energy's strategic goals to provide safe and reliable service while retiring baseload generation units. Through coordination with the Settling Parties, the Company has identified a path to maintaining reliability, continuing to meet regional planning reserve requirements, and ensuring energy adequacy for our customers. The results of our analysis related to energy adequacy under the Settlement Agreement are located in Appendix A. This information demonstrates that the Settlement Agreement will allow us to reliably meet the needs of our customers without over reliance on the regional market. Our transmission analysis, discussed in Section III.C, also demonstrates that the resources selected by the Settlement Agreement will result in a stable system and support our system restoration goals.

[25] Our system includes 1,091 MW of Community Solar and Distributed Generation resources in 2024, and the IRP modeling assumes that Community Solar and Distributed Generation will increase to 2,306 MW by 2030.
[26] Minn. Rule 7843.0500, subp. 3.
[27] *See* IRP Docket, Resource Plan, Chapter 4 at 12–15, Appendices D, K, and R.

2. Impact to Customer Bills

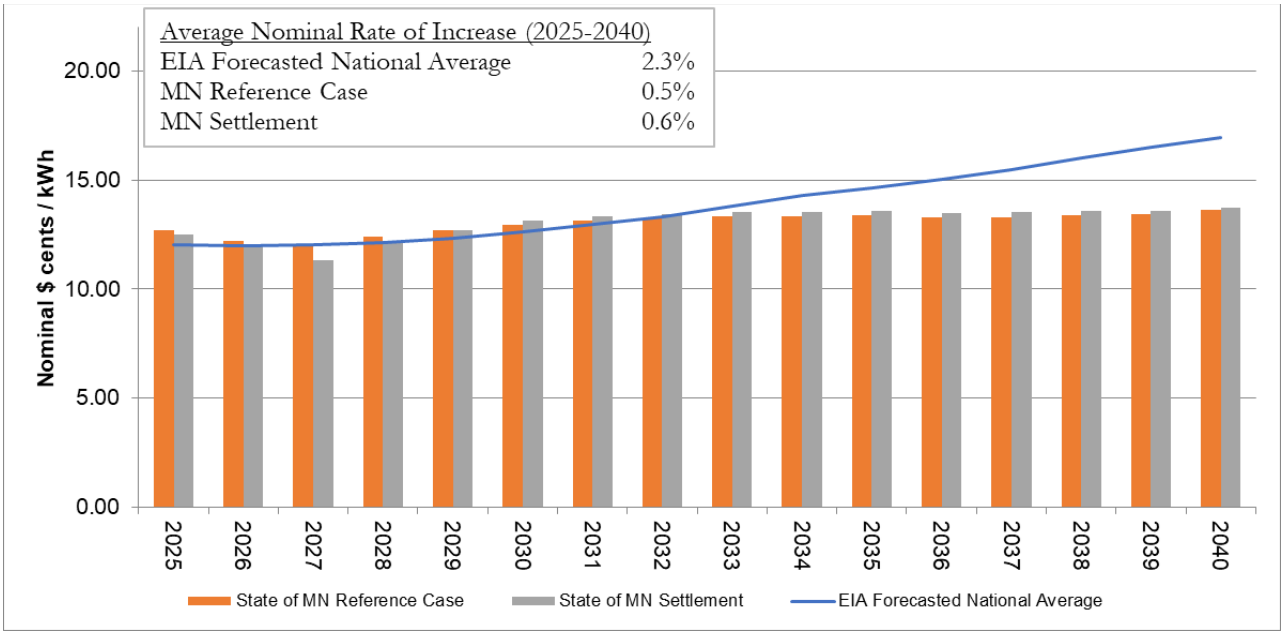
The Settlement Agreement will result in similar impacts to customer bills as the initial Preferred Plan. As with the initial Preferred Plan, our analysis estimates that the Settlement Agreement will result in a less than one percent average annual rate increase for our Minnesota customers. This puts us on a path to outperform our utility peers, based on the Energy Information Administration's predication that utility rates will grow at 2.3 percent annually over the same time period. The estimated cost impacts are displayed in Figures 1 and 2:

Figure 1
Average Nominal Cost Comparison
NSP System[28]



[28] Updated from Figure 6-1 in our initial IRP filing.

Figure 2
Average Nominal Cost Comparison
State of Minnesota[29]



For purposes of this analysis, the "reference case" is the updated Preferred Plan used to model the bids in the Firm Dispatchable Docket. As described in more detail in Section III.C, the initial preferred plan was updated to incorporate an extension of the Manitoba Hydro contract, updates to solar production profiles, and corrections to in-service dates.

For all customers, we estimate that the Settlement Agreement will have cost impacts summarized in Table 3:

[29] Updated from Figure 6-2 in our initial IRP filing.

Table 3
Estimated Incremental Impact of Settlement Agreement
State of Minnesota – All Customers

Year	Reference Case Revenue Req ($000)	Incremental Impact of Settlement ($000)	Settlement Revenue Req ($000)	Incremental Impact (%)
2025	$3,636,699	-$56,970	$3,579,729	-1.57%
2026	$3,738,263	-$54,759	$3,683,504	-1.46%
2027	$3,842,664	-$243,216	$3,599,448	-6.33%
2028	$3,949,980	-$64,808	$3,885,172	-1.64%
2029	$4,060,293	-$4,092	$4,056,201	-0.10%
2030	$4,173,687	$72,685	$4,246,372	1.74%
2031	$4,290,248	$72,408	$4,362,656	1.69%
2032	$4,410,064	$63,908	$4,473,972	1.45%
2033	$4,533,227	$75,759	$4,608,985	1.67%
2034	$4,659,829	$75,916	$4,735,744	1.63%
2035	$4,789,966	$74,971	$4,864,937	1.57%
2036	$4,923,738	$71,868	$4,995,606	1.46%
2037	$5,061,246	$77,281	$5,138,527	1.53%
2038	$5,202,594	$78,474	$5,281,069	1.51%
2039	$5,347,890	$57,352	$5,405,243	1.07%
2040	$5,497,244	$46,793	$5,544,037	0.85%

This analysis indicates that, compared to the reference case, the Settlement Agreement will result in lower bill impacts in the short term, and slightly higher bill impacts from 2030 to 2040.

These modest and reasonable rate impacts further support finding that the Settlement Agreement is in the public interest.

3. Environmental Effects

The Settlement Agreement continues Xcel Energy's commitment to minimizing and addressing environmental effects. Through engagement with the Settling Parties, the Settlement Agreement satisfies our short-term need for firm dispatchable resources

during the 2027 to 2029 timeframe putting the Company in a position to comply with the Carbon Free Standard and Minnesota's other renewable energy standards, as demonstrated in Table 4:

Table 4
Carbon Free Standard Compliance with Settlement Agreement Acquisitions

	2030	2035	2040
NSP Carbon-Free Generation (GWh)*	45,835	52,199	60,481
MN Allocated CF Generation (GWh)**	35,195	40,357	46,935
MN Elec Retail Sales (GWh)	35,726	39,669	44,625
Percentage Carbon Free Generation	98.5%	101.7%	105.2%

**NSP carbon Free generation includes biomass, hydro, utility scale solar, wind and nuclear.*

***MN Allocated CF Generation includes MN share of carbon free generation and all DG solar generation (existing and legislation required).*

Approving the Settlement Agreement will allow the Company to be in compliance with the Carbon Free Standard at each of the milestone years.[30] Additional information about compliance with the Renewable Energy Standard and Solar Energy Standard is provided in Appendix B.

Under the Settlement Agreement, our system will continue the significant transition to clean resources on both a capacity and energy basis, as shown in Figures 3 and 4.[31]

[30] The Company anticipates that the Environmental Report regarding the Firm Dispatchable Docket will be filed around November 22, 2024 once it is completed by the Department of Commerce – Energy Environmental Review and Analysis. The Company will provide any appropriate response after reviewing the Environmental Report.

[31] The Settlement Agreement does not include any provisions about the selection of resources beyond the Five-Year Action Plan, the specific years for acquisitions during the Five-Year Action Plan, the specific categorization of bids in the Firm Dispatchable Docket 23-212, or the existence or non-existence of firm dispatchable needs in 2030 or beyond. The Settlement Agreement does contain provisions confirming that the Company is not requesting approval of any new or incremental procurement processes for firm dispatchable resources at this time.

Figures 3, 4, and 5 were created at the request of Commission Staff in MPUC Information Request 16 and are updated from Figures 1-1, 1-2, and 1-6 from our initial filing in the IRP docket. The updated tables in these Comments assume that the generic firm peaking resources are deleted from 2027 and 2028, the selected resources from the Firm Dispatchable Docket are added, and the remaining resources are added based on the Company's original Preferred Plan. Because these assumptions are outside the provisions of the Settlement Agreement, Figures 3, 4, and 5 may not reflect the specific terms and agreements reached in the Settlement Agreement.

Figure 3
NSP System 2024 and 2040 Settlement Agreement Nameplate Capacity Mix

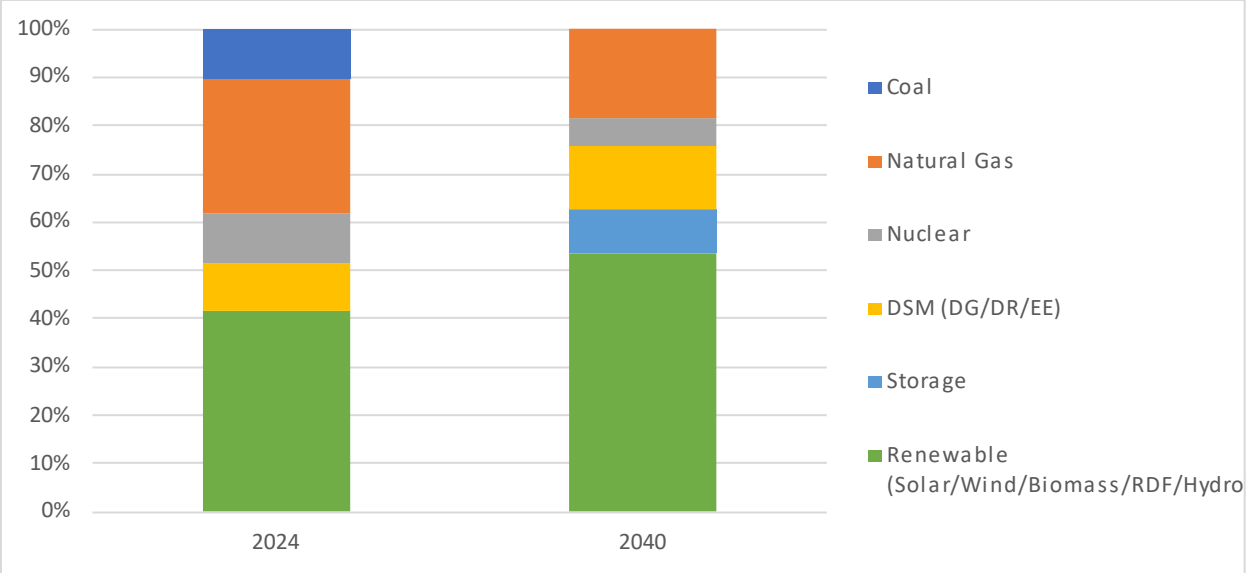


Figure 4
NSP System 2024 and 2040 Settlement Agreement Energy Mix

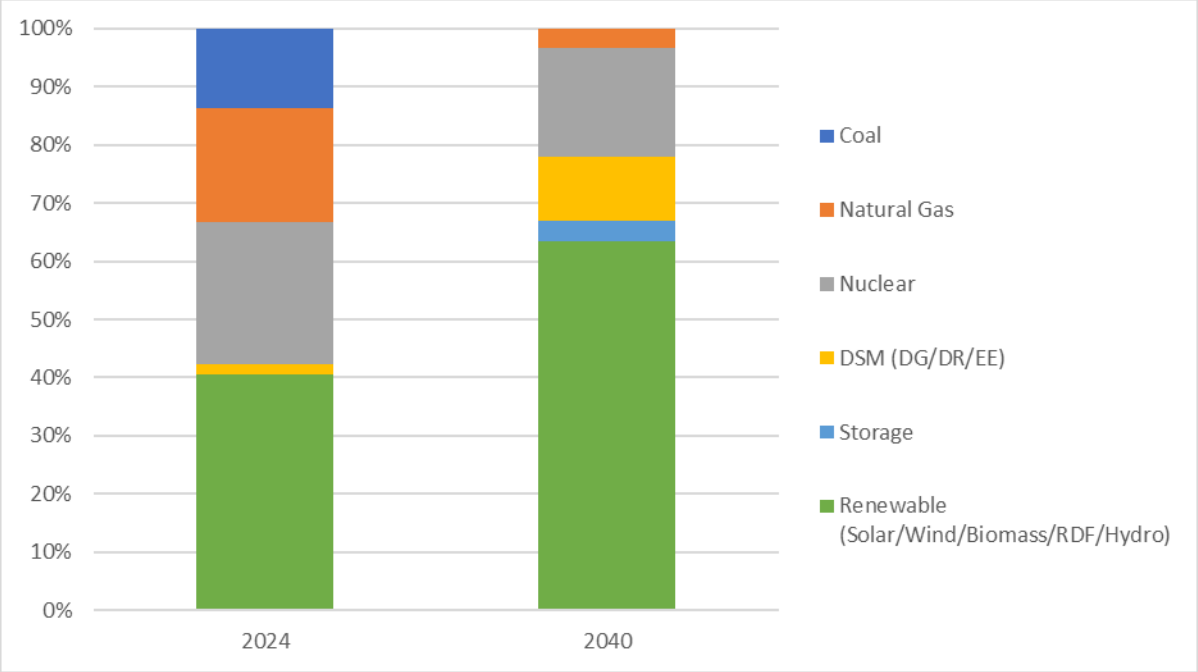
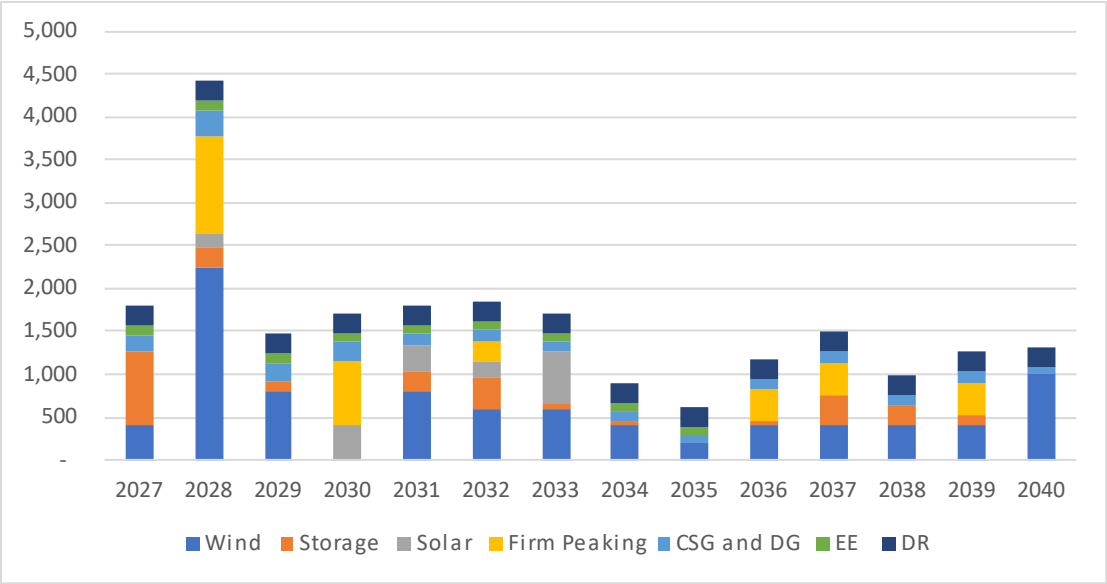


Figure 5
2024-20240 Preferred Plan Resource Additions with Settlement Agreement (MW)



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	400	2,230	800	-	800	600	600	400	200	400	400	400	400	1,000
Storage	860	245	120		240	360	60	60	-	60	360	240	120	
Solar	-	150	-	400	300	200	600		-	-		-	-	
Firm Peaking	-	1,150	-	748		225	-		-	374	374	-	374	
CSG and DG	198	301	215	237	131	134	123	106	94	110	125	121	130	90
EE	108	105	103	87	91	85	82	86	80	0	0	0	0	0
DR	239	239	239	239	238	237	237	236	236	235	235	235	234	234

4. Socioeconomic Impacts

As noted in the initial IRP filing, the Company acknowledges that retirement of legacy generation assets will have a significant impact on the employees and host communities. The Settlement Agreement builds on our existing partnerships by establishing additional commitments for labor and equity goals. Through these agreements, the Settlement Agreement will have a positive socioeconomic effect on our customers and host communities. In addition to these commitments, the Settlement Agreement also includes a specific project—Xcel Energy's Sherco storage project—that is located near an existing host community, and which will result in good-paying jobs during the construction efforts.

Additionally, on October 15, 2024, the Company filed a joint letter with the Coalition of Utility Cities.[32] The joint letter proposed decision options, developed in partnership with several host communities, to reflect Xcel Energy's commitment to continue

[32] Xcel Energy and Coalition of Utility Cities, Joint Letter (Oct. 15, 2024), eDocket No. 202410-210988-01.

working with host communities and providing updates on that work to the Commission. These commitments also support the public interest.

Beyond these specific efforts, the Settlement Agreement will also have positive socioeconomic impacts because it will allow the Company to provide safe, reliable electricity to its customers at reasonable prices. These services at reasonable prices are critical to the everyday lives of our customers.

5. Flexibility to Respond to Change and Limiting Risks

The Settlement Agreement maintains and enhances the Company's ability to respond to changes and limit risks for customers. In particular, the Settlement Agreement continues the Company's strategic objective of securing a diversified resource mix, made up of both Company-owned projects and PPAs. The Settlement Agreement also diversifies the types of resources on our system, ensuring that customers are protected from over-reliance on any single fuel source. As demonstrated by our energy adequacy analysis, the Settlement Agreement also protects customers from an unreasonable level of market reliance.

The Settlement Agreement also satisfies some of our firm dispatchable needs through contract extensions, as discussed in more detail in Section III. Acquiring these resources ensures that we have sufficient energy and capacity to meet customer needs. Doing so through PPA contracts provides flexibility and adaptability in the long-term. In addition, the Settlement Agreement preserves our flexibility to respond if additional large load customers locate in our service territory. Large load customers, such as data centers, have the potential to provide significant benefits to our customers including economic growth and, potentially, reduced need for future rate increases. Maximizing these opportunities, however, may require additional generation to meet the large demand for energy and capacity that data centers require. The Settlement Agreement ensures that we have flexibility to respond to new large loads as appropriate, by ensuring we have adequate resources to meet our existing needs and by including a process for obtaining approval if circumstances change before our next IRP is filed.

III. THE SETTLEMENT AGREEMENT SELECTS REASONABLE PROJECTS TO MEET THE FIRM DISPATCHABLE NEEDS OF XCEL ENERGY'S CUSTOMERS

The Settlement Agreement establishes a resolution of the Firm Dispatchable Docket that is consistent with the public interest and should be approved.

A. Description of the Selected Bids

The Settlement Agreement selects seven projects from the Firm Dispatchable Docket:

- DESRI – North Star Battery Energy Storage System: The North Star Battery Energy Storage System (BESS) proposal involves adding storage capacity to the existing 100 MW North Star Solar Facility. The project would be located in Chisago County, Minnesota, next to the existing North Star Solar substation.

- Invenergy – Lake Wilson: The Lake Wilson proposal includes a 150 MW solar generating facility and up to a 95 MW / 380 MWh BESS located near Lake Wilson in southwestern Minnesota. The project has an existing Generation Interconnection Agreement with Midcontinent Independent System Operator (MISO) for 150 MW for the solar facility, and 20 MW for the BESS. Additional BESS capacity is under consideration in MISO's Surplus Interconnect process. Invenergy proposes to enter into a PPA where the Company will purchase the output of the Lake Wilson project. On April 23, 2024, the Commission issued a Certificate of Need and Site Permit for the Lake Wilson project.[33]

- Invenergy – Cannon Falls: Cannon Falls is a set of two gas-fired combustion turbines, totaling 357 MW in size, located in Cannon Falls, Minnesota. Xcel Energy currently purchases the output of Cannon Falls under a PPA that will expire in 2028. Invenergy proposes to extend the existing PPA with potential modifications to the price and other terms.

  Cannon Falls has an existing interconnection with the Northern Natural Gas interstate pipeline. As part of its current and proposed PPAs, the Company would source and secure the natural gas that Cannon Falls would use. The Cannon Falls facility is also capable of operating on fuel oil.

- National Grid – Plum Creek: The Plum Creek proposal is for a 230 MW wind farm and a 150 MW / 600 MWh BESS located in Redwood, Murray, and Cottonwood Counties, Minnesota. National Grid proposes to enter into a PPA where the Company would purchase the output of the Plum Creek project.

[33] *In the Matter of the Application of Lake Wilson Solar Energy LLC for a Certificate of Need and a Site Permit for the up to 150 MW Lake Wilson Solar and Associated Battery Storage Project in Murray County, Minnesota*, Docket No. IP-7070/CN-21-791, GS-21-792, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING SITE PERMIT at Order Point 5 (Apr. 23, 2024).

In Dockets 18-699, 700, and 701, the Commission issued a Certificate of Need and Site Permit for the Plum Creek Wind farm on September 23, 2021.[34] Subsequently, National Grid requested and received a permit amendment extending the deadline to begin construction to September 23, 2025.[35] National Grid states that it is pursuing an amendment of the permit to include the BESS.

- Onward – Mankato Energy Center: Onward proposed an extension to the existing PPA for the natural gas combined cycle facility at Mankato Energy Center (MEC) 1, with new BESS blackstart capability. The MEC facility has an existing interconnection with the Northern Natural Gas interstate pipeline. As part of its current and proposed PPAs, the Company would source and secure the natural gas that MEC 1 would use. The MEC facility is also capable of operating on fuel oil.

- Xcel Energy – Sherco West 4-hour BESS: Sherco West 4-hour BESS is a new 4-hour 300 MW BESS located near the existing and planned Sherco Solar facilities in Clear Lake Township, Minnesota.

- Xcel Energy – Lyon County Generating Station: The Lyon County project consists two combustion turbine (CT) totaling 420 MW in capacity and associated facilities, to be located at a greenfield generating station in Lyon County, Minnesota near the terminus of the Minnesota Energy Connection transmission line.

The Settlement Agreement does not select Xcel Energy's Bison Generating Station natural gas CT that was proposed to be located in Cass County, North Dakota. The Settlement Agreement also does not select the five projects that were withdrawn before the Settlement Agreement was finalized.

The remainder of this section will explain why it is in the public interest to select these bids.

[34] *In the Matter of Applications of Plum Creek Wind Farm, LLC for a Certificate of Need, Site Permit, and Route Permit for an up to 414 MW Large Wind Energy Conversion System and 345 kV Transmission Line in Cottonwood, Murray, and Redwood Counties*, Docket Nos. IP-6997/CN-18-699, WS-18-700, TL-18-701, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING SITE PERMIT AND ROUTE PERMIT at Order Point 3,4 (Sept. 23, 2021).

[35] Docket Nos. IP-6997/CN-18-699, WS-18-700, TL-18-701, ORDER at 1 (July 5, 2023).

B. There is a Substantial Need for Firm Dispatchable Resources

The Commission authorized the acquisition of firm dispatchable resources in the Firm Dispatchable Docket through its April 15, 2022 Order in our 2019 IRP. Specifically, Order Point 3 states that "[I]t is more likely than not that there will be a need for approximately, but not more than, 800 MW of firm dispatchable resources between 2027 and 2029."[36] The Commission clarified that the "finding will not, by itself, support plans to acquire more than 800 MW."[37] In Order Point 3.C, the Commission further required that:

> Xcel shall analyze this likely need based on up-to-date system-wide modeling, including corrected modeling of wind fleet variability and of exchanges with MISO, in order to –
>
> 1) establish the capacity, energy, resource adequacy, energy availability, ancillary service, and reliability needs, and
> 2) quantify and compare the contribution of the electric system attributes from the different resource options considered to meet the identified grid needs.[38]

The 2019 IRP Order thus recognized the need to acquire firm dispatchable resources, but also contemplated that the final amount to be acquired could change in the future. The Commission explicitly recognized the need for resources might be more or less than 800 MW, and ordered the Company to provide updated system modeling to justify the amount of firm dispatchable resources that ultimately would be needed. This subsection demonstrates that the need for firm dispatchable resources is larger than 800 MW, and the following subsection demonstrates that the selected bids from the Firm Dispatchable Docket are a reasonable way to meet that need.

1. Forecasts for Demand and Energy have Increased

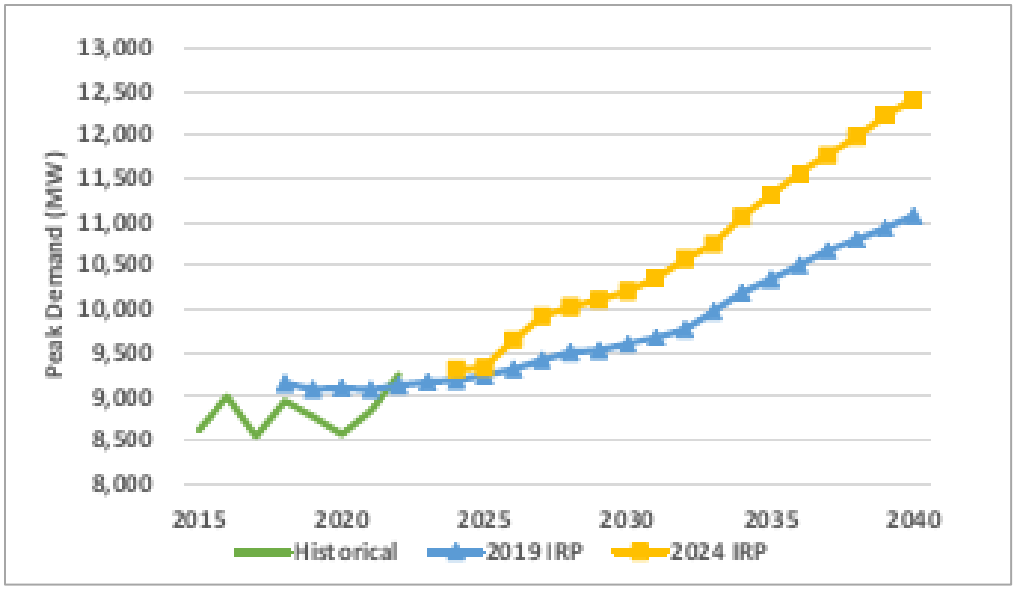
The first step in our updated system modeling is to incorporate updated forecasts for customer energy and demand. The Commission initiated this firm dispatchable procurement based on the forecasting from our 2019 IRP. The sales forecast has changed materially since the 2019 IRP Order, which should not be surprising—it has

[36] *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 APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS at Order Point 3 (Apr. 15, 2022) (hereinafter "2019 IRP Order").
[37] 2019 IRP Order at 14.
[38] 2019 IRP Order at Order Point 3.C.

been two years since the 2019 IRP Order, and more than four years since the underlying forecast was performed.

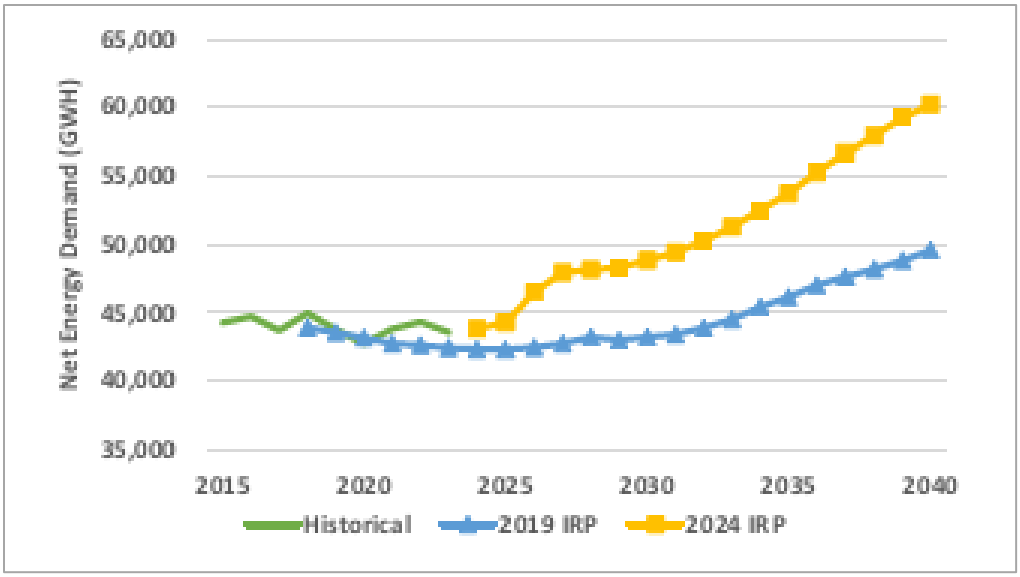
The forecasts used for the 2019 IRP estimated that growth in net customer sales and peak customer demands would be less than one percent annually through the entire planning period.[39] In comparison, the forecast for the 2024 IRP (which served as the basis for analysis of the resource portfolio selected in the Firm Dispatchable Docket[40]) estimates that net peak demand will grow at 1.8 percent per year, and that net energy sales will grow at more than 2.0 percent per year.[41] This change in forecast demand is displayed in Figure 6, and the change in forecast energy requirements is displayed in Figure 7:

Figure 6
Comparison of Baseline Demand



[39] *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, Xcel Supplement at 10–11 (June 30, 2020).
[40] The 2024 IRP filing is based on our fall 2023 forecast. Our updated system modeling uses the same forecast as the 2024 IRP in response to the Commission's stated preference for consistency in forecasting across related proceedings, and to avoid presenting the Commission with two dockets that use different underlying forecasting.
[41] IRP Docket, Initial Filing, Appendix E.

Figure 7
Comparison of Baseline Energy



These forecasts are reasonable and based on underlying methodologies that are generally consistent with methods that the Commission has approved in the past. The sales forecast is described in more detail in Appendix E to the initial filing of our 2024 IRP. The increased growth predicted by the updated forecasts is significant and translates into an increased need to acquire system resources compared to the 2019 IRP.

The primary drivers of our increased sales forecast are due to growth in data center loads and an increase in the adoption of electric vehicles. A smaller but also meaningful impact is expected as a result of increased beneficial electrification for space and water heating.

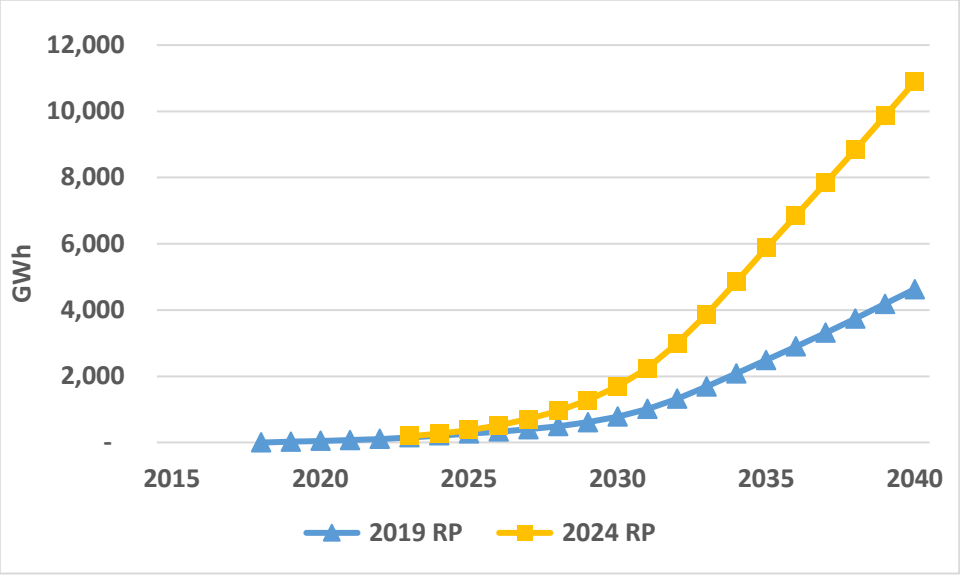
The 2024 IRP base demand and energy forecasts reflect **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of new load from data centers in the 2025–2027 timeframe. This new load exceeds traditional high load sensitivity assumptions and reflects data center growth triggered by machine learning/artificial intelligence technologies, which are more energy-intensive than traditional data processing methods.

Including this level of growth in data center load in our forecast is reasonable because it is based on specific facts and conservative assumptions about known projects. In particular, the Company has a signed Electric Services Agreement (ESA) with **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS]. Several other customers have already conducted

transmission studies, and many more have approached the Company with interest in developing data center projects. If all phases of all prospective projects were completed, it would reflect several thousand MW of new demand within the next decade. It is unlikely that all phases of all prospective data center projects will be completed, but even a fraction of this growth would be much larger than the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of data center load growth included in the base forecast.

The 2024 IRP forecast also is higher than the 2019 IRP forecast because of increased electric vehicle loads. The 2024 IRP base demand and energy forecast assumes approximately 277,000 electric Light Duty Vehicles (LDV) in the Company's service territory by 2030, representing about 6.8 percent of registered LDV. By 2040, electric LDV ownership increases to 1.6 million LDV (about 38 percent of registered LDV). The 2019 IRP demand and energy forecast assumed only about half this rate of electric vehicle adoption, and thus only about half of the energy and demand impact. Figure 8 below compares the 2019 IRP and 2024 IRP electric vehicle energy consumption forecasts.

Figure 8
Comparison of Electric Vehicle Forecasts



The accelerated adoption outlook is driven by three factors: 1) additional observed electric vehicle adoption and consumption to inform the forecast, which has been

higher than forecast in the 2019 IRP, 2) Minnesota programs and goals[42] that support higher electric vehicle adoption levels, and 3) additional sources of information regarding electric vehicle adoption, particularly information from the Electric Power Research Institute, in addition to sources that were used in the past.

In addition to these two main drivers, the 2024 IRP baseline demand and energy forecasts also reflect updated beneficial electrification and energy efficiency assumptions.

The forecasts were reviewed and found to be reasonable by the other Modeling Parties. As discussed above, the Department conducted a detailed analysis of our updated forecasting and concluded that "Xcel's energy and capacity forecasts are reasonable pending the submission of additional information."[43] This additional information is provided in Appendix H to this filing. The CEOs also performed capacity expansion modeling based on the same forecasts used by the Company. In short, each of the Modeling Parties that provided specific capacity recommendations to the Commission agrees that the Company's forecasts—which are substantially higher than the forecasts from the 2019 IRP—are reasonable. The record in the 2024 IRP demonstrates that there is no significant dispute about the material increases in forecasts for demand and energy.

2. *Increased Customer Sales Leads to Increased Need for Firm Dispatchable Resources*

The increased sales forecast led to an increased need for resources, including firm dispatchable resources. This need is supported by the modeling and recommendations provided by each of the Modeling Parties in the 2024 IRP.

The Company's capacity expansion modeling demonstrated a short-term need for more than 800 MW of firm dispatchable resources, as demonstrated in Figure 9:

[42] *See* Minnesota Department of Commerce Electric Vehicle Rebate Program, https://mn.gov/commerce/energy/consumer/energy-programs/ev-rebates-faq.jsp; Minnesota Department of Transportation, *Accelerating Electric Vehicle Adoption: A Vision for* Minnesota (2019) (identifying State goal of powering 20 percent of light-duty cars in the state with electricity by 2030), https://www.lrl.mn.gov/docs/2019/other/190972.pdf.

[43] IRP Docket, Department Comments at 100.

Figure 9
Short Term Resource Needs[44]

	2025	2026	2027	2028	2029	2030
Wind	350	0	400	2,000	800	0
Storage	0	0	480	0	120	0
Solar	585	0	0	0	0	400
Firm Peaking	298	0	748	748	0	748
CSG and DG	124	140	198	301	215	237
EE	103	108	108	105	103	87
DR	234	237	238	239	239	239

The Company's IRP modeling indicated a need to add 748 MW of firm dispatchable resources in 2027, 748 MW in 2028, and 748 MW in 2030, for a total of 2,244 MW from 2026 to 2030.[45] In the specific window targeted by the firm dispatchable procurement in the Firm Dispatchable Docket, the 2024 IRP modeling indicated a need for 1,496 MW of firm dispatchable resources. The Company's modeling also indicates the need to acquire 600 MW of storage between 2027 and 2030.

The modeling performed by the Department and the CEOs also indicated a need for more than 800 MW of firm dispatchable resources. The Department updated some of the Company's modeling parameters and re-ran the capacity expansion model. Following this analysis, the Department recommended that the Company acquire 1,800 MW of peaking resources in 2027 to 2028, an additional 600 MW of peaking resources in 2029 to 2030,[46] and that the Commission "treat battery and combustion turbine units as interchangeable for IRP purposes and defer the exact mix to the resource acquisition proceeding."[47]

CEOs also updated some modeling parameters and re-ran the capacity expansion modeling. CEOs presented four different scenarios with different parameters. Importantly, in programming their model, the CEOs assumed the addition of natural gas units comparable to what is selected by the Settlement Agreement. CEOs explained that their model "assumed that the power purchase agreements . . . for some existing gas units could be extended by 10 years . . . . This change made 968 MW (winter ICAP) of existing gas resources available into the late 2030s . . . ."[48] These assumptions included extensions for the Cannon Falls and Mankato Energy Center units that are

[44] Data for this table is taken from Figure 1-6 in the initial 2024 IRP filing.
[45] The resources indicated in 2025 have already been approved, and include Sherco Solar, Wheaton, and repowered wind.
[46] IRP Docket, Department Comments at 61.
[47] *Id.* at 101.
[48] IRP Docket, CEO Comments at 11.

selected in the Settlement Agreement. The Cottage Grove unit, which the CEOs assumed could also be extended, did not bid into the Firm Dispatchable Docket. It is the Company's understanding, based on negotiations with the plant owner, that LSP-Cottage Grove is not an available resource to the Company. In addition to the 968 MW of natural gas PPA extensions, CEOs "fixed in 374 MW of dispatchable capacity (modeled as a CT on Xcel's Sherco tie-line), as the tie-line approach was approved in the 2019 IRP . . . ."[49]

Based on these assumptions, CEOs modeling analysis includes "the already-approved 374 MW of firm dispatchable capacity [on the Sherco tie-line] and extending 968 MW of existing PPAs."[50] Taken together, these recommendations from CEOs call for acquiring approximately 1,300 MW of firm dispatchable resources by 2030.[51] In addition, CEOs recommended that the Company acquire 800 to 1,200 MW of energy storage by 2030.[52]

In sum, all of the modeling supports the need for adding the amount of resources included in the Settlement Agreement between 2027 and 2029.

3. Deferring the Acquisition of Firm Dispatchable Resources would Create Unacceptable Risks for Customers

The Company recognizes that acquiring more than 800 MW of firm dispatchable resources from the set of resources that bid into the Firm Dispatchable Docket was not the original plan. It is not unusual, however, for the Company to acquire more or less resources in an acquisition proceeding than originally planned when doing so is cost effective and in our customers' interest.[53] As explained above, the underlying energy and capacity needs have changed from what the Commission considered in our 2019 IRP, and consequently the Company's need for firm dispatchable resources to serve our customers' load has increased. It is reasonable to select the identified bids to meet these

[49] *Id.* at 16.
[50] *Id.*
[51] *Id.*
[52] *Id.* at 23.
[53] *See, e.g., In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan*, Docket No. E-002/M-16-777, ORDER APPROVING PETITION GRANTING VARIANCE, AND REQUIRING COMPLIANCE FILING at 6-7 (Sept. 1, 2017) (authorizing the Company to acquire more wind resources than ordered in the 2016-2030 IRP upon finding the proposal reasonable and consistent with the public interest); *In the Matter of Xcel Energy's Wind Repower Portfolio*, Docket No. E-002/M-20-620, ORDER APPROVING WIND FACILITY REPOWERING PROJECTS at 7-8 (Jan. 22, 2021)(authorizing wind repowering projects and PPA despite Company exceeding the 1,000 MW of wind acquisition approved in 2016-2030 IRP because of significant anticipated ratepayer benefits associated with the projects).

needs now because waiting to acquire the needed resources would create risks for our customers.

Our need for firm dispatchable resources arises in the near, but still actionable, future. Deferring a decision on incremental acquisitions, however, would make it difficult or impossible to bring the resources online when our customers need them. A delay may force us to compromise on one of our core goals of affordability, reliability, or environmental stewardship.

Regarding reliability and system adequacy, our need for firm dispatchable resources first arises in 2027, and delaying a decision will make it challenging to acquire resources in that timeframe. For example, measuring from the 2019 IRP Order, by the conclusion of these proceedings, it will likely have taken around three years to select projects to meet the firm dispatchable needs that initially were shown in the 2019 IRP. And once these matters are concluded, the work will not be done. Projects will still need to be permitted—likely taking up to a year—and then actually built. Starting a new acquisition process for firm dispatchable resources now would make it nearly impossible for them to be selected, permitted, and constructed before customers need them in 2027 and 2028.

The Department noted similar issues in its comments in the IRP Docket. The Department pointed to evidence of significant delays in interconnection requests for new generation, and stated that it could be reasonable to assume that no new supply units are possible in the first five years of an IRP model unless they can avoid the MISO queue or are already significantly through the interconnection queue study process.[54]

If we do not have resources available at the time they are needed, there are potentially major impacts. Firm dispatchable resources provide essential grid services and quickly respond at the hours of highest customer demand over the entire year. If we do not have the resources we need to meet the needs of our customers on the hottest summer days, we will have to meet those needs through purchases from the regional market. Relying extensively on the regional market would be a significant risk for our customers. Our energy adequacy analysis, provided in Appendix A, indicates that limiting the acquisition from Docket 23-212 to 800 MW of nameplate capacity could result in our system resources being insufficient to serve our customers. We would then be reliant on the market to meet our customer needs for up to 10,000 MWh of energy over the course of a year. To be clear, under that scenario the market purchases would be necessary not because of our normal interaction with the MISO market, but instead because we would not be able to meet the needs of our customers with our system

[54] IRP Docket, Department Comments at 16.

resources. If the costs of these market purchases spike—because, for example, we are making purchases during times of peak demand to make up for firm dispatchable needs—the impact on customers could be significant. The potential cost impacts are discussed in more detail in Section III.C, below.

In order to avoid these impacts, it is important to select projects now so that they are available when they are needed. Bringing any generating resource online is a time-intensive process, and supply chain delays in the current market can make these timelines even longer. For example, the Lyon County Generating Station project was originally intended to be in-service in 2027 but unavoidable delays in securing delivery of combustion turbines have pushed back the in-service date. We have worked with our suppliers to find the earliest possible date to receive delivery of the combustion turbines, and based on that delivery timeline the updated in-service date is December 2028. Given the global demand for these components, there is often very little that can be done to accelerate these timelines when supply chain delays arise. Lyon County Generating Station must be selected now to so that it can be placed in-service at the time when customers need it. Deferring or delaying selection of the projects from the Firm Dispatchable Docket could make it impossible to meet the needs of our customers in the 2027 to 2029 timeframe.

Deferring a decision could also result in increased costs. It has been our experience that the costs of generation facilities continue to increase, particularly given the frequency of supply chain delays. There are cost effective projects available for selection now, but similar projects a few years down the road could cost significantly more. Waiting to select projects might also require us to rush the construction of other projects in the future to meet customer needs, which could increase costs further.

Regarding environmental stewardship, the portfolio of projects selected by the Settlement Agreement reflects a reasonable balance of renewables, storage, and natural gas to provide reliability to our customers. There is also a reasonable balance between new PPAs, PPA extensions, and new construction. There is no guarantee that a portfolio with this balance will be available in the future at this cost. As described in Appendix B, the Settlement Agreement, including the resources selected from the Firm Dispatchable Docket puts the Company on a path to comply with the Carbon Free Standard and Minnesota's other environmental policy goals. Delaying a decision on incremental resources could limit options to accomplish these goals in the future. For example, relying on purchases from the MISO market to meet our need for firm dispatchable resources could result in a system that is more carbon intensive because of the resources available on the market.

Waiting to select firm dispatchable resources in the future would create risks for our customers, and those risks are unreasonable when a portfolio of projects is available now.

4. Ensuring the full need for Firm Dispatchable Resources is Met Now Provides Flexibility to Accommodate Future Growth

Acquiring projects to meet our firm dispatchable needs now, rather than waiting for a future acquisition process, also would provide flexibility to accommodate future growth.

As discussed above, the sales forecast for the 2024 IRP included a reasonable and conservative estimate of new load related to data centers. As part of the forecast, we prepared sensitivity analyses to evaluate the possible impacts if new data center loads were higher than expected. The results of that analysis are provided in Table 5 and Figures 10 and 11.

Table 5
Demand and Energy Sensitivity Assumptions

Component	High Load Case	Low Load Case
Base Load	Base Case	Base Case
Solar	Base Case	High Solar
Demand-Side Management	Base Case	Base Case
Beneficial Electrification	High BE	No BE
Electric Vehicles	Full Achievement	Low Achievement
Large Commercial & Industrial Customers	High LCI	Low LCI

Figure 10
2024 Integrated Resource Plan Demand Sensitivities

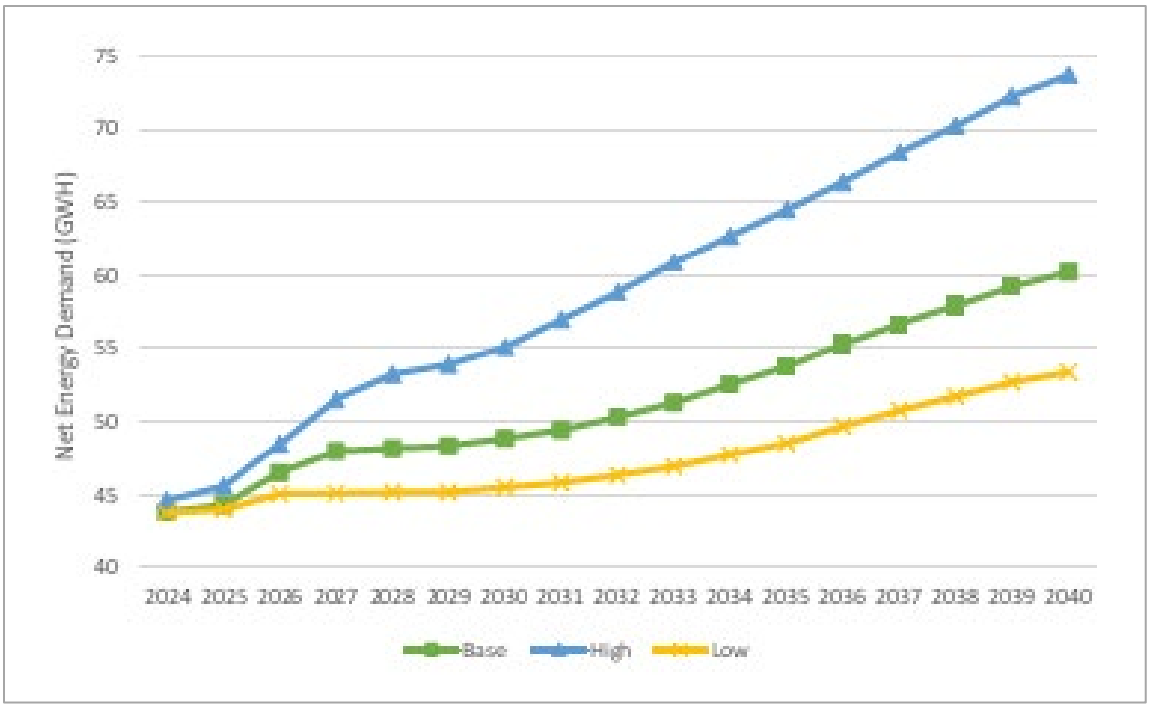
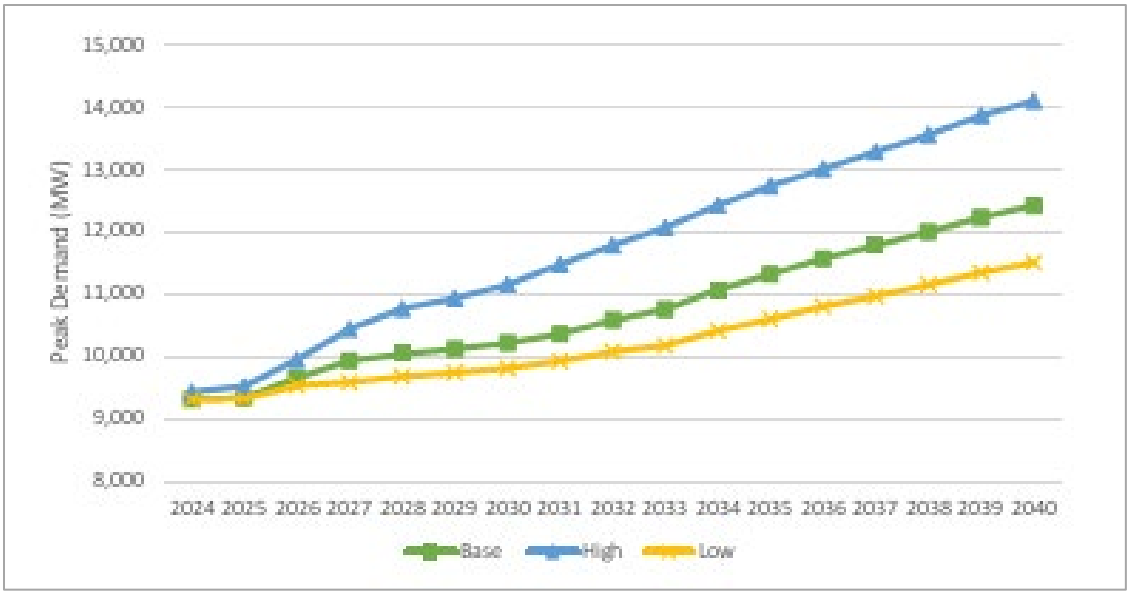


Figure 11
2024 Integrated Resource Plan Energy Sensitivities



The sensitivities show that the Company's resource needs may be materially greater should the higher demand and energy scenario come to pass. Specifically, under the high scenario, the Company's summer peak demand would increase from approximately 9,309 MW in the summer of 2024 (forecasted) to approximately 11,145 MW (an increase of about 1,800 MW) by the summer of 2030. Conversely, the low scenario still results in a summer 2030 peak demand that is 500 MW greater than the 2024 summer peak demand.

Further, there is reason to believe that the high scenario is more likely to occur than the low scenario. The Company recently completed its semi-annual demand and energy forecasts. As indicated in response to MPUC IR 009, the updated Fall 2024 forecast indicates that peak demand in 2030 will be materially higher than was predicted in the Fall 2023 forecast that was used for our capacity expansion modeling in the IRP Docket and Firm Dispatchable Docket. The upward revision to the base scenario is primarily attributable to more data center load than was anticipated in the 2024 IRP. While these forecasts remain subject to variation, the fall 2024 revisions demonstrate our most current data suggests the 2024 IRP high scenario is more likely to occur than the low scenario.

If additional data center load materializes, it could benefit our customers by stimulating economic growth. It also has the potential to delay or reduce future rate impacts as new customers contribute to the costs of the existing system. If the decision to acquire incremental firm dispatchable capacity is delayed, the next few years will be spent focusing on finding alternative ways to serve our existing customers while balancing increased reliance on the market, and our ability to explore partnerships with new data centers may be limited.

C. The Projects Selected in the Settlement Agreement are a Reasonable Way to Meet the Need for Firm Dispatchable Resources

The Settlement Agreement selects seven projects to meet our customers' firm dispatchable needs for the next few years. There is substantial evidence to show that selecting these projects is in the public interest.

1. The Bid Evaluation Process

When the Commission authorized the resource acquisition process in the Firm Dispatchable Docket, it authorized a specific resource evaluation process and resource attribute framework.[55] The evaluation process included five phases:

[55] Firm Dispatchable Docket, ORDER APPROVING PETITION AND REQUIRING COMPLIANCE FILING at 2–3 (Nov. 3, 2023).

1. Project Threshold Review
2. Project Scoring
3. Portfolio Formation
4. Portfolio Viability Assessment & Scoring
5. Cost to Value Comparison and Portfolio Selection

The resource attributes, and the phases to which they are related, are identified in Appendix C.

The first phase,[56] Project Threshold Review, was completed by the Department before the beginning of the contested case proceeding.[57]

The second phase, Project Scoring, was intended to involve individually scoring the received bids to narrow them down into a number that we could reasonably include in capacity expansion modeling. After receiving the bids, however, we determined that it would be possible to include all of the proposals in the capacity expansion model without eliminating any lower scoring bids.

While we did not eliminate any bids, we still conducted the Phase 2 Project Scoring, and its results are included as Appendix D.[58] Since all of the proposals were included regardless of the score, we did not conduct any weighting and the total bid score is the simple sum of the scores for each resource attribute related to Phase 2.

The Company's analysis of the final three phases is discussed below.

2. The Firm Dispatchable Resources Selected by the Settlement Agreement are Supported by Updated Capacity Expansion Modeling and Energy Adequacy Analysis

This section discusses Phase 3, Portfolio Formation, involving capacity expansion modeling using the software program EnCompass and Phase 4a, involving energy adequacy analysis that is also performed using EnCompass.

[56] Phase 1 involves resource attributes 1–10, 17–26, and 59–60.
[57] Firm Dispatchable Docket, NOTICE OF AND ORDER FOR HEARING at Order Point 1 (Apr. 2, 2024).
[58] Phase 2 involves resource attributes 11–14, 27–28, 32–33, 37–38, 43–47, and 49–51.

a) EnCompass Modeling Overview

The EnCompass analysis we used to evaluate the bids is primarily based on the EnCompass analysis used for the 2024 IRP, with a few changes described here. We used the 2024 IRP modeling as the basis of our analysis because the Commission has expressed a clear preference over many proceedings that we should be consistent in our modeling across dockets. The Commission gave specific directives to use consistent modeling during the hearing on October 5, 2023. Given the similar timing and relationships between the two proceedings, using consistent modeling across both dockets is reasonable.

The core assumptions for the EnCompass modeling are described in Appendix F of the 2024 IRP filing, along with changes we made to reflect updates and corrections. With the goal of minimizing the number of disputed issues, we identified three changes for the updated system modeling to evaluate the bids.

The first change was to update the system information in EnCompass to reflect the five-year PPA with Manitoba Hydro. After we completed and filed our 2024 IRP Preferred Plan, and after the Firm Dispatchable Docket was well underway, we negotiated a five-year PPA with Manitoba Hydro that begins when our current PPA with Manitoba Hydro expires in 2025. This five-year PPA secures capacity and takes advantage of a reasonably priced resource for our system.

We included the Manitoba Hydro PPA to make sure that the model accurately reflected our existing system resources. The PPA is for 200 MW of summer capacity through 2030 and a diversity exchange of 350 MW for the first three years and 200 MW for the last three years. Under the diversity exchange, Manitoba Hydro provides capacity in the summer in exchange for winter capacity from Xcel Energy. Our updated EnCompass model indicates the Manitoba Hydro PPA did not change the amount of firm dispatchable resources needed by 2030.

The second change was to update solar production profiles. Through the discovery process in the 2024 IRP, we identified that improvements could be made to our solar production modeling to more accurately reflect when solar production is expected. It is reasonable to include that update to ensure that our results are accurate.

The third change was to update incorrect retirement dates for four existing resources.[59] These changes are minor and occur in the 2034 and 2045–2046 timeframe. It is reasonable to make these minor changes to ensure the accuracy of our results.

[59] These resources are Community Wind North 1&2, Mower County Wind and Hennepin Island Hydro.

b) Modeling Xcel Bids

In preparing the updated system-wide capacity modeling, we included all of the remaining bids in the proceeding except for two. The Settlement Agreement provides that the Company's Bison Generating Station and Sherco 48-hour BESS are not selected, and so we did not provide them as an option for the model.

We also adjusted the price inputs for the Lyon County and Sherco 4-hour BESS bids as reflected in Attachment 1 to the Settlement Agreement. The Settling Parties have unanimously agreed that Lyon County and Sherco 4-hour BESS projects should be selected with the updated prices, so they were incorporated into the model.

c) Designing the EnCompass Model to Evaluate the Bids

The 2019 IRP Order requires the Company to evaluate the bids in the Firm Dispatchable Docket using up-to-date system-wide modeling.[60] The base modeling used for the 2024 IRP demonstrates the actual, updated need for firm dispatchable resources, and the modeling on the bids was used to determine which bids are best suited to meet that need.

To perform that analysis, we started with the results of our updated 2024 IRP capacity expansion modeling and locked generic resource additions in the model through 2037, which is when the term for the shortest bid ends. The initial capacity expansion model determined that the best way to serve the demands of our customers would be to add firm dispatchable resources represented by four generic combustion turbines between 2027 and 2029.[61] To evaluate the bids, we created a firm dispatchable "hole" between 2027 and 2029 by removing the four generic combustion turbines. We then allowed the model to fill the hole by optimizing additions of the bids we received (and restricted the model so that it could not select generic resources).

In other words, we started with the updated 2024 IRP modeling, removed the generic firm dispatchable resources it was selecting between 2027 and 2029, and allowed the model to pick from the project bids to meet the system needs during the acquisition time window between 2027 and 2029. This methodology allows the model to test which bids can meet the identified need for firm dispatchable resources.

[60] 2019 IRP Order at Order Point 3.

[61] The generic combustion turbines modeled in our 2024 IRP have a size of 374 MW. As a result, two combustion turbines is approximately 750 MW, and four is approximately 1500 MW. The model also selects two combustion turbines in 2030.

From this point, we ran three different scenarios through the model. In the first and primary scenario, we allowed the model to select any of the available bids in the Firm Dispatchable Docket. We also ran a series of sensitivities on the first scenario.[62] In the second scenario, we restricted the model so that it could only select no more than 800 MW in nameplate capacity. In the third scenario, we restricted the model so that it could select only renewable bids.

d) Energy Adequacy Analysis

In addition to capacity expansion modeling, we used EnCompass to perform an energy adequacy analysis similar to what was performed for our initial IRP filing. This analysis addresses Phase 4a of the Commission's evaluation framework, and is related to Resource Attribute 15: "Does an unacceptable level of [Loss of Load Hours] or [Expected Unserved Energy] occur during the planning period when the portfolio is modeled?"[63] Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are metrics used to assess the energy adequacy of potential plans. The purpose of an energy adequacy analysis is to evaluate the ability of a set of system resources to meet customer demands under various weather conditions. Specifically, the goal is to identify whether the resource set is able to serve customers at all hours of the year and, if not, to measure the shortfall.

We used EnCompass to perform an energy adequacy analysis to investigate a range of reliability metrics, including LOLH and EUE, for the different study portfolios without market access. Specifically, we stress tested the three portfolios against historical hourly load and renewable production data from 2016 to 2022. The analysis focused 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 (LOLH): Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy (EUE): Total amount of MWh the plan is reliant on the market to serve load.

[62] *See* Appendix E.

[63] Firm Dispatchable Docket, Compliance Filing – Competitive Resource Acquisition Process, Attachment A, Appendix A at 1 (Nov. 13, 2023).

We performed a similar analysis in Appendix D of our 2024 IRP. "MISO Market Reliance Hours" reflects LOLH and "MISO Market Reliance Energy" reflects EUE when the market access is turned off for this analysis. The results of our analysis are included in Appendix A, and are discussed in the context of the capacity expansion model results in this section.

e) Results of EnCompass Modeling on Scenario One

In the first scenario, the model was allowed to select any of the available bids. In order to meet the customer needs, the model selected all of the bids as shown in Table 6:

Table 6
Bids Selected by Scenario One – Settlement Agreement

Scenario One
DESRI North Star Storage
Invenergy Lake Wilson Solar + Storage
Invenergy Cannon Falls
National Grid Plum Creek Wind + Storage
Onward Energy Mankato Energy Center 1
Xcel Energy Lyon County Station
Xcel Energy Sherco 4-hour Storage

In other words, in order to meet our firm dispatchable needs between 2027 and 2029, the optimization model selected all available bids. The Present Value of Social Cost (PVSC) and Present Value of Revenue Requirement (PVRR) of Scenario One are comparable to the results of the base case in the original 2024 IRP Preferred Plan, as shown in Table 7:

Table 7
Scenario One PVSC / PVRR Deltas from Base Scenario ($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
Base – PVSC	$0	$ 50,990	$0	$ 63,493	$0	$ 68,666
Settlement - Study 1 – PVSC	($73)	$ 50,917	($13)	$ 63,480	$4	$ 68,670

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
Base – PVRR	$0	$ 34,859	$0	$ 45,642	$0	$ 49,864
Settlement - Study 1 – PVRR	($75)	$ 34,783	$44	$ 45,685	$69	$ 49,933

This analysis demonstrates that the specific projects selected by the Settlement Agreement are comparable to, and slightly lower cost than the generic resources included in the initial Preferred Plan from 2024 to 2040 on both a PVSC and PVRR basis. Looking out to 2050 shows a slight cost increase on both a PVSC and PVRR compared to our Preferred Plan, but the estimated cost increase is a fraction of a percent. Given the inherent uncertainty in forecasting cost impacts more than 20 years into the future, these minor cost increases should not be a cause for concern. In short, this analysis indicates that Scenario One, which forms the basis for the Settlement Agreement, is a cost-effective way to meet our customers' needs that is consistent with the costs expected in our Preferred Plan.

Energy adequacy analysis indicates that Scenario One, the Settlement Agreement would be sufficient to meet the needs of our customers, as demonstrated in Table 8:

Table 8
Scenario One Energy Adequacy Results

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	Historical Year - Hourly Conditions in 2029	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliant Hours (LOLH)	MISO Market Reliant Energy (MWh) (EUE)
Portfolio 1	2016 Historical	0	0	0	0	0	0
	2017 Historical	0	0	0	0	12	3,708
	2018 Historical	0	0	0	0	0	0
	2019 Historical	0	0	0	0	4	410
	2020 Historical	0	0	0	0	4	1,085
	2021 Historical	0	0	0	0	6	1,208
	2022 Historical	0	0	0	0	0	0

These results indicate that the Settlement Agreement would have sufficient capacity based on all 7 historical years, and would be reliant on the MISO market for energy purchases a maximum of 12 hours per year based on historical data. On average, historical data suggests that we would be reliant on the market for less than 1,000 MWh per year.

In addition to the selection of bids and PVSC/PVRR analysis, we also performed sensitivity analysis on Scenario One. These results are included in Appendix E. The primary conclusion to draw from our sensitivity analysis is that the same portfolio of projects is selected in nearly every sensitivity. In fact, the same portfolio of projects is selected for every sensitivity except for one, low load, which omits two projects. As discussed above, our sales forecast is reasonable and the low load scenario is unlikely to occur. The forecast used in our fall 2023 was conservative and more recent forecasts suggest that, if anything, this forecast was not high enough. Ultimately, the sensitivity analysis supports the approval of the Settlement Agreement because it demonstrates

that the projects selected in the Settlement Agreement are reasonable under a wide range of sensitivity analyses.

f) Results of EnCompass Modeling on Scenario Two – 800 MW Cap

Scenario Two involved restricting the model so that it could not select projects that exceeded 800 MW of nameplate capacity. The purpose of this evaluation was to determine what the consequences would be of limiting our acquisition to 800 MW. As expected, the model selects far fewer bids. Most importantly, this scenario results in poor energy adequacy metrics.

Scenario Two selected the projects shown in Table 9:

Table 9
Bids Selected in Scenario Two

Scenario Two - Capped at 800 MW Nameplate
Invenergy Cannon Falls
Onward Energy Mankato Energy Center 1
DESRI North Star Storage

When limited to selecting no more than 800 MW of nameplate capacity, the model selects only the North Star Storage, Cannon Falls and MEC bids.

The impact of Scenario Two on a PVSC and PVRR basis is shown in Table 10:

Table 10
Scenario Two PVSC / PVRR Deltas from Base Scenario ($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
Base - PVSC	$0	$ 50,990	$0	$ 63,493	$0	$ 68,666
Settlement - Study 2 - PVSC	($162)	$ 50,828	($260)	$ 63,233	($325)	$ 68,341
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**
Base - PVRR	$0	$ 34,859	$0	$ 45,642	$0	$ 49,864
Settlement - Study 2 - PVRR	($373)	$ 34,486	($401)	$ 45,241	($437)	$ 49,427

The PVSC and PVRR analysis for Scenario Two must be considered in the context of the energy adequacy results, displayed in Table 11:

Table 11
Scenario Two Energy Adequacy Results

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	Historical Year - Hourly Conditions in 2029	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliant Hours (LOLH)	MISO Market Reliant Energy (MWh) (EUE)
Portfolio 2	2016 Historical	13	249	4	418	22	6,683
	2017 Historical	4	122	3	225	24	11,075
	2018 Historical	6	140	3	239	33	8,282
	2019 Historical	9	203	2	597	26	6,802
	2020 Historical	12	300	3	673	34	11,476
	2021 Historical	10	212	3	463	42	13,345
	2022 Historical	2	92	1	110	3	251

Our energy adequacy analysis indicates that capping the acquisition from the Firm Dispatchable Docket at 800 MW of nameplate capacity would mean we have a capacity shortfall in every historical year. The peak capacity of the shortfall would range between 110 and 673 MW, with an average peak capacity shortfall of nearly 400 MW. This indicates that the magnitude of the capacity shortfall in those hours could be significant—400 MW is approximately the capacity of Lyon County Generating Station.

For the energy metrics, the analysis indicates that we would be reliant on the MISO market for energy purchases for an average of 26 hours per year, and that the market shortfall purchases could exceed 10,000 MWh per year.

To be clear, we are always offering our resources into the MISO market and purchasing capacity and energy from the MISO market. The shortfalls identified in the energy adequacy analysis indicate situations where the capacity and energy needed to serve our customers is more than we can produce and bid into the MISO market. In that situation, we would be fully reliant on the market to serve our customers, and fully exposed to whatever prices are on the market at that time.

The energy adequacy analysis indicates limitations in the PVSC and PVRR results. When the EnCompass model shows that the Company cannot select enough units to meet need, it purchases all necessary energy from the market. It does not evaluate what level of market participation is reasonable, or the risk it would have for customers to rely on market purchases. Further, the production cost model used to produce the PVSC and PVRR results assumes that energy and capacity can be purchased at relatively low and stable prices. That assumption may not be realistic.

The EnCompass model assumes that market purchases can be made at a relatively stable and non-volatile price range with an average around $35, and an upper range under $150/MWh almost all the time. While that is a reasonable modeling assumption, real-world prices have spiked much higher and will likely do so again. For example, during

Winter Storm Uri in February 2021, the average hourly Minn Hub real time market price was $177.18/MWh, peaking at $888.14/MWh.[64] And on December 23, 2022, not during Winter Storm Uri, the real time market prices from 5 p.m. to 7 p.m. (EST) ranged from $1177.6/MWh to $1781.8/MWh—as much as 50 times higher than the average prices used in EnCompass.[65] If the shortfalls indicated by our energy adequacy analysis took place at a time when prices spike in this way, it could be impactful for customers. Further, price spikes are most likely to occur at precisely the time we would be relying on firm dispatchable resources to meet peak customer demands. Significant market purchases at those times could be punishing for customers.

There are also other ways to estimate the real-world cost of unserved energy. For example, MISO's current tariffed Value of Lost Load (VOLL) estimate is $3500 per MWh. Using this value for a capacity expansion model without market access produces a PVSC that is $185 million more expensive than Scenario One over the 2024–2040 time horizon. If the cost of unserved load was measured using the MISO tariff estimate, Scenario Two is far more expensive than Scenario One. It is only when market access is assumed to be available using the base market price assumption from the IRP that Scenario Two results in lower costs.

In addition to these pricing risks, another risk from relying on the market to serve customer demands is the possibility of actual shortfalls and lack of resources. While our system is integrated into the grid, as the largest utility in MISO Zone 1, our ability to meet our customer's needs is critical to the region. There is no guarantee that the market will have sufficient supply when it is needed at the most critical hours. In recent years, the MISO market has tightened and concerns have grown about resource shortfalls.[66] The problem could be exacerbated by poor planning in other jurisdictions, or reliability events such as unplanned outages or weather emergencies across the MISO region. If the market ever does experience an actual shortfall, it is most likely to occur on a day of peak demand—precisely when our firm dispatchable resources would be deployed. The risk of such a shortfall might be low, but when it comes to providing essential services to our customers the consequences of a market failure could be very high. Relying on the market to the extent required by Scenario Two or Scenario Three, discussed below, actually means relying on other entities—which might be outside the

[64] Historical hourly Minn Hub prices are obtained from MISO via Velocity Suite software. Average and max prices are calculated based on real time market prices during Winter Storm Uri between February 13 and February 17, 2021.

[65] Historical hourly Minn Hub prices are obtained from MISO via Velocity Suite software.

[66] For example, the annual 2024 MISO-OMS survey indicated that resource sufficiency could range from a 1.1 GW surplus to a 2.7 GW shortfall during the 2024 summer season. Press Release, MISO, June 20, 2024, available at *https://www.misoenergy.org/meet-miso/media-center/2024/oms-miso-survey-results-indicate-tight-resource-capacity-in-the-upcoming-planning-year/*.

state and not subject to the Commission's jurisdiction—to fulfill our obligation to provide electricity to customers on the most critical days.

g) Results of EnCompass Modeling on Scenario Three – Renewable Only

Scenario Three restricted the EnCompass model so that it could only select renewable and storage projects, which results in the selections shown in Table 12:

Table 12
Bids Selected in Scenario Three

Scenario Three - Renewable Only
DESRI North Star Storage
Invenergy Lake Wilson Solar + Storage
National Grid Plum Creek Wind + Storage
Xcel Energy Sherco 4-hour Storage

Unsurprisingly, the model selected all of the renewable and storage projects.

There are several critical limitations with the renewable-only study and the resulting portfolio. First, as discussed in more detail below, Scenario Three results in a large amount of unserved energy and market exposure—this means the portfolio is not sufficient to meet our needs for firm dispatchable resources.

Second, the model selects all available renewable resources. When the model is not restricted to select renewable only resources, more projects, including thermal projects, are selected. This suggests that these renewable projects are not the best combination of resources for meeting a firm dispatchable need, only that they are the only ones available to meet a significant resource need.

The impact of Scenario Three on a PVSC and PVRR basis is shown in Table 13.

Table 13
Scenario Three PVSC / PVRR Deltas from Base Scenario ($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
Base - PVSC	$0	$ 50,990	$0	$ 63,493	$0	$ 68,666
Settlement - Study 3 - PVSC	($885)	$ 50,105	($994)	$ 62,499	($1,043)	$ 67,623
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**
Base - PVRR	$0	$ 34,859	$0	$ 45,642	$0	$ 49,864
Settlement - Study 3 - PVRR	($347)	$ 34,512	($281)	$ 45,361	($283)	$ 49,582

As with Scenario Two, the capacity expansion results for Scenario Three must be considered with the context of energy adequacy analysis displayed in Table 14:

Table 14
Scenario 3 Energy Adequacy Results

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	Historical Year - Hourly Conditions in 2029	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliant Hours (LOLH)	MISO Market Reliant Energy (MWh) (EUE)
Portfolio 3	2016 Historical	19	385	4	750	97	46,774
	2017 Historical	15	227	4	473	73	44,685
	2018 Historical	24	139	4	482	187	101,553
	2019 Historical	26	283	4	929	128	66,795
	2020 Historical	28	308	4	892	121	70,071
	2021 Historical	25	270	4	774	130	79,505
	2022 Historical	5	186	2	392	61	25,259

The shortfalls identified for Scenario Three are even more significant than those for Scenario Two. A renewable-only acquisition would lead to a capacity shortfall in every year, with 20 hours of capacity shortfall on average. The peak capacity shortfall for Scenario Three rises as high as 929 MW, suggesting that our system could be short by more than 10% of our overall system capacity.

The energy metrics from Table 14 indicate that we would have to rely on the MISO market for many hours and many MWhs in every historical year. We would have energy shortfalls of, on average, 113 hours, and would be reliant on the market to purchase an average of more than 62,000 MWh per year. In a worst-case scenario, the analysis indicates that we would be reliant on MISO purchases for more than 100,000 MWh to meet the needs of our customers.

Scenario Three relies on the market even more than Scenario Two. These results provide important context when considering the PVSC and PVRR results for Scenario Three. If, for example, the cost of this unserved energy was evaluated using the MISO values for VOLL, the cost of Scenario Three would be $170 million more expensive than Scenario One over the 2024–2040 time horizon.

In addition, all of the pricing and reliability risks that would arise under Scenario Two would be amplified under Scenario Three. It would require a significant and unprecedented level of reliance on the MISO market for our system and customers.

In addition, it is worth recognizing that this renewable-only scenario was allowed to select only renewables during the scope of this acquisition, but generators selected by the base case outside of the 2027 to 2029 window were locked in. Specifically, the updated base case scenario optimized to select two gas-fired CT units in 2030. The

Company does not propose and the Settlement Agreement does not involve selection of those units, but when evaluating the long-term PVSC and PVRR for the renewable-only Scenario Three, it is important to recognize that the model does include additional thermal resources in the out-years.

h) Conclusions Regarding EnCompass Analysis and Energy Adequacy Analysis

When the model is allowed to select freely among the available bids, it selects the bids that are included in the Settlement Agreement. This demonstrates that the Settlement Agreement is in the public interest.

The energy adequacy analysis also indicates that the Settlement Agreement is in the public interest. Resource attribute 15, as approved by the Commission, asks: "Does an unacceptable level of [Loss of Load Hours] or [Expected Unserved Energy] occur during the planning period when the portfolio is modeled?" Energy adequacy analysis indicates that both Scenario Two and Scenario Three fail this criteria because an unacceptable level of LOLH and EUE occur under both scenarios.

Scenario One performs well on both a PVSC and PVRR basis, and satisfies resource attribute 15, indicating that the Settlement Agreement is in the public interest.

i) Hydrogen Special Study

Commission Information Request 12 requested information about the relationship between the Hydrogen Special Study prepared for the initial IRP filing and the CT resources included in the Settlement Agreement. As explained in the IRP filing,[67] the Hydrogen Special Study modified the EnCompass model so that hydrogen was the only advanced technology that could be selected, and it allowed hydrogen blending in natural gas firm dispatchable units up to 100 percent beginning in 2030. With these inputs, the model selected hydrogen generation beginning in 2034, peaked in 2045, and then steeply fell as the hydrogen production tax credit (PTC) expired.

While this is useful information for planning purposes, it has no direct bearing on the resources selected in the Settlement Agreement. For both the initial modeling in the IRP and the updated modeling to support the Settlement Agreement, the generic CT resources and the specific natural gas bids do not assume the co-combustion of any hydrogen.

[67] IRP Docket, Resource Plan, Chapter 5 at 38–40.

In the Settlement Agreement, the Company has committed to additional analysis on these issues and will file a carbon-free feasibility study for the Lyon County Generating Station in the first Integrated Resource Plan after the facility is in-service.

3. The Firm Dispatchable Resources are needed for System Stability and Will Improve System Restoration.

The fourth phase of the evaluation framework consists of two parts referred to here as Phase 4a and 4b. Phase 4a, described in this sub-section, involves analysis of three questions:

1) As per MISO Blackstart Service BPM Manual 022,[68] can the Transmission Operator achieve the goals of its System Restoration Plan with this portfolio?
2) Does an unacceptable level of [loss of load hours] or [expected unserved energy] occur during the planning period when the Northern States Power [NSP] system is modeled with this proposed portfolio?
3) Does Steady State or Stability modeling of the NSP system with this proposed portfolio meet transmission planning criteria?

Questions one and three involve transmission analysis, and question two involves energy adequacy analysis and was discussed in the previous sub-section.[69]

Transmission reliability analysis is an assessment of the impacts of potential changes to the electrical system using computer software. Xcel Energy performs transmission modeling and analysis using the software program Power System Simulator for Engineering (PSS/E) from Siemens and Dynamic System Analysis Tools (DSATools) from PowerTech, which are industry standard tools. PSS/E and DSATools perform a computer simulation, for purposes of this case, using a model of the eastern interconnection in North America. PSS/E and DSATools can be used to conduct a variety of analyses, including steady state analysis, stability modeling, power flow analysis, fault analysis, and dynamic simulation. These analyses provide information about, for example, what will happen if a group of generators is added to the grid, such as potential overloads, stability issues, or other grid impacts. That information can then be used to compare potential solutions to problems that arise from making changes to the grid.

[68] The MISO Business Planning Manual (BPM) 022 is for Blackstart Service, and describes the qualifications and compensation for blackstart units on the MISO system. It is available on MISO's website.
[69] Phase 4a is related to resource attributes 15, 29–30, and 52–56.

The transmission planning criteria referred to in question one are drawn from our Transmission Planning Criteria Manual for the NSPM and NSPW Transmission System, Version 8 (Manual), on file with MISO, and linked at our public website.[70] The Manual establishes technical criteria for areas such as voltage, facility loading, steady state, line impedance, and short circuits, among others. The Manual also identifies when we will study disturbances to the transmission system, a threshold which is based on standards promulgated by the North American Electric Reliability Corporation (NERC). The Commission approved resource attributes 52 through 56 to evaluate essential reliability services and system stability issues, including voltage control/support, frequency regulation, and spinning reserves.

Our PSS/E and DSATools analysis indicates that the bids selected by the Settlement Agreement meet the steady state and stability criteria established in the Manual. The analysis identified thermal violations under N-1-1 (double contingency) situations, but the overloads are mitigated by generation redispatch as allowed by NERC TPL-001-05 standards, and our Transmission Planning Criteria. This analysis indicates that the bids selected by the Settlement Agreement do not require additional infrastructure costs to provide system stability, assuming that already-planned system stability upgrades are completed. Our analysis also indicates that Scenario Two and Scenario Three do not require additional transmission infrastructure to reach system stability under contingency because overloads are mitigated by generation dispatch.

We also evaluated essential reliability services that the Commission identified in resource attributes 52 through 56. Our analysis indicates that each scenario provides adequate reliability services, when combined with our existing system resources, with one exception. Scenario Three (renewable only) does not provide adequate spinning reserves for our system, and thus fails resource attribute 54.

Phase 4a also includes analysis of system restoration requirements, related to resource attributes 29 and 30. Our analysis also indicates that the resources selected by the Settlement Agreement will contribute to our System Restoration Plan. Specifically, the selected bid for MEC includes a new BESS for blackstart services.

As we explained in our 2024 IRP filing, our system currently relies on a centralized system restoration plan based on recovering large thermal generators and using them to re-energize the system. As we continue to transition our fleet and retire these generators, this plan will no longer be feasible. We have developed a new Multi-Zonal System Restoration Plan which will allow us to bring the system back online without reliance on large thermal units that will no longer be available.

[70] The Guide is available on our website at Policy, Procedure, Standards Template (xcelenergy.com).

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

The Settlement Agreement, as compared to Scenario Three (renewable-only), performs better on Resource Attributes 29 and 30, demonstrating that the Settlement Agreement is consistent with our system restoration goals.

4. The Firm Dispatchable Resources Meet Firm Dispatchable Needs

The second part of fourth phase, Phase 4b, involved applying any remaining resource attributes and scoring the portfolio.[71] The results of this analysis are provided as Appendix F.

The results of this scoring analysis look different than scoring would work for a standard RFP. In a standard RFP, we would produce a specific score for each evaluation metric, and use a weighting methodology to compare bids. The evaluation process and list of resource attributes approved by the Commission is structured differently in the Firm Dispatchable Docket. Rather than scoring individual projects, we are evaluating portfolios of projects. The portfolios we evaluated include: 1) the bids selected by Scenario One, and which form the Settlement Agreement, 2) a portfolio that is limited to 800 MW nameplate, and 3) a renewable-only portfolio. The resource attribute analysis compares these three portfolios, rather than individual bids.

Further, in a standard RFP we would create questions where it is possible to assign scores to each metric. Some of the resource attributes approved by the Commission cannot be assigned scores in the same way, for example because they are "yes" or "no"

[71] Phase 4b involves resource attributes 16, 31, 34–36, 39–42, 48, 57–58, and 61.

questions, or because they ask for comparison to our recommended portfolio. As a result, rather than assigning a score we have provided the results of our analysis directly in Appendix D. This analysis, combined with the analysis from other phases and in particular the capacity expansion modeling, demonstrates that the resources selected by the Settlement Agreement are in the public interest.

Our analysis identifies that Scenario One, which forms the basis for the Settlement Agreement, has several advantages:

- Scenario One performs better on resource attributes related to LOLH and EUE, and MISO purchases. As explained above, both Scenario Two and Scenario Three result in unserved capacity and energy, and rely extensively on MISO purchases.

- Scenario One performs the same or better on system restoration times.

- Scenario One will produce the most tax revenue for local governmental units.

- Scenario One will result in the most permanent jobs, retain the most existing jobs, and create the most construction jobs.

Scenario Two would result in lower overall system ramping needs, primarily because it would integrate less renewables and thus require less ramping.

Scenario Three results in the lowest carbon emissions, although, as explained above, it would not acquire enough capacity and energy to meet the needs of our customers, and would leave customers with significant exposure to market purchases.

As explained below, these results, when combined with our other analysis, indicate that Scenario One and the Settlement Agreement are the best choice for our system and customers, and therefore are in the public interest.

5. Selecting the Firm Dispatchable Resources Supports Renewable Expansion.

In addition to the reasons explained above, one advantage of the Settlement Agreement is that Lyon County Generating Station is an essential part of our plan for integrating renewables on the Minnesota Energy Connection (MNEC) transmission line.

The MNEC is a proposed transmission line that will begin at our Sherco site and cross approximately 180 miles towards Lyon County, Minnesota. The purpose of the line is to create transmission capacity so that we can re-use the interconnection rights for the

Sherco coal-fired units after they are retired. The Company plans to connect approximately 2,000 MW of wind resources in the near-term to the MNEC in order to re-use the interconnection rights. Integrating 2,000 MW on the MNEC is likely to cause voltage stability and recovery issues due to the type of wind generation planned and the length of the line.[72] The services provided by firm dispatchable resources can mitigate some of these impacts through grid services like the flexibility to ramp up or down quickly. Lyon County Generating Station is strategically designed and located to provide those services.

Based on our engineering review, the best solution for ensuring stability on the MNEC is the addition of synchronous condensers. A synchronous condenser is a rotating machine, tied to the electrical system, that provides reactive support during adverse system conditions and helps with power factor correction on the system. Our analysis indicates that four synchronous condensers located at the terminal substation of MNEC—Garvin—would be required to ensure stability on the line. Specifically, technical analysis indicates that we cannot integrate more than 1,100 MW of renewables without causing system stability problems unless we install four synchronous condensers.

Lyon County Generating Station will be located near the Garvin Substation, the precise location where synchronous condensers would be needed, and it is planned to include the capability to operate in a synchronous condenser mode. This functionality is provided by a clutch that disengages the turbine from the generator, which allows the facility to operate as a synchronous condenser. Our engineering analysis confirms that if the Lyon County Generating Station is constructed at the Garvin Substation, it can replace two of the four synchronous condensers that would otherwise be required to integrate renewables onto the MNEC.

When Lyon County Generating Station is added with synchronous condenser operating mode, along with two additional synchronous condensers, the MNEC can integrate more than 2,000 MW of renewables that are needed to fully re-use our interconnection rights at Sherco. Without Lyon County Generating Station, we would need to build an additional synchronous condenser for each circuit on the Lyon site to integrate the same amount of renewables. The Company had previously estimated that two synchronous condensers would cost approximately $120 million, but recent information has led to updated analysis regarding these facilities and we now anticipate that the cost estimates will rise.

[72] *See* MISO's Renewable Integration Impact Assessment Summary Report, MISO, Feb. 2021, *available at* RIIA Summary Report520051.pdf (misoenergy.org).

By building Lyon County Generating Station we can ensure stability on the MNEC, effectively re-use our interconnection rights on the MNEC, and avoid costs that would otherwise be required to ensure system stability and maximize renewable integration. Without Lyon County Generating Station, we would need to invest at least $120 million in additional synchronous condensers at the terminal substation.

6. Selecting the Firm Dispatchable Resources is Consistent with the Renewable Energy Preference and the Carbon Free Standard

Selecting the resources identified in the Settlement Agreement is in the public interest because it is consistent with Minnesota's policy goals, including the renewable preference and Carbon Free Standard.

a) The Settlement Agreement, including the selection of the Lyon County Generating Station, is consistent with the Renewable Preference

Minnesota Statutes § 216B.2422, subd. 4 provides that the Commission "shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need . . . unless the utility has demonstrated that a renewable energy facility is not in the public interest." The Commission must consider several factors:

- Whether the resource plan helps the utility achieve the greenhouse gas reduction goals, the renewable energy standard, and the solar energy standard;
- Impacts on local and regional grid reliability;
- Utility and ratepayer impacts resulting from intermittent nature of renewable energy facilities, including the cost of purchasing electricity in the market; and
- Utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

The Settlement Agreement is consistent with the renewable preference requirement.

In particular, the thermal resources in the Settlement Agreement are not being selected instead of alternative renewable resources that could have been selected. Based on our capacity expansion modeling, meeting our firm dispatchable needs from 2027 to 2029 requires selecting all of the renewable bids and the identified thermal bids. The thermal projects meet the renewable preference requirement, in part, because there were no alternative renewable projects to select.

Evaluating the required factors results in the same conclusion:

- The Settlement Agreement ensures that we are on the right track to be in compliance with Minnesota's ambitious CFS, RES, SES, and GHG reduction goals.
- A renewable-only portfolio would result in an unacceptable level of LOLH and EUE, negatively impacting reliability and energy adequacy.
- A renewable-only portfolio would increase reliance on the regional market to meet customer needs, increasing the risk of unexpected price increases; in contrast, the Settlement Agreement will protect customers from the risk of over-reliance on the market.
- The Settlement Agreement supports renewable energy by enabling the integration of more than 2,000 MW on the MNEC.
- The Settlement Agreement reduces transmission system costs by eliminating the need for two synchronous condensers on the MNEC.

For these reasons, the Settlement Agreement is consistent with the renewable preference statute.

b) The Settlement Agreement Ensures that the Company is Positioned to Comply with the Carbon Free Standard

Appendix B provides information about compliance with Minnesota's Carbon Free Standard, Renewable Energy Standard, and Solar Energy Standard. Our analysis indicates that the Settlement Agreement will enable the Company to comply with all of these standards.

7. Selecting the identified bids is consistent with the public interest

The final phase of the evaluation framework involves combining the analysis from the previous phases to identify the best portfolio of resources to meet firm dispatchable needs.

Our analysis clearly demonstrates that the Settlement Agreement, and the selection of the identified bids from Firm Dispatchable Docket, is the best plan for our customers. Each analytical step supports approval of the Settlement Agreement.
The following factors, among others, show that the Settlement Agreement and the selection of the bids from Firm Dispatchable Docket is in the public interest:

- When allowed to choose from all the bids the EnCompass model selects the same bids that are selected in the Settlement Agreement. This is an indication that these bids best meet the needs of our customers.

- The Settlement Agreement will ensure that the Company is positioned to comply with Minnesota's energy policy goals, including the Carbon Free Standard.

- The PVRR and PVSC results of the Settlement Agreement are consistent with, and in some cases lower than, the results of our initial Preferred Plan. When compared to the Preferred Plan, the Settlement Agreement may result in lower costs for the first 15 years. To the extent that PVSC and PVRR increases are predicted in the out-years, the impact is a fraction of a percent.

- The Settlement Agreement will result in modest and appropriate rate impacts of less than one percent per year while acquiring substantial resources to meet customer needs.

- The Settlement Agreement will secure enough capacity and energy to meet the needs of our customers. Limiting the procurement to no more than 800 MW or to renewable-only bids, would not result in enough resources to meet the needs of our customers resulting in an over-reliance on the market to provide needed energy for our system.

- The Settlement Agreement supports our system restoration goals.

- The Settlement Agreement supports our renewable expansion goals by selecting the Lyon County bid. Lyon County is a necessary part of our plan to integrate more than 2,000 MW of renewables on the MNEC, and without it we would need to invest at least $120 million than $100 million in alternate infrastructure.

- The Settlement Agreement performs better on the resource attributes provided by the Commission in areas such as spinning reserves and socioeconomic factors such as local tax revenues and job creation.

For all of these reasons, the Settlement Agreement and its selection of bids from the Firm Dispatchable Docket is in the public interest, and it should be approved by the Commission.

D. Next Steps for Selected Bids

The Settlement Agreement establishes the next steps for the selected bids, consistent with the Commission's historical practice.

The projects proposed by bidders require the execution of PPAs with the Company. While the Settlement Agreement selects the projects, it also recognizes that the specific terms of the PPAs must still be negotiated and approved by the Commission. To that end, the Settlement Agreement provides that the Company will immediately begin PPA negotiations for the selected projects using the original bid documents as the starting point for contract terms. The Company also commits to filing the PPAs for approval with the Commission within four months of the Commission Order approving the Settlement Agreement, or explaining why agreement has not been reached. This process is in the public interest because it will lead to the timely and orderly negotiation of PPA terms that will be submitted to the Commission for approval.

In negotiating the PPAs, the Company intends to negotiate terms that avoid negative impacts to the Company's financial health. PPAs, and especial those for capacity-related resources that include dispatch rights, have the potential to create long-term financial obligations that have debt-like characteristics. When measuring financial risk, ratings agencies[73] may choose to add some portion of these PPA obligations to the Company's debt, which is often referred to as imputed debt. Contracts of this nature are sometimes referred to as finance leases.

The Company is not a party to any finance leases, because the imputed debt from a finance lease could have negative impacts on our customers. The Company has traditionally avoided PPAs that result in imputed debt because it could increase the costs of borrowing, and those costs would be borne by customers. For example, the Company's current investment plans indicate a need for approximately $3 billion in incremental debt financing from 2024 to 2028. Ten basis points in increased borrowing costs would result in $3 million in additional interest expense each year included in rates.

For these reasons, the Company intends to negotiate PPAs for the selected bids that do not result in finance leases. If the Company is not able to successfully resolve the finance lease issue through negotiations, the Company will fully explain the situation for the Commission and present options that could mitigate the negative impacts on our credit metrics and for our customers.

[73] S&P Global Ratings (S&P), Moody's Investors Service (Moody's), & Fitch Ratings (Fitch) each provide credit ratings for the Company's debt. S&P and Moody's each evaluate leases in their analyses, while Fitch does not.

IV. ADDITIONAL INFORMATION ON THE IRP DOCKET

Initial Comments in the IRP Docket were filed on August 9, 2024. In those comments, various parties requested additional information about the IRP. While that information is not necessary to approve the Settlement Agreement, to ensure that the record is complete the Company provides responses to these requests for information in two appendices. In Appendix G, the Company provides its Responses to Parties' Unresolved Issues and in Appendix H, the Company provides its Response to Parties' Comments and Requests for Additional Information.

The Company believes that nearly all substantial issues are resolved in the Settlement Agreement but notes one additional request regarding the Company's Refuse Derived Fuel (RDF) waste-to-energy generating plants. On October 11, 2024, the International Brotherhood of Electrical Workers filed a letter recommending the continued operation of our RDF plants.

In our initial filing in the IRP Docket, we explained that all three of our renewable RDF waste-to-energy generating plants are slated for retirement in 2027, but that 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.

Unfortunately, the extension of the RDF facilities was unintentionally omitted from settlement discussions. We note that no commenters raised any concerns about the RDF plants during the initial comment period. As such, we request that the Commission approve extending the life and operations of our Red Wing, Mankato and French Island RDF plants to 2037, 2037, and 2040 respectively.

CONCLUSION

The Company requests that the Commission approve the Settlement Agreement.

The Company further requests the Commission approve extending the life and operations of our Red Wing, Mankato and French Island RDF plants to 2037, 2037, and 2040 respectively.

Finally, the Company requests that the Commission open a comment period regarding the Settlement Agreement as agreed-upon by the Settling Parties.

Dated: October 25, 2024

Northern States Power Company

Energy Adequacy Analysis

This Appendix provides an overview of the results of our Energy Adequacy analysis for three scenarios used in our EnCompass capacity expansion modeling.

Scenario 1, which is the basis for the Settlement Agreement, removed four generic CT units in 2027 and 2028 and allowed the model to select any of the bids provided in Docket 23-212.

Scenario 2 restricted the model so that it could select no more than 800 MW of bids.

Scenario 3 restricted the model so that it could select only renewable bids.

Scenario 1 Energy Adequacy Results

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	Historical Year - Hourly Conditions in 2029	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliant Hours (LOLH)	MISO Market Reliant Energy (MWh) (EUE)
Portfolio 1	2016 Historical	0	0	0	0	0	0
	2017 Historical	0	0	0	0	12	3,708
	2018 Historical	0	0	0	0	0	0
	2019 Historical	0	0	0	0	4	410
	2020 Historical	0	0	0	0	4	1,085
	2021 Historical	0	0	0	0	6	1,208
	2022 Historical	0	0	0	0	0	0

* LOLH is higher than capacity shortfall hours due to batteries having available capacity but no stored energy.

Scenario 2 Energy Adequacy Results – 800 MW Cap

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	Historical Year - Hourly Conditions in 2029	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliant Hours (LOLH)	MISO Market Reliant Energy (MWh) (EUE)
Portfolio 2	2016 Historical	13	249	4	418	22	6,683
	2017 Historical	4	122	3	225	24	11,075
	2018 Historical	6	140	3	239	33	8,282
	2019 Historical	9	203	2	597	26	6,802
	2020 Historical	12	300	3	673	34	11,476
	2021 Historical	10	212	3	463	42	13,345
	2022 Historical	2	92	1	110	3	251

*LOLH is higher than capacity shortfall hours due to batteries having available capacity but no stored energy.

Scenario 3 Energy Adequacy Results – Renewable Only

		Capacity Adequacy Metrics				Energy Adequacy Metrics*	
Plan	**Historical Year - Hourly Conditions in 2029**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliant Hours (LOLH)**	**MISO Market Reliant Energy (MWh) (EUE)**
Portfolio 3	2016 Historical	19	385	4	750	97	46,774
	2017 Historical	15	227	4	473	73	44,685
	2018 Historical	24	139	4	482	187	101,553
	2019 Historical	26	283	4	929	128	66,795
	2020 Historical	28	308	4	892	121	70,071
	2021 Historical	25	270	4	774	130	79,505
	2022 Historical	5	186	2	392	61	25,259

*LOLH is higher than capacity shortfall hours due to batteries having available capacity but no stored energy.

Compliance with Minnesota Energy Standards

This Appendix provides an overview of specific state targets and our compliance with renewable standards and carbon reduction standards under the Settlement Agreement.

I. Carbon Free Standard

Pursuant to the Settlement Agreement, the Company expects to generate a sufficient amount of GWhs from carbon-free generation sources to comply with the Carbon Free Standard.

	2030	2035	2040
NSP Carbon-Free Generation (GWh)*	5,835	2,199	60,481
MN Allocated CF Generation (GWh)**	5,195	40,357	46,935
MN Elec Retail Sales (GWh)	35,726	39,669	44,625
Percentage Carbon Free Generation	98.5%	101.7%	105.2%

**NSP carbon Free generation includes biomass, hydro, utility scale solar, wind and nuclear.*

***MN Allocated CF Generation includes MN share of carbon free generation and all DG solar generation (existing and legislation required).*

II. Renewable Energy Standard

Pursuant to the Settlement Agreement, the Company expects to generate a sufficient number of RECs throughout the planning period to satisfy our obligations under the Renewable Energy Standard.

	2030	2035	2040
NSP Renewable Energy Generation (GWh)*	31,996	39,182	46,601
MN Allocated Renewable Generation (GWh)**	25,093	30,854	36,803
MN Elec Retail Sales (GWh)	35,726	39,669	44,625
Percentage Renewable Generation	70.2%	77.8%	82.5%

**NSP renewable generation includes biomass, hydro, utility scale solar and wind.*

***MN Allocated renewable generation includes MN share of renewable generation and all DG solar generation (existing and legislation required).*

III. Solar Energy Standard

Pursuant to the Settlement Agreement, the Company expects to generate a sufficient number of RECs throughout the planning period to satisfy our obligations under the Solar Energy Standard.

	2030	2035	2040
NSP Utility Scale Solar Energy Generation (GWh)	5,052	7,508	7,634
MN Allocated Solar Generation (GWh)*	5,424	7,732	8,357
MN Elec Retail Sales (GWh)	35,726	39,669	44,625
Percentage Solar Generation	15.2%	19.5%	18.7%

**MN allocated solar generation includes MN share of utility scale generation and all DG solar generation (existing and legislation required).*

Resource Attributes Matrix

			Proposed Evaluation Stage				
ID	**Attribute Category**	**Metric**	**Phase 1: Threshold Requirement Per Proposal**	**Phase 2: Individual Scoring Per Proposal**	**Phase 3: Portfolio Formation**	**Phase 4a: Portfolio Viability Assessment**	**Phases 4b & 5: Portfolio Scoring & Selection**
1	Capacity	Nameplate capacity of commercially operable project is > 5 MWac.	x				
2	Capacity	Commercially operable project must be transmission-interconnected.	x				
3	Capacity	Commercially operable project must interconnect in MISO Zone 1 with uninterrupted interconnection path to MISO Load.	x				
4	Capacity	Must achieve COD by 12/31/2028	x				
5	Capacity	*For Physical Assets:* Must be able to operate commercially at the highest 0.2 percentile hourly temperature from Jan 1, 2000 until the date the temperature is calculated, using the NOAA NCEI station nearest to the generator, and for cold weather, the smallest of the 50 year regional extreme cold temperature as defined by the NOAA NCEI station nearest to the generator or the Extreme Cold Weather Temperature defined in NERC EOP-012, whichever is colder. *For Demand Response Assets:* Capable of commercial operation at equivalent analog criteria.	x				
6	Capacity	For Existing Projects: Minimum remaining operational life or PPA contract term of 10 years after COD of contract selected in this competitive resource acquisition.	x				
7	Capacity	For New Projects Only: Minimum design life or PPA contract term of 10 years	x				
8	Capacity	For Proposals containing a BESS Project: Must provide estimate of capacity degradation rate via warranty or independent evaluation.	x				
9	Capacity	For Power Purchase Agreements Only: O&M plan must be provided and must be sufficient for proposed contract term	x				
10	Capacity	For Build-Transfer Projects Only: Compliance with Company Technical Specifications	x				
11	Capacity	Level of capacity degradation over project life or PPA contract term relative to other proposals, with a better score for lower degradation.		x			
12	Capacity	Level of accredited capacity over project life or PPA contract term relative to other proposals, with a better score for higher level of accreditation assumptions.		x			
13	Energy availability	Fuel Access For Physical Fuel Assets: Demonstrated firm fuel transport (i.e., contract for firm fuel delivery)		x			
14	Energy availability	For Inverter-Based, Physical Resources Utilizing Renewable Energy: High net capacity factor of renewable component relative to other proposals		x			
15	Energy availability	Does an unacceptable level of LOLH or EUE occur during the planning period when the portfolio is modeled?				x	
16	Energy availability	Does this portfolio have less LOLH and EUE relative to the Reference Portfolio under identical test conditions?					x

Resource Attributes Matrix

ID	Attribute Category	Metric	*Proposed Evaluation Stage* Phase 1: Threshold Requirement Per Proposal	Phase 2: Individual Scoring Per Proposal	Phase 3: Portfolio Formation	Phase 4a: Portfolio Viability Assessment	Phases 4b & 5: Portfolio Scoring & Selection
Blackstart criteria in the section below are required only for those units within a proposal that seeks consideration as a blackstart unit.							
17	Blackstart and system restoration	Initial Unit (Blackstart Unit) must register with MISO as a Blackstart Resource	x				
18	Blackstart and system restoration	Unit capability to operate in isochronous mode	x				
19	Blackstart and system restoration	Unit capability to operate in islanded operation	x				
20	Blackstart and system restoration	The capability to accept instantaneous loading of demand blocks, % of rated output but not less than 1 MW, while controlling frequency and voltage levels within acceptable limits during block loading process	x				
21	Blackstart and system restoration	The ability to control voltage level within acceptable limits during energization/block loading (-10%/+5%).	x				
22	Blackstart and system restoration	The ability to control frequency within 58.7 Hz to 61.8 Hz during energization/block loading	x				
23	Blackstart and system restoration	The ability to dispatch at any time if needed and run in a continuous stable and controllable mode for at least 48 hours without violating any environmental or other restrictions	x				
24	Blackstart and system restoration	Blackstart capacity must have technical capability to 1) run in a continuous stable and controllable mode over entire design operating range of resource (to 0 load); 2) operability in remote load control service (up and down).	x				
25	Blackstart and system restoration	Sufficient reactive reserve capability to allow energization of the transmission system within the station to supply the facility with restoration power	x				
26	Scro	Ability to close to a dead bus	x				
27	Blackstart and system restoration	Locational benefit of unit placed in area with renewables but no current owned/contracted blackstart resource		x			
28	Blackstart and system restoration	Amount/presence of blackstart unit capacity.		x			
29	Blackstart and system restoration	**Attribute:** Flexibility of blackstart units and/or planned target unit (restoration support unit). Evaluated in item #30.				x	
30	Blackstart and system restoration	Does the proposed portfolio meet the goals of the TOP's System Restoration Plan?				x	
31	Blackstart and system restoration	Does the portfolio improve system restoration time relative to the Reference Portfolio?					x

Resource Attributes Matrix

			Proposed Evaluation Stage				
ID	**Attribute Category**	**Metric**	**Phase 1: Threshold Requirement Per Proposal**	**Phase 2: Individual Scoring Per Proposal**	**Phase 3: Portfolio Formation**	**Phase 4a: Portfolio Viability Assessment**	**Phases 4b & 5: Portfolio Scoring & Selection**
32	Environmental Impacts	For a new resource, an applicant must provide the information required of generating facilities under Minn. R. 7849.0320 and 7849.1500, subd. 2. State whether the proposal is located in an environmental justice area using the census criteria identified in Minnesota Statute, section 216B.1691, subd. 1(e). A proposer must provide a climate change analysis of the proposal consistent with the Minnesota Environmental Quality Board's environmental assessment worksheet guidance for developing a carbon footprint and incorporating climate adaptation and resilience.		x			
33	Environmental Impacts	Carbon-free or low-carbon generation resource, with points assigned based on the duration and certainty of emissions avoided. For purposes of this metric, a non□generating resource will receive the same points as a carbon-free resource.		x			
34	Environmental Impacts	Innovative & Emerging Technologies: Long Duration Storage, Hydrogen, Advanced Geothermal, and Others					x
35	Environmental Impacts	Carbon impact of portfolio relative to NSP Reference Portfolio, assuming opportunities to substitute zero-carbon delivered fuels for fossil fuels if provided in portfolio. Any analysis of carbon impact cannot assume the ability to substitute zero-carbon fuels for fossil fuels unless it also properly includes the costs of doing so during the evaluation of project and fuel costs and as part of cost inputs to the capacity expansion modeling. Scoring will account for the certainty and timing of potential fuel substitutions, with higher scores for more certain emissions avoidance and longer durations of zero-carbon operation.					x
36	Environmental Impacts	Carbon impact of portfolio relative to NSP Reference Portfolio					x
37	Costs	Low levelized cost of installed capacity in relation to other proposals. Costs of on-site fuel storage and/or potential conversion to cleaner fuels must be included.		x			
38	Costs	Low levelized cost of accredited capacity in relation to other proposals. The costs of on-site fuel storage and/or potential conversion to cleaner fuels must be included.		x			
39	Costs	Does this portfolio decrease MISO market purchases relative to the Reference					x
40	Costs	Low PVRR relative to other portfolios					x
41	Costs	Low PVSC relative to other candidate portfolios					x
42	Costs	Cost to Value Modeling/Adjusted Value Comparison					x

Resource Attributes Matrix

			Proposed Evaluation Stage				
ID	**Attribute Category**	**Metric**	**Phase 1: Threshold Requirement Per Proposal**	**Phase 2: Individual Scoring Per Proposal**	**Phase 3: Portfolio Formation**	**Phase 4a: Portfolio Viability Assessment**	**Phases 4b & 5: Portfolio Scoring & Selection**
43	Flexibility	Demonstrated up and down ramp capability, through registration or capability to provide one or more MISO products prioritizing ramping capability (i.e., including Short-Term Reserve and Fast Ramping Resources); more points awarded for participation products with a higher level of change capability in terms of capacity per time.		x			
44	Flexibility	Demonstrated ability to start quickly, through registration or capability to provide one or more MISO products prioritizing rapid starts (i.e., including Quick-Start Resource, Short Term Offline Reserve, offline Supplemental Reserves, and Fast-Start Resource) and more points awarded for products with the shorter lead time requirements.		x			
45	Flexibility	Lack of constraints on run time (small minimum run time constraint (i.e., 4 hours or less); ability to deploy rapid response product(s) for a minimum duration of time (i.e., 60 minutes))		x			
46	Flexibility	Increased cycling capability relative to other proposals, demonstrated by minimal cycling costs and lack of technical constraints		x			
47	Flexibility	Large range of dispatchable capacity relative to other proposals		x			
48	Flexibility	Ability of portfolio to improve system ramps relative to the Reference Portfolio					x
49	Essential Reliability Services	Demonstrated capability to provide voltage control/support through registration in MISO Markets to provide Spinning or Regulating Reserves		x			
50	Essential Reliability Services	Demonstrated capability to provide frequency regulation through registration in MISO Markets to provide Spinning or Regulating Reserves		x			
51	Essential Reliability Services	Demonstrated capability to provide spinning reserve through registration in MISO Operating Reserves Market		x			
52	Essential Reliability Services	Demonstrated capability to operate in dynamic voltage support (demonstrated by providing .dyr file for stability modeling)				x	
52	Essential Reliability Services	Portfolio demonstrates adequate voltage control/support capability, including containing asset(s) who have capability for registration in MISO Markets to provide Spinning or Regulating Reserves				x	
53	Essential Reliability Services	Portfolio demonstrates adequate capability of providing frequency regulation, including through asset(s) that have capability for registration in MISO Markets to provide Spinning or Regulating Reserves				x	
54	Essential Reliability Services	Portfolio demonstrates adequate capability of providing spinning reserve, including through asset(s) that have capability for registration in MISO Operating Reserves Markets				x	
55	Essential Reliability Services	**Attribute:** Short-Circuit Current. Portfolio must provide enough Short-Circuit Current to maintain bulk power system stability. Evaluated in item #56.				x	
56	Essential Reliability Services	Does Steady State or Stability modeling of the NSP system with this proposed portfolio meet transmission planning criteria?				x	

Resource Attributes Matrix

			Proposed Evaluation Stage				
ID	**Attribute Category**	**Metric**	**Phase 1: Threshold Requirement Per Proposal**	**Phase 2: Individual Scoring Per Proposal**	**Phase 3: Portfolio Formation**	**Phase 4a: Portfolio Viability Assessment**	**Phases 4b & 5: Portfolio Scoring & Selection**
57	Essential Reliability Services	**Attribute:** Inertial Response. Level of inertial response the portfolio contains above the minimum amount needed to maintain bulk power system stability. Evaluated in item #58.					x
58	Essential Reliability Services	Does the portfolio contribute to any demonstrated need for inertial/stability response relative to the Reference Portfolio?					x
59	Bidder Financial Strength & Experience	Bidder has financial viability & demonstrated experience on same type of project.	x				
60	Energy Justice	Does the proposal utilize union labor?	x				
61	Energy Justice	Analysis of EJ factors of projects in the candidate portfolio.					x

* These Phase 1 Metrics do not apply to demand response.

Project Evaluation Scores

Appendix D is marked "Not-Public" in its entirety as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The individual scoring for projects bid into Docket 23-212 is based on trade secret information provided by the bidders, and Xcel Energy's evaluation of the bids is also maintained as a trade secret. The bid evaluation methodology is the subject of efforts by Xcel Energy to maintain its secrecy and 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 the above-noted information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

1. **Nature of the Material:** The appendix includes the evaluation and scores of projects submitted to the firm dispatchable acquisition.
2. **Authors:** Xcel Energy bid evaluation personnel.
3. **Importance:** The bid evaluation information and methodology are critical to ensuring the confidentiality of future bid evaluations.
4. **Date the Information was Prepared:** June through October 2024.

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

Study 1 Selected Bids in Sensitivity Scenarios									
Bid Nameplate (MW)	**Base**	**Lyon 2050 EOL**	**High Load**	**Low Load**	**High Fuel/ Market Price**	**Low Fuel/ Market Price**	**Wind Fleet Variability**	**High Reg/ Ext Cost of Carbon**	**Low Reg/ Ext Cost of Carbon**
002 Plum Creek Storage PPA	X	X	X		X	X	X	X	X
002 Plum Creek Wind PPA	X	X	X		X	X	X	X	X
004 Lyon Co CT	X	X	X		X	X	X	X	X
005 Sherco West Battery - 4hr	X	X	X	X	X	X	X	X	X
008 Cannon Falls 1 Extension - 10 yrs									
008 Cannon Falls 2 Extension - 10 yrs									
009 Cannon Falls 1 Extension - 12 yrs									
009 Cannon Falls 2 Extension - 12 yrs									
011 Cannon Falls 1 Extension - 20 yrs	X	X	X	X	X	X	X	X	X
011 Cannon Falls 2 Extension - 20 yrs	X	X	X	X	X	X	X	X	X
014 Lake Wilson Solar PPA	X	X	X	X	X	X	X	X	X
014 Lake Wilson Storage PPA - 20 MW	X	X	X	X	X	X	X	X	X
014 Lake Wilson Storage PPA - 75 MW	X	X	X	X	X	X	X	X	X
015 Northstar Storage 50MW PPA 15yr									
016 Northstar Storage 80MW PPA 15yr	X	X	X	X	X	X	X	X	X
017 Mankato Energy Center 1 Extension + BESS Blackstart									
018 Mankato Energy Center 1 Extension + Diesel Blackstart									
019 Mankato Energy Center 1 Extension	X	X	X	X	X	X	X	X	X

Phase 4b: Additional Evaluation Portfolio Criteria

	Attribute	Scenario 1 (Settlement)	Scenario 2 (800 MW Cap)	Scenario 3 (Renewables)
Does this portfolio have less LOLH and EUE relative to Portfolio 1 under identical test conditions?	16	N/A	No. Higher LOLH and EUE in every historical weather year applied.	No. Higher LOLH and EUE in every historical weather year applied.
Does this portfolio improve system restoration time relative to Portfolio 1?	31	N/A	Equal	No
Innovative & Emerging Technologies: Long Duration Storage, Hydrogen, Advanced Geothermal, and Others	34	Contains No Applicable Technology	Contains No Applicable Technology	Contains No Applicable Technology
Carbon impact of portfolio relative to NSP Reference Portfolio, assuming opportunities to substitute zero-carbon delivered fuels for fossil fuels if provided in portfolio. Any analysis of carbon impact cannot assume the ability to substitute zero-carbon fuels for fossil fuels unless it also properly includes the costs of doing so during the evaluation of project and fuel costs and as part of cost inputs to the capacity expansion modeling. Scoring will account for the certainty and timing of potential fuel substitutions, with higher scores for more certain emissions avoidance and longer durations of zero-carbon operation.	35	N/A	Answer is same as that for attribute 36; no zero-carbon delivered fuels provided in portfolio.	Answer is same as that for attribute 36; no zero-carbon delivered fuels provided in portfolio.
Carbon impact of portfolio relative to NSP Reference Portfolio	36	N/A	1.59 Million more tons of CO2 from 2028-2040	3.36 Million fewer tons of CO2 from 2028-2040
Does this Portfolio decrease reliance on MISO Market Purchases Relative to Portfolio 1?	39	N/A	No. More MISO Market Purchases necessary.	No. More MISO Market Purchases necessary.
Low PVRR relative to other portfolios	40	Lowest PVRR out of all 3 portfolios (Rank: 1 out of 3)	Second Lowest PVRR out of all 3 portfolios (Rank: 2 out of 3)	Highest PVRR out of all 3 portfolios (Rank: 3 out of 3)
Low PVSC relative to other candidate portfolios	41	Second Lowest PVSC out of all 3 portfolios (Rank: 2 out of 3)	Lowest PVSC out of all 3 portfolios (Rank: 1 out of 3)	Highest PVSC out of all 3 portfolios (Rank: 3 out of 3)
Does this portfolio improve system ramps relative to Portfolio 1? *(See Ramp Metric Table below)*	42	N/A	System ramping needs lower.	System ramping needs higher.
Inertial Response. Level of inertial response the portfolio contains above the minimum amount needed to maintain bulk power system stability. Evaluated in item #58.		As indicated in approved attribute matrix, evaluated in #58 below.	As indicated in approved attribute matrix, evaluated in #58 below.	As indicated in approved attribute matrix, evaluated in #58 below.
Does the portfolio contribute to any demonstrated need for inertial/stability response relative to the Reference Portfolio?	58	N/A	No; portfolio passes transmission planning criteria.	No; portfolio passes transmission planning criteria.

Phase 4b: Additional Evaluation Portfolio Criteria

	Attribute	Scenario 1 (Settlement)	Scenario 2 (800 MW Cap)	Scenario 3 (Renewables)
Analysis of EJ factors of projects in the candidate portfolio.	61			
The socioeconomic factors of a projects location		2 projects in Environmental Justice area specifically due to criteria 2 from attribute 32, additional info provided in some applications. **	1 project in Environmental Justice area specifically due to criteria 2 from attribute 32, additional info provided in some applications. **	1 projects in Environmental Justice area specifically due to criteria 2 from attribute 32, additional info provided in some applications. **
The involvement of local government, community organizations, and where relevant, Tribal Nations		Three projects indicate involvement	No involvement indicated	Two projects indicate involvement
The estimated local tax revenue it will produce		~$490 million over proposed project terms or useful lifetimes.	~$190 million over proposed project terms or useful lifetimes.	~$462 million over proposed project terms or useful lifetimes.
The temporary and permanent jobs it will create		36-40 permanent jobs created; 30 jobs retained; approximately 850 construction jobs	6 permanent jobs created; 30 jobs retained; approximately 40 construction jobs	20-24 permanent jobs; approximately 680 construction jobs
The payment of prevailing wages, and workforce training opportunities		Indicated by all bids except 1. Types of training & definition of prevailing wage varies.	Indicated by all bids except 1. Types of training & definition of prevailing wage varies.	Indicated by all bids except 1. Types of training & definition of prevailing wage varies.
Commitment to use of diverse suppliers, as demonstrated by a history of use on recent projects		Commitment to use of diverse suppliers provided by all except 3 bids (2 existing facilities & 1 new facility);	Commitment to use of diverse suppliers provided by all except 1 bid	Commitment to use of diverse suppliers provided by all except 1 bid

** Criteria 2 from Attribute 32 is criteria (2) from Minn. Stat. 216B.1691, Subd. 1(e): 35 percent or more households in the area have an income that is at or below 200 percent of the federal poverty level.

Phase 4b: Additional Evaluation Portfolio Criteria

		Net Load - Ramp Behavior			
Plan	**Historical Year - Hourly Conditions in 2029**	**Maximum 3hr Ramp (MW)**	**Maximum 4hr Ramp (MW)**	**Maximum 6hr Ramp (MW)**	**Maximum 8hr Ramp (MW)**
Study 1	2016 Historical	3,824	4,322	4,959	5,054
	2017 Historical	4,076	4,632	4,892	5,146
	2018 Historical	4,285	4,694	4,694	4,923
	2019 Historical	4,066	4,339	4,899	5,128
	2020 Historical	4,625	4,854	5,246	6,194
	2021 Historical	4,223	4,484	4,906	4,906
	2022 Historical	4,505	4,517	4,862	6,185
	Average	**4,229**	**4,549**	**4,923**	**5,362**
Study 2	2016 Historical	3,644	4,199	4,472	4,898
	2017 Historical	3,719	4,078	4,437	4,818
	2018 Historical	4,229	4,415	4,434	4,789
	2019 Historical	3,653	4,005	4,489	4,973
	2020 Historical	4,535	4,535	4,972	5,755
	2021 Historical	4,067	4,342	4,477	4,600
	2022 Historical	4,031	4,436	4,636	5,774
	Average	**3,982**	**4,287**	**4,560**	**5,087**
Study 3	2016 Historical	3,837	4,322	4,613	4,939
	2017 Historical	4,083	4,496	4,692	5,002
	2018 Historical	4,289	4,698	4,698	4,867
	2019 Historical	4,035	4,455	4,899	5,128
	2020 Historical	4,625	4,854	5,246	6,194
	2021 Historical	4,206	4,484	4,717	5,061
	2022 Historical	4,568	4,568	4,738	5,907
	Average	**4,235**	**4,554**	**4,801**	**5,300**