



2302 Great N. Drive
Fargo, North Dakota 58102

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

October 1, 2026

–Via Electronic Mail and U.S. Mail–

Brian Johnson, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: SUPPLEMENT
XCEL ENERGY 2024-2040 NORTH DAKOTA RESOURCE PLAN
CASE NO. PU-24-160

Dear Mr. Johnson:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Supplement to the 2024-2040 North Dakota Resource Plan (ND Resource Plan), initially filed with the North Dakota Public Service Commission on April 8, 2024 pursuant to N.D.C.C. §§ 49-05-04.4 and 49-05-17.

Since our initial ND Resource Plan filing in April 2024, market and industry changes – as well as the passage of time and the resources we have recently acquired – necessitate updated planning and modeling to ensure we continue to serve North Dakota customers safely, reliably, and affordably into the future. We have worked with Commission Staff to develop updated scenarios that align with least-cost planning principles and test a range of potential futures. In this Supplement, we present the results of our updated modeling, including an updated ND Preferred Plan, and respectfully request Commission approval of new system resources that we have acquired since the 2024 ND Resource Plan filing.

We are providing a public version of the Supplement electronically to the Commission. Pursuant to N.D.C.C. § 69-02-02-04, we are also providing an original and seven hard copies of the public version of the Supplement via U.S. Mail.

Appendix A to the Supplement contains trade secret information. In accordance with N.D.C.C. § 69-02-09-02, an Application for Trade Secret Protection was provided

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

with our initial filing. The trade secret information provided in Attachment A is of the sort described in the Application. Commission action on the Application is pending. We are providing a hard copy of the Trade Secret Application and the Not-Public version of Appendix A via U.S. Mail.

We look forward to working with the Commission and Commission Staff on this filing, and note that we are in the process of developing our next full Upper Midwest Integrated Resource Plan, which we anticipate filing late 2026

Please contact me at (701) 241-8632 or alex.j.nisbet@xcelenergy.com if you have questions regarding this submission. Alternatively, you may wish to contact Chris Shaw, Manager of Regulatory Policy, at christopher.j.shaw@xcelenergy.com.

Sincerely,

/s/

ALEX J. NISBET
REGULATORY POLICY SPECIALIST
XCEL ENERGY | ND

Enclosures
cc: Adam Renfandt
Victor Schock

2024-2040 NORTH DAKOTA RESOURCE PLAN SUPPLEMENT

I. INTRODUCTION

Northern States Power Company doing business as Xcel Energy, presents this Supplement to its 2024-2040 North Dakota Resource Plan (the 2024 ND Resource Plan or 2024 Plan). Since our initial ND Resource Plan filing in April 2024, market and industry changes as well as the passage of time necessitate updated planning and modeling to ensure we continue to serve North Dakota customers safely, reliably, and affordably into the future. In this Supplement we are also requesting Commission approval of new system resources that we have acquired since the 2024 ND Resource Plan filing.

Since our 2024 Plan filing, the Company entered into a Settlement Agreement with stakeholders in Minnesota regarding our Upper Midwest Integrated Resource Plan filed with the Minnesota Public Utilities Commission (MPUC) in February 2024.¹ The Settlement Agreement also encompassed the Company's firm dispatchable resource acquisition process, which sought dispatchable resources to meet the need identified in the Company's 2019 Upper Midwest Integrated Resource Plan. In April 2025, the MPUC – the only other jurisdiction in our Upper Midwest service territory that makes a determination on our Integrated Resource Plans – approved the Settlement Agreement with modifications. Since then, the Company has undertaken a number of resource acquisition efforts to meet near-term needs identified in the Resource Plan approved by the MPUC. In addition to the firm dispatchable resources the MPUC approved as part of the Settlement Agreement, the MPUC has approved the acquisition of additional resources as discussed below.

The resource acquisitions the Company has made over the past two-plus years address near-term and medium-term system needs for reliability and resource adequacy – providing capacity, energy, and flexibility, while enabling efficient reuse of valuable interconnection rights and capturing time-sensitive federal tax incentives that benefit all of the Company's customers, including those in North Dakota. These resources, totaling approximately 5,660 megawatts (MW), were selected through competitive, rigorous acquisition processes, ensuring competitive pricing that is inherently

¹ For the purpose of the Company's integrated resource planning, Upper Midwest is defined as Xcel Energy service areas in Minnesota, Michigan, North Dakota, South Dakota, and Wisconsin.

reflective of market realities. Acquiring these resources now mitigates exposure to the wholesale market and ensures resource adequacy for our customers. For these reasons, we respectfully request that the Commission approve these new resources.

In this Supplement filing, we explain updated modeling and analysis we have conducted, aiming to provide a robust set of scenarios and sensitivities that illustrate a range of possible future resource mixes to serve North Dakota. We also explain our Updated ND Preferred Plan, which includes new resources the Company has competitively procured since the time of the 2024 Plan filing.

We are not, however, requesting Commission approval of our Updated ND Preferred Plan. We are currently in the process of preparing a new Upper Midwest Integrated Resource Plan, which we anticipate filing in late 2026; as such, this Supplement does not seek to evaluate all potential future scenarios, but rather updates previous modeling and provides a limited set of additional analyses to develop an Updated ND Preferred Plan. The forthcoming Resource Plan will further evaluate the need for additional system resources beyond what we have already acquired to meet the needs of our customers. Rather, we are requesting Commission approval of new system resources, shown in Table 1 below, which we have acquired since the 2024 ND Resource Plan filing.

The remainder of this filing is organized as follows. First, we discuss the state of the industry to provide important grounding and context that impacts our resource planning and acquisition processes overall. We then explain the resources and resource procurement processes we have undertaken since our 2024 ND Resource Plan filing. Then, we discuss our updated modeling and the scenarios we reviewed, and explain our Updated ND Preferred Plan, which includes all resources we have recently acquired for our Upper Midwest customers, and which will benefit North Dakota customers by reducing risk. Finally, we provide a rate impact analysis of our Updated ND Preferred Plan.

We respectfully request the Commission approve the resources shown in Table 1 below.

II. STATE OF THE INDUSTRY

Since we filed our ND Resource Plan, the industry has continued to rapidly evolve and is continuing to experience sustained and overlapping cost pressures and uncertainties,

affecting the economics of generation resources. Global supply chain disruptions, growing demand, labor market constraints, higher interest rates, evolving trade policies, and new tax regulations are collectively driving up the cost of project development and operations. Some of these dynamics necessitate changes to modeling assumptions used to derive our Updated ND Preferred Plan, most notably generic resource cost assumptions. We highlight some of these industry dynamics below.

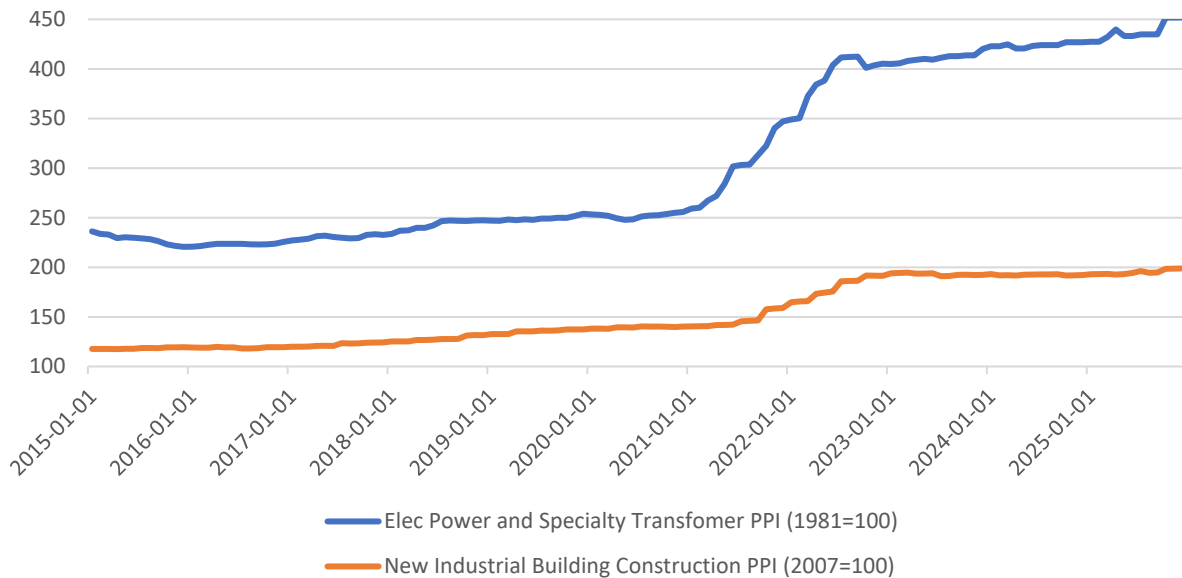
A. Supply Chain Disruptions and Equipment Availability

Global supply chain constraints remain a persistent and well-documented challenge. Extended lead times and higher prices for critical components such as blades, drivetrains, and tower sections are disrupting project schedules and increasing overall costs. For example, lead times for power transformers have continued to increase since 2021 due to pandemic-related supply delays and increasing demand.² Developers have reported similar procurement difficulties for high-voltage electrical equipment and wind turbine generators, further straining project timelines and budgets.

Figure 1 below shows two illustrative Producer Price Indices (PPI) published by the Federal Reserve Bank of St. Louis, highlighting the scale of recent cost escalations across broader segments of the U.S. economy following a prior period of relative price stability.

² See, e.g., <https://www.woodmac.com/news/opinion/transformer-troubles-manufacturing-and-policy-constraints-hit-us-transformer-supply/>.

Figure 1
Illustrative Federal Reserve Producer Price Indices
for New Generation Projects³



The average PPI for Electric Power and Specialty Transformer Manufacturing from November 2021 to December 2025 was 65 percent higher than the average from 2015 to 2020. For New Industrial Building Construction, average PPI was 43 percent higher. These supply chain challenges continue to exert upward pressure on project costs and delivery times.

B. Generation Capacity Lagging Behind Demand Growth

Electricity demand is rising faster than at any point in the past three decades, increasing competition for generation resources and driving up market prices. As the U.S. Energy Information Administration notes, electricity demand has increased by 2.1 percent per year, on average, over the last five years – following 15 years of nearly flat electricity consumption across the U.S. Through 2050, EIA projects continued electricity

³ U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Electric Power and Specialty Transformer Manufacturing [PCU335311335311P] retrieved from FRED, Federal Reserve Bank of St. Louis; and Producer Price Index by Industry: New Industrial Building Construction [PCU236211236211] retrieved from <https://fred.stlouisfed.org/series/PCU335311335311P> (Retrieved January 30, 2026).

consumption growth, with data centers being a major factor.^{4,5} Consistent with these nationwide figures and longer-term forecasts, the Company is experiencing higher anticipated load growth in the near-term than reflected in the ND Resource Plan load forecast. The updated EnCompass modeling in this Supplement incorporates an updated load forecast as further discussed in Appendix A.

C. Rising Labor Costs and Workforce Constraints

Labor shortages and rising demand for energy infrastructure development are driving up labor costs across the industry. As utilities and developers work to meet growing electricity needs and replace retiring generation, competition for skilled construction labor has intensified. This has resulted in higher contractor pricing, increased schedule risks, and elevated overall project costs.

D. Impact of Elevated Interest Rates on Project Financing

Higher interest rates translate into increased borrowing costs and a higher cost of capital. This shift has significant impacts for the energy sector, where adding or replacing generation resources requires substantial, capital-intensive investments that often take years to bring online. As borrowing costs rise, so do the expenses associated with financing and constructing these projects.

E. Evolving Trade Policies Introduce Volatility in Project Development

Project development costs have been, and continue to be, affected by recent shifts in federal trade policy. Over the past year, changes in tariff regimes have introduced significant volatility into the cost and procurement of key project components. Although the Company continues to evaluate opportunities to source components domestically, current market conditions limit the feasibility of relying exclusively on U.S.-based manufacturing for generation and storage resources. Constrained investment in expansion of domestic manufacturing requires developers to rely on a diversified global supply chain to procure key components in a timely and cost-effective manner. As trade policy continues to evolve, developers face heightened exposure to price volatility, supply-chain disruption, and regulatory risk.

⁴ U.S. Energy Information Administration, Annual Energy Outlook 2026.
See <https://www.eia.gov/outlooks/aeo/narrative/index.php#Electricity> and
https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative.pdf (accessed September 28, 2026).

F. Federal Aviation Administration Permitting

Under federal law, any tower over 200 feet tall must receive review approval from the Federal Aviation Administration (FAA) to ensure air navigation safety.⁶ Projects must receive a Determination of No Hazard (DNH) in order to proceed with construction. As part of FAA's process, the U.S. Department of Defense (DOD) Military Aviation and Installation Assurance Clearinghouse⁷ must review the requests for possible impacts to air surveillance radar, missile silos, areas where the military conducts aerial training, etc. DOD must give its approval before FAA can issue a DNH, which authorizes construction. In late 2025, DOD announced that its part of the process would take longer. In April 2026, DOD communicated its intent to extend the review process to include new rounds of interagency assessment, with reports that the agency had stopped reviews of onshore wind projects all together.

A coalition of renewable energy trade associations sued DOD in May, and in August 2026, the U.S. District Court for the District of Oregon granted a preliminary injunction ordering DOD to resume processing wind energy project applications under existing frameworks, staying DOD's review freeze pending final adjudication. At this time, the implications of permitting delays are still being assessed, and court proceedings continue. Impacts may vary significantly based on project location, system characteristics, and the specific mitigation measures required by federal agencies. We raise this issue to note that assumptions regarding the timing and availability of future wind resources warrant caution, particularly where those resources remain hypothetical or unapproved.

G. Modifications to Renewable Energy Tax Credit Provisions

The passage of Public Law No. 119-21, also known as the One Big Beautiful Bill Act (OBBBA), on July 4, 2025, introduced a significant restructuring of federal tax incentives for renewable energy development. The legislation phases down tax credits that have historically supported the viability of wind, solar, and energy storage projects.

Under Public Law No. 119-21, wind and solar projects that did not begin construction by July 4, 2026 must be placed in service by December 31, 2027 to qualify for full tax credits. Wind and solar projects that began construction by July 4, 2026 remain subject to U.S. Department of Treasury guidance that allows projects to qualify for full tax

⁶ 49 U.S.C 44718; Pub. L. 115–254, div. B, title V, § 576, Oct. 5, 2018, 132 Stat. 3391.

⁷ 10 U.S.C § 183a.

credits if placed in service by the end of the fourth calendar year following the year construction begins.

On July 7, 2025, the President issued an Executive Order directing the Treasury to issue “new and revised” guidance within 45 days, limiting the use of broad safe harbor provisions unless a substantial portion of the facility has already been constructed. In response, the U.S. Department of Treasury/Internal Revenue Service issued guidance reaffirming the four-year window to place projects in service. However, the guidance eliminated the previously available “Five Percent Safe Harbor” for most wind and solar projects. Instead, developers must satisfy the Physical Work Test, which requires that physical work of a significant nature commence under a binding written contract before a project can qualify as having begun construction.⁸

This change, along with the accelerated timeline for beginning construction on wind and solar projects, significantly narrows the pathway to eligibility and demands more rigorous documentation and project execution. Energy storage projects, while not subject to the same immediate cutoff, face a gradual phase-out of incentives beginning in 2034. The credit value will decline incrementally – 75 percent in 2034, 50 percent in 2035, and fully sunset by 2036.⁹ This timeline provides a longer runway for storage deployment but introduces long-term uncertainty for developers and investors.

The OBBBA also imposes new restrictions on the use of components sourced from foreign entities of concern (FEOCs), effective for projects beginning construction after December 31, 2025. These provisions are part of a broader effort to reduce reliance on Chinese supply chains and are expected to affect procurement.¹⁰ The combined effect of these provisions is a narrowing window of opportunity for developers to secure tax credit eligibility. Projects in development at the time of the OBBBA’s passage sought to accelerate permitting, interconnection, and procurement activities to meet the statutory deadlines.

⁸ IRS Notice 2025-42, “Beginning Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities” Available at <https://www.irs.gov/pub/irs-drop/n-25-42.pdf>.

⁹ Basis, One Big Beautiful Bill: Final Impact Analysis on IRA Clean Energy Tax Credits (July 9, 2025). Available at <https://www.buildwithbasis.com/insights/one-big-beautiful-bill-final-impact-analysis-on-ira-clean-energy-tax-credits>.

¹⁰ Id.

In our updated EnCompass modeling for this Supplement, we updated certain underlying assumptions to reflect the effect of expiring tax credits. First, the modeling scenarios assume either that new wind and solar projects will not be eligible for production tax credits (PTCs) past 2030, or that no PTCs are available at all. Second, we assume that four-hour battery energy storage systems (BESS) will not receive investment tax credits due to FEOC restrictions.

H. Capacity Accreditation Changes and the Direct Loss of Load Methodology

The Midcontinent Independent System Operator (MISO) is undertaking a major reform of how it accredits capacity resources for resource adequacy purposes. After moving to a seasonal planning construct in the 2023-2024 Planning Year, MISO continues to evolve its accreditation and planning constructs. The new methodology, known as Direct Loss-of-Load (DLOL), was approved by the Federal Energy Regulatory Commission (FERC) in October 2024 and is scheduled for implementation in the 2028–2029 Planning Year. During a three-year transition period (Planning Years 2025–26 through 2027–28), MISO is publishing indicative DLOL results alongside the legacy accreditation values so that market participants can prepare.

The DLOL methodology will replace three separate, resource-type-specific accreditation approaches with a single framework that applies to all internal capacity resources except external resources and Load Modifying Resources (LMRs). The DLOL framework seeks to address a core problem: that MISO’s current methods did not consistently value resource availability during the hours when the system is most at risk of losing load, and that the rapid growth of variable and energy-limited resources demands a more rigorous and comparable approach.

While all types of resources use the same DLOL framework, the resulting accreditation values differ significantly by resource class because they reflect actual or expected availability during critical hours. Wind resources receive relatively low accreditation values under DLOL, but accreditation does not vary significantly as more wind capacity is added to the system. For battery storage, accreditation under DLOL is highly sensitive to dispatch modeling assumptions and the duration and timing of LOL events relative to the battery’s storage capacity and state of charge. For four-hour BESS, indicative DLOL accreditation ranges widely, from 8-99 percent of installed capacity (ICAP) depending on the season and other assumptions.

On the opposite end of the spectrum, solar resources receive very low DLOL accreditation values because LOL events frequently occur during evening, nighttime, or early morning hours, when solar output is zero or minimal. Greater solar penetration across the MISO footprint results in LOL hours being pushed to periods when stand-alone solar resources are not available. Indicative DLOL class-average values range from approximately 0–46 percent of ICAP, with the lowest values in winter and fall (often near 0–5 percent) and somewhat higher values in spring and summer when daytime risk events are more common. As solar penetration increases, its accreditation tends to decline further because additional solar pushes LOL risk toward hours when solar is not producing.

The updated EnCompass modeling in this Supplement incorporates DLOL accreditation assumptions.

I. Market Trends and Costs

Recent market conditions have led to resource costs that are significantly higher than those assumed in earlier planning efforts, and pricing in recent resource acquisitions has reflected these market conditions. While the 2024 IRP assumed declining leveled costs over time, updated market data show higher prices in both the near term and the long term, consistent with current industry conditions. As shown in Attachment A, this Supplement reflects updated costs for generic resources, in line with recent trends.

III. RESOURCE PROCUREMENTS

Since our 2024 ND Resource Plan filing, we have advanced multiple complementary resource acquisition efforts, including:

- Firm Dispatchable Request for Proposals (RFP) / Minnesota IRP Settlement
- 2024 NSP Wind, Solar, and Storage Request for Proposals (2024 RFP)
- Expedited Resource Addition Study (ERAS) processes (ERAS 1 and ERAS 2)
- Wind Development Transfer Request for Proposals (Wind Dev-Transfer)

Together, these processes address near-term and medium-term system needs for capacity, energy, and flexibility, while enabling efficient reuse of valuable interconnection rights and capturing time-sensitive federal tax incentives that benefit North Dakota customers.

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 10 of 25

Table 1 provides an overview of the resources selected through each process, and we discuss each acquisition process briefly below.

Table 1: Resource Acquisitions and Extensions

Project	Acquisition Process	Technology	Capacity	Contract Structure	Location	Inter-connection / Notes
Sherco West BESS	Firm Dispatchable RFP / MN IRP Settlement	BESS	300 MW	Self-Build	Becker, MN	Reuse of Sherco Unit 1 interconnection rights
Cottage Grove BESS*	Firm Dispatchable RFP	BESS	80 MW	PPA	Cottage Grove, MN	Transmission-interconnected
North Star BESS	Firm dispatchable RFP / MN IRP Settlement	BESS	100 MW	PPA	Chisago County, MN	Transmission-interconnected
Mankato Energy Center extension and BESS addition	Firm dispatchable RFP / MN IRP Settlement	Gas CT and BESS	720 MW (CT) 12 MW/48 MWh (BESS)	PPA (extension)	Mankato, MN	Transmission-interconnected
Cannon Falls Energy Center extension	Firm Dispatchable RFP / MN IRP Settlement	CT dual fuel gas/oil	357 MW	PPA (extension)	Cannon Falls, MN	Transmission-interconnected
Cannon Falls Energy Center expansion	ERAS 1	CT dual fuel gas/oil	57 MW	PPA (incremental capacity)	Cannon Falls, MN	Transmission-interconnected
Lyon County CT	Firm Dispatchable RFP / MN IRP Settlement	CT	420 MW	Self-Build	Lyon County, MN	Reuse of Sherco interconnection rights; Sherco gen-tie
Sherco Solar 4†	2024 RFP	Solar	200 MW	Self-Build	Clear Lake Township, MN	Reuse of Sherco interconnection rights
Fillmore Solar	2024 RFP	Solar	15 MW (addition)	PPA	Fillmore County, MN	Transmission-interconnected
Grant Solar	2024 RFP	Solar	99 MW	PPA	McCook County, SD	Transmission-interconnected
Gopher State Solar	2024 RFP	Solar	200 MW	PPA	Renville County, MN	Transmission-interconnected
Lemon Hill Solar	2024 RFP	Solar	180 MW	PPA	Olmsted County, MN	Transmission-interconnected
Blue Lake BESS	2024 RFP	BESS	135.5 MW	Self-Build	Scott County, MN	Transmission-Interconnected

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 11 of 25

Project	Acquisition Process	Tech-nology	Capacity	Contract Structure	Location	Inter-connection / Notes
Sherco South BESS	2024 RFP / ERAS 2	BESS	300 MW	Self-Build	Becker, MN	Independent ERAS interconnection at Sherco
Crowned Ridge BESS	2024 RFP	BESS	120 MW	PPA	Codington County, SD	Transmission-interconnected
Crane BESS	2024 RFP	BESS	200 MW	PPA	Olmsted County, MN	Transmission-interconnected
Mayhew Lake BESS	2024 RFP	BESS	100 MW	PPA	Benton,	Transmission-interconnected
Sandhill BESS	ERAS 1	BESS	200 MW	PPA	Olmsted County, MN	ERAS third-party project
Benton II BESS	ERAS 1	BESS	300 MW	PPA	Benton County, MN	ERAS third-party project
Nobles BESS	ERAS 2	BESS	300 MW	Self-Build	Nobles County, MN	ERAS independent interconnection
Little Rock Wind†	Wind Development Transfer	Wind	300 MW	Development Transfer	Near Worthington, MN	Reuse of Sherco interconnection rights; Sherco gen-tie (Alternate transmission interconnection also under evaluation)
Box Car Wind (Phases 1–4) †	Wind Development Transfer	Wind	969 MW	Development Transfer	Near Balaton, MN	Reuse of Sherco interconnection rights; Sherco gen-tie

* Selected as replacement project for Plum Creek Wind + Storage project, which was selected in the firm dispatchable RFP, but later withdrawn.

† Little Rock Wind and Box Car Wind Phases 3 and 4 are proposed to be part of the Clean Energy Accelerator Charge in the Company’s pending electric service agreement (ESA) with Google for a data center in Pine Island, Minnesota. See Section E below.

As discussed in the Introduction, the Company respectfully requests the Commission approve the resources shown in Table 1 above.

October 1, 2026

A. Firm Dispatchable RFP and Minnesota IRP Settlement

In 2023, the Company initiated a resource procurement process to meet the need for up to 800 MW of firm dispatchable generation. The need was identified in the Company's 2019 Integrated Resource Plan. The process was conducted under a competitive framework approved by the MPUC. In February 2024, the Company filed its 2024 Resource Plan, and after a robust procedural process, entered into a Settlement Agreement in October 2024, which included the projects selected through the firm dispatchable RFP process. In addition to the Company-owned resources shown in Table 1 above, the firm dispatchable RFP and subsequent processes resulted in new and extended power purchase agreements (PPAs) for battery energy storage system (BESS) and gas combustion turbine resources. The MPUC approved the Settlement Agreement with modifications on April 21, 2025.¹¹

B. 2024 RFP

The Company initiated the 2024 RFP to procure up to approximately 1,600 MW of wind, solar, storage, and hybrid resources needed to meet system capacity and energy requirements identified in the 2024 IRP Five-Year Action Plan. The RFP was also designed to enable reuse of interconnection rights made available by the planned retirement of Sherco Units 1 and 3 and Blue Lake units. The MPUC approved the Minnesota projects on March 25, 2026.¹²

C. ERAS 1 and 2

In response to persistent delays in MISO's Definitive Planning Phase (DPP) interconnection studies and growing concerns about tightening resource adequacy margins across the region, MISO established the ERAS process as a temporary mechanism to accelerate interconnection reviews for projects needed to address near-term reliability risks. Unlike the standard DPP queue, which can take multiple years to complete, ERAS provides a streamlined pathway to a Generator Interconnection Agreement, with studies typically completed within three to six months for projects that can demonstrate urgent reliability value and meet stringent eligibility requirements. This reform is intended to ensure that essential generation projects can proceed without being stalled by broader queue backlogs.

¹¹ See Minnesota PUC Docket Nos. E002/RP-24-67 and E002/CN-23-212.

¹² See Minnesota PUC Docket No. E002/M-24-230.

The ERAS portfolio includes projects that were not sourced through a competitively bid process. However, these projects supplement the Company's recent broader efforts to competitively procure resources, which also served to inform pricing. The Company proposed PPAs and one self-build project to the MPUC. In addition, the Company proposed an independent interconnection for the Sherco South BESS that was selected in the 2024 RFP. The MPUC approved the ERAS 1 PPAs on February 17, 2026, and the ERAS 2 projects on July 1, 2026.¹³

D. Wind Dev Transfer

The Wind Dev Transfer RFP aimed to secure renewable resources capable of reusing the remaining Sherco interconnection rights, after previous RFP processes failed to result in PPA or Build Transfer projects in the identified geographic area. In contrast to a build-transfer, the dev-transfer acquisition process allows the Company to take ownership of projects at an earlier stage – after a majority of the development work has been completed, but before construction activities begin. This RFP had several requirements stemming from the Company reusing transmission interconnection rights from its retirement of Sherco Units 1 & 3 at its Sherco Generating Station – one of which is the need to own any generation, consistent with MISO and FERC requirements. The RFP was issued on October 31, 2023, and the MPUC approved the two projects shown in Table 1 above on September 18, 2026.¹⁴

E. Google ESA Projects

The Company has requested approval from the MPUC of electric service agreements (ESA) to provide electricity to Google's planned data center near Pine Island, Minnesota.¹⁵ The agreements provide for new load and benefits for all Upper Midwest customers. As part of the ESA, Google agrees to support the development of a portfolio of clean energy resources and associated infrastructure, in support of its objectives, through a Clean Energy Asset Charge (CEAC) mechanism. Under the ESA, the CEAC establishes a methodology for calculating and tracking the revenue requirements associated with designated clean energy assets and is designed to ensure that costs attributable to serving Google are recovered from Google rather than shifted to other customers. The proposed ESA specifies Sherco Solar 4, Little Rock Wind, and Box Car Wind Phases 3&4 as CEAC resources. While the projects are

¹³ See Minnesota PUC Docket Nos. E002/RP-24-67 and E002/CN-23-212.

¹⁴ See Minnesota PUC Docket No. E002/M-23-342.

¹⁵ See Minnesota PUC Docket No. E002/M-26-170.

system resources to meet system capacity and energy needs for all customers, if the ESA is approved as proposed, Google would pay the revenue requirements associated with each asset within the CEAC portfolio during the ESA term (15 years per asset).

IV. MODELING

The Company's updated modeling builds on the 2024 ND Resource Plan framework, with targeted updates to reflect current assumptions, resource additions, and analytical priorities. We provide an overview of our modeling approach in this section. Appendix A provides detailed descriptions and tables showing our updated EnCompass modeling assumptions and inputs, and Appendix B provides additional, detailed views of modeling results. We address assumptions, scenarios, and results in this section, including our Preferred Plan.

A. Modeling Assumptions and Scenarios

The updated modeling scope begins with the "Scenario 3" from the 2024 Plan base scenarios – the "extend all nuclear" scenario. For that scenario, the Prairie Island 1 and 2 retirement dates extend from 2033/2034 to 2053/2054, and the Monticello retirement date extends from 2040 to 2050. This new Base scenario aligns with our plans for the nuclear resources.¹⁶ The new Base scenario was also updated to reflect the most recently available load forecast and updated generic resource pricing, as shown in Appendix A. The Base scenario allows market energy purchases through 2030 in the expansion plan, subject to an import limit of 2,300 MW.¹⁷

In addition to updating the Base scenario, the Company worked with Commission staff to develop three Change Case scenarios. Each Change Case scenario reflects a different mix of the resources added since April 2024 as shown in Table 1. These three scenarios use actual revenue requirements for all projects.

1. Scenario 1: Includes **all resources** as shown in Table 1.
2. Scenario 2: Includes only **natural gas and BESS resources** shown in Table 1, omitting wind and solar.
3. Scenario 3: Includes **only natural gas resources** shown in Table 1, omitting wind, solar, and BESS.

¹⁶ The extension of Monticello's retirement date to 2050 was approved by the MPUC for planning purposes as part of the Settlement Agreement in Minnesota.

¹⁷ This constraint provides a reasonable limit on energy market reliance and was developed in previous IRPs based on historical data.

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 15 of 25

Each Change Case scenario was then run under four sensitivities: (1-2) with and without PTCs available for wind and solar through 2030, (3) with a high expected unserved energy (EUE) penalty, and (4) lower EUE penalty, to test the system's reliance on market purchases by reducing the unserved energy penalty from \$1 million to \$242.71/MWh, the top one percent value from the NSP Hub.

All scenarios include MISO's DLOL capacity accreditation methodology beginning with the 2028-2029 Planning Year (starting June 1, 2028). Lastly, in all Change Case scenarios, the model does not allow new generic CT additions prior to 2030, to reflect the reality of turbine procurement lead times.

Table 2 below summarizes the scenarios modeled.

Table 2: ND Resource Plan Supplement Modeling Scenarios

Scenario	Procured Resources Included	PTC for Wind and Solar	Unserved Energy Penalty	Generic CT Additions
Base A	None – generics only	Through 2030	Higher value	No restrictions
Base B	None – generics only	None	Higher value	No restrictions
Base C	None – generics only	Through 2030	Lower value	No restrictions
Base D	None – generics only	None	Lower value	No restrictions
1A	All resources shown in Table 1	Through 2030	Higher value	Not allowed before 2030
1B	All resources shown in Table 1	None	Higher value	Not allowed before 2030
1C	All resources shown in Table 1	Through 2030	Lower value	Not allowed before 2030
1D	All resources shown in Table 1	None	Lower value	Not allowed before 2030
2A	Gas and BESS resources shown in Table 1	Through 2030	Higher value	Not allowed before 2030
2B	Gas and BESS resources shown in Table 1	None	Higher value	Not allowed before 2030

Scenario	Procured Resources Included	PTC for Wind and Solar	Unserviced Energy Penalty	Generic CT Additions
2C	Gas and BESS resources shown in Table 1	Through 2030	Lower value	Not allowed before 2030
2D	Gas and BESS resources shown in Table 1	None	Lower value	Not allowed before 2030
3A	Gas resources shown in Table 1	Through 2030	Higher value	Not allowed before 2030
3B	Gas resources shown in Table 1	None	Higher value	Not allowed before 2030
3C	Gas resources shown in Table 1	Through 2030	Lower value	Not allowed before 2030
3D	Gas resources shown in Table 1	None	Lower value	Not allowed before 2030

Finally, we conducted a “markets off” sensitivity on the expansion plans resulting from each scenario. This “markets off” sensitivity removes market purchases and then redispatches the remaining resources to help illustrate how we would dispatch resources to serve our native load absent market availability. This view allows us to quantify risk associated with market purchases and ensures our plan does not result in overreliance on market purchases or exposure to unreasonable risk.

B. Modeling Results and Preferred Plan

1. Expansion Plans

Each modeling scenario results in a capacity expansion plan showing resource additions needed to meet our customers’ needs over the planning period. The model could select from standalone storage, wind, solar, and natural gas peaking resources to meet capacity needs. The tables below show the expansion plans under scenarios 1A, 2A, and 3A. These scenarios are parallel to one another in that they include the same underlying variables: PTC available for wind and solar through 2030, and a high EUE penalty, which the Company believes are most representative of future reality. The remaining difference between the scenarios highlighted in this section is the mix of resources from Table 1 that are “forced” into the model, as explained above. Appendix B includes expanded tables showing results for all scenarios.

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 17 of 25

The Company's Updated ND Preferred Plan is Scenario 1A. It includes all resources we have acquired since filing the 2024 Plan, as shown in Table 1 above, and further adds approximately 5 gigawatts (GW) of capacity through 2040, consisting of standalone storage and natural gas peaking plant resources.

The initially filed 2024 ND Resource Plan aligned closely with the plan ultimately approved by the MPUC. However, the industry dynamics discussed above, including increased costs for renewable resources, have resulted in further divergence between the North Dakota scenarios and the overall Upper Midwest plan. Nevertheless, the diverse mix of resources – including natural gas, BESS, wind, and solar – included under Scenario 1A benefit North Dakota customers by ensuring reliability, meeting the Company's required MISO reserve margin, limiting market exposure, and taking advantage of expiring tax credits for resources that we have already acquired. As we explain further below, our Updated ND Preferred Plan significantly reduces unserved energy and associated market exposure, and provides a hedge against natural gas price volatility – ultimately protecting customers and ensuring we are able to meet our obligation to serve safely and reliably.

Table 3 below shows the expansion plan above and beyond previously acquired resources under our Updated ND Preferred Plan.

Table 3: Updated ND Preferred Plan Expansion Plan (Scenario 1A)

Generic Additions by Year – Nameplate (MW)	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Standalone Storage	120	-	-	300	540	60	180	-	120	-	-	-	-	1,320
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Natural Gas Peaking	-	-	748	599	-	-	-	225	-	225	599	748	599	3,743
Total	120	-	748	899	540	60	180	225	120	225	599	748	599	5,065

Totals may not sum due to rounding.

For comparison, Table 4 and Table 5 below summarize the expansion plans under the parallel scenarios 2A and 3A. Scenario 2A includes only the natural gas and BESS resources shown in Table 1 and excludes wind and solar. Scenario 3A includes the

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 18 of 25

natural gas resources shown in Table 1 and excludes the procured BESS, wind, and solar. In other words, Scenario 2 and Scenario 3 are starting from progressively higher capacity deficits that the model must make up for by selecting other generic resources. Thus, Scenarios 2 and 3 add more total resources over the modeling period.

Table 4: Expansion Plan Under Scenario 2A

Generic Additions by Year – Nameplate (MW)	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Standalone Storage	120	-	-	-	540	120	-	-	180	60	-	-	-	1,020
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Natural Gas Peaking	-	-	748	1,122	-	-	374	-	-	374	-	1,122	374	4,114
Total	120	-	748	1,122	540	120	374	-	180	434	-	1,122	374	5,134

Totals may not sum due to rounding.

Table 5: Expansion Plan Under Scenario 3A

Generic Additions by Year - Nameplate (MW)	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Standalone Storage	1,560	240	60	360	300	60	180	120	240	120	-	-	-	3,240
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Natural Gas Peaking	-	-	1,122	748	374	-	-	-	-	-	374	748	748	4,114
Total	1,560	240	1,182	1,108	674	60	180	120	240	120	374	748	748	7,354

Totals may not sum due to rounding.

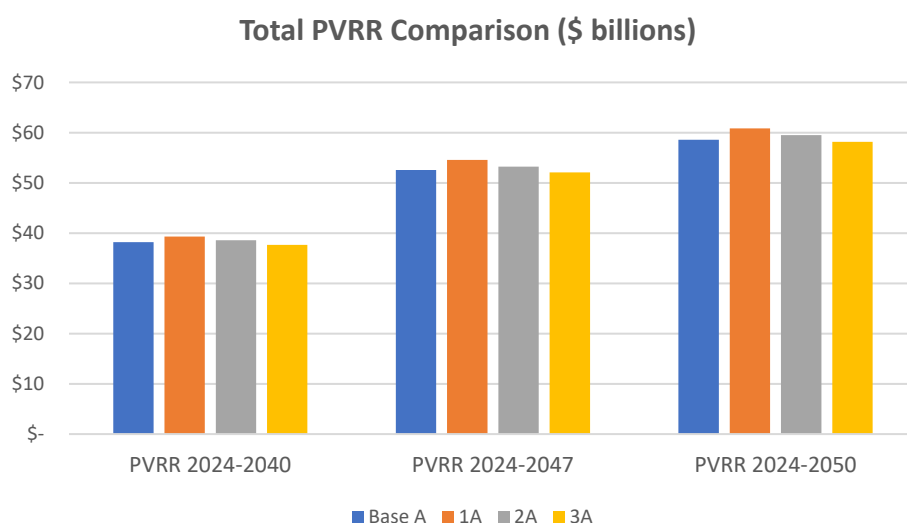
2. Portfolio Costs

The Company’s production cost modeling shows the present value revenue requirement (PVRR) for each scenario. However, at the outset, we note that PVRR comparisons have uniquely limited value in this analysis because they compare theoretical revenue

requirements of generic resources with actual revenue requirements for projects that the Company has already acquired to meet the same generic need identified.

Figure 2 below shows a comparison of the PVRR for Scenarios 1A, 2A, and 3A compared to the Base A case.

Figure 2: PVRR Scenario Comparison



As shown in Figure 2 above, on a PVRR basis, Scenario 1A has higher modeled costs compared to the Base A scenario. However, we caution that an apples-to-apples comparison provides limited value in this case because Scenario 1A uses the actual costs for procured resources, whereas the Base scenarios omit those procured resources from the expansion plan and fill that same capacity need with generic resources (at generic pricing assumptions). Thus, comparing Scenario 1A to the Base A scenario is less of a comparison to a “business as usual” or “no change” scenario, and represents a hypothetical counterfactual based a generic pricing that may not be available for procurement in the market.

3. *Risk Mitigation*

The Company’s Updated ND Preferred Plan (Scenario 1A) maintains reliability and energy adequacy while limiting reliance on MISO wholesale market purchases. The Updated ND Preferred Plan also reduces exposure to natural gas price volatility. The

resources the Company has acquired and included in the Updated ND Preferred Plan provide benefits to North Dakota customers in both reliability and risk mitigation, as we explain below.

a. Market Exposure and Expected Unserved Energy Risk

We evaluated energy adequacy under different scenarios to ensure the plans can serve customers reliably across all hours of each year. Under all scenarios that assume a higher penalty for EUE (A and B scenarios), the expansion plans ensure reliability and result in no unserved energy.¹⁸

At the same time, the model relies on significant market purchases to meet customer needs, particularly through 2030 as the resources we have already acquired are coming online. Table 6 below shows total market purchases under our Preferred Plan and Scenario 2A and 3A scenarios for 2028 through 2030. Compared to our Preferred Plan, Scenario 2A (which excludes wind and solar resources) and Scenario 3A (which excludes wind, solar, and BESS resources) result in more market purchases – that is, we would need to rely more on the market in order to serve customers reliably.

Table 6: Market Purchases (2028-2030)

Scenario	Gross Market Purchases (GWh)	Delta Compared to Scenario 1A – Preferred Plan (%)
Scenario 1A – Preferred Plan	16,673	-
Scenario 2A	17,922	7.49%
Scenario 3A	17,207	3.15%

All three scenarios can serve customers reliably without any unserved energy by relying, to varying degrees, on market purchases; however, the “markets off” sensitivity helps quantify the true market exposure associated with different scenarios by quantifying any customer load that cannot be served by Company resources and is therefore reliant on market purchases. As shown in Table 7 below, when market purchases are not available, unserved energy and associated penalties increase.

¹⁸ A lower EUE penalty cost, assumed in the C and D scenarios, makes the model more willing to rely on the market, resulting in fewer procured resources overall, and more unserved energy. See Appendix B.

Compared to our Updated ND Preferred Plan, Scenarios 2A and 3A increase unserved energy by a factor of 1.4 and 1.7, respectively.

**Table 7: Unserved Energy and EUE Penalty Costs (2028-2030)
Markets Off Sensitivity**

Scenario	Unserved Energy (MWh)	EUE Penalty Costs (\$B)	Unserved Energy Delta Compared to Scenario 1A – Preferred Plan (Ratio)
Scenario 1A – Preferred Plan	22,996	23.0	-
Scenario 2A	33,141	33.1	1.44
Scenario 3A	39,080	39.0	1.70

When viewed in this way, assuming that market purchases may not be available or may be high cost, our Updated ND Preferred Plan provides an important and meaningful hedge against market exposure and price volatility, particularly in the near term as our fleet transition continues and we finish deploying the resources we have already procured. These resources provide further protection to North Dakota customers from high market prices and help ensure we can serve our own load reliably even when regional supply is constrained.

b. Gas Price Volatility Risk

Relative to our Updated ND Preferred Plan, Scenarios 2A and 3A rely on higher amounts of natural gas-fired resources. Table 8 below highlights the gas usage and cost in 2030-2035 after the resources shown in Table 1 are operational.

**Table 8: Natural Gas Usage (2030-2035)
Markets On Sensitivity**

Scenario	Gas Usage (MMBtu)	Gas Usage Delta Compared to Scenario 1A – Preferred Plan (%)	Gas Costs (\$000)	Gas Costs Delta Compared to Scenario 1A – Preferred Plan (%)
Scenario 1A – Preferred Plan	611,215,424		2,776,026	
Scenario 2A	778,590,200	27.4%	3,574,309	28.8%
Scenario 3A	794,586,508	30%	3,654,582	31.6%

As shown in Table 8 above, compared to our Updated ND Preferred Plan, Scenarios 2A and 3A increase reliance on natural gas by approximately 27 percent and 30 percent, respectively. Even assuming natural gas prices remain constant, that increased reliance on natural gas in Scenarios 2A and 3A results in approximately \$0.8 billion and \$0.88 billion higher costs, respectively. This divergence in cost would increase at higher natural gas prices. Our Updated ND Preferred Plan includes more resources that have zero fuel costs, providing important resource diversity and hedge against natural gas price volatility.

V. RATE IMPACT ANALYSIS

In this section we present rate impacts of our Updated ND Preferred Plan and Scenario 3A, which excludes recently acquired battery storage, wind, and solar resources.¹⁹

As discussed in our 2024 Plan, producing a detailed analysis of rate impacts in a resource planning process with long time horizons is challenging due to the potential changes in our rates and resource needs over time. Factors that can impact the estimated rate impacts in the planning period include generation ownership structure, tax treatment, regulatory decisions, large customer load additions, changes in customer class allocations, and others.

The simplifying assumptions made in both the calculation methodology and the input variables mean that these estimated impacts may not align with the actual rates set by the Commission for various customer classes in the future. We caution that this information should not be interpreted as directly comparable to customer rate impact information we would provide as part of a rate case filing.

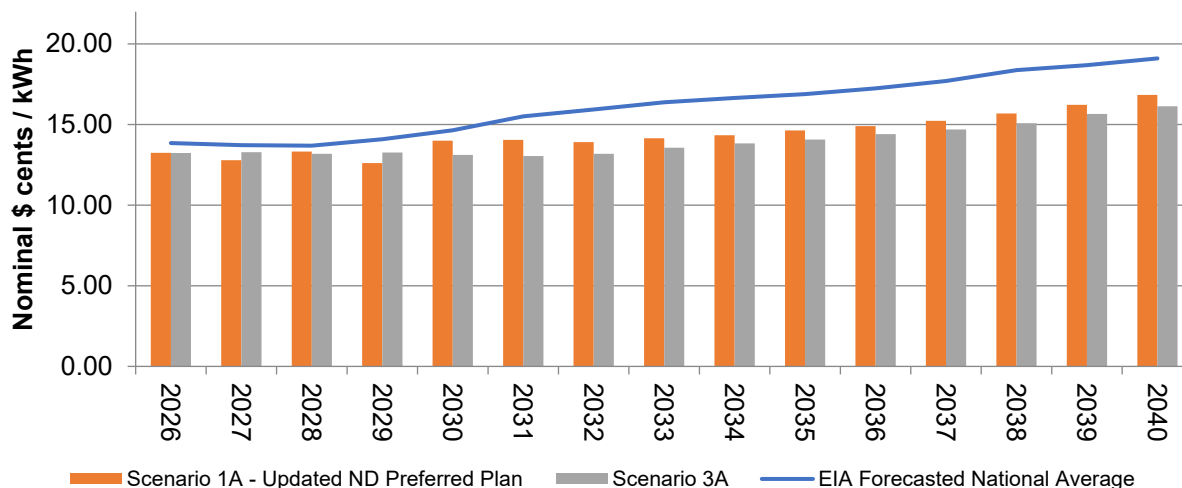
Our customer cost impact analysis shows that the Updated ND Preferred Plan does not materially increase costs for our customers. The Updated ND Preferred Plan results in an estimated average annual increase in retail rates of 1.7 percent across our system, compared to the EIA forecasted national average electricity rate increase of 2.3 percent. We provide further analysis of our Updated ND Preferred Plan below.

¹⁹ This analysis does not reflect effects of the proposed Google ESA CEAC discussed in Section III.E, because the ESA is pending MPUC approval. If approved, the CEAC resource costs would be direct-assigned to the Minnesota jurisdiction.

1. *Preferred Plan Average Nominal Cost Comparison to National Average*

We begin by comparing the cost impact on North Dakota customers of our Updated ND Preferred Plan and Scenario 3A, which excludes recently acquired battery storage, wind, and solar resources as compared to the national average as forecasted by the EIA. To show the cost impact of our proposal over the long term, we provide a compound average growth rate (CAGR) comparison of our Updated ND Preferred Plan and Scenario 3A in Figure 3 below. As illustrated in Figure 3, the Updated ND Preferred Plan remains lower than the national average.

Figure 3: Average Nominal Cost Comparison – Scenarios 1A and 3A (2026-2040)



* Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2026, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.²⁰

The results above indicate that the 2026-2040 CAGR for average rates is expected to be slightly higher for the Updated ND Preferred Plan (1.7 percent) as compared to Scenario 3A (1.4 percent). However, as discussed above, Scenario 3A results in greater exposure to market purchases and natural gas costs. The Updated ND Preferred Plan provides a reasonable balance of costs and risks.

²⁰ See [U.S. Energy Information Administration - EIA - Independent Statistics and Analysis](#) The EIA's Annual Energy Outlook was published in 2026.

2. *Revenue Requirements Forecast Methodology*

To calculate the long-term rate impacts of the Updated ND Preferred Plan, we first developed a forecast of revenue requirements for a Reference Case. This forecast leverages retail revenue requirements from the Company's rate case test years approved by each Commission in our five jurisdictions: Minnesota,²¹ North Dakota,²² South Dakota,²³ Wisconsin,²⁴ and Michigan²⁵ to create an NSP System revenue requirement for 2024. We identified annual costs through the end of the planning period (2040) using the CAGR of generation and fuel costs from the EnCompass model Reference Case. This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the EnCompass model to create a "business as usual" long term rate projection.

To determine the revenue requirement impact for the Updated ND Preferred Plan and Scenario 3A, we identified the differential in annual expenses and capital spend of each scenario compared to the Reference Case Encompass model results. This annual differential was added to the annual Reference Case revenue requirements to create the Updated ND Preferred Plan and Scenario 3A annual revenue requirements.

VI. CONCLUSION

We appreciate Commission Staff's engagement on our 2024 Plan that led to this Supplement. The pace of change in resource planning over the past few years, including broad economic and industry dynamics, significantly impacted the analysis provided in our 2024 Plan. These changing variables combined with North Dakota's policy preferences and requirements merit a comprehensive update to the 2024 Plan.

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

²² *Northern States Power Company 2021 Electric Rate Increase Application*, Order on Settlement, Case No. PU-20-441 (August 18, 2021).

²³ *In the Matter of the Application of Northern States Power DBA Xcel Energy for Authority to Increase Its Electric Rates*, Order Granting Joint Motion for Approval of Settlement Stipulation; Order Approving Refund Plan, Docket No. EL22-017 (June 8, 2023).

²⁴ *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, 4220-UR-126 (December 20, 2023).

²⁵ *Id.*

PUBLIC DOCUMENT—NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160
2024-2040 North Dakota Resource Plan Supplement
Page 25 of 25

We are now working on our next Upper Midwest Integrated Resource Plan, which will address additional topics such as jurisdictional planning, consideration of the ND rate case settlement, firm dispatchable additions, natural gas generation in North Dakota, and large load additions. For this reason, we are not requesting Commission approval of the Updated ND Preferred Plan in this Supplement. Rather, we respectfully request that the Commission approve our acquisition of the resources shown in Table 1 above, which total over 5 GW of competitively procured capacity and energy resources to serve our customers reliably and affordably. We respectfully request that the Company be allowed to recover costs for approved renewable resources through the Renewable Energy Rider (RER).

October 1, 2026

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

Case No. PU-24-160

2024-2040 North Dakota Resource Plan Supplement

Appendix A: EnCompass Modeling Assumptions - 12 Pages Total

The Not-Public version of Appendix A describes the updates to base modeling assumptions made in the North Dakota Resource Plan Supplement compared to those in the initial 2024-2040 North Dakota Resource Plan filed April 8, 2024.

Appendix A is marked “Not-Public” in its entirety as it contains trade secret information including sensitive forecasted load, production, and cost data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. The Company takes efforts to protect this information from public disclosure.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Table B-1: Expansion Plans through 2040

Scenario Name	Standalone Storage - Generic	Wind - Generic	Solar - Generic	Firm Peaking - Generic	Total MW	Delta MW vs Base		Procured MW	Total MW	Delta MW vs Base
Base B	2,820	0	0	5,236	8,056	12		0	8,056	12
Base A	2,880	0	0	5,164	8,044	0		0	8,044	0
Base D	3,360	0	0	4,714	8,074	29		0	8,074	29
Base C	3,660	0	200	4,714	8,574	529		0	8,574	529
1A	1,320	0	0	3,745	5,065	-2,979		5,695	10,760	2,716
1B	780	0	0	3,966	4,746	-3,299		5,695	10,441	2,396
1C	960	0	0	4,114	5,074	-2,970		5,695	10,769	2,725
1D	1,620	0	0	3,740	5,360	-2,684		5,695	11,055	3,011
2A	1,020	0	0	4,114	5,134	-2,910		3,735	8,869	825
2B	900	0	0	4,340	5,240	-2,805		3,735	8,975	930
2C	840	0	0	4,114	4,954	-3,090		3,735	8,689	645
2D	780	0	0	4,114	4,894	-3,150		3,735	8,629	585
3A	3,240	0	0	4,114	7,354	-690		1,599	8,954	909
3B	2,940	0	0	4,114	7,054	-990		1,599	8,654	609
3C	2,820	0	100	4,416	7,336	-708		1,599	8,936	891
3D	2,700	0	0	4,340	7,040	-1,005		1,599	8,639	595

Table B-2: PVRR – All Scenarios

Scenario Name	Delta (\$m) vs Base	NPV (\$m) 2024-2040	Delta (\$m) vs Base	NPV (\$m) 2024-2047	Delta (\$m) vs Base	NPV (\$m) 2024-2050
		\$ -		\$ -		\$ -
Base B	\$ (50)	\$ 38,163	\$ (178)	\$ 52,399	\$ (199)	\$ 58,392
Base A	\$ -	\$ 38,213	\$ -	\$ 52,578	\$ -	\$ 58,591
Base D	\$ (454)	\$ 37,759	\$ (490)	\$ 52,088	\$ (512)	\$ 58,079
Base C	\$ (694)	\$ 37,518	\$ (678)	\$ 51,900	\$ (612)	\$ 57,979
1A	\$ 1,102	\$ 39,314	\$ 1,997	\$ 54,575	\$ 2,263	\$ 60,854
1B	\$ 1,435	\$ 39,648	\$ 2,106	\$ 54,683	\$ 2,355	\$ 60,946
1C	\$ 1,116	\$ 39,329	\$ 1,845	\$ 54,423	\$ 2,072	\$ 60,663
1D	\$ 666	\$ 38,879	\$ 1,364	\$ 53,942	\$ 1,554	\$ 60,146
2A	\$ 370	\$ 38,583	\$ 647	\$ 53,224	\$ 902	\$ 59,493
2B	\$ 389	\$ 38,602	\$ 632	\$ 53,209	\$ 816	\$ 59,407
2C	\$ 396	\$ 38,609	\$ 653	\$ 53,231	\$ 848	\$ 59,439
2D	\$ 295	\$ 38,507	\$ 551	\$ 53,129	\$ 727	\$ 59,318
3A	\$ (543)	\$ 37,670	\$ (503)	\$ 52,074	\$ (408)	\$ 58,183
3B	\$ (400)	\$ 37,812	\$ (351)	\$ 52,226	\$ (320)	\$ 58,271
3C	\$ (361)	\$ 37,852	\$ (261)	\$ 52,316	\$ (158)	\$ 58,433
3D	\$ (321)	\$ 37,892	\$ (375)	\$ 52,203	\$ (338)	\$ 58,253

Table B-3: Market Purchases, Expected Unserved Energy, Gas Purchases, and Gas Costs – Markets On

In the C and D scenarios, the unserved energy penalty is lower. A lower penalty cost makes the model more willing to rely on the market, resulting in fewer procured resources and more unserved energy.

Scenario Name	Gross Purchases (GWh) 2028-2030	Unserved Energy (MWh) 2028-2030	EUE Penalty Costs 2028-2030	Gas Usage (MMBtu) 2030-2035	Gas Costs (\$000) 2030-2035	Gas Cost Delta vs Preferred		Gas Use vs Base (%)	Gas Use vs Preferred (%)
Base B	19,405	0	0	794,516,765	3,727,994	951,968		0.7%	30.0%
Base A	19,105	0	0	789,061,936	3,698,150	922,123		0.0%	29.1%
Base D	19,152	82	19,821	761,525,267	3,559,378	783,352		-3.5%	24.6%
Base C	20,496	17	4,007	740,745,787	3,462,377	686,350		-6.1%	21.2%
1A	16,673	0	0	611,215,424	2,776,026	0		-22.5%	0.0%
1B	16,799	0	0	627,626,189	2,866,579	90,553		-20.5%	2.7%
1C	16,684	0	0	618,287,180	2,818,865	42,839		-21.6%	1.2%
1D	16,794	0	0	597,263,507	2,705,616	-70,410		-24.3%	-2.3%
2A	17,922	0	0	778,590,200	3,574,309	798,282		-1.3%	27.4%
2B	17,930	0	0	778,534,772	3,574,294	798,268		-1.3%	27.4%
2C	17,926	1	217	774,252,191	3,553,076	777,050		-1.9%	26.7%
2D	15,220	0	0	773,396,203	3,546,985	770,959		-2.0%	26.5%
3A	17,207	0	0	794,586,508	3,654,582	878,555		0.7%	30.0%
3B	17,223	0	0	800,130,183	3,686,111	910,085		1.4%	30.9%
3C	14,253	0	0	785,847,388	3,611,410	835,384		-0.4%	28.6%
3D	14,232	0	0	800,884,908	3,689,296	913,270		1.5%	31.0%

Table B-4: Market Purchases, Expected Unserved Energy, Gas Purchases, and Gas Costs – Markets Off

Scenario Name	Gross Purchases (GWh) 2028-2030	Unserved Energy (MWh) 2028-2030	EUE Penalty Costs 2028-2030	Gas Usage (MMBtu) 2030-2035	Gas Costs (\$000) 2030-2035	Gas Cost Delta vs Preferred	Gas Use vs Base (%)	Gas Use vs Preferred (%)	EUE MWh vs Base (Ratio)	EUE MWh vs Preferred (Ratio)
Base B	0	44,814	44,813,912,000	839,025,539	3,924,461	1,027,518	0.7%	31.2%	1.26	1.95
Base A	0	35,647	35,646,774,000	833,146,041	3,892,746	995,803	0.0%	30.3%	1.00	1.55
Base D	0	178,436	43,308,243	805,860,376	3,755,103	858,160	-3.3%	26.0%	5.01	7.76
Base C	0	529,840	128,597,359	784,503,367	3,655,523	758,580	-5.8%	22.7%	14.86	23.04
1A	0	22,996	22,995,540,000	639,336,010	2,896,942	0	-23.3%	0.0%	0.65	1.00
1B	0	22,996	22,995,541,000	656,227,818	2,989,603	92,660	-21.2%	2.6%	0.65	1.00
1C	0	128,973	31,302,920	646,559,452	2,939,893	42,950	-22.4%	1.1%	3.62	5.61
1D	0	128,876	31,279,424	625,540,601	2,826,682	-70,260	-24.9%	-2.2%	3.62	5.60
2A	0	33,141	33,141,032,000	817,595,751	3,742,374	845,432	-1.9%	27.9%	0.93	1.44
2B	0	33,135	33,134,747,000	817,840,510	3,743,738	846,796	-1.8%	27.9%	0.93	1.44
2C	0	191,640	46,512,829	813,478,016	3,722,164	825,222	-2.4%	27.2%	5.38	8.33
2D	0	191,100	46,381,936	813,883,660	3,723,645	826,703	-2.3%	27.3%	5.36	8.31
3A	0	39,080	39,079,648,000	832,564,591	3,818,701	921,759	-0.1%	30.2%	1.10	1.70
3B	0	39,034	39,034,454,000	838,293,835	3,851,069	954,127	0.6%	31.1%	1.10	1.70
3C	0	191,509	46,481,120	815,269,603	3,728,842	831,899	-2.1%	27.5%	5.37	8.33
3D	0	91,668	22,248,688	835,495,425	3,835,267	938,324	0.3%	30.7%	2.57	3.99