BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY, FOR A CERTIFICATE OF NEED FOR ADDITIONAL DRY CASK STORAGE AT THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT INDEPENDENT SPENT FUEL STORAGE INSTALLATION

MPUC Docket No. E002/CN-24-68
OAH Docket No. 25-2500-39971

DIRECT TESTIMONY AND ATTACHMENTS OF SACHIN SHAH

ON BEHALF OF

**THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTMENT OF COMMERCE**

FEBRUARY 10, 2025

DIRECT TESTIMONY AND ATTACHMENTS OF SACHIN SHAH
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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Sachin Shah. I am a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources, (Department or DOC). My business address is 85 7th Place East, Suite 280, Saint Paul, Minnesota 55101.

Q. What is your educational and professional background?

A. A summary of my educational and professional background is presented in Ex. DOC-___, SS-D-1 (Shah Direct).

II. PURPOSE

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses a subpart of Certificate of Need (CN) criteria established in Minnesota Rules part 7855.0120. Specifically, I consider:

- 7855.0120 A (1), which concerns the accuracy of the applicant's forecast of demand for the type of energy or service that would be supplied by the proposed facility.

Q. Do you address Minnesota Rules part 7855.0120 C (1) which concerns the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs?

A. No. Department witness Mr. Ari Zwick addresses that in his testimony.

Q. How is your testimony organized?

A. My testimony addresses Northern States Power d/b/a Xcel Energy's (Xcel, or the Company) proposed project (Project) in one part. This part discusses the accuracy of Xcel's demand and energy forecast.

III. REVIEW OF XCEL'S FORECASTS

Q. Please describe recent forecasts that Xcel has provided to the Commission.

A. Xcel is required to submit biennial Integrated Resource Plans (IRP) for Minnesota Public Utilities Commission (Commission) review and approval. The IRP process permits the Commission and stakeholders to examine a utility's current and planned electricity generation for the next 15 years.[1] In addition to IRPs, Xcel must produce forecasts on an annual basis.[2]

Q. Did the Department review Xcel's most recent IRP forecast?

A. Yes. In Xcel's most recent IRP proceeding (Docket No. E002/RP-24-67), the Department analyzed the Company's forecast. The Department concluded that the Company's demand and energy forecasts were reasonable for planning purposes. Consequently, for that IRP, the Department used Xcel's forecast as inputs in the capacity expansion plans

[1] Minn. Pub. Utils. Comm'n, *Resource Planning* (last visited Jan. 24, 2025), https://mn.gov/puc/activities/economic-analysis/planning/irp/ and https://mn.gov/puc/activities/economic-analysis/planning; Minn. R. 7843; Minn. Stat. § 216B.2422 Subd. 2.

[2] Minn. R. 7610.0300.

used by the Department. Those capacity expansion plans utilized the EnCompass modeling software.[3]

Q. How did the Department conduct its forecast analysis in the IRP proceeding?

A. Because the purpose of analysis was to establish an acceptable base forecast for long-term planning purposes, the Department focused on evaluating Xcel's forecasts and the exogenous adjustments that Xcel had made. Based on reviewing 15 years of data, the Department concluded that Xcel's demand and energy forecasts were reasonable for planning purposes.[4]

Q. Did Xcel rely on the same forecast in its CN application for the proposed project?

A. Yes. Xcel used the same forecast vintage that it identified as "Fall 2023 forecast."[5] Also See Xcel's response to Minnesota Public Utilities Commission (MPUC) Information Request (IR) Nos. 1, 9, and Office of Attorney General (OAG) IR No. 2, included as Ex. DOC-__, SS-D-3 (Shah Direct).

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[3] *In re the Application of Northern States Power Company d/b/a Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan.*, MPUC Docket E002/RP-24-67, Comments of the Minnesota Department of Commerce, Division of Energy Resources at 7-8, 24-62 and Attachment 4 (Aug. 9, 2024) (Department Aug. 2024 Comments) (eDocket Nos. 20248-209394-02 and 20248-209394-04). *See* Ex. DOC-__, SS-D-2 (Shah Direct).
[4] Department Aug. 2024 Comments at Attachment 4. *See* Ex. DOC-__, SS-D-2 (Shah Direct).
[5] Xcel Energy Reply Comments at 1(Mar. 15, 2024 (eDocket No. 20243-204406-01). *See* Ex. DOC-__, SS-D-4 (Shah Direct).

Q. Please provide the Department's conclusion on the accuracy of Xcel's forecast used in this docket.

A. Based on the above discussion, I conclude that for purposes of this proceeding Xcel's forecast can be used.

Q. Do you address the capacity expansion models used in the IRP proceeding or in this docket?

A. No. That aspect of the capacity expansion modeling is addressed by Dr. Steve Rakow.

IV. CONCLUSION

Q. Please provide your conclusions.

A. Based on the above discussion, I conclude that for purposes of this proceeding Xcel's forecast can be used.

Q. Does this conclude your direct testimony?

A. Yes.

Sachin Shah
Minnesota Department of Commerce,
Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN55101-2198

EDUCATION

- University of North Carolina-Charlotte, Master of Science, Economics, 1996.
- University of North Carolina-Charlotte, Bachelor of Arts, Major in Economics and Minor in Political Science, 1993

Prior to joining the Department of Commerce from January, 1998 till July, 1999, I worked at a CPA firm in St. Louis where I prepared tax returns and maintained clients' general ledger databases. After leaving the CPA firm I worked as Brokerage Service Associate with American Express Financial Advisors. I Assisted clients and financial advisors with their brokerage account service needs via telephone, provided basic financial market information and processed securities transactions and payment requests. Obtained Series 7 securities registration / license.

EXPERIENCE AT DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

I have been employed as a Rates Analyst with the Department of Commerce, Division of Energy Resources (DOC-DER) since February, 2000. During my time with the Department of Commerce, Division of Energy Resources I have been assigned a wide variety of filings dealing with a number of different issues. For example:

As a rates analyst for the Department of Commerce, Division of Energy Resources, my duties have included evaluating comments on different issues, such as investigating and filing testimony and comments for forecasting in:

- UtiliCorp United Inc.'s Request for an Increase in Rates in Docket No. G007,011 /GR-00-951;
- Great Plains Request for an Increase in Rates in Docket No. G004/GR-02-1682;
- Hutchinson Utilities Commission's Certificate of Need proceeding in Docket No. G252/CN-01-1826;
- Dakota Electric's Request for an Increase in Rates in Docket No. E 111/GR-03-261;
- Interstate Power and Light Company's Request for an Increase in Electric Rates in Docket No. E001/GR-03-767;
- CenterPoint Energy Minnegasco, a Division of CenterPoint Resources Corp., Request for an Increase in Rates in Docket No. G008/GR-04-901;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-04-1511;
- Montana Dakota Utilities d/b/a Great Plains Request for an Increase in Rates in Docket No. G004/GR-04-1487;
- Alliant Energy d/b/a Interstate Power and Light Company's Resource Plan in Docket No. E001/RP-05-2029;
- Great River Energy's Resource Plan in Docket No. ET2/RP-08-784;
- Dakota Electric's Request for an Increase in Rates in Docket No. E 111/GR-09-175;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-09-1153;
- Interstate Power and Light Company's Request for an Increase in Electric Rates in Docket No. E001/GR-10-276;
- Alliant Energy d/b/a Interstate Power and Light Company's Resource Plan in Docket No. E001/RP-08-673;
- Minnesota Power and Great River Energy's Certificate of Need proceeding in Docket No. ET2, E015/CN-10-973;
- Xcel Energy's Certificate of Need proceeding in Docket No. E002/CN-11-332;
- Xcel Energy's Certificate of Need proceeding in Docket No. E002/CN-12-113;
- Minnesota Power's Resource Plan in Docket No. E015/RP-13-53;
- In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need in Docket No. E002/CN-12-1240; and
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-13-868;
- Minnesota Power's Certificate of Need proceeding in Docket No. E015/CN-12-1163;
- Xcel Energy's Resource Plan in Docket No. E002/RP-15-21;
- Minnesota Power's Resource Plan in Docket No. E015/RP-15-690;
- Minnesota Energy Resources Corporation's Request for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G011/GR-15-736;
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-15-826;
- Minnesota Power's Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E015/GR-16-664;
- Minnesota Energy Resources Corporation's Request for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G011/GR-17-563;
- Great Plains Natural Gas Co., a Division of MDU Resources Group Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G004/GR-19-511;
- CenterPoint Energy Resources Corp., D/B/A. CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota in Docket No. G008/GR-19-524;
- Xcel Energy's Resource Plan in Docket No. E002/RP-19-368;
- Otter Tail Power Company, for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E017/GR-20-719;
- Minnesota Power's Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E015/GR-21-335;
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-21-630;
- In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Additional Dry Cask Storage at the Monticello Nuclear Generating Plant Independent Spent Fuel Storage Installation in Docket No. E002/CN-21-668;
- Great River Energy's Resource Plan in Docket No. ET2/RP-22-75;

(Continued on Next Page)

- Minnesota Power's Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E015/GR-23-155; and
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Natural Gas Rates for Service in Minnesota in Docket No. G002/GR-23-413.

My duties have also included reviewing miscellaneous rate and fuel procurement filings involving gas utilities, for example, evaluating Demand Entitlement and True-up filings. I was previously responsible for producing the Quarterly PGA summary and producing and coordinating the publication of the DOC-DER's Annual Automatic Adjustment Reports (Gas). I have also provided testimony on natural gas in The Matter of Application of Mankato Energy Center, LLC, A Wholly Owned Subsidiary of Calpine Corporation, for a Certificate of Need for A Large Electric Generating Facility in Docket No. IP6345/CN-03-1884. I have also worked on various Rider Petitions such as in Docket Nos. E002/M-15-805, E015/M-14-990, E015/M-15-876, and G004/M-19-273. I have also worked on various Renewable Natural Gas Petitions such as in Docket Nos. G008/M-18-547, G008/M-20-434, G022/M-24-236 and provided guidance and assistance in Docket Nos. G004/M-24-73. I also provided testimony on CenterPoint's proposed Cost of Gas in Docket Nos. G008/GR-21-435 and G008/GR-23-173. I have also worked on CenterPoint's Natural Gas Innovation Act (NGIA) Petition in Docket No. G008/M-23-215. I have worked on natural gas issues in the Commission Investigation into Gas Utility Resource Planning in Docket No. G008,G002,G011/CI-23-117.

SEMINARS

National Association of Regulatory Utility- Commissioners' 42ntl Annual Regulatory Studies Program, Institute of Public Utilities, Michigan State University, 2000

COMMERCE DEPARTMENT

August 9, 2024

PUBLIC DOCUMENT

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/RP-24-67

Dear Mr. Seuffert:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Northern States Power Company, doing business as Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan.

The Petition was filed on February 1, 2024 by Northern States Power Company.

The Department recommends **approval with modifications** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ DR. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

SR/ar
Attachment

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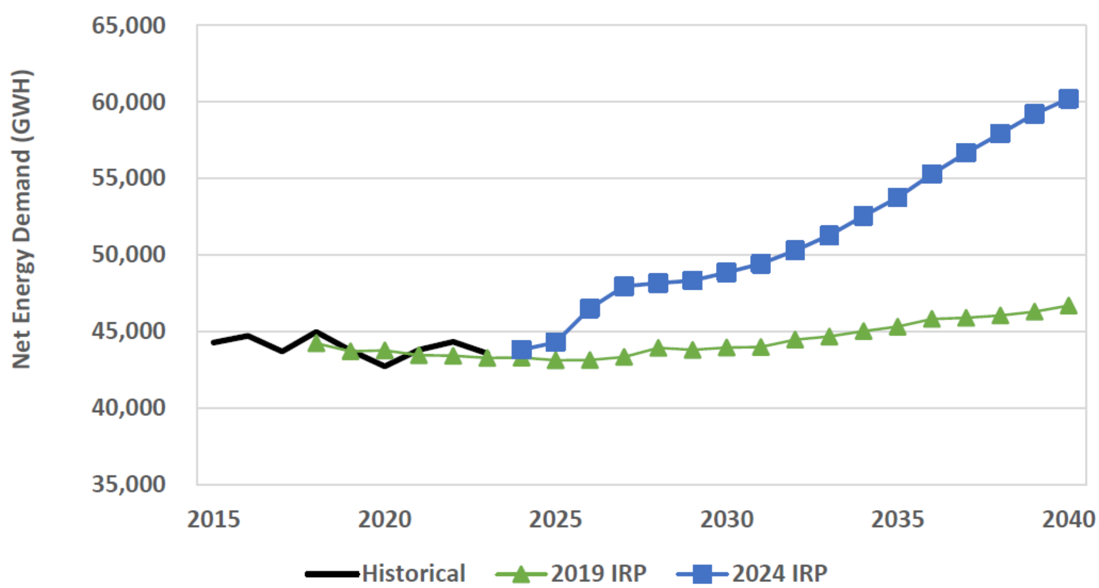
C. DEMAND AND ENERGY FORECASTS

In the IRP the forecast is an important input to the capacity expansion model (CEM) used by Xcel—EnCompass. In Xcel's most recent IRP (Docket No. E002/RP-19-368), the forecast was essentially flat. Therefore, the Department did not analyze Xcel's individual forecasts. Instead, the analysis was limited to a search for bias in the forecast results as a whole.[20]

The Petition explains that Xcel's forecast has changed significantly: "our base case forecasts now anticipate average annual growth rates of 1.8 percent in our peak demand, and 2 percent for our energy forecast over the 2024-2040 planning period." Xcel attributes the change to significant energy and demand growth rates to forecasted large new data center loads and acceleration in adoption of electric vehicles.[21] The change in forecast is illustrated by Figure 1-3 of the Petition, which is replicated below.

Screenshot 1: Xcel's Figure 1-3 Net Energy Requirements After Energy Efficiency (GWh)



Given the significant change shown in Screenshot 1, the Department determines that a more detailed forecast analysis is necessary. As a result, for this IRP the Department analyzes the forecast models proposed by Xcel for each customer class in each jurisdiction:

- Minnesota, Michigan, North Dakota, South Dakota, and Wisconsin
- Residential with and without Space Heating
- Small (SmCI) and Large (LCI) Commercial and Industrial.
- Public Authorities.
- Public Street and Highway Lighting.

[20] See the Department's February 11, 2021 comments in Docket No. E002/RP-19-368, Document ID 20212-170853-02
[21] See the Petition at Chapter 3, page 4.

To approach each case above two approaches were considered:

1. econometric models using weather, demographic, and economic data; and
2. a combination of trend analysis and historical averages.

The Department analyzed each model separately since together they represent the most relevant piece of the forecast. Particularly to econometric models, the Department's approach involves three steps:

1. Reverse engineering the input/output spreadsheet provided for each econometric model, to establish a baseline model that mimics the model used by Xcel.
    a. This baseline model was estimated, and the results were compared against Xcel results.
2. Using this baseline model, variables were omitted in order to understand the effect of each on the forecast.
3. New models were estimated, without the constraint on parameters imposed on 1.

Overall, the analysis of the econometric forecast models produced similar conclusions:

- Regardless of the forecast trend, the year distribution of energy load for historical and forecast data has a similar shape. The level of the distribution, on the hand, is dependent on the forecast trend.
- Demographic and economic variables are the main drivers of forecast long-run growth.

Furthermore, the Department analyzed each exogenous adjustment component separately, since they are the elements that accounted for the most change comparatively to the previous IRP:

- Demand-Side Management (DSM)
- Beneficial Electrification (BE)
- Solar
- Data Centers
- Electric Vehicles (EV)

Overall, the Department concludes the forecast of each of these elements is reasonable and no major issues were found. Finally, the Department analyzed the peak demand and 8760 procedure. Unlike the previous elements, the Department was not able to reproduce this step once it requires the use of a specialized software. However, the Department analyzed inputs and outputs and believes this procedure is reasonable, and an improvement from the previous IRP towards a more realistic and accurate forecast.

A detailed discussion of the forecast analysis is provided in Attachment 4. Based upon the detailed forecast analysis, the Department concludes that Xcel's forecasts are reasonable to use for IRP purposes.

D. SPOT MARKETS IN IRP

Xcel's load, generation resources, and load management all participate in Midcontinent Independent System Operator, Inc.'s (MISO) spot market construct. MISO members bid their load and resources into MISO's spot markets and the result is that all of MISO's resources serve all of MISO's load. Therefore, it is important to understand how MISO's spot markets work for a proper understanding of an IRP. Briefly, a utility's resources do not serve that utilities load. Instead, a utilities resources serve as a hedge against spot market risks.

be acceptable. Capacity (in the form of load management) can be acquired in nearly any size as well. In summary, the units being selected in Xcel's IRP do not have to be acquired in any one size increment. Overall, the Department concludes that reporting the potential ideal plan costs is a reasonable way to use EnCompass.

G. ENCOMPASS MODELING

The general process followed by the Department when reviewing CEM data is as follows:

1. Obtain base case file and the commands necessary to recreate the various scenarios explored by Xcel;
2. Conduct a "matching analysis" to make sure the Department can replicate the Company's outputs;
3. Review the base case's inputs and outputs for reasonableness;
4. Create a new base case, which includes any changes deemed necessary to the Company's base case;
5. Run scenarios of interest on the new base case to explore various risks and alternative futures;
6. Assess the results of the scenarios and establish a new preferred case; and
7. Run scenarios of interest on the new preferred case to test the robustness of the preferred case.

This section provides the Department's review of Xcel's CEM analysis.

1. Matching Xcel's Results

First, in Department Information Request No. 1 the Department received the inputs and outputs used by Xcel in the Company's modeling. These data are verified in a process referred to as "matching," and ensures the modelling runs can be replicated and that the inputs and outputs match. The primary purpose of this step is to ensure that the Department is using the same input data as Xcel. If the modeling runs can't be replicated, it indicates a discrepancy in the data. If parties use different data than the utility, all subsequent party analysis has the potential to be meaningless. Therefore, the matching process is a critical component of analyzing a utility's model.

As discussed above, EnCompass first determines the cost of an ideal expansion plan, adding fractions of units and then searches for a plan that adds full units whose cost is within a certain fraction of the cost of partial unit plan. When such a plan is found EnCompass stops. The fraction is determined by the modeler and is referred to as the "MIP stop basis." The basis for the MIP is the "objective function."

The cost that most closely aligns with the objective function in EnCompass is the net present value (NPV) Plan Cost from the Plan Costs Report.[47] However, to match Xcel's results the Department instead used the sum of the NPV Operating Cost and NPV Carrying Charge Cost from the Company Capital Report.[48]

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[47] The NPV Plan Cost value from the Plan Costs report is the same as the objective function in the System Annual report.
[48] The Plan Costs Report is only generated from expansion plan runs, not production cost runs. In response to Department Information Request No. 1, Xcel provided the Department with the cost results of its production cost runs, the final step in Xcel's modeling process, but not its expansion plan runs, which are the initial step. In general, this is not a problem, since the cost results from production cost runs will be more precise than those of expansion plan runs; however, this also means that the Department must rely on a different report during the matching process. The Department discussed this with EnCompass technicians and the most appropriate proxy in this case is the sum of NPV Operating Costs and NPV Carrying Charges, as found in the Company Capital Report. Operating Costs represent the total plan costs, less any fixed costs that cannot be avoided. While the Operating Cost value is closely aligned with the objective function of the MIP stop basis, it is not the same. The objective function does contain some fixed costs and is equal to the NPV of the total plan cost, which can be found in the "Present Value (PV) Cost ($000)" column in EnCompass' Plan Cost Report. From the Department's perspective, it is logical to include some fixed costs when matching an expansion plan run, since incorrect fixed cost data for new units could completely change an expansion plan. However, production cost runs are based on an existing expansion plan; as such, fixed cost data is already validated in the parent expansion plan and does not need to be validated again.

Broadly speaking, parties in Minnesota IRP proceedings tend to work with one of two types of runs: expansion plan runs (also called "fully optimized" runs) and production cost runs (also called "8760" runs). Expansion plan runs use simplified time inputs (for example, one week each month) and result in an expansion plan. Production cost runs then "lock in" the expansion plan and re-run the dispatch routine with that predetermined set of resources but using more detailed time inputs.

The Department identified 75 runs that needed to be matched to adequately validate Xcel's data. The Department's full matching results can be found in Attachment 2.

Of the 75 runs the Department attempted to validate, the Department was unable to match the following eight runs:

- Scenario 1 - Sens Y - Carbon Free – PVSC
- Scenario 2 - Sens Q - Mkt Off – PVSC
- Scenario 3 - Sens J - High Reg High SCGHG – PVSC
- Scenario 3 - Sens Q - Mkt Off - PVSC
- Scenario 3 - Carbon Free - Advn Tech – PVRR
- Scenario 3 - Carbon Free - Advn Tech – PVSC
- Scenario 3 - Carbon Free - SMR Only – PVRR
- Scenario 3 - Carbon Free - SMR Only - PVSC

It is not clear which datasets or scenario assumptions might be the cause of the discrepancies between the Xcel's and the Department's results for these eight runs. In addition, the difference might also be due to use of different versions of EnCompass rather than the data.[49] Based on the structure of the Company's database, the Department suspects that the discrepancies of the last four runs (Advn Tech and SMR Only) may be related, and notes that it is possible the Sens Q discrepancies are related as well.

The Department's primary concern is its inability to match the Sens J run, as this is a Commission-required externality sensitivity on Xcel's preferred Scenario. The five unmatched Carbon Free runs relate to Xcel's internal corporate goal to become 100% carbon free in its upper Midwest footprint by 2050—not to Xcel's Minnesota Carbon Free Standard requirements—and thus are less critical for either the Department or the Commission to evaluate. The two "Sens Q" runs lock in the expansion plans of the Company's base cases for Scenarios 2 and 3—both of which were matched—and simply run a new dispatch routine on each wherein Xcel has no market access. While this type of run is an important exercise to understand the value of access to the market, it is not reflective of reality. Given that the expansion plans of the Sens Q runs were matched, and the unlikelihood of a Sens Q future, the Department is less concerned about its inability to match these two runs.

The Department intends to work with Xcel to ensure that Scenario 3 – Sens J is appropriately validated. Further, while the Department is less concerned about the inability to match the other seven runs, the Department would caution parties about the unverified nature of the utility's inputs and outputs for those runs.

[49] Xcel used version 7.1.1 while the Department used version 7.2.3.

2. *Department Changes to Xcel's Assumptions*

After validating Xcel's datasets and reviewing the Company's assumptions and results, the Department then made a number of changes to the Company's base assumptions, both to the structure of Xcel's database and to the input values.

i. *Structural Changes*

The first changes made by the Department were structural. As noted above, Xcel only permitted the EnCompass model to optimize the expansion plan in certain sensitivities. By contrast, the Department ran an expansion plan run and a production cost run for each sensitivity examined, with three exceptions, noted below.

The following table depicts the Department's model, which can be compared to Xcel's model as shown in Attachment 4.

Table 7: Department's EnCompass Structure
Runs Performed Demarcated With an "x," Runs Not Performed Demarcated With Shading

SensID	Sensitivity Short Name	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
		Exp Plan	Prod Cost	Exp Plan	Prod Cost	Exp Plan	Prod Cost	Exp Plan	Prod Cost
Base	Base	x	x	x	x	x	x	x	x
A	PVRR for Dispatch		x		x		x		x
B	High Fuel Mkt Price	x	x	x	x	x	x		
C	Low Fuel Mkt Price	x	x	x	x	x	x		
D	High Load	x	x	x	x	x	x		
E	Low Load	x	x	x	x	x	x		
F	Data Center Load	x	x	x	x	x	x		
G	High Tech Costs	x	x	x	x	x	x		
H	Low Tech Costs	x	x	x	x	x	x		
I	Edison Mkt Costs	x	x	x	x	x	x		
J	HighRegHighEnv	x	x	x	x	x	x		
K	LowRegLowEnv	x	x	x	x	x	x		
L	NoRegHighEnv	x	x	x	x	x	x		
M	NoRegMidEnv	x	x	x	x	x	x		
N	NoRegLowEnv	x	x	x	x	x	x		
O	RBDC Opt-Out	x	x	x	x	x	x		
P	25% Battery ELCC	x	x	x	x	x	x		
Q	Mkt Off Dispatch		x		x		x		
R	Market On Expansion Plan	x	x	x	x	x	x		
S	Wind Profile Variability	x	x	x	x	x	x		
T	Environmental Programs	x	x	x	x	x	x		
U	High Tech + High Load	x	x	x	x	x	x		
V	Low Tech + Low Load	x	x	x	x	x	x		
W	10hr Battery+Hybrid	x	x	x	x	x	x		
X	DG Bundles	x	x	x	x	x	x		
Y	Carbon Free	x	x	x	x	x	x		
ZA	All Advanced Tech	x	x	x	x	x	x		
ZB	H2 at CTs	x	x	x	x	x	x		
ZC	LDES	x	x	x	x	x	x		
ZD	SMR	x	x	x	x	x	x		
ZD	High CT Cost	x	x	x	x	x	x		
ZE	Load Shift	x	x	x	x	x	x		
ZF	High DG Capacity	x	x	x	x	x	x		
ZG	High Energy Tie Dispatch		x		x		x		

The Department notes that Sensitivities L, M, and N did not need to have individual expansion plans run, as they will share the same expansion plan.[50] The Department ran all three simply because it was easier to elect to do so when changing the model's inputs. The Department also did not elect to run Sens A – PVRR as an expansion plan; an expansion plan of this run should theoretically match those of sensitivities L, M, and N, the Commission's "No Regulatory Costs" run. The Department also chose not to run Sens Q – Market Off as an expansion plan; this is because all runs were performed with the Market Off; an expansion plan of this run should theoretically match the base case.

Notably, the Department changed the "All Advanced Tech," "Hydrogen at Combustion Turbines (H2 at CTs)," "Long Duration Energy Storage (LDES)," and "Small Modular Nuclear Reactors (SMR)" sensitivities from Xcel's setup. In these sensitivities, Xcel makes available to the model these types of advanced technologies for selection. Under Xcel's database, these sensitivities all have "Sens Y – Carbon Free" as a parent sensitivity. The Sens Y—Carbon Free sensitivity represents Xcel's corporate goal of 100% carbon free by 2050.[51] However, under Xcel's setup, this means that these advanced technologies are only available for selection under Xcel's corporate goal future. The Department instead set the base sensitivity as the parent scenario for these four sensitivities, so that the technologies could be studied absent Xcel's corporate goals. The Department then named the sensitivities Sens IDs of ZA, ZB, ZC, and ZD.

The Department also ran the base case for "Scenario 4," a scenario in which Prairie Island is retired at the current retirement dates of 2033/2034, but Monticello's retirement is extended to 2050.

The Department also added the following additional sensitivities for study:

- Sens ZE – High CT Cost: This sensitivity contemplates a future in which combustion turbine costs are higher than anticipated. The Department multiplied the combustion turbine cost by a factor of 1.25. For CT resources with a transmission cost adder, the Department first multiplied the base CT cost by 1.25, then added the transmission cost adder.
- Sens ZF – Load Shift: This sensitivity contemplates a future in which policies such as Time of Use (TOU) rates have a meaningful impact on shifting residential load. The Department incorporated Xcel's response to Department Information Request No. 31, in which the Department asked Xcel to provide a demand dataset that amends the base case forecast by incorporating the following assumptions:[52]
    - 5% reduction in residential demand 2030 to 2034;
    - 10% reduction in residential demand 2035 to 2039;
    - 15% reduction in residential demand 2040 to 2044; and
    - 20% reduction in residential demand 2045 to 2055.
- Sens ZG – High DG Capacity: This sensitivity contemplates a future in which policies are enacted that drastically lower the cost and expand the capacity of distributed solar and community solar garden resources. The Department multiplied the following time series by a factor of 1.5: CSG Legislation Capacity, DG Solar Legislation Capacity, DGSolar_Monthly Capacity. The Department did not attempt to change any historical values; to account for DGSolar_Monthly Capacity already added in 2023, the Department first subtracted 100 MW from the string of values, then multiplied the remainder by 1.5.

[50] This is because these sensitivites represent the Commission's "No Regulatory Cost" futures, and only include Environmental (externality) costs; since environmental costs do not affect the model's decisions—either in the expansion plan or in the dispatch routine—these runs will produce the same expansion plan and same dispatch routine. Once those are run, the costs will differ based on the differing values of environmental costs.
[51] Note that this is not the same as Minnesota's Carbon Free Standard, which all runs should meet.
[52] The Department also specified that no changes should be made to residential demand prior to 2030 or to non-residential demand, and that the energy forecast should only be changed if it were needed to incorporate the above changes.

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- Sens ZH—High Energy Tie Dispatch: This senstivity contemplates a future in which Grid-Enhancing Technologies (GETs) are effectively able to expand the capacity of existing tranmission. To capture this effect, the Department increased the Company's connection to the market by increasing the Maximum (export) and Reverse (import) Energy Limits of the MISO Area from **[TRADE SECRET DATA HAS BEEN EXCISED].** This sensitivity was not able to be run as a capacity expansion run since the capacity expansion runs are performed under "market off" assumptions. Therefore, the Department ran this sensitivity only as a Production Cost (dispatch) run.

ii. Input Changes

The Department made the following changes to Xcel's base case inputs to establish a new model.

a. Environmental Cost Values

First, the Department changed the externality costs for PM2.5, SOx, Pb, NOx, and CO from the high costs used by Xcel to the mid-point costs.[53] The Department has consistently used the mid-point costs in resource planning and resource acquisition proceedings. Note that Xcel used the mid-point for both CO_2 externality costs and CO_2 regulatory costs and so no adjustment was necessary.

b. Capacity Market Prices

Second, the Department reduced the capacity market prices. Table F-15 of Appendix F of the Petition shows the prices used by Xcel, which are based upon capacity cost of a generic greenfield H-Class combustion turbine. In terms of MISO's Planning Resource Auction (PRA) Xcel's inputs represent the Cost of New Entry (CONE). CONE is the maximum possible price in the PRA. In nearly all circumstances the actual price in the PRA is substantially less than CONE. To reflect actual PRA prices the Department reduced Xcel's input to $2.19 per kW-month or 10 percent of Xcel's value. Table 8 below shows recent MISO PRA prices and the equivalent Xcel price.

Table 8: Model Input and Recent PRA Prices
($/MW-day)

PRA Year	LRZ 1 Price
6/2024-8/2024[54]	$ 10.00
6/2022-5/2023	$ 236.66
6/2021-5/2022	$ 5.00
6/2020-5/2021	$ 5.00
6/2019-5/2020	$ 2.99
Department Input	$ 28.76
Xcel Input	$ 287.58

[53] Table F-5 of Appendix F of the Petition provides Xcel's externality cost inputs.
[54] Note that the PRA for MISO years 2019-20 through 2022-23 was annual but the PRA for MISO year 2023-24 consisted of four seasons. For simplicity only the summer price is provided. For all results see: https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf

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c. Wind and Solar Costs

Third, the Department increased the levelized cost of energy (LCOE) for the generic wind and solar expansion units.[55] Tables F- 31 through F-36 of Appendix F of the Petition show the base LCOE (with and without transmission) and the high and low LCOE sensitivities (again with and without transmission) for the generic wind and solar expansion units. The Department compared Xcel's the LCOE band resulting from Xcel's inputs to recent prices for projects approved by the Commission and found that the actual prices exceed the high end of Xcel's band. To reflect actual market prices the Department changed the base case LCOE to be equal to the high LCOE plus 10 percent.[56] Xcel's LCOEs and the Department's adjusted LCOEs for the base case are shown below in Table 9. The projects reviewed by the Department as the basis for the adjustment are shown in Table 10.

Table 9: Generic Renewable Pricing (LCOE, $/MWh)

Sensitivity	Wind	Solar	Source
Low LCOE, with Transmission (2026)	$ 16.68	$ 40.69	Table F-33
Base LCOE, with Transmission (2026)	$ 20.98	$ 46.38	Table F-31
High LCOE, with Transmission (2026)	$ 22.79	$ 50.05	Table F-35
Department LCOE, with Transmission (2026)	$ 25.06	$ 55.06	
Low LCOE, without Transmission (2026)	$ 11.19	$ 31.46	Table F-34
Base LCOE, without Transmission (2026)	$ 15.04	$ 36.69	Table F-32
High LCOE, without Transmission (2026)	$ 16.43	$ 39.50	Table F-36
Department LCOE, without Transmission (2026)	$ 18.08	$ 43.45	

[55] The Department considered changes to the other expansion units but lacked sufficient historical data to question Xcel's inputs.
[56] This adjustment to the base case means that Xcel's High LCOE sensitivity is actually a low sensitivity in the Department's analysis.

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Table 10: Recent Renewable Pricing (LCOE, $/MWh)

Project	Wind	Solar
	[TRADE SECRET DATA HAS BEEN EXCISED]	
Apple River Solar[57]		
Sherco Solar 3		
Sherco Solar 1 and 2[58]		
Northern Wind[59]		
Grand Meadows Repower[60]		
Nobles Repower		
Border Winds Repower		
Pleasant Valley Repower		
Ewington Repower		
Heartland Divide II[61]		

d. Unserved Energy and Capacity Prices

Fourth, the Department changed the unserved energy and capacity prices to the EnCompass default values of $10,000/MWh and $250/kW-year, respectively. Xcel's values were $1,000,000/MWh and $100,000/kW-year. Xcel set these values extremely high, presumably to prevent the model from preferring to incur unserved energy or capacity costs. The Department was concerned that Xcel's extraordinarily high inputs may distort the resulting expansion plan.

e. DR FirmCap

Fifth, the Department changed FirmCap of the "DR 2 - MN 400 ERS" resource from 0 to 100. FirmCap is a percentage value applied to MaxCap, meaning that the setting of zero effectively rendered this resource to have a capacity of 0 for reliability purposes. This resource appears to represent the Company's Demand-Response Bundle 4, which is a locked-in planned change resource. The Department understands this resource has not yet officially been approved through MISO, and thus the Company decided to set FirmCap to 0. Given that many of

[57] See Table 1 of Xcel's May 5, 2023 petition in Docket No. E002/M-22-403 for the LCOEs of Apple River Solar and Sherco Solar 3.
[58] See Page 15 of Xcel's April 12, 2021 Petition in Docket No. E002/M-20-891 for the LCOE of what is now known as Sherco Solar 1 and 2.
[59] See Table 1 of the Department's August 25, 2022 Comment in Docket No. E002/M-20-620 for the LCOE of Northern Wind.
[60] See Table 1 of the Department's December 2, 2020 comment in Docket No. E002/M-20-620 for the LCOEs of Grand Meadows Repower, Nobles Repower, Border Winds Repower, Pleasant Valley Repower, and Ewington Repower.
[61] See Page 10 of Xcel's October 29, 2020 petition in Docket No. E002/M-20-806 for the LCOE of Heartland Divide II.

the Company's locked-in resources are at various levels of regulatory uncertainty, the Department concluded that setting the FirmCap of this resource to 100 was reasonable.

f. Planned Projects Plan ID

Finally, the Department changed a component of Xcel's Plan Projects Report in post-processing. Xcel had four resources representing DR and EE that were locked into the model as planned changes but were not labeled as such in the Plan Projects Report.[62] This had to do with a technicality in the way the resources were locked into the model.[63] Since Xcel's model considered these resources to be locked-in, and since the Department was using the Plan Projects report, the Department changed these four resources from having PlanID of "1" (generally used for optimized units) to having a PlanID of "Planned Projects." This change only impacts how the resources are reported and does not impact the decision-making of the model.

3. Department Outputs

After making the changes described above, the Department sought to answer the following questions:

- What were the preferred expansion plans under each of the four nuclear retirement scenarios?
- How did the four nuclear retirement scenarios rank in terms of cost?
- Are there any other issues worth discussing?
- Based on the Department's results, should the Commission approve Xcel's preferred plan of extending the retirement dates of both Prairie Island and Monticello?

i. Expansion Plans

a. Base Case

The following table shows the Department's expansion plan results for each Scenario's base sensitivity from years 2024-2040.

[62] Specifically, these resources were DR 2 – MN 400 ERS, DR 2 – MN 400 SS, EE 2_24-29Mid, and EE 2_30-35Mid. These first two resources represent DR Bundles 3 and 4, and the second two resources collectively represent EE Bundle 2.

[63] Xcel set the Resource Units to "0" in EnCompass, unlike other locked-in changes, which have the Resource Units set to "1." However, for these four resources, Xcel set Minimum Projects to "1," effectively locking-in the resource. In the Department's version of EnCompass, locked-in resources are given a PlanID of "Planned Changes" in the Plan Projects Report; however, these four resources did not have that label, potentially due to the method of locking-in the resources.

Table 11: Department's Expansion Plan Results (2024-2040 Installed MW)

	Battery	CT	DR	EE	Solar PV	Wind	Total
Scenario 1 (Current Retirement Dates)	1,140	5,088			1,100	9,600	16,928
Scenario 2 (Current Monti, Extend PI)	1,140	4,862			900	7,200	14,102
Scenario 3 (Extend Monti, Extend PI)	1,320	4,191			800	7,400	13,711
Scenario 4 (Extend Monti, Current PI)	1,620	4,862			1,000	9,000	16,482

The Department observes the following:

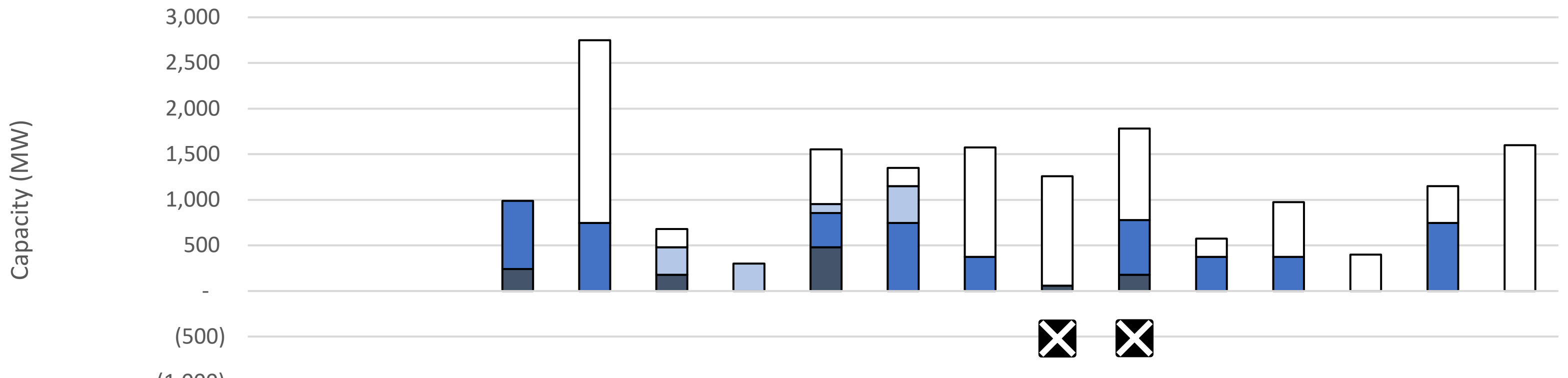
- Scenario 1 yielded the largest total added capacity and Scenario 3 yielded the smallest total added capacity. This is logical, since extending nuclear retirement dates will mean fewer builds are needed to make up for the shortfall in capacity;
- Incremental demand response or energy efficiency was never selected by EnCompass;[64]
- Of all scenarios, Scenario 1 added the most CT, Solar PV, and Wind capacity, while Scenario 4 added the most Battery capacity;
- Although Scenario 3 added less capacity than Scenario 2, Scenario 3 added more Battery and Wind capacity than Scenario 2;
- In general, extending the Prairie Island retirement date has more of an impact on the expansion plan additions than extending the Monticello retirement date; while the difference in Total capacity between Scenarios 1 and 2 is 2,826 MW, the difference between Scenarios 1 and 4 is only 446 MW. This ratio of these capacity additions is not commensurate with the capacity retirements of Prairie Island (totaling 1,040 MW under current retirement dates) and Monticello (totaling 617 MW) due to differences between installed capacity and accredited capacity of the resources in question.

The following figures show these additions as they appear over the course of the planning period.

[64] Recall, however, that the model assumes a certain level of demand response and energy efficiency built-in. The results here specifically indicate that Energy Efficiency Bundle 3 and Demand Response Bundles 5 and 6 were not selected in the base sensitivities.

Charts 2 and 2A: Capacity Expansion Plan for Scenario 1

Chart 2 Planning Period, 2024-2040 and Chart 2A Study Period, 2024-2055



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	-	-	-	-	2,000	200	-	600	200	1,200	1,200	1,000	200	600	400	400	1,600
Solar PV	-	-	-	-	-	300	300	100	400	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	748	748	-	-	374	748	374	-	599	374	374	-	748	-
Battery	-	-	-	240	-	180	-	480	-	-	60	180	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	(521)	(519)	-	-	-	-	-
Total Additions	-	-	-	988	2,748	680	300	1,554	1,348	1,574	1,260	1,779	574	974	400	1,148	1,600

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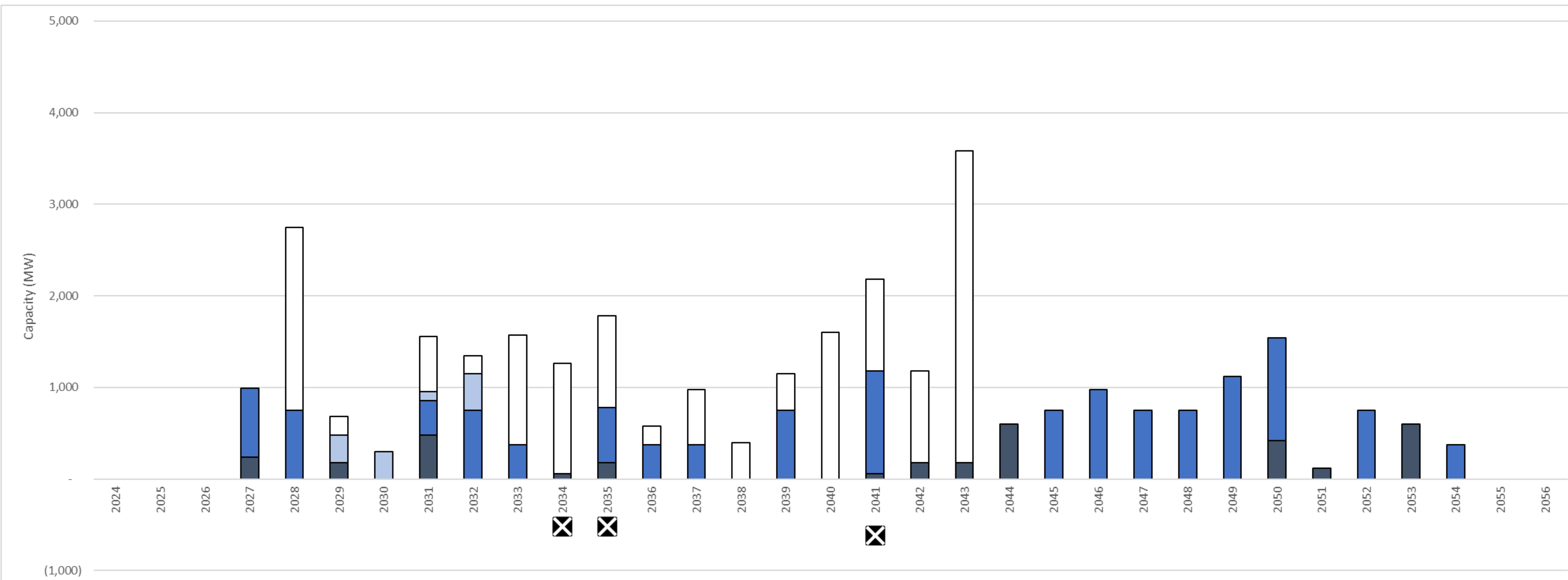
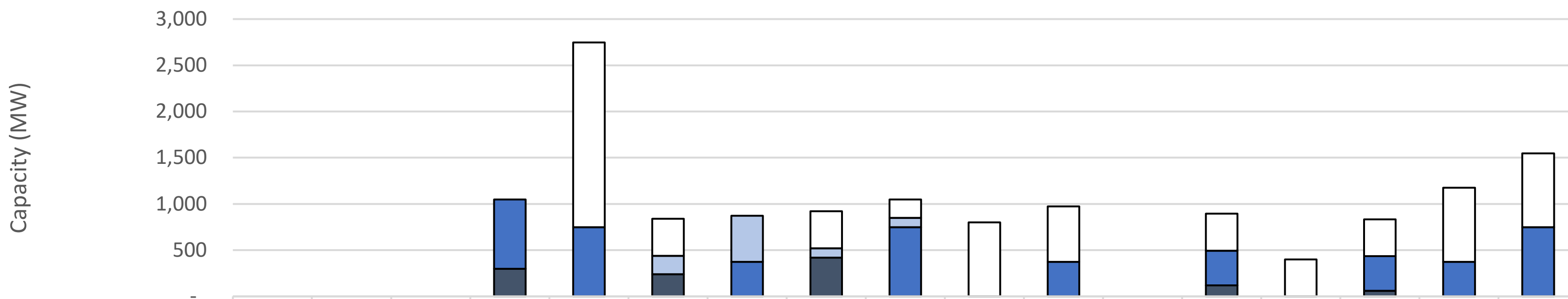
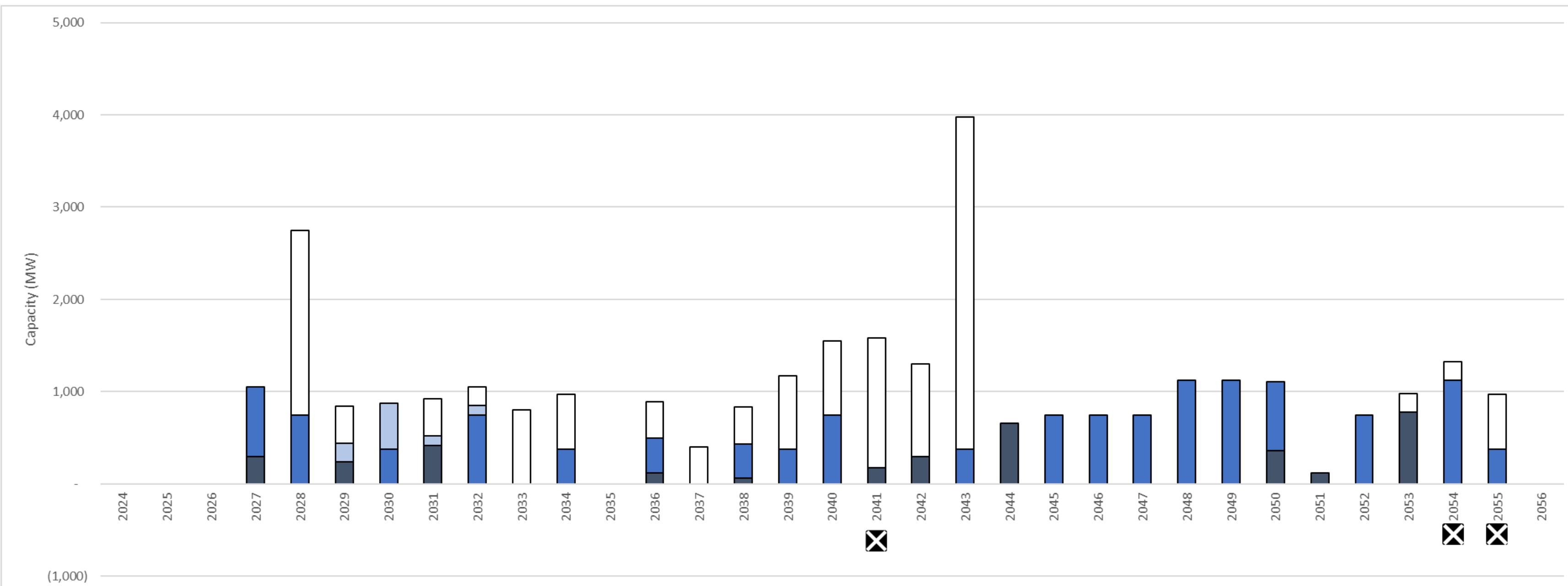


Charts 3 and 3A: Capacity Expansion Plan for Scenario 2

Chart 3 Planning Period, 2024-2040 and Chart 3A Study Period, 2024-2055



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	-	-	-	-	2,000	400	-	400	200	800	600	-	400	400	400	800	800
Solar PV	-	-	-	-	-	200	500	100	100	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	748	748	-	374	-	748	-	374	-	374	-	374	374	748
Battery	-	-	-	300	-	240	-	420	-	-	-	-	120	-	60	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Additions	-	-	-	1,048	2,748	840	874	920	1,048	800	974	-	894	400	834	1,174	1,548


5,000
4,000
3,000
2,000
1,000
-
(1,000)
Capacity (MW)
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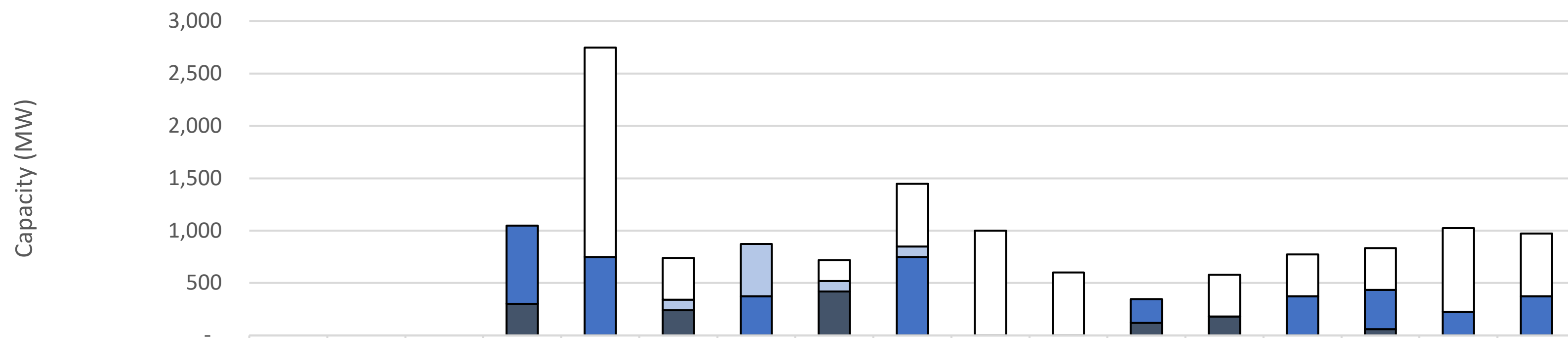
2056

Charts 4 and 4A: Capacity Expansion Plan for Scenario 3

Chart 4 Planning Period, 2024-2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	-	-	-	-	2,000	400	-	200	600	1,000	600	-	400	400	400	800	600
Solar PV	-	-	-	-	-	100	500	100	100	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	748	748	-	374	-	748	-	-	225	-	374	374	225	374
Battery	-	-	-	300	-	240	-	420	-	-	-	120	180	-	60	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Additions	-	-	-	1,048	2,748	740	874	720	1,448	1,000	600	345	580	774	834	1,025	974

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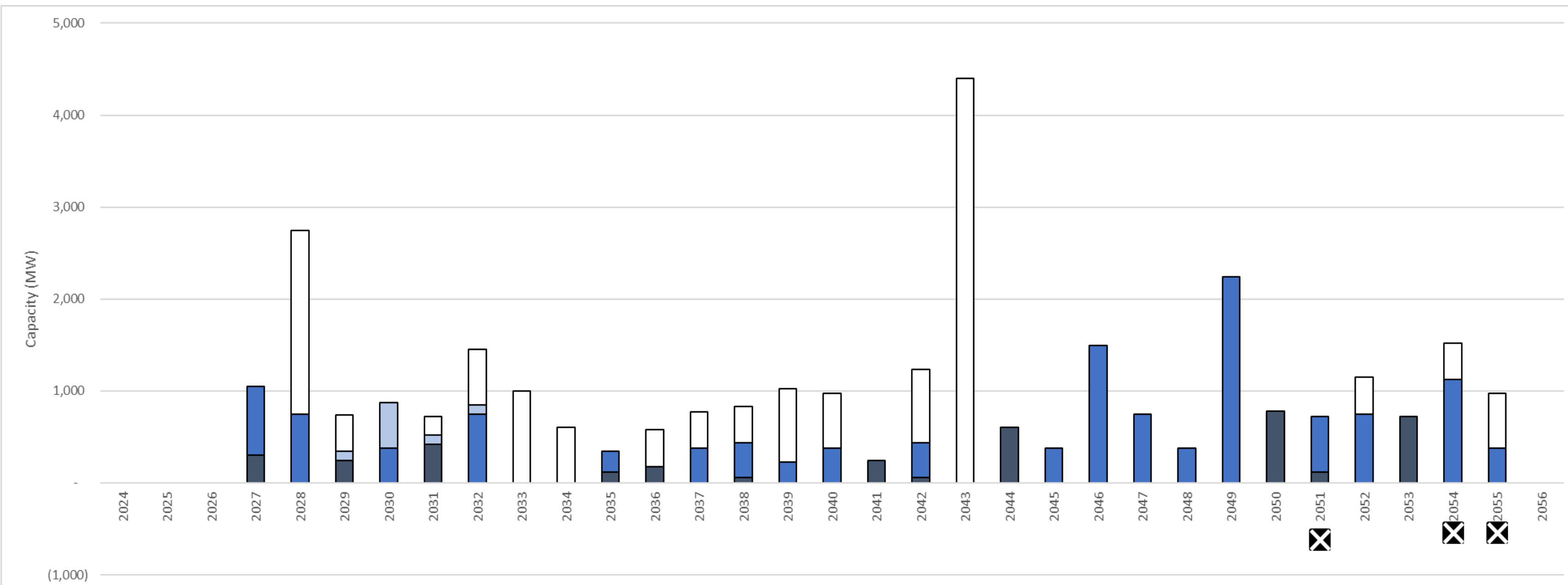
Chart 4A Study Period, 2024-2055



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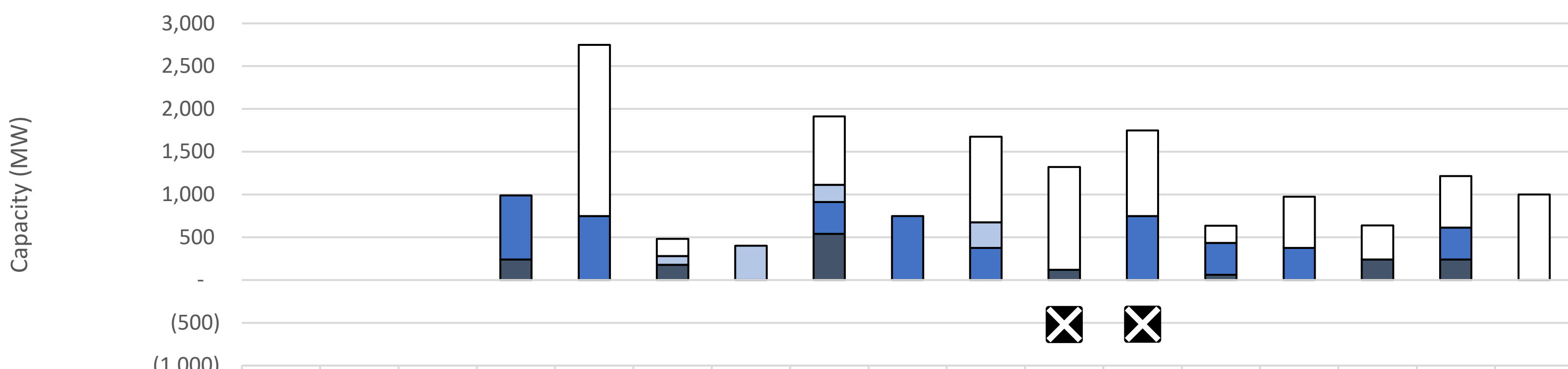
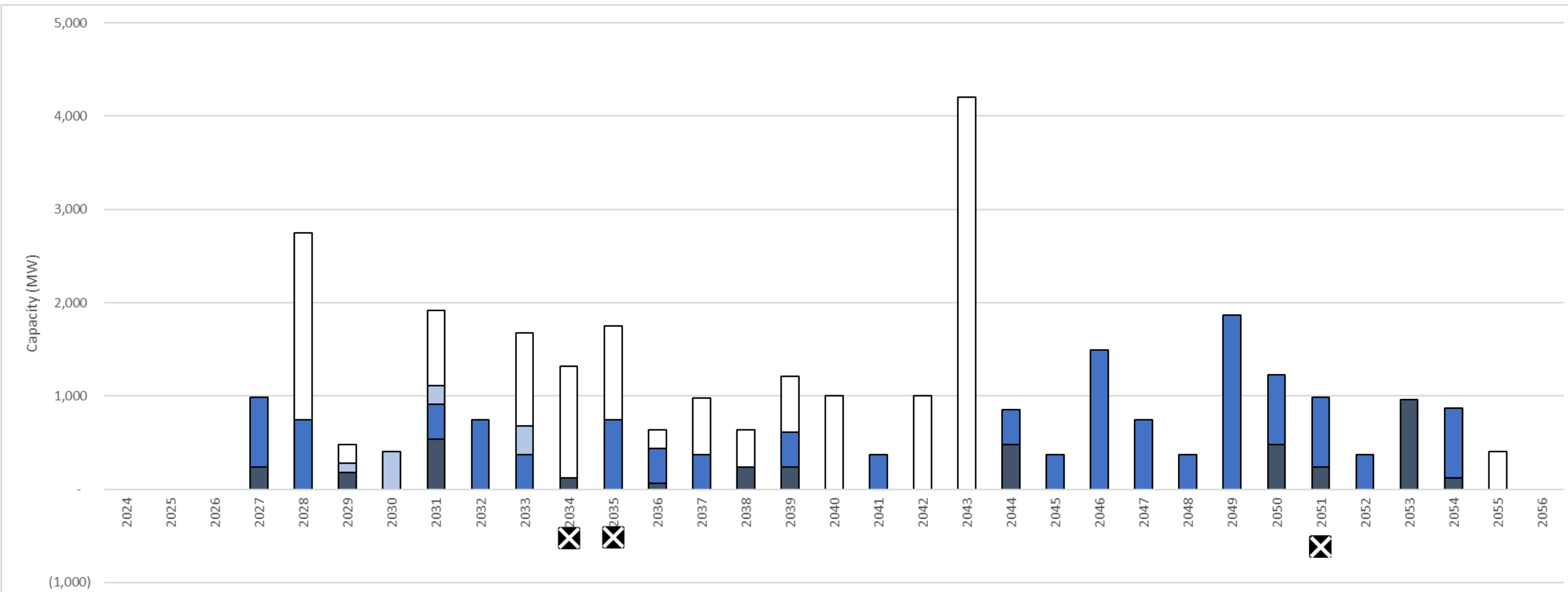
Charts 5 and 5A: Capacity Expansion Plan for Scenario 4

Chart 5 Planning Period, 2024-2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	-	-	-	-	2,000	200	-	800	-	1,000	1,200	1,000	200	600	400	600	1,000
Solar PV	-	-	-	-	-	100	400	200	-	300	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	748	748	-	-	374	748	374	-	748	374	374	-	374	-
Battery	-	-	-	240	-	180	-	540	-	-	120	-	60	-	240	240	-
Nuclear	-	-	-	-	-	-	-	-	-	-	(521)	(519)	-	-	-	-	-
Total Additions	-	-	-	988	2,748	480	400	1,914	748	1,674	1,320	1,748	634	974	640	1,214	1,000

Chart 5A Study Period, 2024-2055



The Department observes the following about the above expansion plan figures:

- Regardless of nuclear retirement date, each Scenario adds exactly 1,496 MW of Combustion Turbine (CT) resources and 240 to 300 MW of battery resources in years 2027-2028;
- Regardless of nuclear retirement date, each Scenario adds exactly 2,000 MW of wind in 2028.

Overall, regardless of the decision regarding nuclear retirement dates, the 5-year action plan is focused on wind and CT resources. Again note that the Department has consistently understood CT resources to be representative of "peaking" resources. The exact technology to meet the peaking need will be determined in a separate resource acquistion docket.

The following table compares the Department's capacity expansion plan results to Xcel's.

Table 12: Department's vs. Xcel's Base Expansion Plan Results (2024-2040 Installed MW)

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Dept	Xcel	Dept	Xcel	Dept	Xcel	Dept	Xcel
Battery	1,140	2,220	1,140	1,440	1,320	2,100	1,620	
CT	5,088	4,488	4,862	4,488	4,191	3,592	4,862	
DR	-	69	-	69	-	69		
EE	-	-	-	-	-	-		
Solar PV	1,100	2,400	900	1,700	800	1,500	1,000	
Wind	9,600	11,200	7,200	8,800	7,400	8,400	9,000	
Total	16,928	20,377	14,102	16,497	13,711	15,661	16,482	

Xcel's results consistently add more (installed) capacity than the Department's across Scenarios 1-3. While Xcel's results show greater (installed) capacity added for battery, solar, and wind resources, the Department's results show greater (installed) capacity added for peaking (CT) resources.

One explanation is that the Department increased the LCOEs of wind and solar to be more in line with recent costs of these technologies. This cost increase explains why the Department's results consistently add fewer solar and wind resources which, in turn, may have led to more combustion turbine resources. The swap-out of Solar and Wind for CTs is not one-for-one, since CTs have higher accredited capacity across all seasons than do wind and solar but produce less energy. As a result, fewer CTs are needed to meet the same capacity requirements as wind and solar, meaning that the Department's results add less capacity overall. Since CTs are not energy-intensive, this indicates to the Department that Xcel's system needs may be more related to capacity than energy. Finally, adding as will be shown below, the Department's scenarios result in a substantial reduction in curtailments.

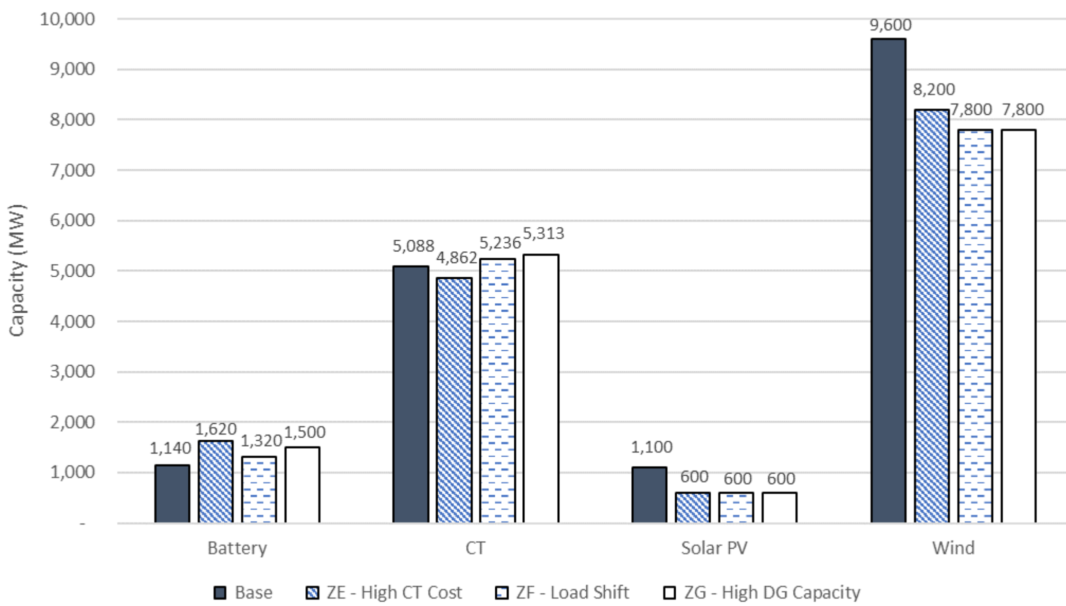
It is unclear why Xcel's model prefers to add batteries and the Department's prefers to add CTs. In any event, both CTs and batteries are peaking technologies and the exact choice is best deferred to a resource acquisition proceeding which can weigh the costs and benefits of actual projects in a more detailed manner.

Finally, the Department notes that Xcel's results consistently add a 2024 demand-response resource, whereas the Department's do not. Recall that although there are EE and DR locked-in or planned changes appearing in both models, this particular 69 MW DR resource is not considered a planned change. In the Department's results, only High Load sensitivities selected this resource.

b. Department Sensitivities

The following chart shows the 2024-2040 Scenario 1 expansion plan results of Department sensitivities ZE (High CT Cost), ZF (Load Shift), and ZG (High DG Capacity).[65]

Chart 6: Department's Expansion Plans (2024-2040) for Sensitivities ZE, ZF, ZG, Scenario 1



The Department observes the following:

- Compared to the sensitivities studied, the Scenario 1 base case adds between 1,400 and 1,800 more MW of wind;
- As expected, less CT capacity was added under the High CT scenario (4,862 MW) than under the base case (5,088 MW); this appears to have been made up with increased batteries (1,620 MW in High CT vs 1,140 MW in base case);
- Load Shift and High DG Capacity added the same amounts of solar (600 MW) and wind (7,800 MW), both of which were less than in the base case (1,100 solar and 9,600 wind);
- In general, the sensitivities studied by the Department tended to add additional battery and CT and less solar and wind.

The following chart shows expansion plan results for these sensitivities across Scenarios 1, 2, and 3:

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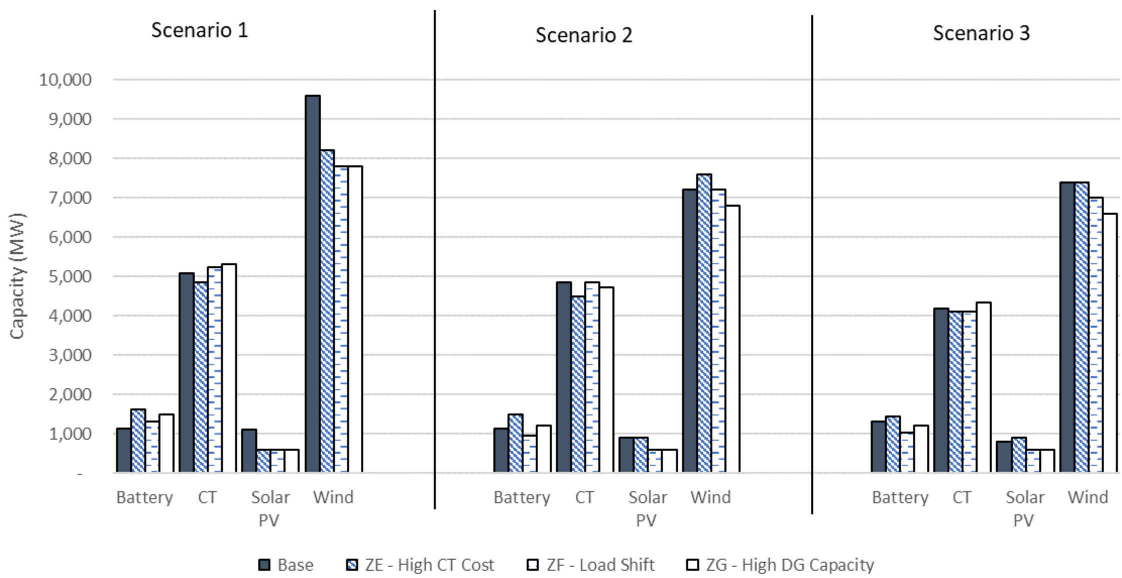
[65] Recall that although the Department ran an additional four sensitivities for Scenarios 1 to 3, only three of these were able to be run with expansion plans; Sens ZH (High Energy Tie Limit) was only run as a production cost run.

Chart 7: Department's Expansion Plans (2024-2040) for Sensitivities ZE, ZF, ZG, Scenarios 1-3



The Department observes similar trends under Scenarios 2 and 3. Notably, however, wind additions drastically decrease from Scenario 1 to Scenarios 2 and 3 across all sensitivities. Under Scenario 2, wind additions were highest in the High CT Cost sensitivity.

ii. Energy Results

Since the Department's modeling shows fewer capacity additions than Xcel's, the Department's energy source and sink analysis is of particular importance. Again, the Department examined its PVRR rather than PVSC runs, as PVRR will be more reflective of how resources are dispatched in MISO.

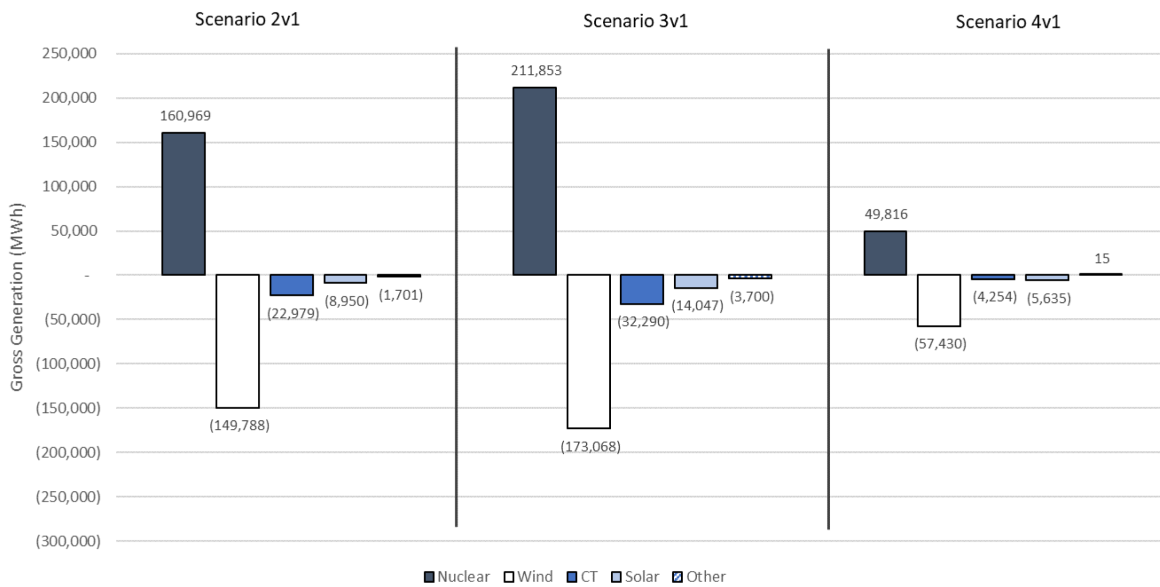
The following results show the Department's total sources and sinks for the base cases of Scenarios 1 to 4. This can be compared to same table in the review of Xcel's modeling, see Attachment 3.

Table 13: Department's Bae Case Energy Sources and Sinks, 2024-2055 GWh

Nuclear Retirement Scenario	Sources			Sinks		
	Net Generation	Purchases	Total	Energy (Load Forecast)	Sales	Total
Scenario 1 PVRR	2,060,303	221,629	2,281,932	1,995,587	286,345	2,281,932
Scenario 2 PVRR	2,070,172	213,308	2,283,480	1,995,587	287,894	2,283,480
Scenario 3 PVRR	2,077,159	209,208	2,286,367	1,995,587	290,780	2,286,367
Scenario 4 PVRR	2,060,426	220,779	2,281,206	1,995,587	285,619	2,281,206

Table 13 demonstrates that in the Department's results, sinks are equal to sources, which is what should happen. It also shows Scenario 3 to have the highest total net energy production (GWh), and Scenario 4 to have lowest net total energy production. However, these values to not take into account curtailment; the Department added back curtailment to net generation to arrive at gross generation. The following figure looks at the gross generation by resources, comparing Scenario 1 to Scenario 2, Scenario 1 to Scenario 3, and Scenario 1 to Scenario 4. This figure can be compared to the same figure in the analysis of Xcel's results; see Attachment 3.

Chart 8: Department's Change in Gross Generation (GWh) from Scenario 1, by Technology (2024-2055) (PVRR Sensitivities)



Compared with Scenario 1, under Scenario 2:

- Nuclear gross generation increases by 160,969 GWh (same as Xcel's, as expected);
- The increase in nuclear gross generation is countered by a decrease in gross wind generation of (149,788), with smaller decreases in CT gross generation (22,979) and Solar PV gross generation (8,950). Relatively little (1,709) is attributable to other resources.
- The sum of all gross generation changes is (22,449) over the 2024-2055 study period, meaning extending only the Prairie Island retirement date will result in a reduction of approximately 22.4 GWh (compared to Xcel's results of 34.3 GWh).

Compared with Scenario 1, under Scenario 3:

- Nuclear gross generation increases by 211,853 GWh (same as Xcel's, as expected);
- The increase in nuclear gross generation is counteracted with a decrease in gross wind generation of (173,068), with smaller decreases in CT gross generation (32,290) and Solar PV gross generation (14,047). Relatively little (3,700) is attributable to other resources.
- The sum of all gross generation changes is (11,252), meaning extending both the Prairie Island and Monticello retirement dates will result in a reduction of approximately 9.5 GWh (compared to Xcel's 57.5 GWh).

Compared with Scenario 1, under Scenario 4:

- Nuclear gross generation increases by 49,816 GWh;
- The increase in nuclear gross generation counteracted with a decrease in gross wind generation of (57,430), with smaller decreases in CT gross generation (4,254) and Solar PV gross generation (5,635). The sum of other resources is slightly positive (15); in this instance, gross generation due to combined cycle units increased instead of decreased, resulting in a slight positive.
- The sum of all gross generation changes is (17,488), meaning extending only the Monticello retirement date will result in a reduction of approximately 17.5 GWh.

Recall that decreases in gross generation are attributable to two different things: fewer of those resources being built in the expansion plan and curtailment. The following table shows wind curtailment rates (curtailment/gross generation) for years 2024-2055, alongside wind capacity additions and average curtailment rates for the 5-Year Action Plan (2024-2030), the planning period (2024-2040), and the study period (2024-2055). It can be compared with the same table which shows Xcel's results, see Attachment 3.

Table 14: Department's Average Wind Curtailment Rates
Higher Rates Correspond to Darker Shading[66]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2024	0.4%	0.4%	0.4%	0.4%
2025	2.1%	1.7%	2.0%	2.1%
2026	5.0%	5.0%	4.9%	5.1%
2027	5.4%	5.3%	5.3%	6.0%
2028	13.2%	12.9%	12.8%	13.1%
2029	14.3%	15.2%	14.9%	14.2%
2030	14.6%	15.6%	15.7%	14.0%
2031	15.8%	14.9%	14.3%	16.7%
2032	17.1%	15.8%	17.2%	16.3%
2033 (PI Normal)	18.7%	17.0%	18.0%	17.9%
2034 (PI Normal)	19.3%	18.5%	20.0%	18.6%
2035	16.5%	15.7%	17.1%	15.8%
2036	16.8%	16.6%	17.9%	16.3%
2037	15.2%	14.4%	15.7%	14.5%
2038	15.5%	14.5%	15.7%	14.6%
2039	15.5%	15.0%	16.4%	14.5%
2040 (Monti Normal)	18.5%	16.3%	18.1%	17.3%
2041	18.5%	17.4%	16.9%	16.2%
2042	21.2%	20.4%	20.2%	20.1%
2043	30.3%	31.4%	33.3%	31.5%
2044	29.8%	30.9%	33.5%	31.7%
2045	27.8%	28.5%	30.0%	28.7%
2046	25.3%	25.7%	28.1%	26.8%
2047	24.3%	24.5%	26.2%	25.2%
2048	24.6%	24.7%	27.1%	26.1%
2049	23.6%	23.9%	25.2%	24.7%
2050 (Monti Extend)	25.5%	25.7%	26.4%	25.7%
2051	24.4%	24.4%	23.1%	22.3%
2052	24.4%	24.7%	24.2%	22.3%
2053 (PI Extend)	24.1%	23.8%	22.8%	22.1%
2054 (PI Extend)	24.0%	22.6%	22.2%	22.1%
2055	24.1%	21.6%	21.3%	23.1%
2024-2030 Average Wind Curtailment %	7.9%	8.0%	8.0%	7.9%
2024-2040 Average Wind Curtailment %	13.2%	12.6%	13.3%	12.8%
2024-2055 Average Wind Curtailment %	18.6%	18.3%	19.0%	18.3%

Most importantly, whereas Xcel's highest curtailment rate was ~38% in 2043-2044 Scenario 3, the Department's highest curtailment rates were ~33-34% in that same time period. This difference indicates that, while the Department is still showing periods where wind may be overbuilt in Xcel's system, wind is less overbuilt than in

[66] The results of this table correspond to Step 3, not Step 2, and so do not reflect the curtailment spikes discussed above.

Xcel's results. Also, Xcel's results showed average wind curtailments to be highest in Scenario 3 only in the short term, the Department's results showed average wind curtailments to be highest in Scenario 3 across short-, medium-, and long-term horizons.

iii. Cost Results

a. Base Case Results

The following table shows the Department's cost results for each Scenario, broken down by revenue requirement and externalities. These "Total" figures are reflective of Xcel's three cost streams (EnCompass generated revenue requirement, EnCompass-generated externality costs, and Xcel's post-processing externalities cost).

Table 15: Department Base Case Present Value Social Cost (PVSC) Results, (NPV, $m)

2024-2040	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Revenue Requirement	36,296	36,090	35,673	36,186
Externalities[67]	16,895	16,597	16,420	17,038
Total	53,191	52,687	52,093	53,224

The Department's results showed the least cost plan to be Scenario 3 at $52,093,000,000 and the highest cost plan to be Scenario 4 at $53,224,000,000. This result is somewhat surprising, since it seems to indicate that the value of extending Monticello is only realized when Prairie Island is also extended. Given time constraints, the Department was unable to examine this result further, but would be interested in seeing Xcel's results under a Scenario 4.

The following table compares the Department's to Xcel's Present Value of Societal Costs and Present Value Revenue Requirement for each Scenario, from 2024-2040.

Table 16: Department vs Xcel Base Case PVSC and PVRR Results, (NPV, $m)

PVSC	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Department	53,191	52,687	52,093	53,224
Xcel	51,037	50,624	50,252	
PVRR	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Department	38,686	38,734	38,391	38,912
Xcel	34,678	34,581	34,215	

The Department and Xcel found that Scenario 3 was the least cost nuclear retirement Scenario, both in terms of PVSC and PVRR.[68]

b. Sensitivity results

[67] These externalities costs reflect both the EnCompass-generated externalities cost and Xcel's post-processing externalities cost.

[68] Note that sometimes PVSC sometimes refers simply to PVRR + Externalities; if this were the case here, the Revenue Requirement from Table 15 would be equal to the Department's PVRR results from Table 16. However, in this case, Xcel and the Department ran separate dispatch routines for the PVRR and PVSC runs, using the same expansion plan. The differences in dispatch routine result in two different cost results because the PVSC runs incorporate the Commission's regulatory cost of carbon, whereas the PVRR runs do not.

The Department then compared the costs of each Scenario across the base case and all 33 additional sensitivities. The following table shows the Department's cost results in 2024 net present value millions of dollars (NPV $m) for years 2024-2040. The following values continue to incorporate Xcel's three cost streams.

Table 17: Department Cost Results for all Sensitivities and Scenarios, 2024-2040 (NPV, $m), Higher-cost Scenarios with Darker Shading

SensID	Sensitivity Short Name	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Base	Base - PVSC	53,191	52,687	52,093	53,224
A	PVRR	38,686	38,734	38,391	38,912
B	High Fuel Mkt Price	53,857	53,207	52,994	
C	Low Fuel Mkt Price	49,705	48,713	48,322	
D	High Load	59,551	58,889	58,498	
E	Low Load	50,266	49,678	49,371	
F	Data Center Load	61,170	60,098	59,743	
G	High Tech Costs	53,254	52,643	52,264	
H	Low Tech Costs	47,548	47,479	47,228	
I	Edison Mkt Costs	52,082	51,760	51,261	
J	HighRegHighEnv	61,635	61,143	60,724	
K	LowRegLowEnv	49,380	48,623	48,286	
L	NoRegHighEnv	74,823	73,019	72,494	
M	NoRegMidEnv	59,397	58,181	57,718	
N	NoRegLowEnv	50,842	49,956	49,531	
O	RBDC Opt-Out	53,317	55,554	54,834	
P	25% Battery ELCC	53,840	55,331	54,680	
Q	Mkt Off Dispatch	56,813	55,839	55,197	
R	Market On Expansion Plan	49,497	48,561	48,398	
S	Wind Profile Variability	53,230	52,963	52,476	
T	Environmental Programs	53,450	52,381	52,022	
U	High Tech + High Load	59,618	58,655	58,315	
V	Low Tech + Low Load	46,070	45,951	45,589	
W	10hr Battery+Hybrid	53,117	52,805	52,189	
X	DG Bundles	53,157	52,348	52,045	
Y	Carbon Free	52,316	52,096	51,732	
ZA	All Advanced Tech	50,629	50,770	50,401	
ZB	H2 at CTs	51,083	50,987	50,676	
ZC	LDES	51,947	51,571	51,127	
ZD	SMR	53,012	52,545	52,194	
ZE	High CT Cost	54,185	52,773	52,366	
ZF	Load Shift	53,945	52,599	52,127	
ZG	High DG Capacity	54,396	53,387	52,945	
ZH	High Energy Tie Dispatch	53,278	52,787	52,199	

The Department found that across the base case and 31 of the 33 sensitivities, Scenario 3 was the least-cost nuclear retirement Scenario. For two sensitivities—RBDC Opt-Out and 25% Battery ELCC—Scenario 1 was found to be the least cost plan. The Department discusses these results in further detail below.

The Department also found that across 29 of the 33 sensitivities, Scenario 1 was found to be the highest-cost nuclear retirement Scenario. For three sensitivities—RBDC Opt-Out, 25% Battery ELCC, and All Advanced Tech—Scenario 2 was found to be the highest-cost Scenario. In the base sensitivities (both PVSC and Sens A-PVRR), the Department found Scenario 4 to be the highest-cost nuclear retirement Scenario.

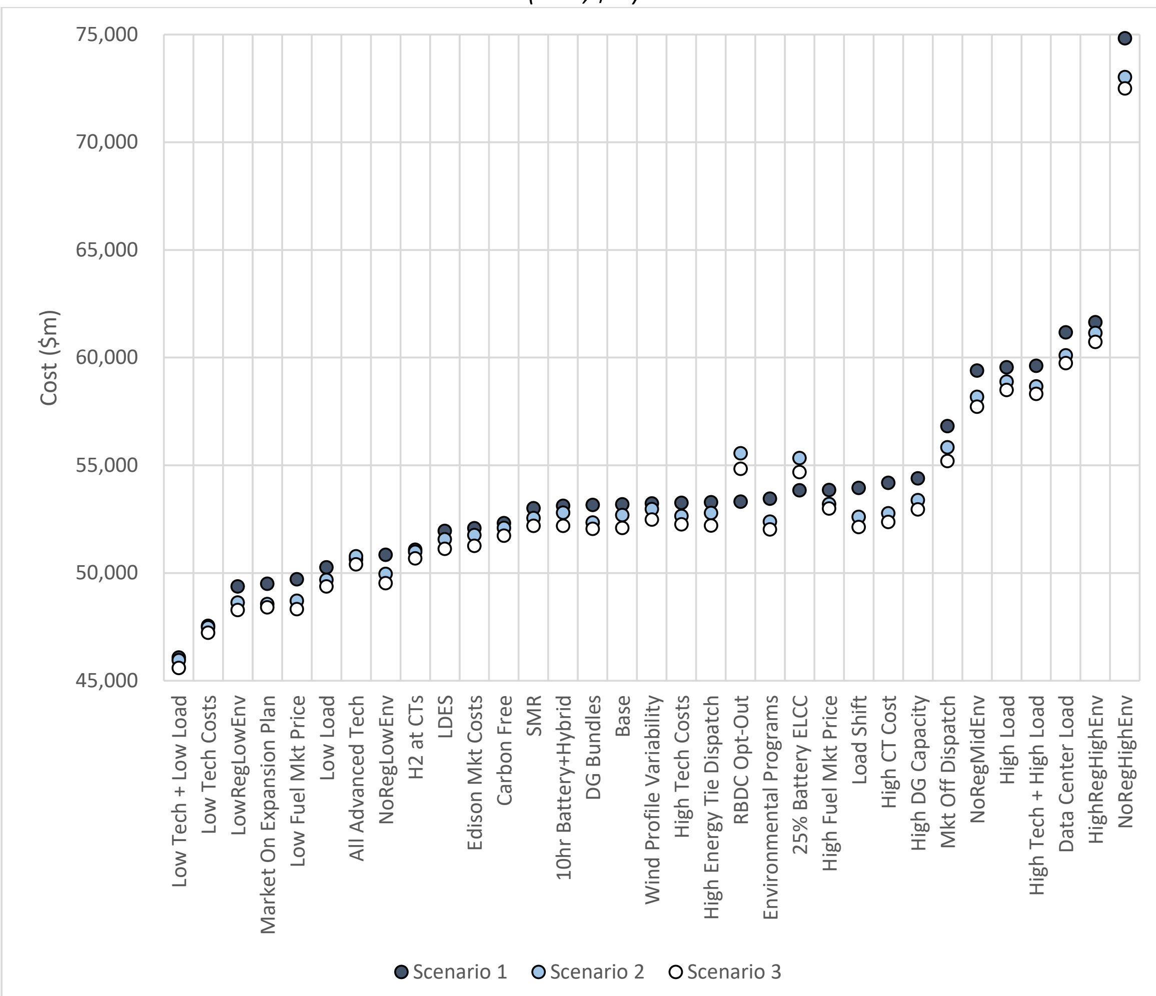
In its four additional sensitivities studied (ZE, ZF, ZG, and ZH), the Department's results showed Scenario 3 to be least-cost and Scenario 1 to be highest-cost, in keeping with the trends across all sensitivities.[69]

After comparing costs across Scenarios, the Department then compared costs across sensitivities. The purpose of this is to see where the base case falls along the cost spectrum of examined sensitivities and also to identify any potential outliers.

The following chart shows costs grouped by sensitivity, plotted from least cost to highest cost (on a Scenario 1 basis).

[69] Recall that the Department was only able to perform Sens ZH (High Energy Tie Limit) as a production cost run, and so only had cost values and no expansion plan values.

Chart 9: Department Cost Results per Sensitivity, 2024-2040
(NPV, $m)



In the above chart, the Department observes that the Base case falls in the middle of examined sensitivities, indicating that it is not an outlier. The only major outlier appears to be Sens L- NoRegHighEnv cost. The unusually high cost results of this plan is consistent with past analyses the Department has done for IRPs; in Minnesota Power's IRP comments, the Department noted that NoRegHighEnv cost runs were consistently more costly than other carbon futures.[70] This result is logical, as the sensitivity's decisions—both in expansion plan and dispatch routine—are based upon the assumption of no regulatory carbon costs; recall that environmental costs do not affect either the expansion plan or dispatch routine. Therefore, the model behaves as if it will not be penalized for selecting resources with higher carbon intensities, and after those decisions have been made, the higher environmental costs get "tacked on" at the end.[71]

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[70] See Dept Figure 5 in Department's July 29, 2022 *Supplemental Comments* in Docket No. E015/RP-21-33. Document ID 20227-187976-01.
[71] As noted above, the externality values allow cost comparison of two different runs to each other.

Typically, at this point the Department would also want to perform a MIP Uncertainty analysis, as it did in its comments for GRE's IRP.[72] This type of analysis shows if there is any meaningful difference between two plans. For example, the results of the base case for Scenario 1 might be meaningfully different from the results of the Scenario 3 base; but the results of the Scenario 3 base might be no different from Sens X- Selectable DG Bundles or Sens S- Wind Profile Variability (the sensitivities to the immediate right and left of the base case in Chart 7 above). However, due to Xcel's two-step approach with the expansion plan, performing this type of analysis would be extremely burdensome: while a normal expansion plan run will optimize once for the entire planning period, Xcel's Step 2 expansion plan run re-optimizes once every four years. In the event the Department was able to perform such an analysis, it would likely be limited to comparing only a few specific runs. The Department recommends Xcel perform a MIP Uncertainty Analysis in its next IRP filing if it is feasible.

c. RBDC Opt-Out and 25% Battery ELCC Results

The RBDC Opt-Out sensitivity represents a future in which Xcel opts out of MISO's Reliability-Based Demand Curve (RBDC) construct. MISO's RBDC was recently approved by FERC and is expected to be implemented during the 2025-2026 MISO planning year. As described by Xcel, RBDC, "is a proposed design for MISO's Planning Resource Auction that aims to reflect the reliability value of capacity and produce more efficient and stable capacity prices."[73] MISO's RBDC proposal provides an opt-out provision; if a utility decides to opt-out of RBDC, then that utility incurs a percentage adder on top of its existing seasonal planning reserve margin requirements. For the RBDC Opt-Out sensitivity, Xcel overwrites the base PRM requirements with a base=plus adder PRM requirement.

Planning reserve margins are a percentage above and beyond the utility's expected load; they are a built-in "cushion" to make sure the system will have enough resources to reliably serve customers. The RBDC Opt-Out sensitivity increases the size of the cushion, meaning that the utility would need to build more accredited capacity under this sensitivity.

The 25% Battery ELCC sensitivity reflects a future in which batteries perform more poorly than anticipated for reliability purposes. Effective Load Carrying Capability (ELCC) refers the amount of load a resource can dependably and reliably serve, as a percentage of the resource's installed capacity. ELCC is a way of measuring a resource's accredited capacity for reliability purposes and is a metric used in MISO's capacity construct. In EnCompass, capacity accreditation is captured through a variable called "FirmCap," which is a percentage applied to a resource's "MaxCap" or installed capacity. The battery seasonal accredited capacity (SAC) changes over the course of the planning period but varies from lows of 68% to highs of 100%, with an average of 87%; this range means that, on average, a 60 MW battery counts as about 52 MW for reliability purposes. For the 25% Battery ELCC sensitivity, Xcel overwrote all the SAC values with a blanket 25% value, meaning that the same 60 MW battery counts as about 15 MW for reliability purposes. Theoretically, this sensitivity should have the effect of reducing the battery resources selected, and presumably making up for that difference with firm dispatchable resources such as CTs.

The Department encountered very strange results in both the RBDC Opt-Out and 25% Battery ELCC sensitivities. The following tables show the expansion plan outcomes for each sensitivity, compared to the base runs.

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[72] See pages 27-30 of the Department's August 8, 2023 Comments in Docket No. ET2/RP-22-75. Document ID 20238-198066-01.
[73] See Appendix F at page 2.

Table 18: Expansion Plans (2024-2040 MW) for the Base Case, Sens O, and Sens P

Scenario 1	Base	Sens O - RBDC Opt-Out	Sens P - 25% Battery ELCC
Battery	1,140	1,440	420
Combustion Turbine	5,088	5,088	6,358
Solar PV	1,100	1,100	1,400
Wind	9,600	9,600	9,400
Total	16,928	17,228	17,578
Scenario 2	**Base**	**Sens O - RBDC Opt-Out**	**Sens P - 25% Battery ELCC**
Battery	1,140	-	-
Combustion Turbine	4,862	-	-
Solar PV	900	600	600
Wind	7,200	6,600	7,000
Total	14,102	7,200	7,600
Scenario 3	**Base**	**Sens O - RBDC Opt-Out**	**Sens P - 25% Battery ELCC**
Battery	1,320	-	-
Combustion Turbine	4,191	-	-
Solar PV	800	600	600
Wind	7,400	6,400	6,600
Total	13,711	7,000	7,200

While Scenario 1 produced expected results, Scenarios 2 and 3 selected no batteries or CTs in those sensitivity runs, *while still costing more*. This result left only one explanation, which the Department verified in a review of outputs: the Scenario 2 and 3 sensitivities were electing to incur the cost of unserved energy, rather than build capacity to meet that unserved energy. All three Scenario 1 results and all three base case results incurred no unserved energy costs, whereas the Scenario 2 and 3 RDBC Opt-Out and 25% ELCC incurred between $13.4 and $15 billion in unserved energy costs over the course of the planning period. It is not clear to the Department why EnCompass determined it is cheaper to incur the unserved energy cost rather than build peaking units in two scenarios but not the other. Given the speculative nature of these sensitivities and lack of time the Department did not pursue this issue further.

Since the Department adjusted the unserved energy and capacity prices downwards from Xcel's assumptions, the Department expected Xcel's RBDC Opt-Out and 25% Battery ELCC sensitivities to build more capacity than in the Department's similar sensitivities instead of incurring unserved energy costs. This is exactly what the Department found; Xcel's Scenario 3 sensitivities (recall the Company did not run these sensitivities on either Scenarios 1 or 2) resulted in reasonable expansion plans and incurred no unserved energy costs. This indicates that Xcel's high unserved energy cost can trigger the addition of peaking units.

d. Cost Conclusions

The Department concludes that the model shows Scenario 3 to be the least-cost option across all reliable sensitivities examined. However, the Department's results also indicate that the value of extending Monticello was only realized when paired with extending Prairie Island as well, as the Department's "Scenario 4" (Extend Monticello, Current Prairie Island Retirement) was found to be the highest-cost Scenario.

iv. Emissions Results

The Department calculated tons of carbon emissions over the 5-Year Action Plan period (2024-2030), the Planning Period (2024-2040), and the Study Period (2024-2050).[74] The following table shows the Department's results:

Table 19: Department's Carbon Dioxide Emissions Results by Scenario and Time Period (tons)

		Scenario 1	Scenario 2	Scenario 3	Scenario 4
PVSC	2024-2030	60,874,374	61,742,837	61,807,643	61,059,866
	2024-2040	99,621,287	96,860,259	95,456,595	100,643,189
	2024-2050	142,777,560	132,449,577	125,989,120	138,956,954
PVRR	2024-2030	68,790,901	69,739,589	69,845,008	68,953,587
	2024-2040	122,841,593	120,028,723	118,438,299	123,952,600
	2024-2050	178,926,730	168,165,627	161,303,676	175,037,466

Recall that tons of CO2 in the PVSC results are higher than PVRR results, because, although the two share the same expansion plan, the dispatch routines are different. Because the PVSC dispatch routine incorporates the Commission's regulatory carbon costs, resources that are more carbon-intensive will be less likely to run, which results in lower emissions. The PVRR dispatch routine has no regulatory costs, and thus is closer to a real-world dispatch scenario, which results in higher emissions. The emissions from a PVSC dispatch routine represent a "best case," highest-savings scenario, whereas the PVRR results represent a more likely scenario.

Regardless of emissions from a PVSC or PVRR scenario, the above table shows that in the immediate 5-Year Action Plan period (2024-2030), Scenario 3 was found to have the highest emissions results. Over the Planning Period (2024-2040) and Study Periods (2024-2055), however, Scenario 3 was found to have the lowest emissions, whereas Scenario 4 and Scenario 1 were found to have the highest emissions.

These results indicate that extending the life of Prairie Island yields lowest CO2 emissions in the medium and longer term, and that extending the life of Monticello is more likely to result in lower emissions only when done in conjunction when extending Prairie Island.

The Department then used Xcel's emissions outputs template provided in response to Department Information Request No. 1 to create a projection showing CO2 emissions reductions from 2005 levels, which are set to 28,031,614 tons. The following chart shows emissions reductions expressed as a percentage, with the lighter lines representing the PVSC results and darker lines representing PVRR results.

[74] The Department modified the Study Period to end in 2050 to match Xcel's emissions results.

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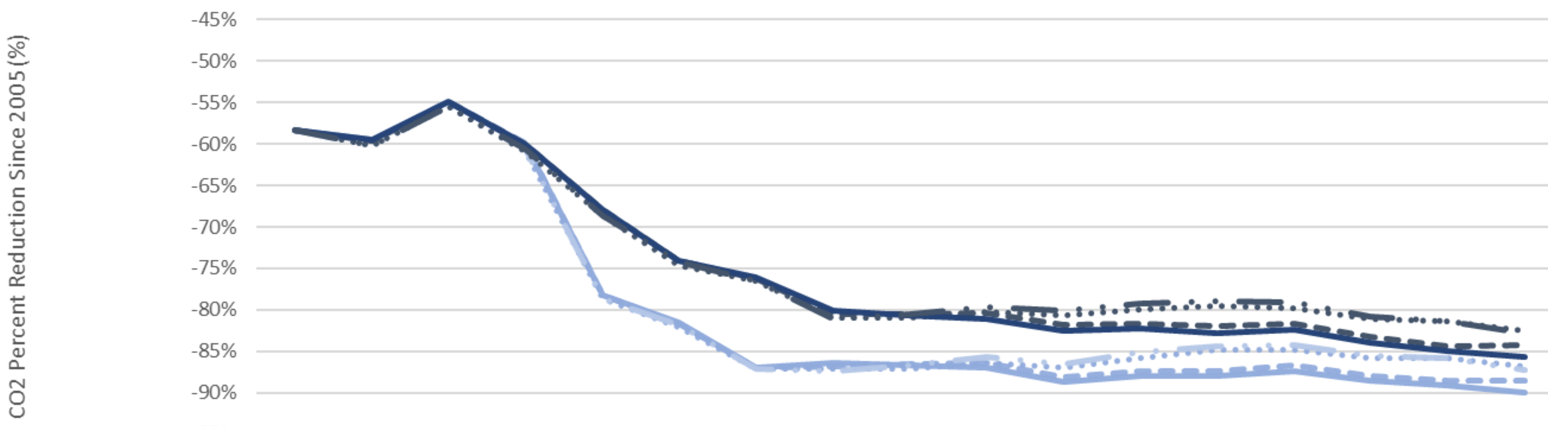
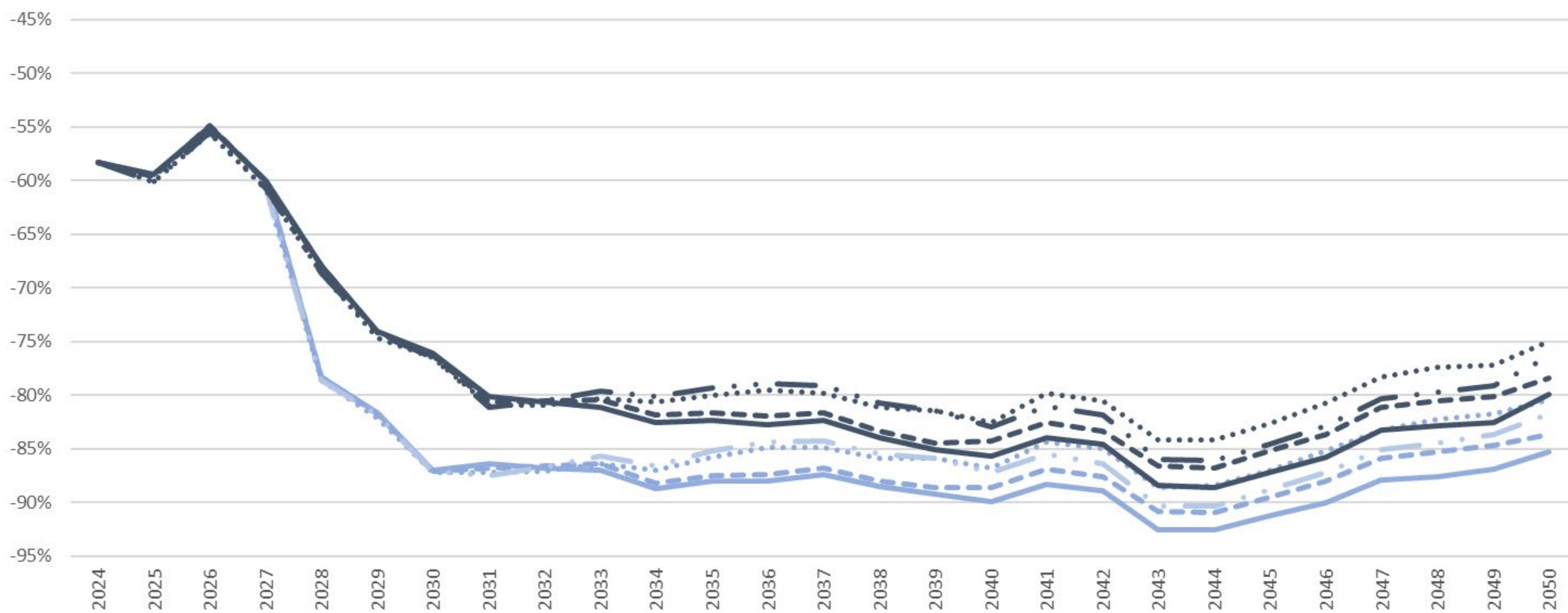
Charts 10 and 10A: Department's CO2 Emissions Reductions by Scenario (% Reduction Since 2005)

Chart 10 Planning Period 2024-2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PVSC - Scenario 1	-58%	-60%	-56%	-61%	-79%	-82%	-87%	-87%	-87%	-86%	-87%	-86%	-85%	-85%	-86%	-86%	-87%
PVSC - Scenario 2	-58%	-60%	-55%	-60%	-78%	-82%	-87%	-87%	-87%	-86%	-88%	-87%	-87%	-87%	-88%	-89%	-89%
PVSC - Scenario 3	-58%	-59%	-55%	-60%	-78%	-82%	-87%	-86%	-87%	-87%	-89%	-88%	-88%	-87%	-89%	-89%	-90%
PVSC - Scenario 4	-58%	-60%	-56%	-61%	-79%	-82%	-87%	-87%	-87%	-86%	-87%	-85%	-84%	-84%	-86%	-86%	-87%
PVRR - Scenario 1	-58%	-60%	-56%	-61%	-69%	-75%	-77%	-81%	-81%	-80%	-81%	-80%	-79%	-80%	-81%	-81%	-83%
PVRR - Scenario 2	-58%	-60%	-55%	-60%	-68%	-74%	-76%	-81%	-81%	-80%	-82%	-82%	-82%	-82%	-83%	-84%	-84%
PVRR - Scenario 3	-58%	-59%	-55%	-60%	-68%	-74%	-76%	-80%	-81%	-81%	-83%	-82%	-83%	-82%	-84%	-85%	-86%
PVRR - Scenario 4	-58%	-60%	-56%	-61%	-69%	-74%	-76%	-81%	-81%	-80%	-80%	-79%	-79%	-79%	-81%	-81%	-83%

Chart 10A Study Period 2024-2055



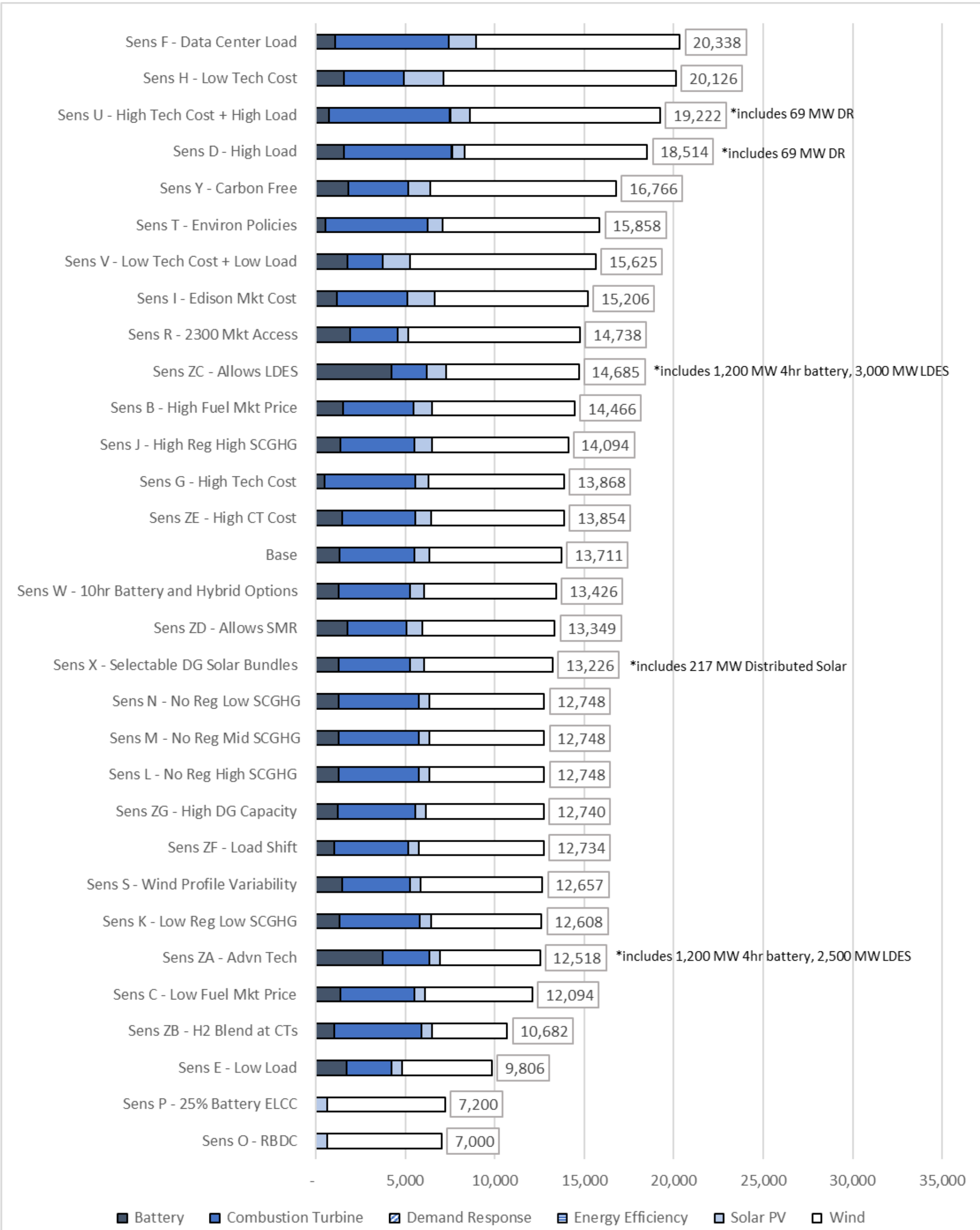
The Department found that emissions reductions appear to peak around the years 2043-2044; after that period, emissions reductions appear to slightly rise again. The Department found that combined cycle (CC) units are all retiring in that time frame, resulting in more combustion turbine (CT) activity to replace the CC activity. Since CTs have a worse heat rate than CCs, higher emissions result. However, the Department notes that since this period extends beyond the planning period considered by the Commission, it is not of immediate concern and it will be addressed in future Xcel IRPs.

v. Expansion Plan Results – Scenario 3

After the Department concluded that Scenario 3 was the least-cost nuclear retirement option, the Department then further examined the sensitivities of Scenario 3.

The following figure plots the expansion plans of all Scenario 3 sensitivities examined.

Chart 11: Department's Capacity Expansion Results (MW) by Sensitivity for Scenario 3



The Department notes the following about the above Chart:

- Sens L, M, and N resulted in the exact same expansion plan. This outcome is correct, as these sensitivities reflect the Commission's No Regulatory Cost futures with varying levels of Environmental Costs. Because the Commission's environmental (or externality) costs do not affect expansion plan decisions, these sensitivities produce the exact same expansion plan.
- The 69 MW Demand-Response resource that was selected in each of Xcel's base scenarios was only selected in two Department sensitivities: Sens D – High Load and Sens U – High Load + High Tech Costs.
- The preference for incurring unserved energy costs over building new capacity is observable in the Sens O and P (which have no Battery or CT additions), particularly when compared with the other sensitivities.
- The highest level of battery capacity additions was observed in Sens ZC – Long Duration Energy Storage, followed by Sens ZA – All Advanced Tech. The Department notes that both of these sensitivity selections include the generic battery resources (included in all sensitivities) as well as Long Duration Energy Storage resources (included in only these two sensitivities).

The Department notes that the above chart only shows optimized additions occurring during the planning period (2024-2040). However, the Department encountered some interesting additions occurring in the post-2040 period. Since this timeframe is so far out the Department does not consider these additions to be as meaningful or pressing, but notes them for complete disclosure of future issues:

- Between 2040 and 2055, the Sens ZC - LDES sensitivity added an additional 19,200 MW of LDES resources.
- Between 2048 and 2055, the Sens ZD – SMR sensitivity includes 5,400 MW of Small Modular Nuclear additions between years 2048 and 2055.

The Department then compared the Scenario 3 base sensitivity expansion plan results for years 2024-2040 to select metrics for all sensitivities. These results are shown in the following table.

Table 20: Scenario 3 Base Expansion Plan Compared to the Mean, Median, and Mode of All Sensitivities
Capacity Added in MW, Units Added by Number, 2024-2040[75]

Addition Type	Metric	Battery	CT	DR	EE	Solar PV	Wind	Total
Capacity Added (MW)	All Sens Mean (Rounded)	1,402	3,799	5	-	886	7,834	13,926
	All Sens Median	1,320	3,966	-	-	800	7,400	13,711
	All Mode	1,260	n/a	-	-	600	7,400	n/a
	Base	1,320	4,191	-	-	800	7,400	13,711
Units Added (Count)	All Sens Mean (Rounded)	22	10	-	-	9	39	81
	All Sens Median	22	11	-	-	8	37	79
	All Sens Mode	21	11	-	-	6	37	71
	Base	22	12	-	-	8	37	79

[75] For this table, the Department considered the Commission's three "No Regulatory Futures" runs to be one result, since each produced the same expansion plan.

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The Department observes from the above table that the Scenario 3 Base expansion plan results are fairly representative of the average results of all Scenario 3 sensitivities over the 2024-2040 period.

The Department then compared its Scenario 3 base expansion plan to Xcel's for the 2024-2030 period (5 Year Action Plan), the 2024-2040 period Planning Period), and the 2024-2055 period (Study Period). The results are shown in the following table[76]:

Table 21: Xcel and Department Scenario 3 Expansion Plan by Technology and Period (MW)

	Xcel 2024-2030 (5 Year Action Plan)	Department 2024-2030 (5 Year Action Plan)	Xcel 2024-2040	Department 2024-2040	Xcel 2024-2055	Department 2024-2055
Battery	600	540	2,100	1,320	4,980	3,840
Combustion Turbine	2,244	1,870	3,592	4,191	12,122	12,645
Demand Response	69	-	69	-	69	-
Energy Efficiency	-	-	-	-	-	-
Solar PV	-	600	1,500	800	1,500	800
Wind	3,200	2,400	8,400	7,400	16,200	14,000
Total	6,513	5,410	15,661	13,711	34,871	31,285

The Department found that its Scenario 3 results consistently add less total capacity across all periods than Xcel's. In the five-year action plan, which is the focus of the proceeding, the Department's results show fewer peaking resources (DR, CT, and Battery), less wind capacity, but more solar capacity than Xcel's results show.

In the Planning Period and Study Period, the Department's results add more CTs than Xcel's results. As described earlier, this result is likely due to the Department's higher LCOE assumptions for wind and solar, which cause the Department's model to prefer CTs to wind and solar. It is unclear to the Department why its model prefers to add CTs instead of batteries; however, as mentioned earlier, the Department considers batteries and CTs to serve a similar function on the grid as a firm dispatchable peaking resources. Therefore, the Department considers these to be interchangeable, with the exact technology used to be determined in a resource acquisition proceeding.

The following tables shows the exact timing of the Department's Scenario 3 resources selected in the 5-Year Action Plan and compare the Department's results to Xcel's 5-year action plan.

[76] For this table, the Department considered the Commission's three "No Regulatory Futures" runs to be one result, since each produced the same expansion plan.

Table 22: Department 5-Year Action Plan by Technology (MW)

	Battery	CT	Solar PV	Wind
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	300	748	-	-
2028	-	748	-	2,000
2029	240	-	100	400
2030	-	374	500	-
Total	540	1,870	600	2,400

Table 23: Comparison of 5-Year Action Plans by Technology (MW)

Resource Type	Xcel's Proposed 5-year Action Plan	Department Modeling Results
Wind	Add 3,200 MWs of wind through 2030: • 2,800 MW is assumed to utilize the Sherco Generation tie line; • 400 MW of generation is generic and non-location specific.	Add 2,400 MWs of wind through 2030 using the Sherco Generation tie line.
Solar	Add 400 MW of solar in 2030 using the King generation tie line.	Add 600 MW of solar in 2030 using the King generation tie line.
Firm Dispatchable	Add 2,244 MW of firm dispatchable by 2030: • 374 MW in 2028 is located on the Sherco generation tie line; and • the rest is non-location specific.	Add 1,870 MW of firm dispatchable by 2030: • 374 MW in 2028 is located on the Sherco generation tie line; and • the rest is non-location specific.
Battery	Add approximately 600 MW by 2030; of this amount, 120 MW is on the Sherco generation tie line in 2029.	Add approximately 540 MW by 2030; of this amount, 240 MW is on the Sherco generation tie line in 2029.
Nuclear	Extend the life of Monticello by 10 years (to 2050). Extend the life of Prairie Island by 20 years (2053 and 2054).	Same.
Refuse Derived Fuel (RDF)	Extend the life of the Red Wing, Mankato, and French Island RDF plants to 2037, 2037, and 2040 respectively.	Not analyzed.
Energy Efficiency	Achieve an average annual level of 780 GWh of energy efficiency as ordered at the conclusion of the 2019 IRP (Docket No. E002/RP-19-368).	Same.

4. Department Modeling Recommendation

The Department recommends that the Commission approve Xcel's proposed Scenario 3 to extend both Prairie Island and Monticello nuclear plants.

The Department recommends that for the five-year action plan the Commission require Xcel to use the following targets for resources acquisition:

- 1,800 MW of peaking resources in 2027 to 2028;
- 600 MW of peaking resources in 2029 to 2030;
- 600 MW of solar in 2029 to 2030; and
- 2,400 MW of wind in 2028 to 2029.

H. ASSESSMENT OF ENERGY EFFICIENCY

In this section the Department reviews how Xcel modeled energy efficiency in EnCompass and Xcel's compliance with speaking with statutory and rule requirements, the new Energy Conservation and Optimization (ECO) Act of 2021 requirements, and past Commission Orders concerning the energy efficiency.

1. Xcel's Filing

Xcel's filing states that its preferred plan will achieve 2.0 to 2.5 percent annual energy savings, corresponding to a total of 780 GWh on an average annual basis.[77] To model these savings, the Company developed three bundles of energy efficiency that were entered into EnCompass:

- Bundle 1 ("Minimum Scenario"): Minimum statutory requirements, reflect energy savings of 1.75% of weather normalized sales;
- Bundle 2 ("Programmatic Scenario"): Estimated savings derived from the 2024-2026 ECO Triennial filing; and
- Bundle 3: ("High Achievement"): Estimated savings under a high-achievement scenario, drawing on the Xcel's 2019 IRP "Optimal Bundle" and reflecting the State's most recent energy efficiency potential analysis.

Of the three energy efficiency bundles, the first two were "locked in" to EnCompass, meaning that they were required resources in the Company's expansion plan. Bundle 3 was an "optimized" resource, or available for EnCompass to select as a resource.

2. Department Review

Broadly speaking, Xcel's IRP must demonstrate compliance with three separate spheres of energy efficiency-related requirements:

- Statutory and rule requirements of utility integrated IRPs as they relate to conservation;
- Statutory requirements of ECO and by extension, Xcel's approved 2024-2026 ECO Triennial filing; and
- Commission Orders concerning the energy efficiency.

The following sections detail Xcel's compliance with each of these spheres within its IRP.

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[77] This corresponds with 582 GWh for each planning year; when combined with energy efficiency "embedded" in the forecast totals 780 GWh on an average annual basis.

ATTACHMENT 4: Forecast Analysis

A. INTRODUCTION

1. Overview

The base of the forecast consists of calculating energy requirement forecast for all jurisdictions and customer classes, these being:

- 5 jurisdictions
  - NSPM: Minnesota, North Dakota, and South Dakota
  - NSPW: Michigan and Wisconsin
- 6 classes of customers:
  - Residential
  - Small Commercial and Industrial
  - Large Commercial and Industrial
  - Public Street and Highway Lighting
  - Public Authority
  - Interdepartmental

Xcel used two approaches to compute the forecast for each jurisdiction and customer class:

- econometric models using weather, demographic, and economic data; and
- a combination of trend analysis and historical averages.

2. Department Analytical Approach

The Department evaluated the models proposed for each jurisdiction and customer class. The Department approach involved three steps:

1. Reverse engineering the input/output spreadsheet provided for each econometric model, to establish a baseline model that mimics the model used by Xcel.
   a. This baseline model was estimated, and the results were compared against Xcel predictions (in-sample[164]) and forecasts (out-of-sample[165]).
2. Using this baseline model, variables were omitted in order to understand the effect of each on the forecast.
3. New models were estimated, without the constraint imposed on parameters on bullet 1. above.
   a. New variables were created. For example:
      i. Using an outlier detection method, new outlier variables were created.
      ii. Weather variables were decomposed into population and weather indexes (heating degree days (HDD) and temperature humidity index (THI)).
   b. Considering an extensive combination of exogenous variables, two classes of models were estimated:
      i. Dynamic Linear Regression.
      ii. SARIMAX $(p,d,q)(P,D,Q)_{12}$.[166]
   c. Criteria were established to obtain the "best" estimated model:
      i. Dynamic Linear Regression models were evaluated considering their adjusted-R^2.
      ii. SARIMAX models were evaluated across two metrics:
         1. The Adjusted Akaike Information Criteria (AICC)

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[164] In-sample prediction refers to using the same data used to estimate the model to obtain forecasts.
[165] Out-of-sample prediction refers to using new data, that is, data not used in the model estimation, to obtain forecasts.
[166] Seasonal Autoregressive Integrated Moving Average with Exogenous Regressors (SARIMAX).

2. The accuracy of in-sample prediction.[167]
3. A SARIMA model was also computed and evaluated under the same metrics.

d. Considering the best performing model – for each metric imposed, results were compared against each other, and the forecast provided by Xcel.

The Department analyzes each of these forecasts individually, with each model producing similar results:

- Regardless of the forecast trend, the year distribution of energy for historical and forecast data has a similar shape. The level of the distribution is dependent on the forecast trend.
- Demographic and economic variables are the main drivers of the forecast's long-run growth.

For all these models, Xcel presented historical data from June 2008 to May 2023. This time frame is used whenever discussing historical data unless otherwise noted. For each of the energy sales forecast cases below, different combinations of demographic, economic, and other variables were used. Forecasts for these exogenous variables[168] were supplied to Xcel by third parties. Below the Department makes explicit comments about relevant variables, omitting those that, in its analysis, have no meaningful impact. Finally, all the models considered here are for energy sales in billing cycles. No losses are considered. The transformation to calendar cycle, including accounting for weather effects, and the determination of energy at the generator level[169] will be done in later steps described below.

As part of the forecast analysis below the Department presents a series of charts that show information for the various jurisdiction-customer class combination. The top chart presents estimated distributions for historical and forecast energy consumption data. In the horizontal axis is the range of monthly energy consumption and in the vertical axis is the "frequency"[170] of this amount across the historical or forecast period. The two bottom graphs are boxplots for monthly energy, aggregated by each month, for historical (left graph) and forecast data (right graph). Below we provide interpretation of these graphs for each jurisdiction and class of customer.

B. MICHIGAN FORECASTS

1. Residential

Historical residential energy usage in Michigan presents a small positive long-term trend, reflected by a year-on-year growth of 0.68 percent from 55.2 GWh in 2009 to 60.2 GWh in 2023. However, this growth was not steady with some years usage dropping from the previous year. Forecasted energy usage captures this long-term trend and grows from 60 GWh in 2024 to 66.8 GWh in 2040, a year-on-year growth of approximately 0.67 percent. As a result, from this growth, the distribution of monthly forecast values is shifted to the right, that is, during the forecast period higher levels of monthly energy usage are more likely.

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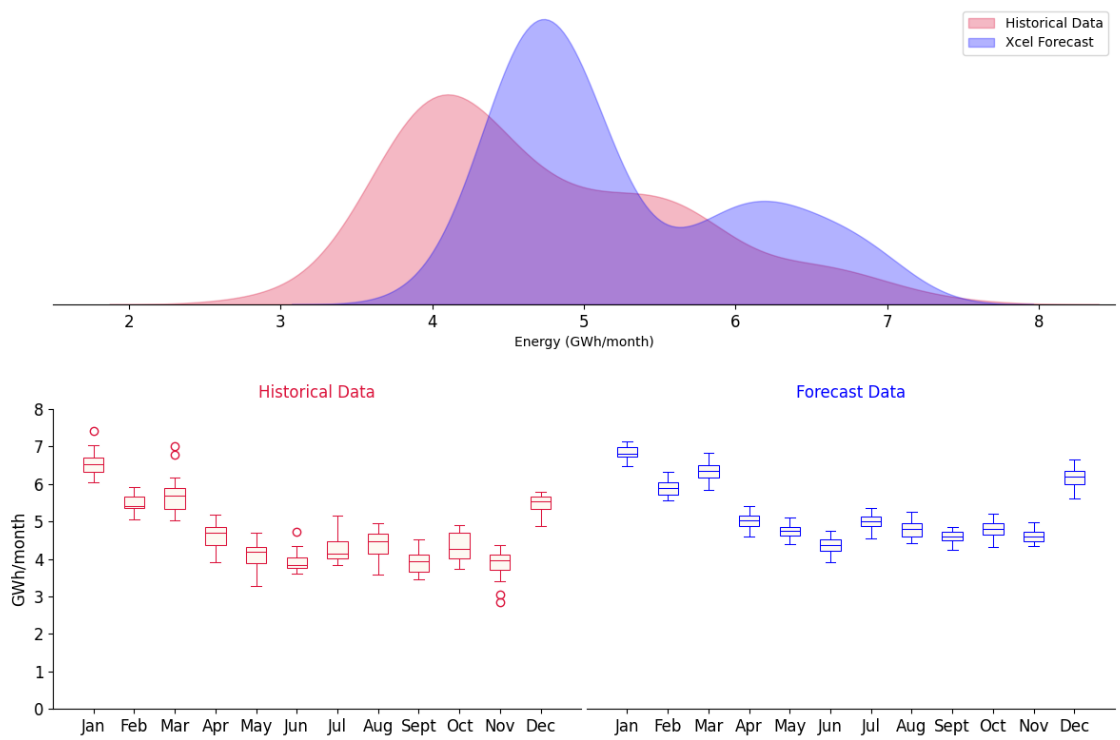
[167] This was measured using the root mean squared error metric.

[168] Exogenous variables are variables external to the model and whose role is explaining other variables in the model or model outcomes. For example, income is an exogenous variable used to explain energy consumption.

[169] Energy at the generator level means adding losses to energy consumption. Hence, energy at the generator level is greater than energy consumption.

[170] These are probability distributions obtained through a kernel density estimation. Hence, in the vertical axis is the probability distribution.

Chart A4-1: Michigan Residential Monthly Energy: Historical and Forecast



The overall distribution across months is similar, as can be observed by considering the positions of the boxplots on the left (historical) and on the right (forecast). More notably, the forecast distribution has smaller variance distribution, observed by boxplots with short whiskers, and its level is not remarkably higher than the level of the historical distribution, that is, conditional on a month, the boxplot on the left (historical) is centered close to the center of the boxplot on the right.

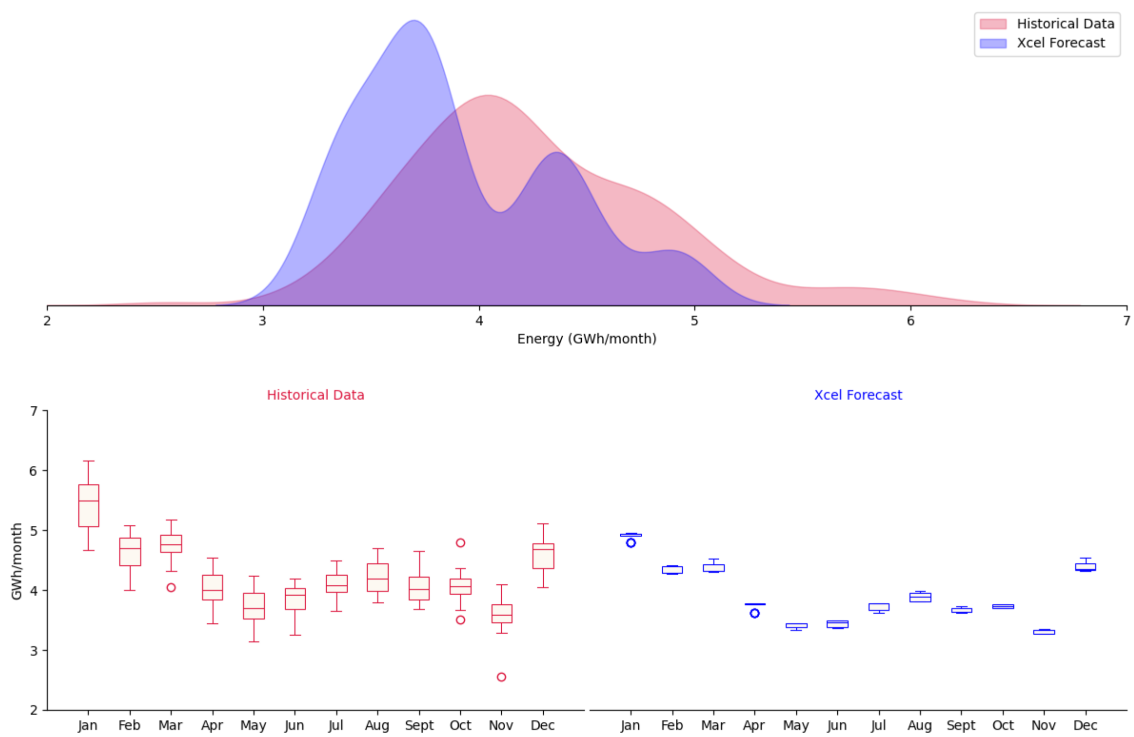
Besides weather indexes and binary variables this model incorporates two exogenous variables: the number of customers and real income. The former decreases over the forecast period, while the latter **[TRADE SECRET DATA HAS BEEN EXCISED]**. By considering different models and combinations of variables, the Department concludes that the most relevant component driving growth is real income, although its impact is attenuated by the decrease in the number of customers.

Attempts to replicate the data provided by Xcel produces similar results, although the long run trend is higher than the one present in Xcel's forecast. However, by 2040 the maximum monthly deviation is less than 2 GWh. Taking into consideration the models estimated with different parametrizations and exogenous variables, the results are not different enough from Xcel's forecast to matter for IRP purposes. Hence, the Department concludes that the forecast for Michigan Residential is reasonable for IRP purposes.

2. *Small Commercial and Industrial*

For the period between June 2008 to early 2018, historical energy usage for small commercial and industrial (C&I) is fairly constant, with an average around 52 GWh per year. However, from late 2018 to mid-2020 energy usage gradually declines, and from that point until May 2023 the behavior again revolves around a level, although at a lower level, with a year average of around 47 GWh. In 2009, the energy usage was around 52.7 GWh, dropping to a forecast usage of 46.9 GWh in 2024. By 2040, the forecasted usage is 47 GWh, an implied year-on-year growth rate of 0.01 percent. In other words, the forecast presents intra-year variability, with peaks during the winter, but there is almost no inter-year variability.

Chart A4-2: Michigan Small C&I Monthly Energy: Historical and Forecast



From the distributions above, it is possible to observe that the historical data distribution is shifted to the right compared to the forecast distribution, confirming that the forecast maintains a lower level compared to the historical data. Moreover, considering the boxplots for the forecast data, one can observe they are compressed indicating that there is a low variability of energy consumption values for every month.

The only exogenous variable included in Xcel's model that grows over the forecast period is the number of customers. The series presents a significant reduction in the number of customers around 2019, which correlates with the drop in energy usage.[171] Although the number of customers grows over the forecast period, it has very small impact over the forecast of energy usage. The small impact of consumer growth on energy consumption can also be understood through the historical period and the relation between energy usage and number of customers. From 2008 until early 2020, the number of customers grew, but energy usage presented no long-term trend.

The model used to replicate Xcel's data is able to match in-sample predictions and forecast (out-of-sample predictions). Moreover, removing number of customers from the model has no impact on long-term trends. That is, the forecast level is close to Xcel's forecast level, and energy usage fluctuates around it. Further exploring models with different parametrizations and exogenous variables produce similar results. The only exception is one of the parametrizations that captures the drop in energy usage in the last years leading to 2023 and incorporates this into a negative trend. However, this model has an in-sample prediction accuracy much smaller than models with exogenous variables. Hence, the Department concludes that the forecast for Michigan Small Commercial and Industrial is reasonable for IRP purposes.

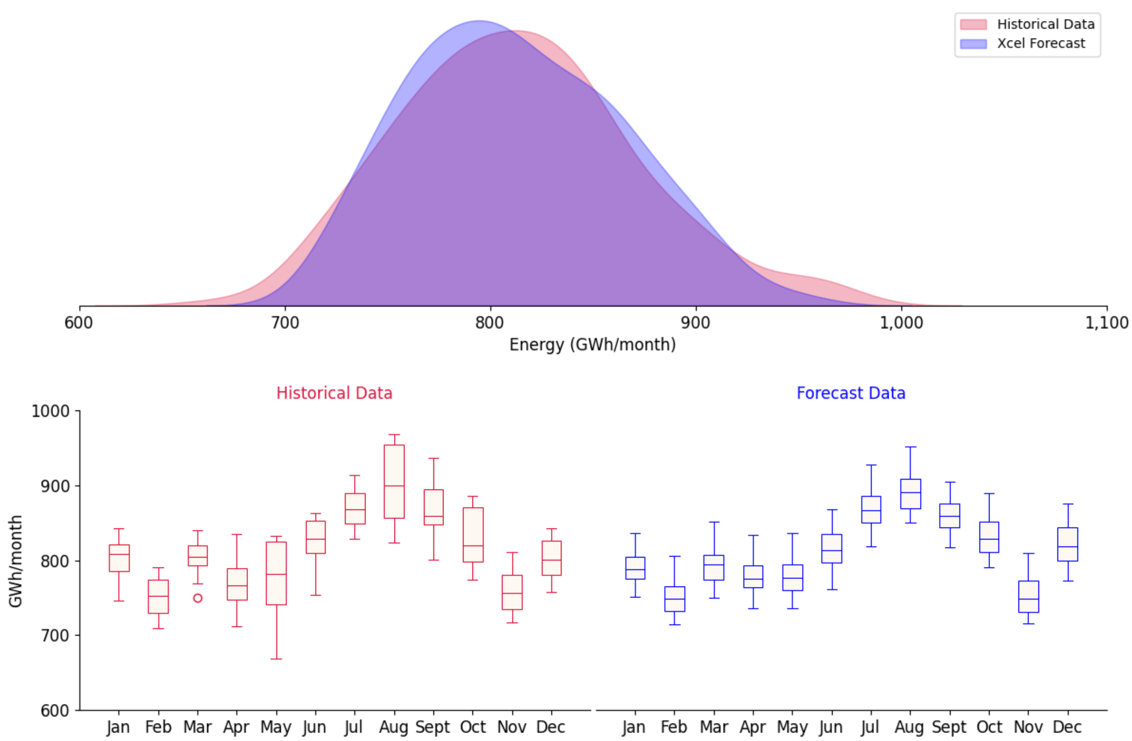
[171] The Department is not implying any causation here.

C. MINNESOTA FORECASTS

1. Large C&I

For the period between 2009 until 2019, average yearly energy usage was close to 9,870 GWh. In 2020 it drops to just over 9,175 GWh, and slowly grows to 9,425 GWh in 2022. This growth continues over the forecast period, with energy usage growing from 9,341 GWh in 2024 to 10,319 GWh in 2040, a 0.62 percent year-on-year growth rate.

Chart A4-3: Minnesota Large C&I Monthly Energy: Historical and Forecast



The first observation from above graph is the overlap between the historical and forecast distributions. Notably, once energy usage drops around 2020, this overlap indicates that the forecast grows to the high levels in the historical data. Moreover, the month-on-month pattern is fairly similar, although the forecast data presents smaller variance (more compressed boxplots).

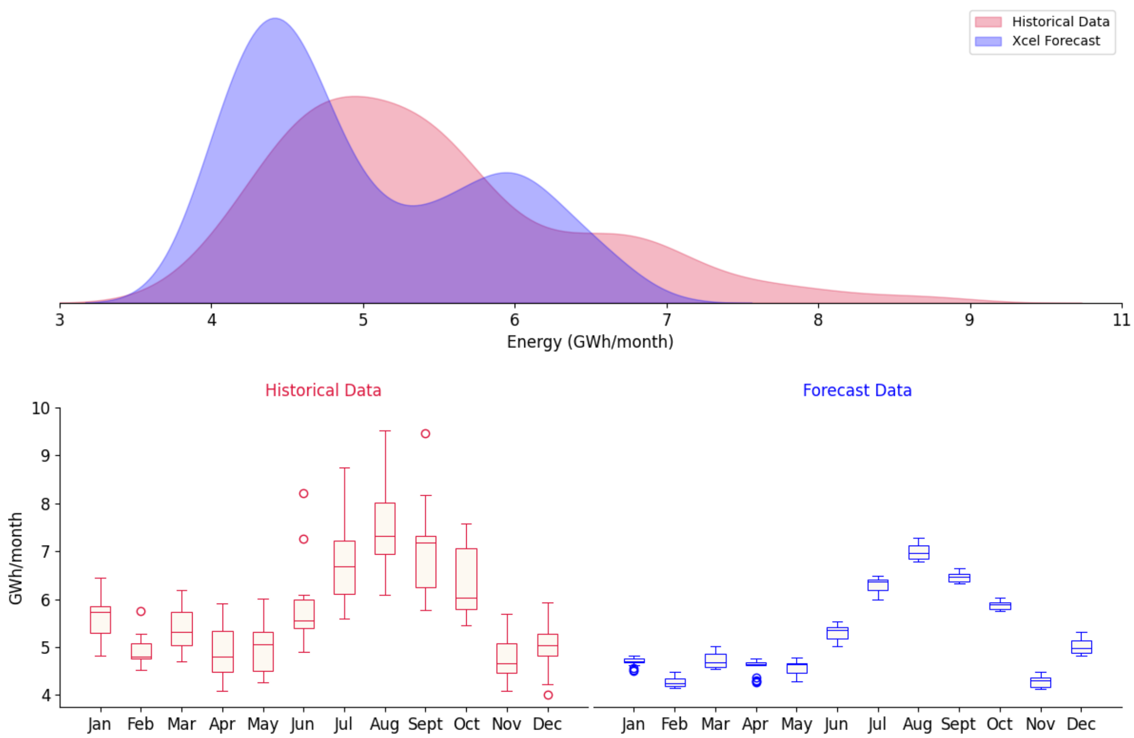
Xcel's model incorporates the number of customers and an industrial production index. Although the number of customers varies over the historical period, it is constant over the forecast period, hence having minimal effect on energy usage forecast. On the other hand, the industrial production index and energy usage in the historical period **[TRADE SECRET DATA HAS BEEN EXCISED].** For the forecast period, the index's forecast **[TRADE SECRET DATA HAS BEEN EXCISED]**, and this effect may be captured by the model and thus generates the growth in energy usage.

The model estimated to replicate Xcel's data produces in-sample predictions and out-of-sample forecasts close to Xcel's data. Moreover, models that excluded industrial production index are not able to replicate the positive trend in Xcel's forecast. While models with alternative parametrization and different set of exogenous variables are able to improve in-sample prediction, the overall positive trend forecasted values generated are in line with Xcel's forecast. Hence, the Department concludes that the forecast for Minnesota Large Commercial and Industrial is reasonable for IRP purposes.

2. Public Authorities

Sales to Minnesota Public Authorities were just over 80 GWh in 2009 but decline persistently to a low of 61.7 GWh in 2015. In the following years, although increasing from the 2015 low, sales do not reach the prior peak. The yearly average was 72.7 GWh during 2009-2014, dropping to 65.9 GWh during 2015-2022. Xcel's forecast follows the declining trend starting in 2018, from a level of 64.2 GWh in 2024 to 62.6 GWh in 2040, an annual decline of around 0.16 percent.

Chart A4-4: Minnesota Public Authorities Monthly Energy: Historical and Forecast



In the graph above, one can observe that the monthly profile is similar between the historical and forecast periods, although the forecast variance is much smaller than the historical period variance. Moreover, observing the distributions, the forecast distribution's range of values is smaller than the historical distribution's (values in the horizontal axis), and it has two peaks. Finally, the forecast distribution has higher frequency of smaller values when compared to the historical distribution, indicating the prevalence of smaller GWh/month as observed above.

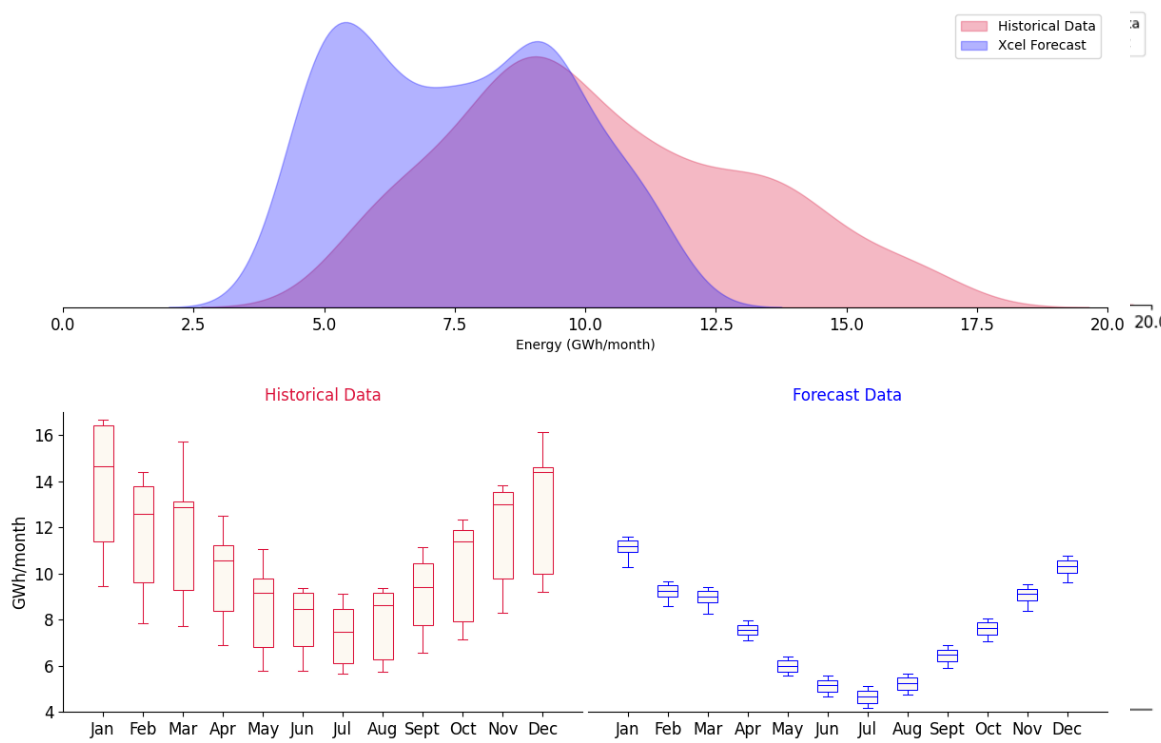
Xcel's model uses real gross metropolitan product (GMP) as one of the exogenous variables in its model. However, upon further analysis of GMP time series, the Department concludes this variable has a small linear relation with Minnesota Public Authority energy consumption. Moreover, during the period from 2009 to 2040, **[TRADE SECRET DATA HAS BEEN EXCISED]**. The only exception is a drop early in 2020. Nonetheless, the series quickly returns to its previous level and its forecast grows steadily. The Department considered model estimations without the inclusion of GMP, and these models produced results with similar features to Xcel's forecast, although they forecasted lower energy sales levels.

The model used to replicate the Company's forecast produces results that are almost identical to the Company's in-sample prediction and forecasts. Moreover, other models estimated produce more accurate in-sample predictions, but when used to produce forecasts, the data obtained presents the same long-run downward trend and replicates a considerable portion of the historical data variability. Hence, the Department concludes that the forecast for Minnesota Public Authorities is reasonable for IRP purposes.

3. Public Street and Highway Lighting

From 2009 to early 2013 Minnesota Public Street and Highway Lighting annual energy sales grew by 1.4 percent year on year. However, from 2014 until early 2023 energy sales fell consistently and the range between the maximum and minimum sales in a given year reduced considerably compared to the early years. During the whole 2009-2022 period, energy sales fell by 3.2 percent year on year, falling from 137.7 GWh in 2009 to 90.1 GWh in 2022. During the forecast period, energy sales grow consistently at a 0.78 percent yearly rate, from 85.3 GWh in 2024 to 96.6 GWh in 2040.

Chart A4-5: Minnesota Public Street and Highway Lighting Monthly Energy: Historical and Forecast



The Company's forecast captures the overall yearly pattern of the historical data, as one can observe the V-shaped boxplot patterns (across the months from January to December) in both the historical and forecast data. Moreover, the forecast distribution is more concentrated around the mean than the historical distribution, which is also shown by the length of the forecast data boxplots.

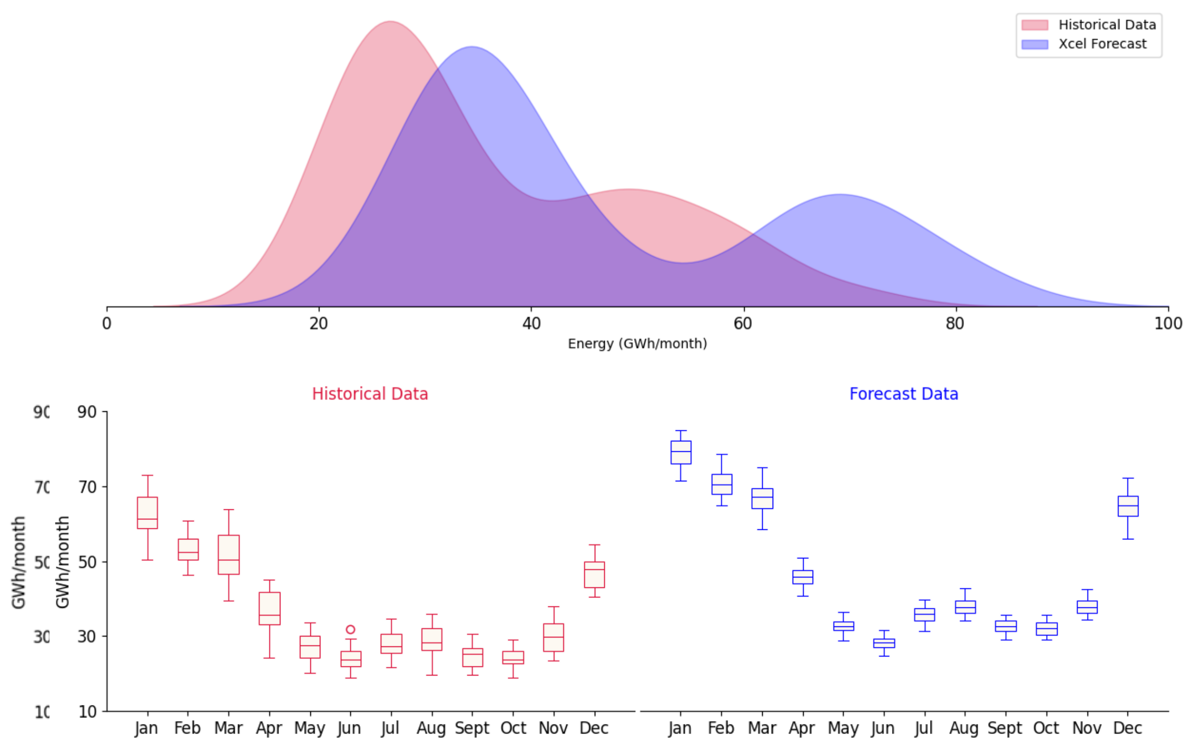
The Company's model includes exogenous variables that are not constant over the whole 2008-2040 period considered: light emitting diode (LED) sales and total population. While total population **[TRADE SECRET DATA HAS BEEN EXCISED]**, LED sales are constant over the whole forecast period. Estimating a model that does not account for total population produces similar in-sample predictions, but forecasts are flat, while the variability of the data remains similar to the Company's forecast. Estimating a model that does not include LED sales produces less accurate in-sample predications than the Company's and other forecasts that incorporate the decrease in energy sales observed in the last years of the historical period.

The model estimated to replicate the Company's data produces more accurate in-sample predictions. However, the forecast for energy sales is stagnant over the forecast period contrary to the Company's forecast. On the other hand, when considering other model parametrizations estimated by the Department, most models produce in-sample predictions as accurate or more accurate than the Company's and produce forecasts that followed the same patterns observed in the Company's forecast. For some of these models the deviation to the Company's forecast was smaller than 2 percent by 2040. Hence, the Department concludes that the forecast for Minnesota Public Stret and Highway Lighting is reasonable for IRP purposes.

4. Residential with Space Heating

From late 2008 to early 2023, historical energy usage grows. Considering only full years, it grows at a compound annual growth rate of around 2.2 percent from 387 GWh in 2009 to 513 GWh in 2022. Comparing individual months, the minimum growth rate was July, growing at 0.7 percent year-on-year from 2008 to 2022, and the maximum growth rate was March, growing 3.6 percent year-on-year from 2009 to 2023. The forecast provided by Xcel grows at a year-on-year growth rate around 1 percent, from 522 GWh in 2024 to 613 GWh in 2040.

Chart A4-6: Minnesota Residential with Space Heating Monthly Energy: Historical and Forecast5



From the top graph in the figure above, the forecast distribution is very similar to the historical distribution although it is shifted to the right. Moreover, while the relative position of the boxplots within the historical or the forecast datasets is similar, the forecast boxplots are shifted vertically, accounting for the growth in the forecast.

Two of the exogenous variables incorporated into the model are 1) number of customers and 2) real per-capita personal income.[172] In the modelling, a 24-month window simple moving average is used for real income, to smooth the series variability. **[TRADE SECRET DATA HAS BEEN EXCISED].** The Department evaluated the

[172] Minneapolis-St. Paul-Bloomington area.

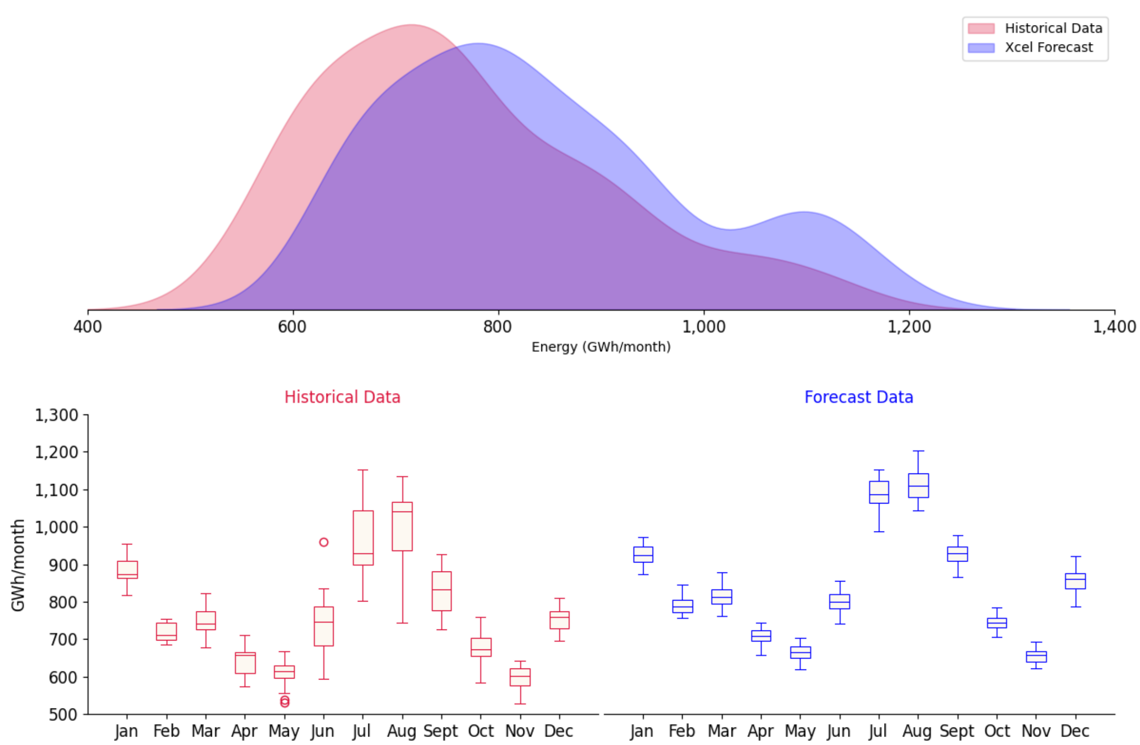
contribution of each variable in the forecast. While both contribute to the growth observed in the forecast, real income is more relevant to the growth rate, while number of customers contribute to the variability of the series. While number of customers grows at a year-on-year rate smaller than energy sales forecast, at 0.8 percent, real income **[TRADE SECRET DATA HAS BEEN EXCISED].**

The model estimated to replicate Xcel's forecast also presents a long-run positive trend. However, while the model outputs result in a higher growth rate, they do not produce an increase in variability as big as Xcel's data. As a result, the difference between the forecast produced and Xcel's forecast increase over time, although this difference is never significant. Finally, models estimated with different parameters achieved better in-sample predictions but did not differ significatively from Xcel's forecast data. Hence, the Department concludes that the forecast for Minnesota Residential With Space Heating is reasonable for IRP purposes.

5. *Residential without Space Heating*

Sales to Minnesota Residential without Space heating grew at 1.1 percent year-on-year from 2009 to 2022. Averaging at 9,193 GWh per year, from 8,313 GWh in 2008 to 9,642 GWh in 2024. Similarly, to the forecast for Minnesota Residential with Space Heating, sales to Residential without Space Heating grows over the forecast period, at a year-on-year rate of 0.47 percent, from 9,750 GWh in 2024 to 10,515 GWh in 2040, resulting in an average for the period of 10,101 GWh.

Chart A4-7: Minnesota Residential without Space Heating Monthly Energy: Historical and Forecast



One can observe that the distribution for historical and forecast data have a similar distribution. More important, the distribution of boxplots across the months for both historical and forecast periods is fairly similar, which indicates that the forecast is capturing the sales pattern.

The model proposed by Xcel includes two demographic/economic variables, the Minnesota real per capita personal income and number of customers. **[TRADE SECRET DATA HAS BEEN EXCISED]**. Unlike Residential with

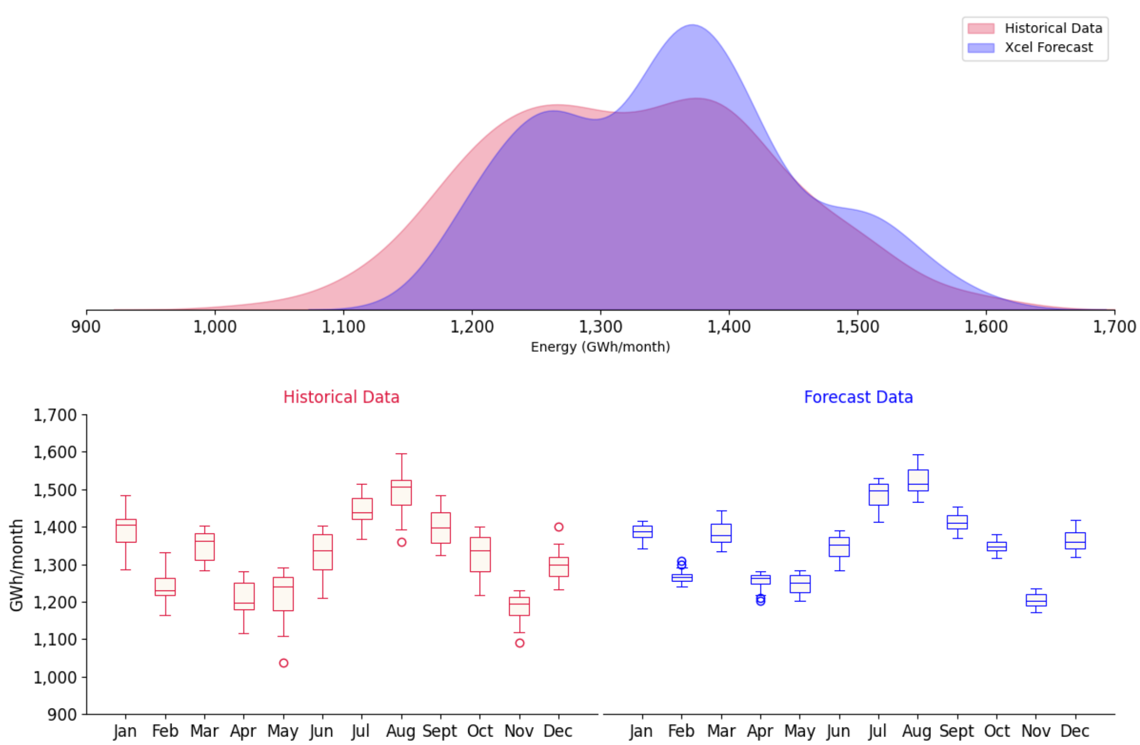
Space Heating, forecast sales to Minnesota Residential without Space Heating **[TRADE SECRET DATA HAS BEEN EXCISED]**. This discrepancy is expected given the different profile of customers.

When estimating a model to replicate Xcel's forecast, the Department obtains a similar result for in-sample prediction, and the forecast is in line with the Company's, with a deviation of less than 4 percent in 2040. The Department estimated models without either real per capita income or number of customers, and obtained a sales forecast that is stagnant over time, which suggests that these two variables are responsible for most of the growth observed in the forecast. Moreover, considering models with different parametrizations estimated by the Department, energy sales profile over the forecast period is very similar to Xcel's forecast, and energy sales in 2040, the highest deviation, are always smaller than 4 percent (the same magnitude as the model with the same parametrization as Xcel's model). Hence, the Department concludes that the forecast for Minnesota Residential without Space Heating is reasonable for IRP purposes.

6. Small C&I

Minnesota Small Commercial and Industrial sales is almost flat over the forecast period with a year-on-year growth rate of 0.23 percent, growing from 15,335 GWh in 2008 to 15,801 GWh in 2022. The forecast growth less than 0.2 percent year on year, from 15,971 GWh in 2024 to 16,469.6 GWh in 2040.

Chart A4-8: Minnesota Small C&I Monthly Energy: Historical and Forecast



The two monthly energy distributions almost overlap. Moreover, comparing the boxplots for historical and forecast data, one can observe the forecast reproduces the overall month pattern of energy sales.

Among the exogenous variables included in the model, **[TRADE SECRET DATA HAS BEEN EXCISED].**: number of customers and total nonfarm employment.[173] Both variables **[TRADE SECRET DATA HAS BEEN EXCISED]**. The

[173] Nonfarm employment for Minneapolis-St. Paul-Bloomington area is included in the Company's model as a 3-month window moving average.

Department estimated models excluding one or both of these variables at a time, and the results obtained point to both contributing to the growth observed in the Company's forecast.

The model used to replicate the Company's data produces in-sample predictions very close to the Company's data. However, the Company's forecast is higher than the model's forecast. Yet, by 2040 the year difference is smaller than 1 percent. Moreover, considering other parametrizations used by the Department, no model outputs forecast data that displays characteristics different than the Company's forecast. Hence, the Department concludes that the forecast for Minnesota Small Commercial and Industrial is reasonable for IRP purposes.

D. NORTH DAKOTA FORECASTS

1. Large C&I

From 2010 to 2022 North Dakota Large Commercial and Industrial sales were flat, growing by less than 0.1 percent year-on-year from 350.6 GWh in 2010 to 353 GWh in 2022.[174] The Company's forecast data also grows at a year-on-year rate of less than 0.1 percent year-on-year, growing from 353.6 GWh in 2024 to 358.3 GWh in 2040.

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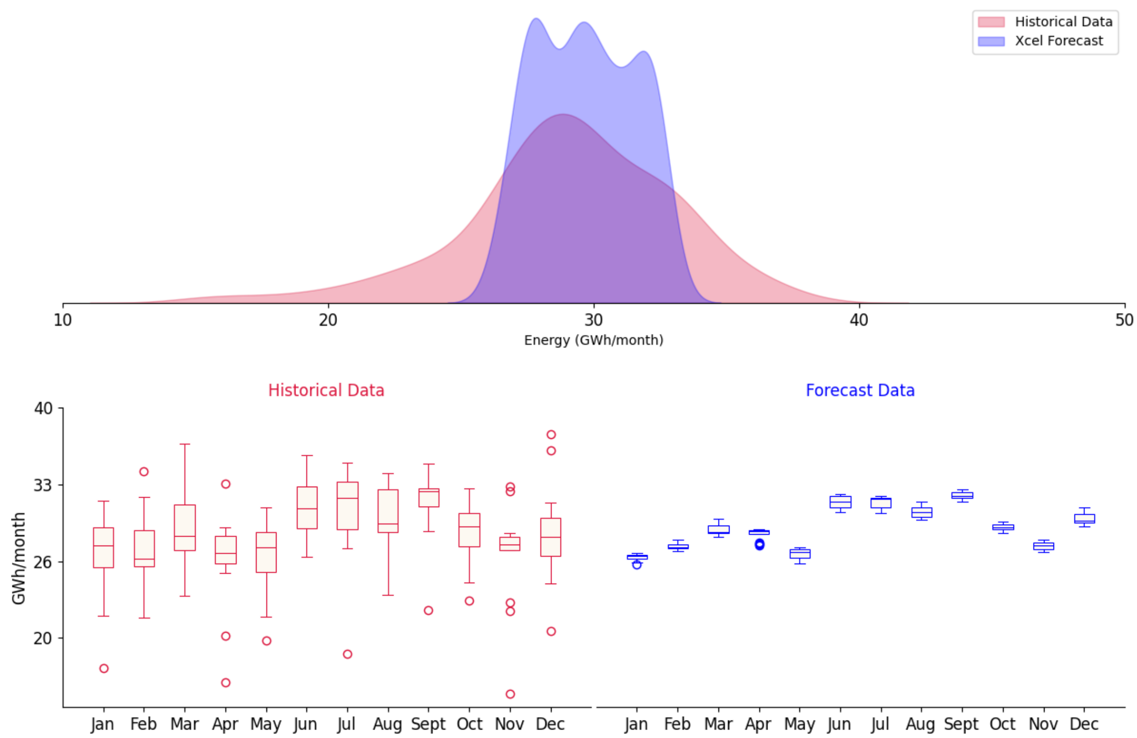
[174] The Department did not consider the year of 2009, since the data provided by the Company of 305.7 GWh is almost 10 percent smaller than the minimum yearly sale during 2010 to 2020, and almost 16 percent less than the average for the same period.

Chart A4-9: North Dakota Large C&I Monthly Energy: Historical and Forecast



Both historical and forecast distributions are centered around the same point. However, as can be observed from the small (comparatively to the historical data boxplots) boxplots centered close to the same level for the forecast data, the variability of monthly energy consumption in the forecast period is less dispersed than the historical data. As a result, although the forecast is able to capture the overall sales pattern across the year, the forecast does not capture most of the variability of the historical data. However, most of this variability is concentrated around the first years 2008 until mid-2010 and then after 2019.

The first period coincides with the 2007-2009 financial crises, and the second period with the Covid pandemic. The Department tested models that would account for these two events, however, the models' results improved marginally compared to the Department's model replicating the Company's forecast as well as other model parametrizations tested, suggesting that these two events had only temporary effects on energy sales.

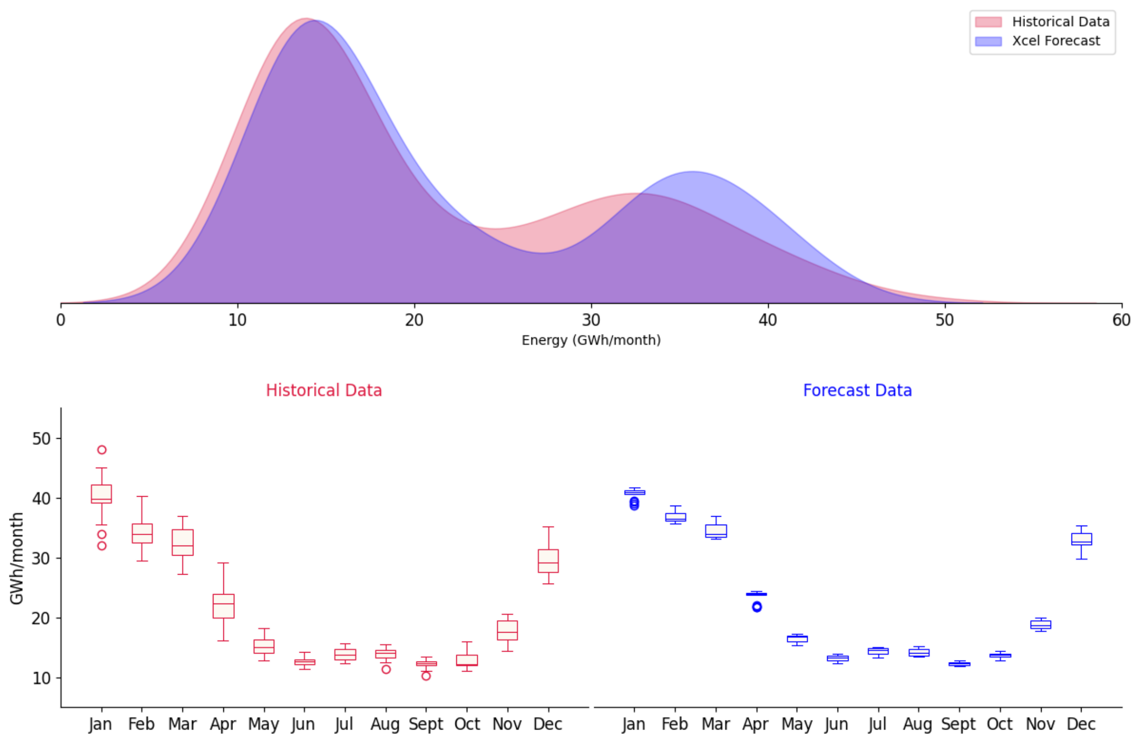
The only exogenous variable considered that **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period is total nonfarm employment. However, during the historical period employment **[TRADE SECRET DATA HAS BEEN EXCISED]** than energy sales. As a result, its impact in the forecast is very small once the relation is not accurately captured by the models. When the Department excluded employment as an explanatory variable, in-sample forecasts were similar to other models tested by the Department as well as the Company's in-sample prediction, and the forecast was almost flat, diverging from the Company's forecast by less than 1 percent.

In conclusion, the model estimated by the Department produces results very similar to the Company's in-sample and out-of-sample predictions. Moreover, other parametrizations estimated produced similar results. Hence, the Department concludes that the forecast for North Dakota Large Commercial and Industrial is reasonable for IRP purposes.

2. Residential with Space Heating

From 2009 to 2022 North Dakota Residential with Space Heating sales were almost flat, growing by 0.31 percent per year from 258.6 GWh in 2009 to 269 GWh in 2022. The average yearly energy sales for the period was 256.7 GWh. The Company's forecast grows at 0.2 percent from 268 GWh in 2024 to 277.1 GWh in 2040.

Chart A4-10: North Dakota Residential with Space Heating Monthly Energy: Historical and Forecast



From above chart, it is observable that the Company's forecast is able to capture the monthly sales pattern, note how the historical boxplots pattern across the months is mirrored by the forecast boxplots. Moreover, the forecast distribution is almost on top of the historical distribution, the major exception being the peak on the right tail as a result of the increase of sales over time.

The two exogenous variables considered that grow over the forecast period are number of customers[175] and the price of oil **[TRADE SECRET DATA HAS BEEN EXCISED]**.[176] The number of customers is almost flat over the forecast period, growing 0.13 percent per year, while price of oil **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Department estimated models without both variables and obtained forecasts with a smaller growth rate than the Company's, indicating that both variables contribute to the Company's forecast growth.

The Department estimated a model to reproduce the Company's forecast and it produces very close in-sample predictions, and a forecast marginally higher than the Company's forecast. Considering other models estimated by the Department, the results obtained were not very different from the Company's forecast, although when aggregating by year the Company's forecast was almost always higher than the Department's forecast. In any case, given how small this component is compared to the whole system's energy, the Department is not

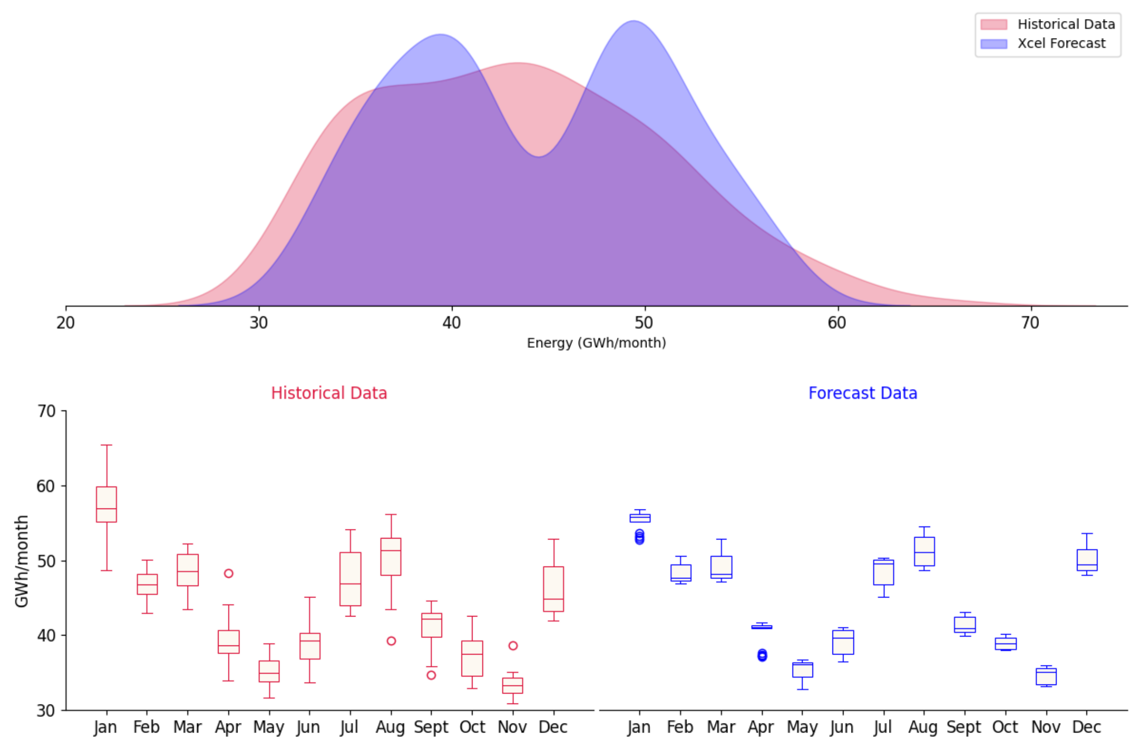
[175] Embedded on the weather variables, which are a product of a weather index, THI or HDD, and the number of customers.
[176] Average price of West Texas Intermediate Crude Oil.

concerned with this deviation. The Department concludes that the forecast for North Dakota Residential with Space Heating is reasonable for IRP purposes.

3. Residential without Space Heating

From 2009 to 2022 North Dakota Residential without Space Heating sales were almost flat, growing by 0.15 percent year-on-year, from 513.3 GWh in 2009 to 523.2 GWh in 2022. The average energy sales for the period was 521.8 GWh. The Company's forecast grows at 0.12 percent per year, from 529.1 GWh in 2024 to 539.3 GWh in 2040. The average sales in the forecast period are 532.8 GWh.

Chart A4-11: North Dakota Residential without Space Heating Monthly Energy: Historical and Forecast



From the chart above, one can observe that the forecast is able to reproduce the overall monthly pattern, though it produces a less-dispersed distribution. In particular, one can observe that the historical distribution is hump-shaped, while the forecast distribution has two humps. This reflects the forecast structure, with high levels of consumption for January and December and again in July and August, and lower levels for April through June and September through November, in addition to small boxplots.

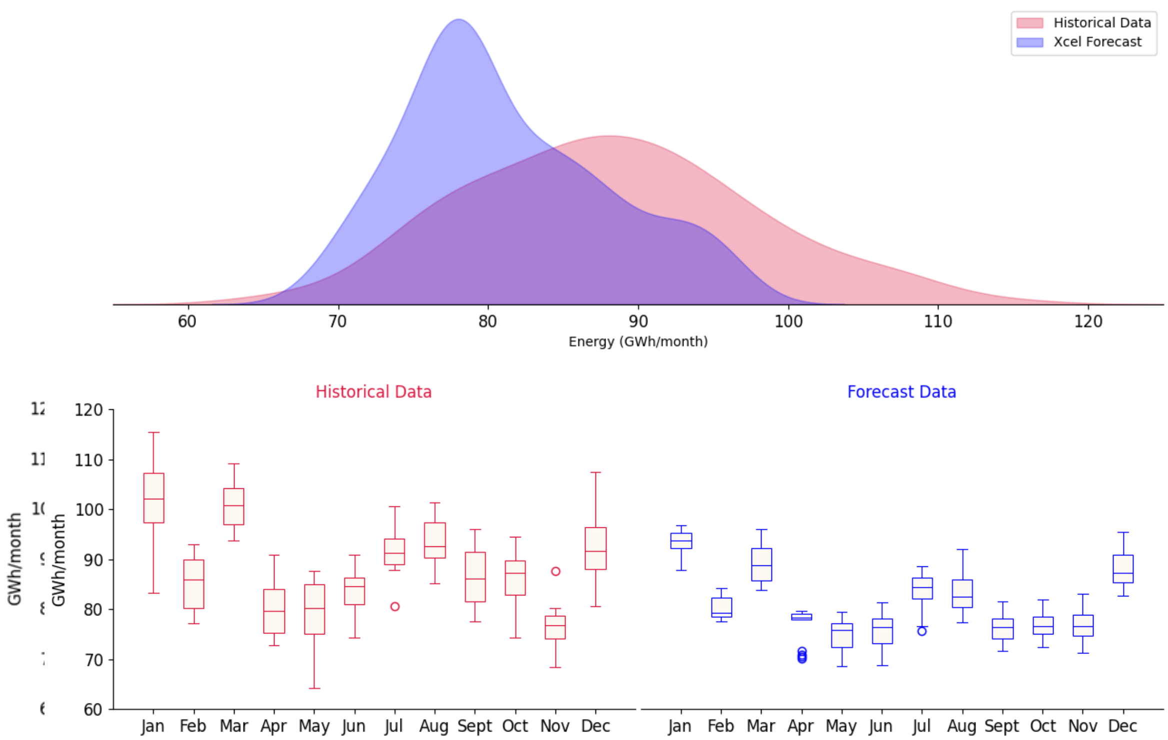
Similar to North Dakota Residential with Space Heating, two of the exogenous variables considered **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast periods: the price of oil, and the number of customers. Both **[TRADE SECRET DATA HAS BEEN EXCISED]** than the forecast, number of customers at 0.24 percent and price of oil at**[TRADE SECRET DATA HAS BEEN EXCISED]**. By considering models without one or both of these variables, the Department observes that the forecast produced is flatter than the Company's forecast, although by 2040 the biggest deviation is around 3.5 percent.

The Department estimated a model to replicate the Company's forecast and it produces similar results in in-sample predictions, and the forecast differences are smaller than 1 percent. Moreover, other model parametrizations estimated by the Department produce similar results. Particularly, forecasts are almost stagnant and the maximum deviation with respect to the Company's forecast is always less than 1 percent. Hence, the Department concludes that the forecast for North Dakota Residential without Space Heating is reasonable for IRP purposes.

4. Small C&I

North Dakota Small Commercial and Industrial energy sales decrease over both the historical and the forecast periods. From 2009 to 2022, energy sales drop from 1,077.7 GWh to 1,004.3 GWh, a year-on-year decrease rate of 0.54 percent. From 2024 to 2040, energy sales drop form 1,004.2 GWh to 954.3 GWh, a year-on-year decrease rate of 0.32 percent.

Chart A4-12: North Dakota Small C&I Monthly Energy: Historical and Forecast



Both historical and forecast distributions are hump-shaped, which can be observed by boxplots' means being close to each other; in order words, there is not much variation in energy sales across the year. Moreover, the peak in the forecast distribution is to the left of the historical distribution's peak and is higher, two features which are explained by the decreasing yearly rate and the fact that the forecast does not account for all the variability in the historical data.

The two exogenous variables considered that **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period are number of customers and total nonfarm employment; their yearly growth rates are 0.14 percent and **[TRADE SECRET DATA HAS BEEN EXCISED],** respectively. Over the historical period, number of customers and energy sales have a negative correlation, while total nonfarm employment has a **[TRADE SECRET DATA HAS BEEN EXCISED]** correlation, although **[TRADE SECRET DATA HAS BEEN EXCISED]**.[177] As a result, models

[177] A Pearson correlation of **[TRADE SECRET DATA HAS BEEN EXCISED]**.

estimated without one of these variables, or both, present a smaller (in absolute value) yearly decrease rate or a very small yet positive growth rate. However, in all the cases where at least one of these variables is omitted, the in-sample accuracy decreases considerably compared to models that include both.

The Department estimated a model to replicate the Company's forecast and it produces in-sample predictions that perform worse than the predictions presented by the Company, and produces a forecast with greater variability, resulting in an increase in the difference between the estimated model's forecast and the Company's reported forecast over the forecast period. However, when considering different parametrizations, including adding variables other than the ones proposed by the Company[178], they present a considerably higher in-sample prediction accuracy, some of the models exceed the Company's accuracy, and the forecasts produced show a similar stagnant pattern with a small decrease yearly rate. Hence, the Department concludes that the forecast for North Dakota Small Commercial and Industrial is reasonable for IRP purposes.

E. SOUTH DAKOTA FORECASTS

1. Large C&I

From 2009 to 2022, South Dakota Large Commercial and Industrial energy sales grow at 1.3 percent yearly rate, from 335.4 GWh in 2009 to 396.1 GWh in 2022. Over the forecast period, energy sales are expected to grow at 0.58 percent, from 418.2 GWh in 2024 to 458.6 GWh in 2040. Average yearly sales grow from 366.6 GWh in the historical period to 437.7 GWh in the forecast period.

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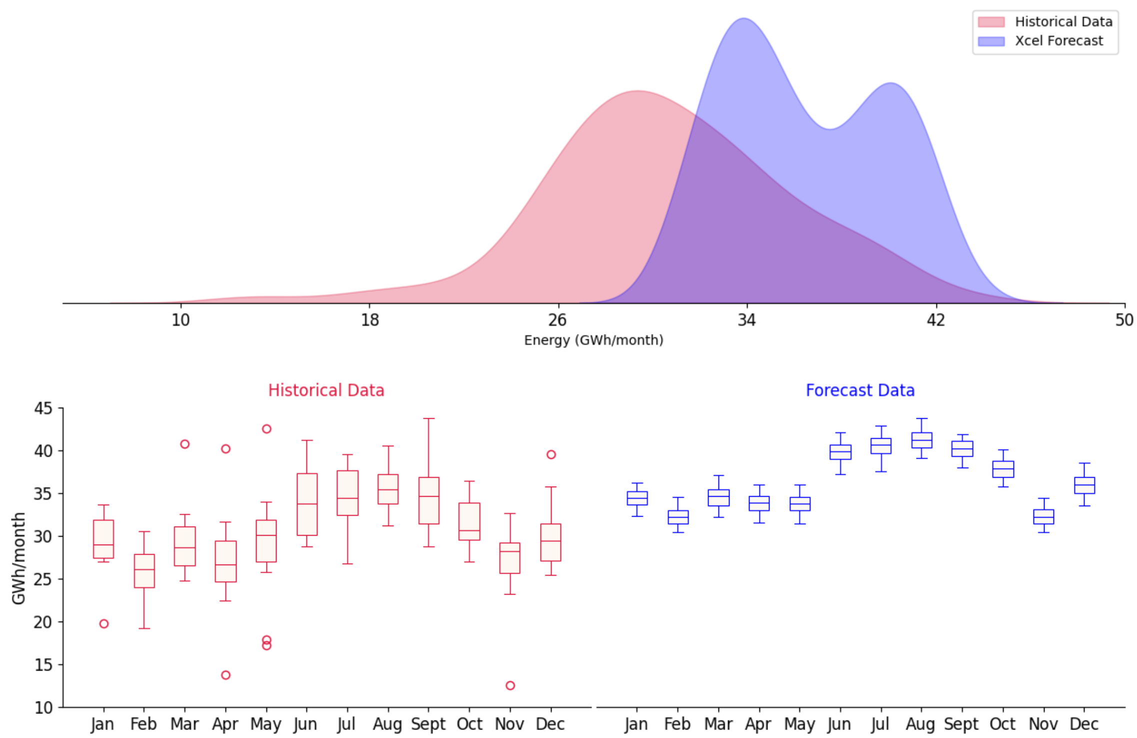
[178] New variables include outlier binary variables and different transformations for the weather indexes and population variables.

Chart A4-13: South Dakota Large C&I Monthly Energy: Historical and Forecast



In the above chart one can observe that the forecast is able to capture the monthly pattern of the historical data, although the level of the boxplots for forecast data is higher comparative to the historical data, reflecting the yearly growth in the forecast. Moreover, the forecast presents two peaks, reflecting the higher usage around summer months and lower usage around winter months.[179] This is not present in the historical data partially as a result of the greater variability.

Total nonfarm employment is the only exogenous variable included in the Company's model, **[TRADE SECRET DATA HAS BEEN EXCISED].** Whenever this variable is excluded, the estimated models produce flat forecasts, indicating this variable plays a role in the forecast growth rate. Moreover, these estimated models have worse in-sample accuracy than the Company's model and other models estimated by the Department.

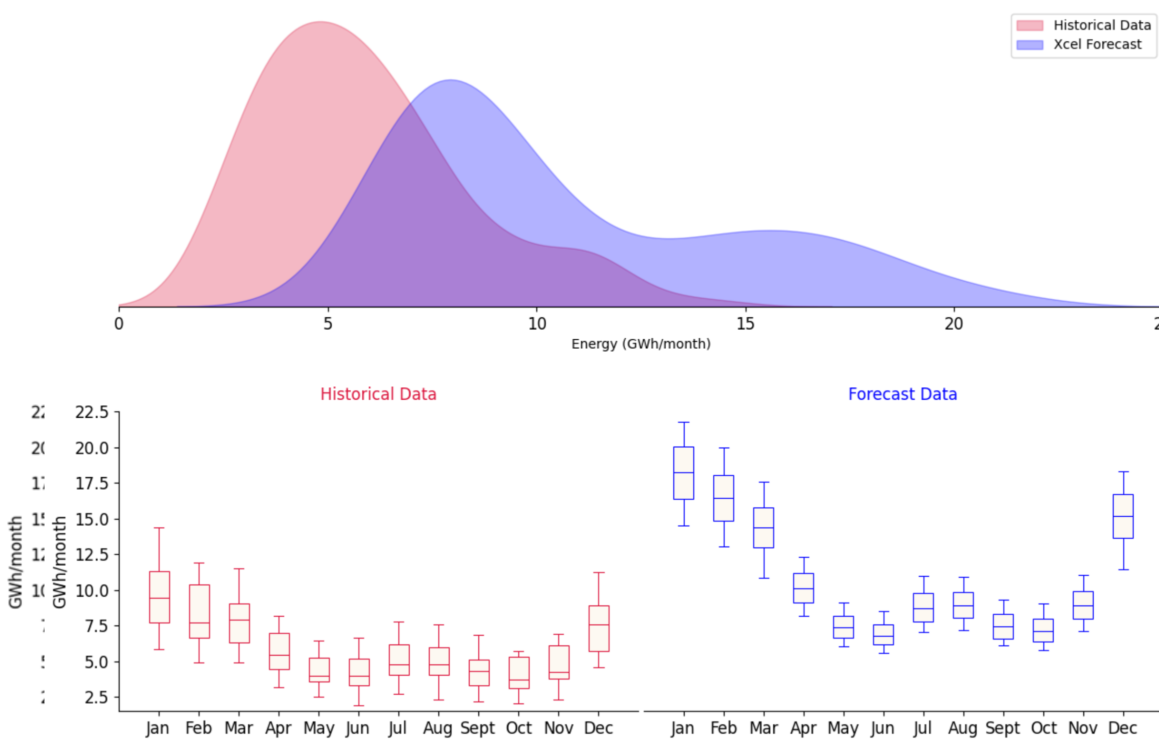
The model estimated to replicate the Company's forecast produces identical in-sample predictions and forecasts. Moreover, other estimated models, that have different parametrizations, produce forecasts that present a positive growth rate, and values similar to the Company's forecast. As observed above, the forecast is not able to replicate the historical data variability. Attempting to bridge that gap, the Department estimated models that included binary variables for outliers in the data. While these models produce more accurate in-sample predictions, they produce forecast similar to the Company's forecast, indicating the variability in the historical period was temporary. Hence, the Department concludes that the forecast for South Dakota Large Commercial and Industrial is reasonable for IRP purposes.

[179] Recall, peaks represent a higher frequency of monthly energy consumption values, while the horizontal axis represent the value of energy consumption. For example, in the chart above, the winter peak is centered around 34 GWh/month while the summer peak is centered around 40 GWh/month. That is, over the summer monthly consumption values around 40 GWh are more frequent, while over the winter monthly consumption values around 34 GWh are more frequent.

2. Residential with Space Heating

From 2009 to 2022, South Dakota Residential with Space Heating energy sales grew by a 6.8 percent yearly rate, from 43.2 GWh to 102 GWh. The Company's forecast grows at 2.6 percent yearly growth rate, from 104.1 GWh in 2024 to 157.5 GWh in 2040. Average yearly sales grow from 70.9 GWh in the historical period to 129.8 GWh in the forecast period.

Chart A4-14: South Dakota Residential with Space Heating Monthly Energy: Historical and Forecast



The above chart shows that, while the forecast data apparently captures the yearly energy sales pattern, with higher levels during the winter and early spring, it is also the case that the Company's model accentuates the variability in the data, observed by winter and early spring boxplots being considerably higher than during other months in the year, and the distribution of the forecast data is more dispersed.

The patterns observed above result mainly from two exogenous variables, number of customers and real per capita income, the only exogenous variables that **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period. The Department considered different model parametrizations that exclude one or both of these variables. As discussed in some cases above, while income is related to the long-run growth, the number of customers is related to the increase in variability. As a result, a model without the former grows at a smaller rate than the Company's forecast, while a model that does not include number of customers produces growing forecasts that have a smaller variance. By removing both variables, models can produce some long-run growth, resulting in a positive trend in the historical period, although they forecast a growth rate that is smaller than the Company's forecast, and the data has smaller variability.

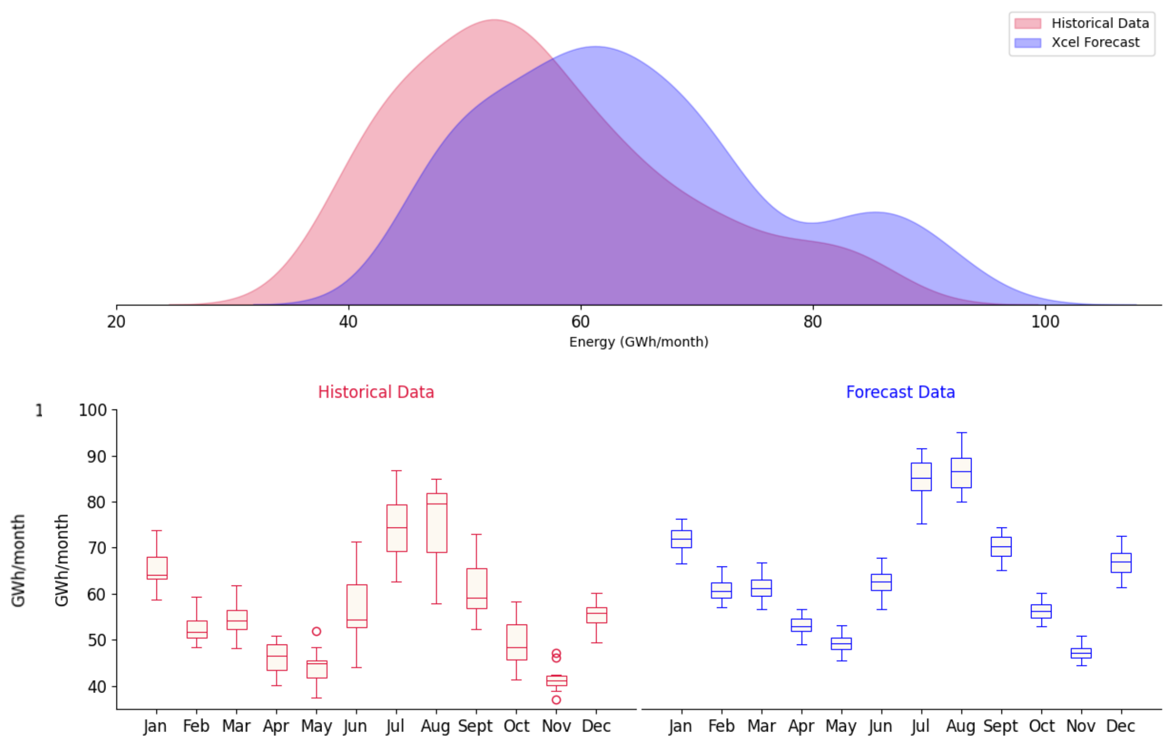
The model estimated aiming at reproducing the Company's forecast produces similar in-sample predictions, and forecasts that deviate from the Company's forecast by less than 2 percent. However, considering models with different parametrizations, while better in-sample predictions can be achieved, the forecasts are close to the Company's forecast, presenting a long-run and increasing variability.

Hence, the Department concludes that the forecast for South Dakota Residential with Space Heating is reasonable for IRP purposes.

3. Residential without Space Heating

From 2009 to 2022 South Dakota Residential without Space Heating energy sales grown by 1.6 percent year-on-year, from 605 GWh to 746.7 GWh. The average energy sales for the period was 677.5 GWh. The Company's forecast grows at 0.64 percent yearly, from 736.7 GWh to 816.2 GWh. The average yearly sales during the forecast period is 772.6 GWh.

Chart A4-15: South Dakota Residential without Space Heating Monthly Energy: Historical and Forecast



From the above chart one can observe from above that the Company's forecast is able to capture the yearly pattern of the historical data, and it does not increase much the variability of the data, although the months of July and August appear to have higher levels in the forecast data comparative to the other months, relative to the historical data. Beyond that, the growth in the forecast period results in boxplots shifted up in the forecast data compared to the equivalent forecasts in the historical period.

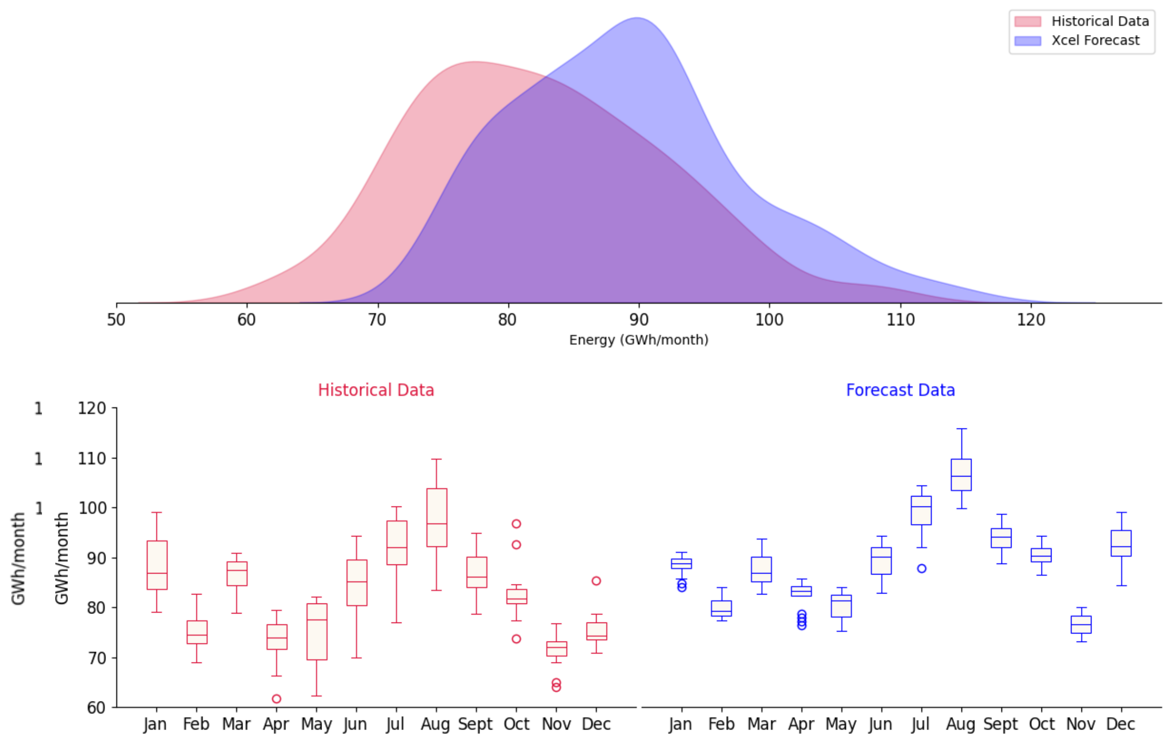
Similarly, to the same class of customers for other jurisdictions, two exogenous variables, number of customers and real per capita income, are the only exogenous variables that **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period. While number of customers grows at a 1 percent yearly rate, real per capita income **[TRADE SECRET DATA HAS BEEN EXCISED]**. Moreover, models that do not include real per capita income produce forecasts that have a considerably smaller growth rate, while models that do not include number of customers produce growing forecasts at a similar rate as the Company's forecast growth rate, however, with smaller variance. Naturally, by excluding both variables, models produce stagnant forecasts without an increase in variance over the forecast period.

The model estimated to replicate the Company's data produces very similar in-sample predictions and the forecast is in line with the Company's forecast, with the biggest deviations smaller than 1 percent. Considering other models estimated by the Department, while better in-sample predication can be achieved, the overall forecast patterns are maintained. Hence, the Department concludes that the forecast for South Dakota Residential without Space Heating is reasonable for IRP purposes.

4. Small C&I

South Dakota Small C&I energy sales are almost flat over the historical and forecast periods, growing at 0.87 percent and 0.3 percent respectively. Energy sales grow from 922.9 GWh in 2009 to 1,032.4 GWh in 2022, and from 1,045 GWh in 2024 to 1,096.6 GWh in 2040.

Chart A4-16: South Dakota Small C&I Monthly Energy: Historical and Forecast



In the above chart both historical and forecast data are hump-shaped, with the forecast distribution's peak to the right of the historical distribution's peak. The Company's forecast replicates the overall yearly patterns of the historical data, although energy sales levels are higher, and less dispersed.

The Company's model includes number of customers and total nonfarm employment as the only variables that **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period. The former grows at 1.4 percent year-on-year while the latter **[TRADE SECRET DATA HAS BEEN EXCISED]**. To understand the contribution of each variable in the forecast, the Department estimated models excluding one of them, or both. The results are similar to what is observed in similar cases above. While excluding total nonfarm employment results in forecasts with a smaller growth rate, excluding the number of customers contributes to forecasts with smaller variance.

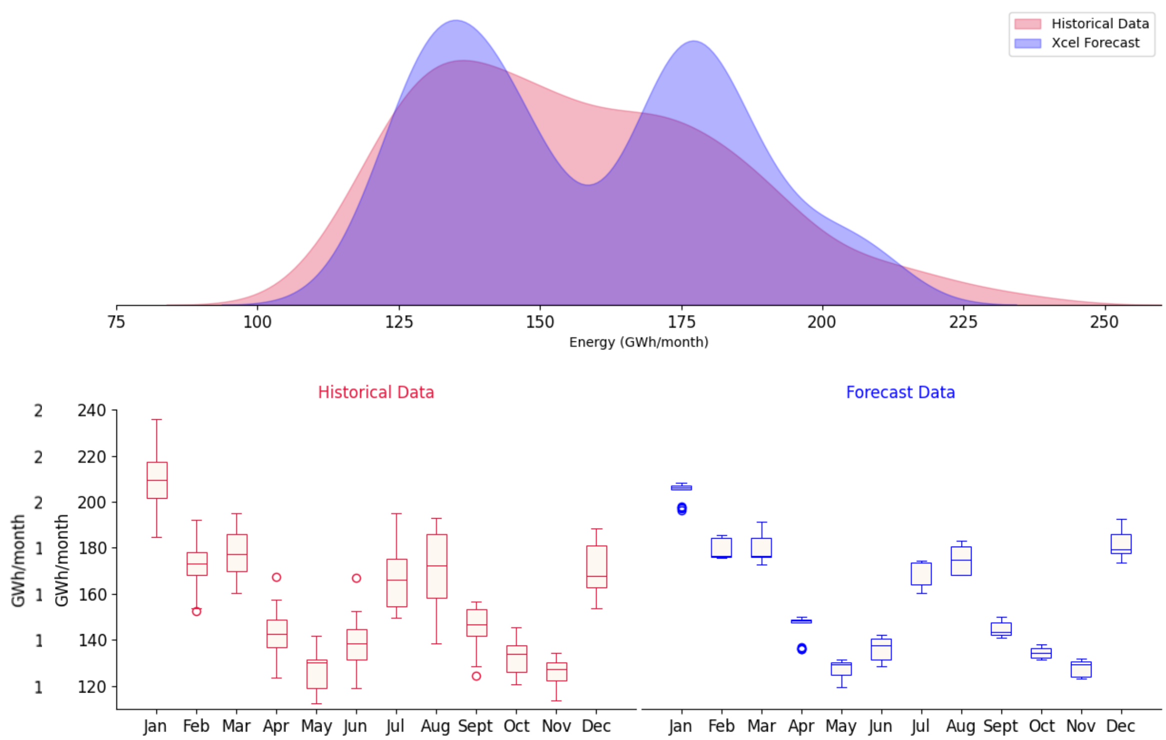
The model estimated to replicate the Company's data produces very similar in-sample predictions and forecasts. The biggest deviation in the two forecasts is less than 1 percent. Moreover, other models estimated are able to produce more accurate in-sample prediction models, but they generate forecasts that do not present any features that distinguish them from the Company's forecast. Hence, the Department concludes that the forecast for South Dakota Small Commercial and Industrial Sales is reasonable for IRP purposes.

F. WISCONSIN FORECASTS

1. Residential

From 2009 to 2022 Wisconsin Residential energy sales were almost flat growing by 0.23 percent year-on-year, from 1,874.4 GWh to 1,931,5 GWh. The average yearly energy sales in this period was 1,883.5 GWh. The Company's forecast is almost constant over the period, with yearly energy sales of 1,915.5 in 2024 and 1,910.4 in 2040, and an average yearly sale of 1,907.8 GWh.

Chart A4-17: Wisconsin Residential Monthly Energy: Historical and Forecast



In the above chart the relative position of the historical and forecast distributions points to the flat forecast, while the presence of two peaks in the forecast distribution reflects the reduction in intra-month variability and the presence of two major consumption levels, during winter and summer, and periods of lower consumptions, during spring and fall.

Xcel's model includes two exogenous variables that either increase or decrease over the forecast period, intensity[180] and number of customers.[181] The former **[TRADE SECRET DATA HAS BEEN EXCISED]** year-on-year rate, while the latter increases by 0.4 percent on a yearly basis. Moreover, the correlation between either of

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[180] Intensity is a Wisconsin specific variable that aims at capturing demographic and economic components relevant to energy sales.
[181] Embedded on the weather variables, which are a product of a weather index, THI or HDD, and the number of customers.

these variables and energy sales, historical[182] or forecast[183], is **[TRADE SECRET DATA HAS BEEN EXCISED].** The Department investigated the relevance of each variable by estimating models that excluded one of them, or both, and results found were in line with previous models. The model that excluded intensity produced forecast with a slightly higher yearly growth rate than the Company's forecast, however, by 2040 the two forecasts diverged by less than 1 percent. The model that excluded number of customers produced flat forecasts, however, with smaller variance than the Company's forecast. The model that excluded both variables produced flat forecasts and was less dispersed around the forecast mean.

The model estimated to reproduce the Company's forecast produce in-sample predictions close to those reported by the Company, and almost flat forecasts, although marginally higher than the Company's, in any event they diverged by less than 0.5 percent by 2040. Moreover, other models estimated by the Department produce forecasts in line with the results reported by the Company. These models had more accurate in-sample predictions and almost flat forecasts. Finally, although these models produced less dispersed forecast, around the forecast mean, the yearly energy sales were very close to the Company's forecast, diverging by less than 2 percent by 2040. Hence, the Department concludes that the forecast for Wisconsin Residential Sales is reasonable for IRP purposes.

2. *Small C&I*

From 2009 to 2018, Wisconsin Small C&I energy sales grow at 0.98 percent year-on-year, from 2,582.4 GWh to 2,819 GWh. From 2018 to 2022, decreases by -1.5 percent year on year, reaching 2,657.7 GWh. During the forecast period, energy sales grow consistently at 0.2 percent year-on-year, from 2,704.8 GWh in 2024 to 2,793.9 GWh in 2040.

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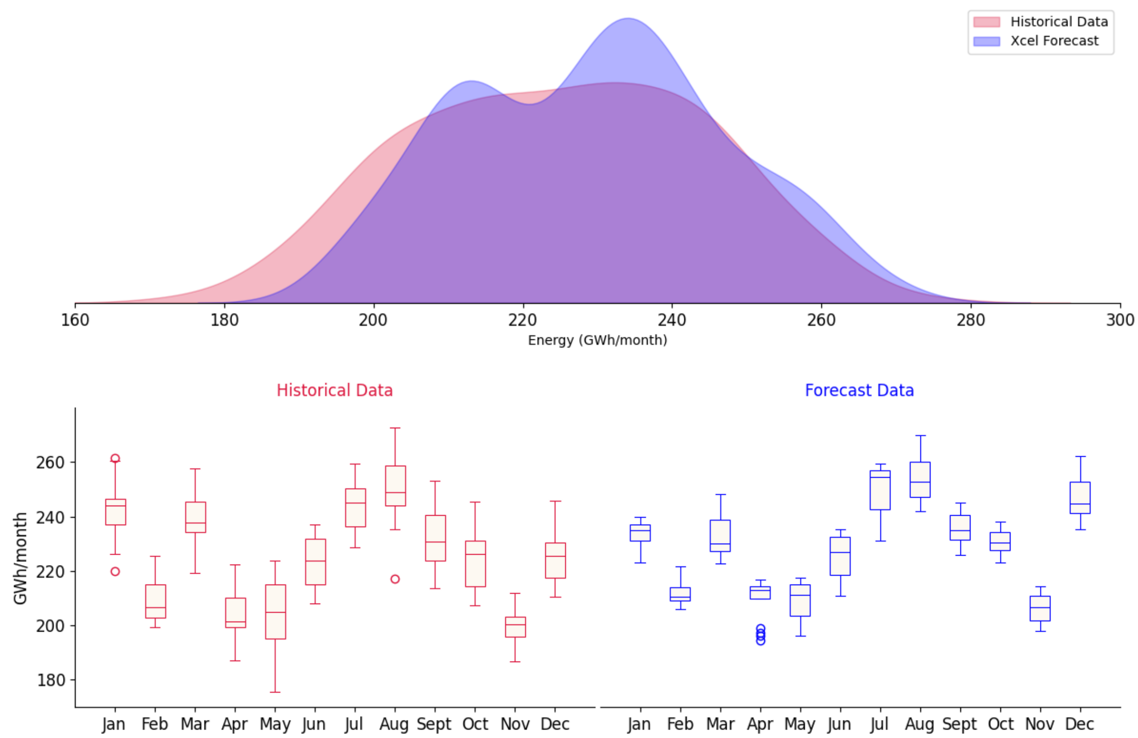
[182] Historical energy sales and intensity have a Pearson correlation of -0.043 while number of customers have a correlation of 0.044.
[183] Forecast energy sales and intensity have a Pearson correlation of -0.01 while number of customers have a correlation of -0.011.

Chart A4-18: Wisconsin Small C&I Monthly Energy: Historical and Forecast



In the above chart most of the mass of the historical and forecast distributions overlap, with two distinctive features being the exception. First, because of the growth in the forecast, the right tail of the forecast distribution is thicker than the historical distribution. Second, the forecast distribution has two peaks, the one most to the right represents higher energy sales during the months of July, August, and December, and the one to the left representing intermediate energy sales values during the months of January, March, June, September, and October. Moreover, the Company's forecast is able to reproduce the yearly pattern observed in the historical data.

Two of the exogenous variables included in the Company's model **[TRADE SECRET DATA HAS BEEN EXCISED]** over the forecast period, total nonfarm employment **[TRADE SECRET DATA HAS BEEN EXCISED]** yearly and number of customers [184] also grows 0.45 percent yearly. Models estimated that do not include total employment nonfarm produce forecasts with a smaller growth rate than the Company's forecast. However, models that do not include number of customers fail to capture several characteristics of the historical data, producing low accuracy in-sample prediction, and producing a forecast that fails to capture the variability of the historical data. The model estimated that does not include both variables not only fails to capture the variability of the historical data, but also produces a flat forecast.

The Department estimated a model to replicate the Company's forecast and it produces accurate in-sample predictions, to the same order as the Company's forecast. The forecast generated by the model is close to the Company's forecast, and the maximum deviation happening in 2040 is smaller than 1 percent. Other models estimated by the Department are able to generate more accurate in-sample prediction, however, when computing the forecast, the results obtained are similar to the Company's forecast. Although the Department's models' forecast does not incorporate as much variability around the forecast mean as the Company's forecast,

[184] Embedded on the weather variables, which are a product of a weather index, THI or HDD, and the number of customers.

the differences are small and when aggregating by year less than 1 percent. Hence, the Department concludes that the forecast for Wisconsin Small Commercial and Industrial energy sales is reasonable for IRP purposes.

G. CALENDARIZATION TRANSFORMATION

In order to compute the forecast based on a calendar cycle, that is, to account for energy for every day and month in the calendar year, it is necessary to transform energy sales computed based on billing cycles. For example, consider a customer billed for usage between June 10 to July 9 and between July 10 and August 9. To determine the energy used in July it is necessary to account for the portion of energy billed in the first billing cycle that was consumed in July, that is, from July 1 to July 9, plus the portion of energy billed in the second billing cycle that was consumed in July, that is, from July 10 to July 31.

In the forecast, this transformation is conducted for every jurisdiction and class of customer considered above. The calendarization process used by the Company is the following:

1. The days in each billing cycle are aligned with calendar days.
2. Billing cycle weather impact is netted out of the billing cycle energy sales forecast, resulting in a non-weather sales forecast.
3. The non-weather sales forecast for each jurisdiction and class of customer is then calendarized by dividing it by billing days, then multiplying by calendar days, resulting in a calendar weather sales forecast.
4. Billing cycle weather is adjusted by normal weather to create a calendar weather sales forecast.
5. Adding calendar weather sales forecast to calendar non-weather sales forecast produces calendarized sales forecast.

In response to Department Information Request No. 39, the Company provide the file 24-0067 DOC-039_Attachment A TRADE SECRET.xlsx that includes all the inputs and outputs of the calendarization process. In this file:

- Sheet 2023V2_MetrixOut has the data for each forecast discussed in the Econometric Models section above.
- Sheets Cal_Coef, CalW_Adj, and Weather contain weather related data, including weather indexes (HDD and THI) and billing cycle and calendar cycle energy sales impacted by weather.
- Sheet Cal_Coef contains the relation between billing cycle days and calendar cycle days.

The Department evaluated the calendarization transformation and believes this process is reasonable for IRP purposes and necessary, so that the final system energy forecast is evaluated based on calendar days. Although the Department does not have the expertise required to evaluate the weather components involved, the Department did raise a concern regarding the billing cycle and calendar cycle days alignment, discussed in the section Losses Resulting from the Calendarization Process below. Beyond this point the Department has no objections to Xcel's calendarization transformation for IRP purposes.

H. YEARLY PROFILE SHAPING

The calendarized forecast, obtained after billing data is transformed to account for weather effects and into a calendar cycle, is subject to another transformation which uses historical yearly profiles to redistribute the calendarized data aiming at eliminating potential outliers.

For the first year in the forecast, 2024, each month's percentage of the annual energy is calculated as the average of the historical percentage for year 2018 to 2022. Note, summing the percentage for every month in 2024 adds up to 100 percent. For all years after that, a month's percentage of the yearly energy is equal that month's percentage of the yearly energy in 2024. Thus, while the forecasted energy grows during the forecast period, the growth is assumed to not change the historical distribution of consumption across months. Once this transformation redistributes energy considering the monthly percentages of the yearly energy, each year's energy forecast before and after the transformation is the same.

The Department analyzed the yearly profile for each class of customer and jurisdiction for the years 2018 to 2022, and the historical yearly profiles are very similar. Hence, the Department believes it is reasonable to use the same yearly profile as the baseline for the years in the forecast.

Finally, for all the econometric models considered above, one important assumption made was that no changes in behavior would be assumed. Hence, the usage across the years shouldn't change much month-to-month, although they can increase in level (as observed in the analyzes above for all jurisdictions and classes of customers). As a result, although the energy may vary across the years, the intra-year energy month-to-month should be reasonably constant across years,[185] the Department believes this transformation is reasonable for IRP purposes.

I. OTHER LOADS

This component of the forecast is composed of energy for the following classes of customer:

- Inter-Departmental (ID);[186]
- Public Authority (OS); and
- Street Lightning (PS).

The Department explains below Xcel's forecasting process and the contribution of each jurisdiction and class of customer to the system's energy.[187] Below the Department presents its analysis of each component.

1. NSPM

a. Billing Cycle

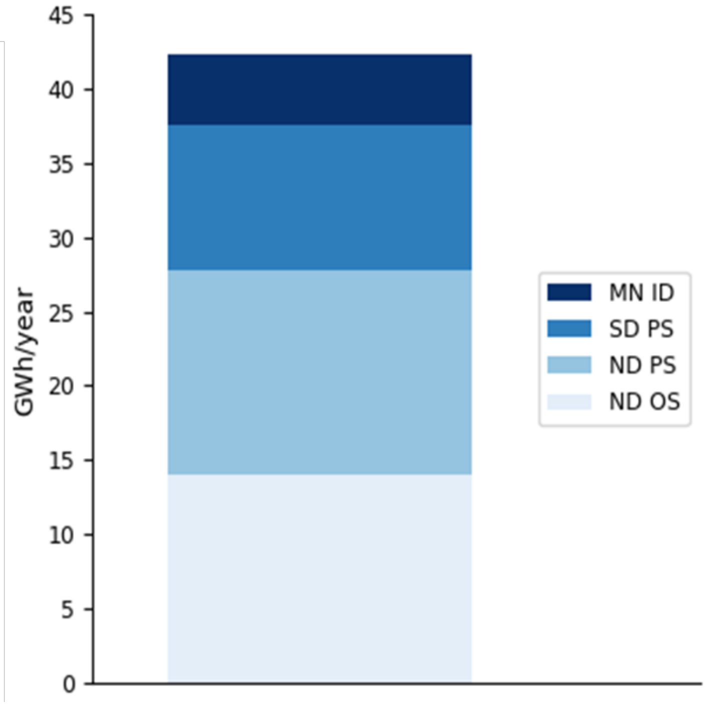
For some jurisdictions, annual energy was modelled as constant across the forecast period using historical values to set a baseline. The following series were modelled using this approach:

- Inter-Departmental: Minnesota.
- Public Authority: North Dakota.
- Street Lightning: North Dakota and South Dakota.

Both billing cycle historical data and forecast data were provided for all of these series. In the following figure, the Department presents the yearly contribution of each component:

[185] This does not include EV, BE, solar, DSM, or EE, which will affect the yearly profile. This is further discussed in section Peak Load Demand—8760 Procedure below.
[186] Inter-Departmental use for NSP is any electricity usage by Xcel's Gas Departments.
[187] The Department discussed Minnesota Public Authority and Street Lightning above since they are modelled using econometric models. Moreover, some jurisdictions and classes of customers do not impact the forecast, hence, are not mentioned below.

Chart A4-19: Energy (2024-2040 year-on-year constant)



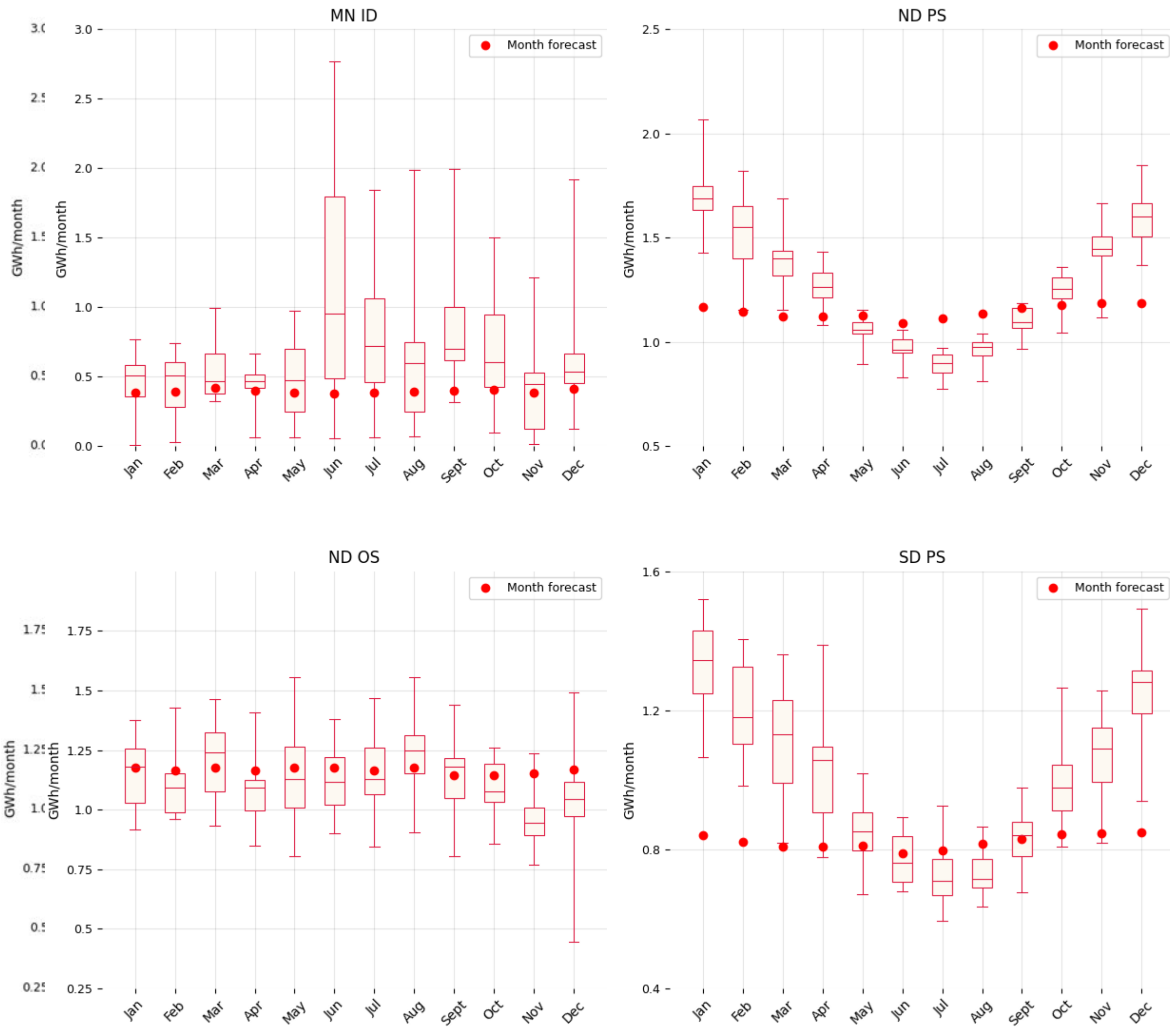
Since Xcel's annual energy requirement is in the tens of thousands of GWh it is clear that these components have almost no impact on the system energy forecast.

Xcel's forecast was produced as follows:

1. Values for the period between June 2023 and May 2024 were calculated as an average of the previous twelve months. For example, January 2024 energy is the average for the period January 2023 to December 2023.
2. For months from June 2024 until December 2040, the energy was the same as the energy in the same month in the previous year. For example, June 2024 through June 2040 have the same energy as June 2023.

The approach of the Department was to consider the distribution of historical monthly energy (captured by the boxplots) against the forecasts produced as averages (red dotted points) in the following graphs:

Chart A4-20: Historical Distribution (Jan 2008 to May 2023) vs Forecast



The whiskers in the above picture span the whole distribution of historical values – conditional on each month, while red dotted points represent the average of the previous twelve months. Red dotted points within those whiskers represent forecasts close to actual historical values. While most of the values are within those bounds or close, the Department notes that a few forecast values deviate from historical values, for example July North Dakota PS or January South Dakota PS.[188]

However, as noted above, since these classes represent less than 0.1 percent of system energy, the Department is not concerned with these discrepancies for resource planning purposes.

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[188] Red dotted points can be outside the whiskers because they are calculated as averages of the past twelve months, while the whiskers are conditional on each month, that is, all the load values for a given month.

b. Calendar Cycle

In order to transform the forecast billing cycle data, the same calendarization transformation as previously mentioned is used. The Department analyzed this data as well and, as expected, this process redistributes energy from billing to calendar days, the results are similar to the ones discussed in the section above. The Department maintains its position that there are no relevant issues in terms of resource planning regarding this section of the forecast.

c. Yearly Profile Shaping

Different from the components discussed so far, this section's data is not reshaped although month profiles are provided. The Department recommends Xcel in reply comments:

- explain why the following data is not reshaped:
    - Inter-Departmental: Minnesota.
    - Public Authority: North Dakota.
    - Street Lightning: North Dakota and South Dakota.

2. NSPW

The following series are also modelled in the forecast:

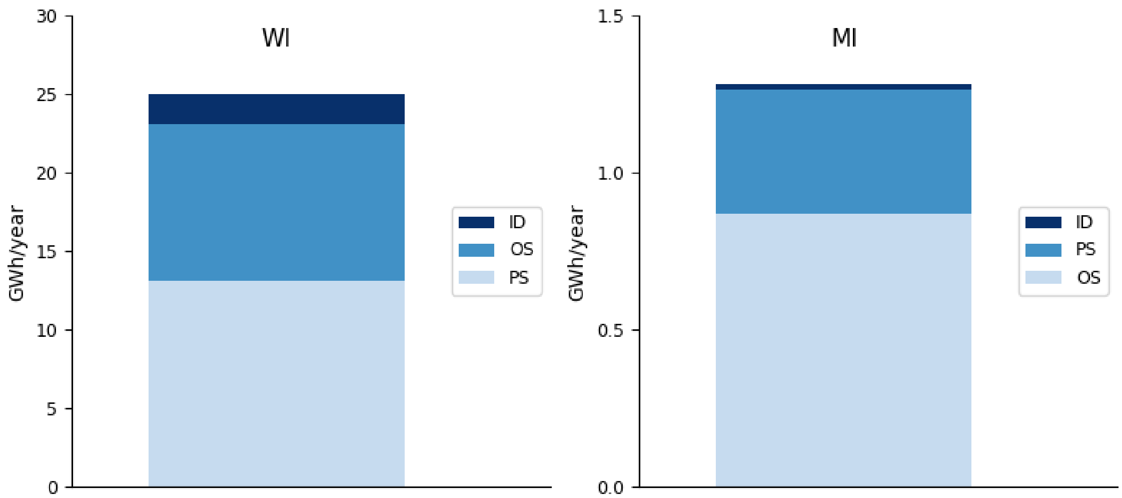
- Michigan and Wisconsin: Inter-Departmental, Public Authority, and Street Lightning.

However, while historical data was provided, the Department notes that billing cycle forecast data was not provided in response to any information request.

Nonetheless, the Department received forecast data which it analyzes below. The Department notes that Xcel did not present the method used to compute its forecast or specified whether or not this data is calendar cycle adjusted.[189]

[189] The Department assumed the data as calendar cycle adjusted in its analysis.

Chart A4-21: Other Loads (2024 to 2040 average)



The above chart shows the average annual energy for NSPW. Similar to NSPM's Other Loads, the annual average is less than 0.1 percent of the system energy. Moreover, the Department analyzed the year-on-year energy, and the time series is very close to the average values. As a result, the Department has no concerns for planning purposes about this component of the forecast.

In an effort to reproduce this data, the Department used the same forecast method as used in the previous series (the average of the previous 12 months to construct the baseline year, and year-on-year constant after the baseline year) and the billing to calendar cycle transformation method (both methods describe above) using the historical data provided. However, the Department was not able to replicate the results presented by the Company.

The Department recommends the Company provide in reply comments an explanation of the discrepancies found by the Department's attempt to replicate the data present in sheets WI Cal and MI Cal.[190]

3. *Company Use*

Each jurisdiction's energy forecast is impacted by the Company's energy for that jurisdiction. Xcel's provide historical data for Minnesota, North Dakota, and South Dakota as well as forecasts for each.[191] The forecasts are calculated as follows:[192]

1. Values for the period between June 2023 and May 2024 were calculated as an average of the company usage for the three previous months. For example, July 2023 energy is the average of July's energy for the years 2020, 2021, and 2022.
2. For months from June 2024 until December 2040, the energy was the same as the energy in the same month in the previous year. For example, June 2024 through June 2040 have the same energy as June 2023.

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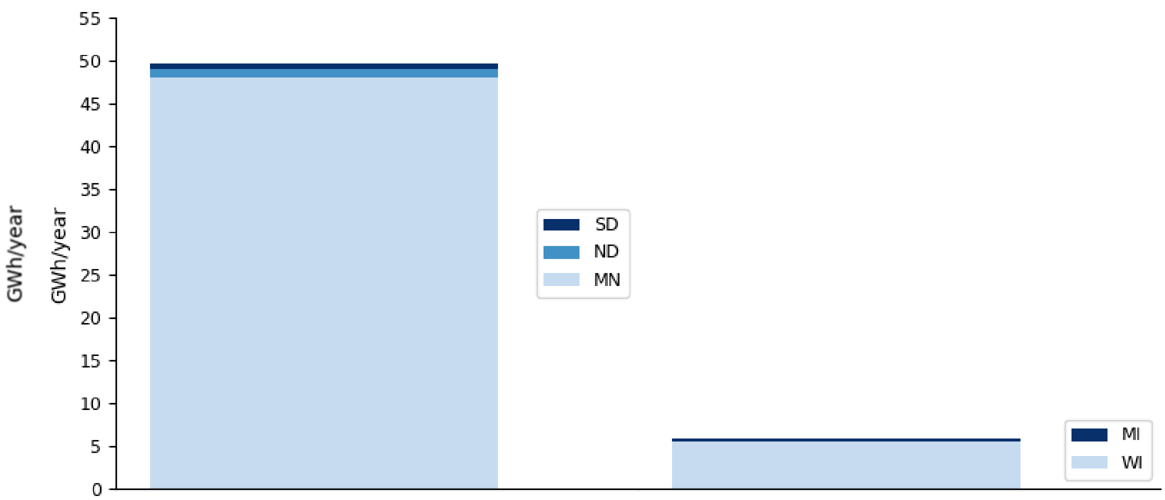
[190] The referred data is located in the file: 24-0067 DOC-039_Attachment A TRADE SECRET.xlsx.
[191] Although the Company did not specify whether these data is billing or calendar cycle, the Department assumed it as calendar cycle data.
[192] 24-0067 DOC-039_Attachment A TRADE SECRET.xlsx, sheet 2023V2_8760In. The Department notes, forecast values are present in sheet 2023V2_Prelim, however, the forecast method is slightly different. Hence, the forecast values are also different.

Once the forecast for Minnesota, North Dakota, and South Dakota are calculated as averages of the same month in previous years, it is clear that the forecasted data will be placed inside the distribution of historical data conditional on each month (this is not the case for Other Loads forecast, as mentioned above).

Xcel did not present historical data for NSPW, or the way the Company's forecast was calculated. However, similar to NSPM, the period from Jun 2023 to May 2024 is the baseline and every month after has the same energy as the baseline. It is important to note, this data is not subject to billing to calendar cycle or yearly profile shaping transformations. Otherwise, although the forecast would the same as the baseline year, the transformed data would not (details of why can be obtained from sections above).

Consider the Company's usage for any year from 2024 to 2040:

Chart A4-22 Company Use (2024-2040 year-on-year constant)



Similar to Other Loads, the contribution of Company Use to the whole system's energy is small, representing less than 0.1 percent of the system total. As a result, for planning purposes the Department does not have any objections to the way the forecast was computed. However, the Department recommends the Company extend the number of years it uses to compute the baseline year.[193]

4. *Loss Factors*

Loss factors to compute energy at the generator level from the customer-meter forecasts were calculated by using historical data and econometric models including month dummy variables[194] for all jurisdictions and jurisdiction-specific variables.[195] The econometric models were then used to estimate losses for a baseline year, and the baseline year is assumed to be the losses for every year for the forecast period.

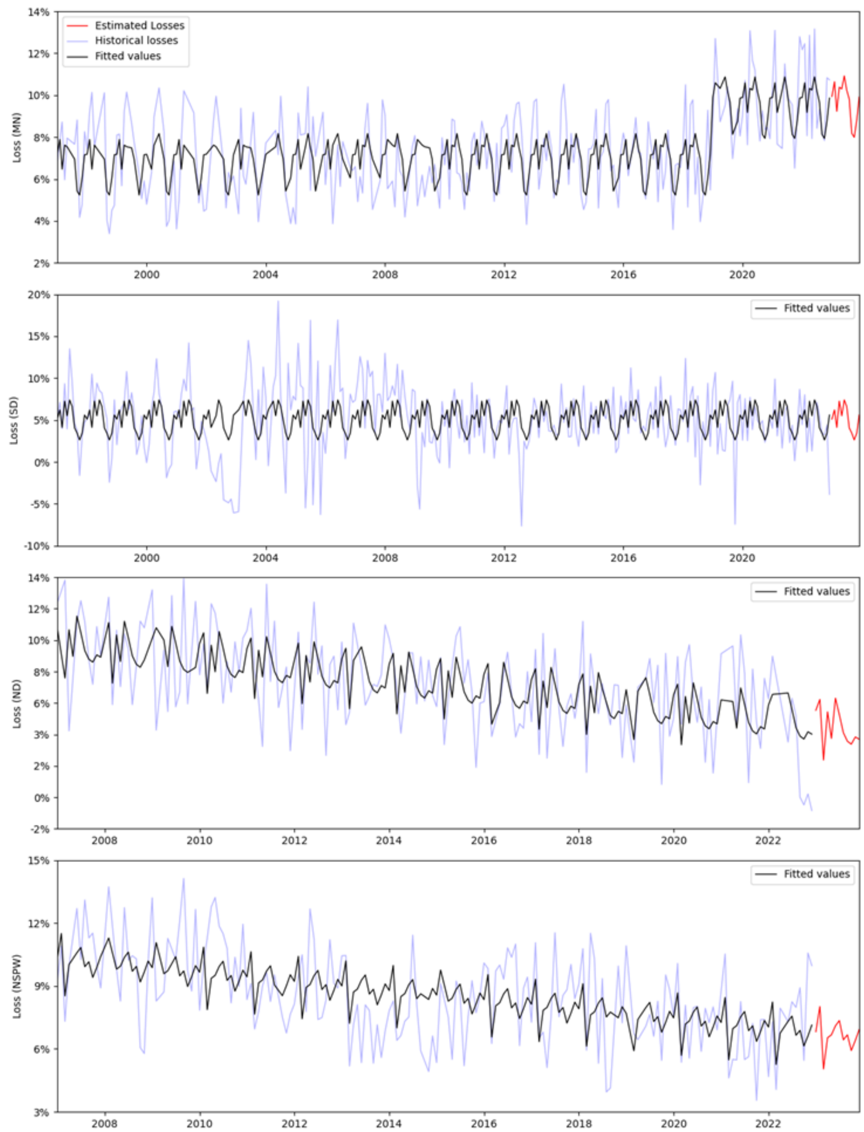
The Department evaluated the econometric models presented by the Company and agrees with the Company's procedure. While jurisdiction specific variables are necessary to account for features of each jurisdiction, dummy variables should be able to capture a relevant portion of the variability in the historic losses once those

[193] For this IRP, the Company uses data from January 2020 to May 2023.
[194] Dummy variables are variables that assume values of 0 or 1, conditional on a rule. For example, a dummy variable for the month of March is 1 when the month is March and 0 otherwise.
[195] The North Dakota and NSPW models included a time trend, and Minnesota's model included another dummy variable that capture a change in level.

should be stable over the years, unless some extreme event takes place, such as a change in the system infrastructure or weather-related events. Such extreme events are beyond the consideration of the forecast, which is based upon typical conditions.

In the following graph the Department presents the historical losses, the fitted values[196], and the estimated losses used in the forecast.

Chart A4-23 Historical Losses vs Fitted Losses



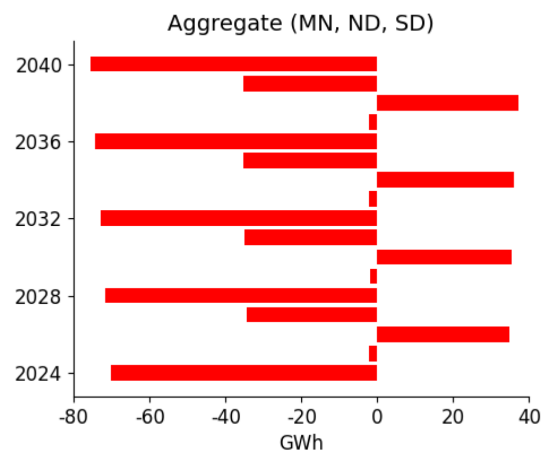
Although the fitted values cannot replicate the whole data variability, they incorporate the overall historical trend. This is also observed for the estimated losses, used in the forecast. As a result, the Department believes that the estimated values for losses are reasonable for IRP purposes and can be used to calculate energy at the generator level.

[196] Fitted values are predicted values using the model and the data used to estimate the model parameters.

5. Losses Resulting From Calendarization

The Department evaluated any losses or surpluses resulting from the calendarization transformation by considering the billing cycle energy forecast[197] and the weather adjusted and calendarized energy forecast.[198] If the process of calendarization only rearranges billing cycle energy sales into calendar days, then the subtraction of billing cycle energy forecast from calendarized energy forecast should be equal to zero. If this operation produces positive values, it means that the calendarization process is distributing more energy in calendar cycle than the actual billing cycle energy, while if the result is negative, it means that the calendarization transformation is not distributing all billing cycle energy into calendar cycle energy. In the graphs below, the Department show the results of this operation for Minnesota, South Dakota, North Dakota, and aggregate.[199]

Chart A4-24 Historical Losses vs Fitted Losses



[197] Sheet 2023V2_MetrixOut from the file: 24-0067 DOC-039_Attachment A TRADE SECRET.xlsx
[198] Sheet 2023V2_Prelim from the file: 24-0067 DOC-039_Attachment A TRADE SECRET.xlsx
[199] The Department does not compute this operation for Michigan and Wisconsin once the calendarized data for these jurisdictions was not provided. While the Department believes this data could be reverse engineered from the data provided by Xcel, it deemed it unnecessary since it would not change the conclusion of the exercise.

Most notably from the above graphs is the observation that there are discrepancies for every year in the forecast and for all three jurisdictions considered. Moreover, it is clear that these discrepancies follow a 4-year window pattern, most likely reflecting any calendar adjustments necessary as a result of a leap year every 4 years in the forecast period. Finally, although small, the discrepancies are increasing over the forecast period. The Department cannot provide an explanation for this fact. Therefore, the Department recommends the Company reply comments explain why a discrepancy remains when transforming the energy usage from billing cycle to calendar cycle.

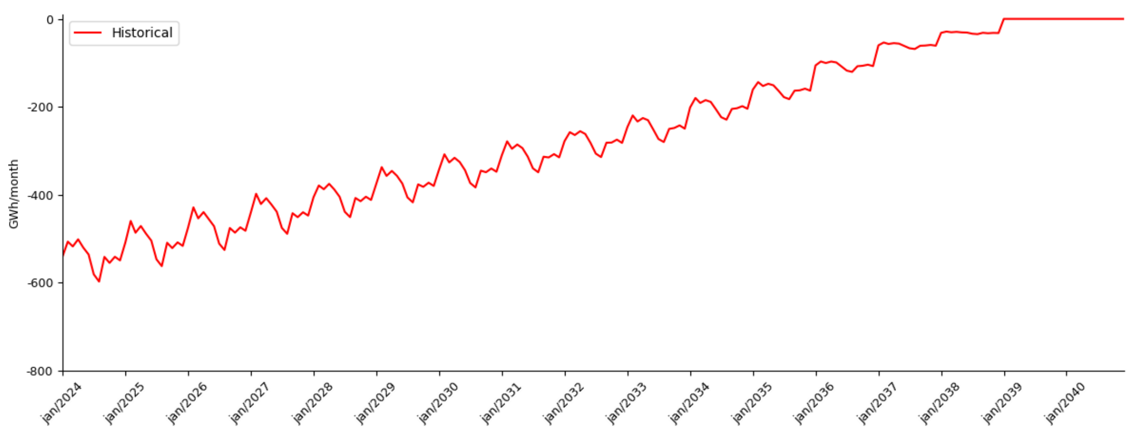
The Department acknowledges these values are small and have a negligible impact on the system energy forecast. However, the Department recommends the Company consider updating its calendarization process aimed at eliminating these discrepancies.

J. EXOGENOUS ADJUSTMENTS

1. Minnesota DSM

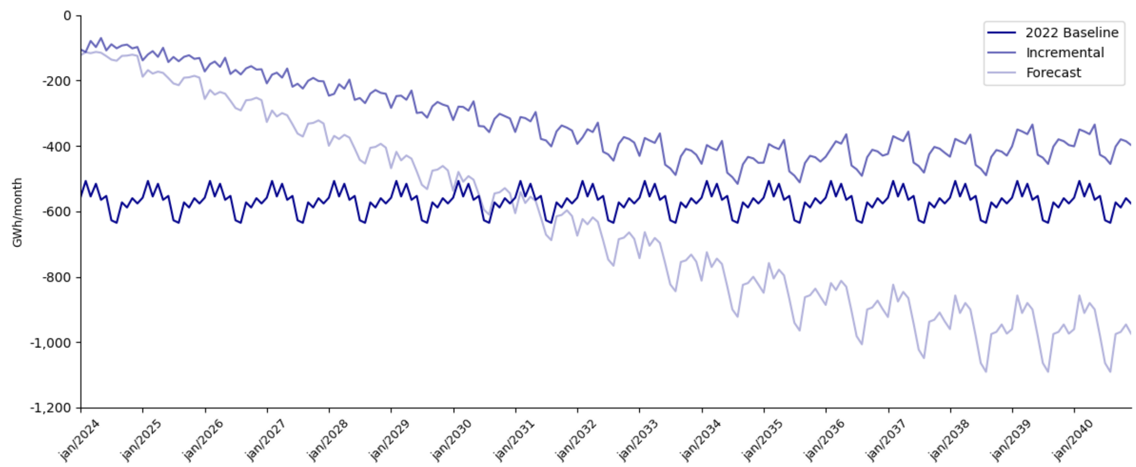
Part of the contribution of Minnesota demand-side management (DSM) in the energy forecast is historical DSM. Historical DSM represents all measures existing as of 2022. Since the measures gradually expire the impact of these measures will depreciate over time, without replacement. Hence, over time past historical DSM has a smaller impact on energy forecast. This effect can be observed in the graph on the following picture.

Chart A4-25 Historical Demand-Side Management



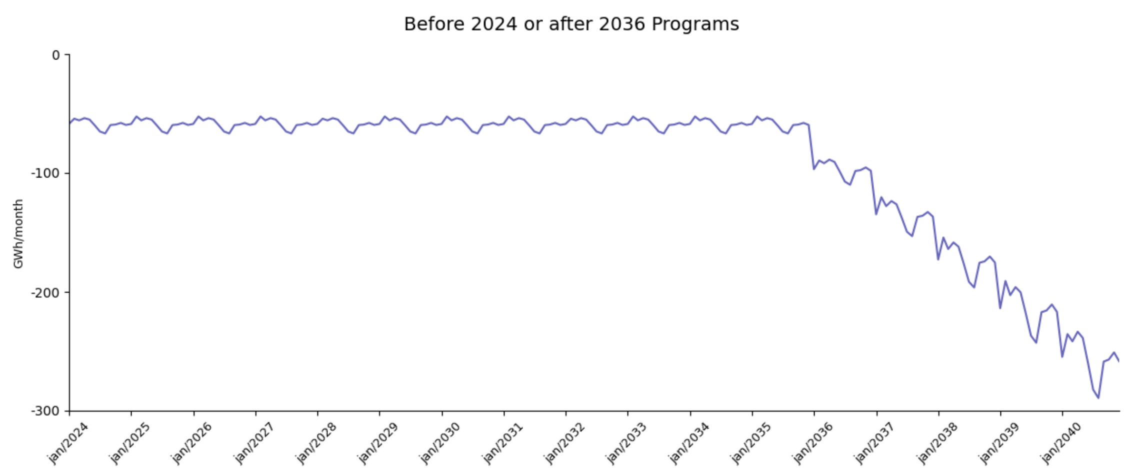
In the chart below DSM forecast represents all the existing programs until 2022, which are assumed to continue over the forecast timeframe. Note, these programs are assumed to peak around 2038 and are maintained thereafter. Base DSM represents the historical contribution of DSM using 2022 as the base year. Note that this series is the constant series on the following chart. The third series in the chart below, DSM incremental, represents all DSM measures implemented in excess of the baseline year of 2022. In effect, DSM incremental is the residual of subtracting base DSM from historical DSM plus forecast DSM.

Chart A4-26 DSM – Baseline, Incremental and Forecast



Since EnCompass only models DSM projects from 2024 to 2035, it is necessary to include in the energy forecast the forecast of measures implemented until 2023 and in 2036 and after. The impact of those programs can be observed in the curve labeled 2024-2036 Programs in the chart below.

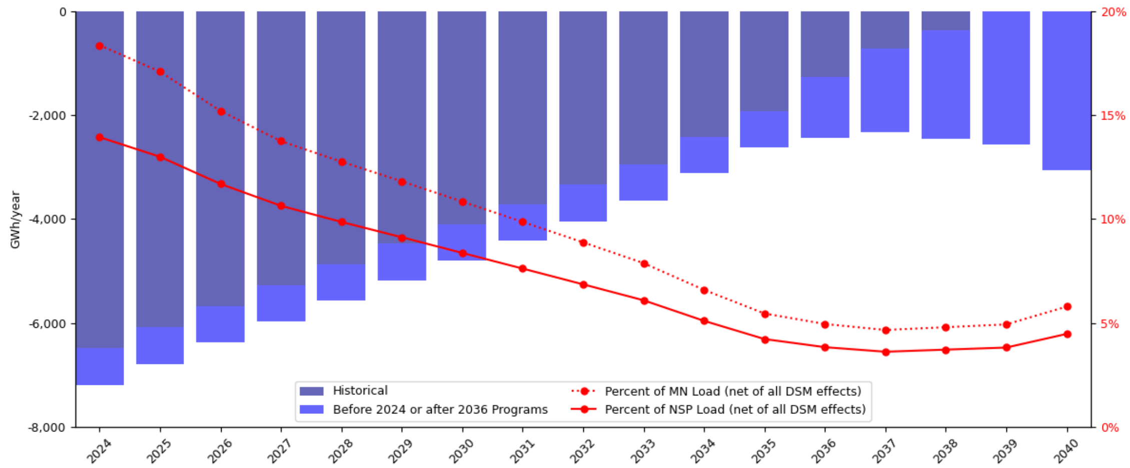
Chart A4-27 Monthly Energy: Historical and Forecast



Most notably, once no new programs are implemented after 2023, the series is constant until 2036, when new programs are implemented, hence the observed increase in energy savings.

The aggregation of historical DSM and programs until 2023, or in 2036 and after represents the whole contribution of Minnesota DSM into the system load forecast. In 2024, DSM reduces energy requirements by almost 8,000 GWh. However historical DSM reduces over time, and the effect of the programs not modelled in EnCompass are constant before 2036. Then, the overall DSM's contribution falls until 2037, when it reaches the minimum contribution in reducing energy requirements.

Chart A4-28 Aggregated Yearly DSM



The red solid line in the bottom chart is the percent of Minnesota DSM of NSP energy net of DSM effects. This contribution reduces over the forecast period as a result of two forces, the increase in energy requirements as a result of other components, and the drop in the amount of energy savings due to a fall in DSM measures until 2037.

The Department analyzed Minnesota DSM's contribution to Xcel's energy forecast. However, before providing a final recommendation, the Department recommends the Company in reply comments:

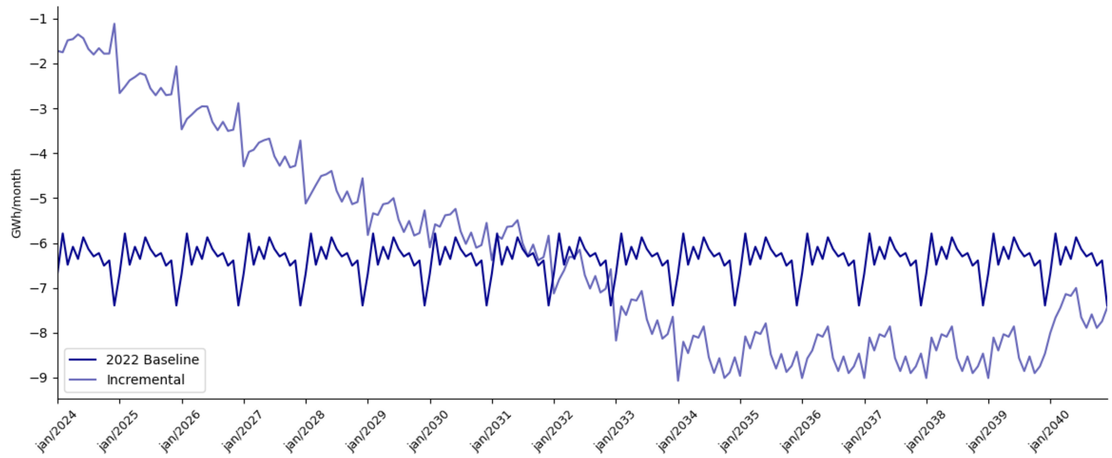
- Provide details about the DSM programs that contribute to DSM Before 2024 or after 2036.

2. South Dakota DSM

Contrary to how Minnesota was treated, South Dakota DSM is not modelled in EnCompass. Base DSM represents all DSM as of 2022. Furthermore, incremental DSM represents all DSM incremental to the baseline year 2022 and, similarly to Minnesota incremental DSM, it grows until 2034 and remains constant until the end of 2039 when it decreases slightly.[200]

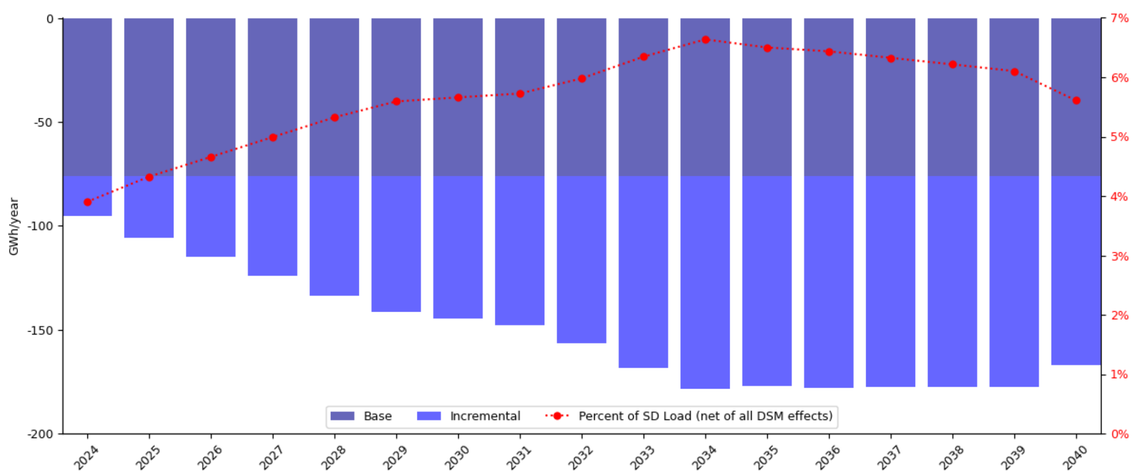
[200] The decrease in energy savings from 2039 to 2040 is not observed in Minnesota's incremental DSM.

Chart A4-29 DSM – Baseline and Incremental



Total DSM is base DSM plus incremental DSM. Once forecast DSM is embedded in total DSM, South Dakota total DSM increases over the forecast period. Moreover, DSM as a percent of South Dakota's energy increases over the forecast period. However, South Dakota DSM as a share of total system energy forecast is at most 0.3 percent.

Chart A4-30 DSM – Baseline and Incremental



The Department analyzed South Dakota DSM's contribution to Xcel's load forecast. However, before providing a final recommendation, the Department recommends the Company in reply comments:

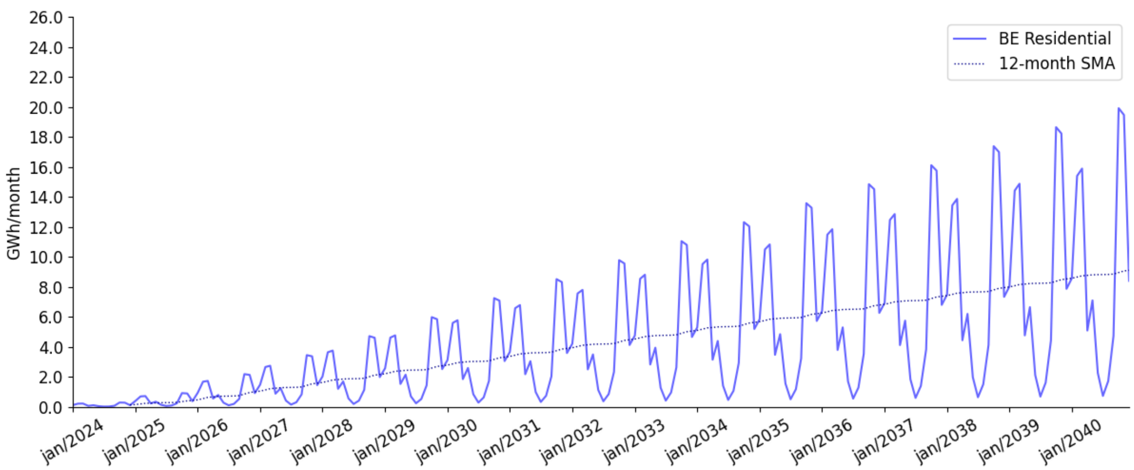
- Explain why South Dakota incremental DSM decreases around the end of the forecast period.
- Provide details about the DSM programs that contribute to DSM incremental.

3. Beneficial Electrification

Beneficial electrification (BE) is only forecasted for Minnesota and is within the residential and business sectors. The Department analyzed both the monthly and yearly energy.

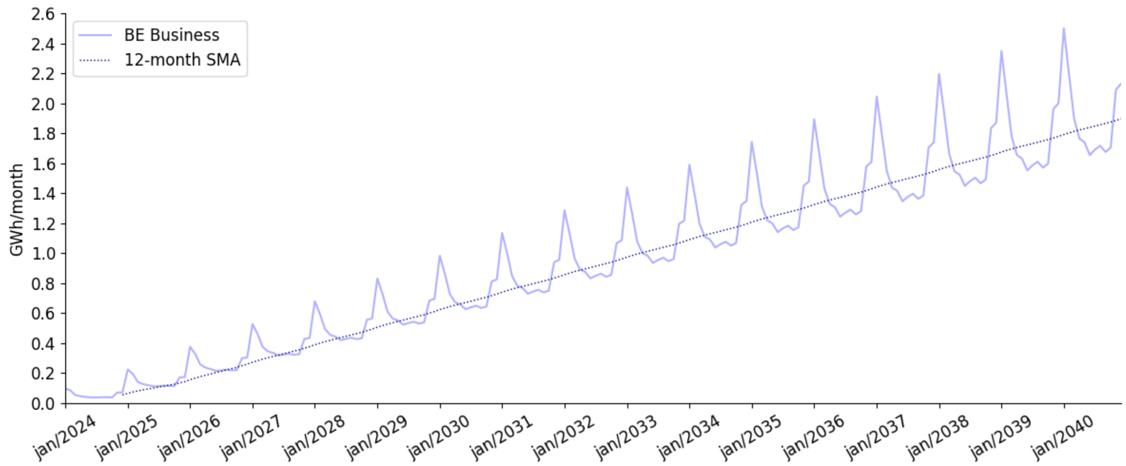
Considering monthly energy for both residential and business sectors, one can observe that throughout the forecast period energy increases in a similar pattern year-on-year. In particular, months' relative position in terms of energy load forecast is constant for almost all the years.[201] For example, October is the month with the biggest energy load in BE residential while July is the smallest, for all the years in the forecast period. However, the actual difference in energy load for any two months in the same year grows from year to year. For example, the difference in energy load between January and June for 2025, 2035 and 2040 is 112.4 MWh, 600.9 MWh and 845.2 MWh, respectively, in BE business.

Chart A4-31 Beneficial Electrification Monthly - Residential



[201] For the initial years in the forecast, there are exceptions among the lowest energy level values for both residential and business. For example, in years 2024 and 2025, 4th lowest energy load month is April and September is the 5th, but from year 2026 onwards their relative position is swapped, in BE residential.

Chart A4-32 Beneficial Electrification Monthly - Business



Considering the facts observed, while the relative position can be a result of no changing in energy usage customers' behavior, a hypothesis used by the Company[202] although not in the context of BE, the increase in the load spread between months within a given year can be explained by the increase in the number of customers. However, the Company did not provide the assumptions supporting the forecast.[203]

On the other hand, in evaluating the two sectors the Department notes the forecast is fundamentally different. BE residential presents a considerable increase in intra-year energy load volatility and intra-year spread between the biggest and smallest energy load months:[204]

- In 2027:
  - October's energy is equal to 2,098.5 percent July's energy.
  - Energy standard deviation is 1132.2.
- In 2040:
  - October's energy is equal to 2,668.6 percent July's energy.
  - Energy load standard deviation is 6,584.8.

Although BE business intra-year volatility increases, the energy load percentual spread between the biggest and smallest energy load months decreases:[205]

- In 2027:
  - January's energy is equal to 166.1 percent June's energy.
  - Energy load standard deviation is 20.3.
- In 2040:
  - January's energy load is equal to 151.1 percent June's energy.
  - Energy load standard deviation is 258.5.

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[202] Xcel Energy Integrated Resource Plan, Docket No. E002/RP-24-67, Appendix E, page 6.
[203] In response to the Department Information Request No. 7, the Company stated "The 'ExoAdj' tab contains the monthly Beneficial Electrification forecast (at generator) series assumed in the IRP." Sheet ExoAdj is included in the file: "24-0067 DOC-003_Attachment A.xlsx".
[204] We compare 2026 and 2040 because 2026 is the first year the relative order of energy load per month is the same as 2040.
[205] We compare 2027 and 2040 because 2027 is the first year the relative order of energy load per month is the same as 2040.

There is evidence that a higher share of BE business' growth is a result of a higher long-run trend, relative to BE residential, which can be observed by evaluating the 12-month simple moving average for both sectors. While the increase in BE residential spread indicates an increase in the number of customers as a factor driving overall BE increase.

Finally, the Department evaluated the annualized growth rate for both sectors and each month, considering the whole forecast period.

4. Solar

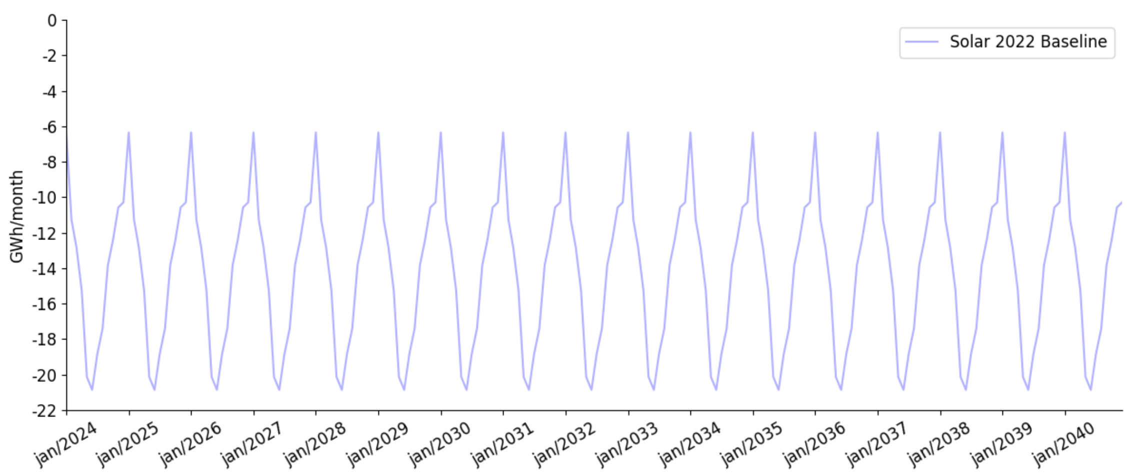
Solar Generation is modeled only for Minnesota and has the following components in the forecast:

- Behind-the-Meter 2022 Baseline;
- Behind-the-Meter Incremental; and
- Solar gardens:
  - **[TRADE SECRET DATA HAS BEEN EXCISED]**

As discussed in the Petition's Appendix E[206], behind-the-meter 2022 baseline and incremental are added back into the forecast, so they can be modelled as a supply-side resource in EnCompass. However, baseline solar is included in the Company's 8760 input, so peak demand can incorporate the historical effects of behind-the-meter solar. In what follows Total Energy refers to behind-the-meter 2022 baseline plus behind-the-meter incremental.

Behind-the-meter 2022 baseline represents all the historical solar generation as of 2022 and assumed to continue at the same level for the whole forecast period.

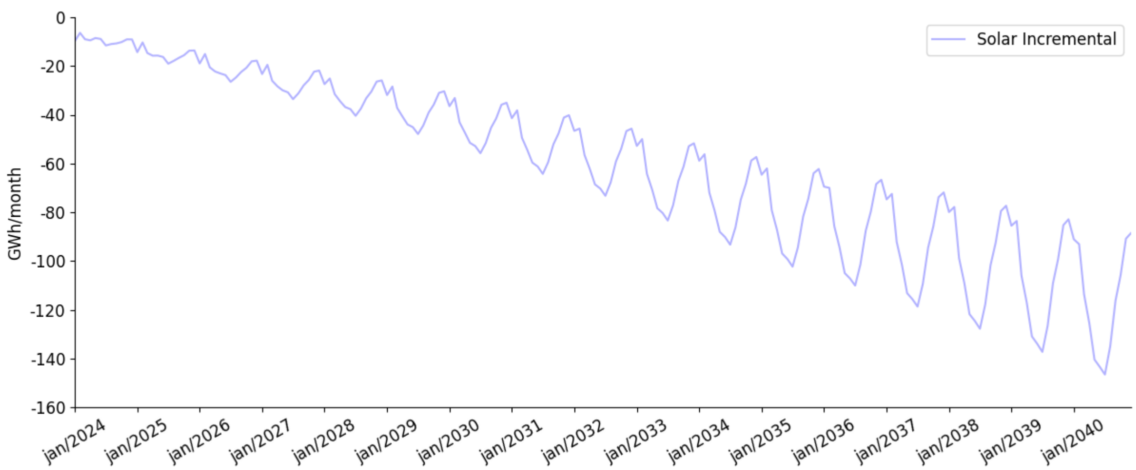
Chart A4-33 Solar - Baseline



On the other hand, behind-the-meter incremental, that is, in excess of 2022 baseline, expands through the forecast period.[207]

[206] Xcel Energy Integrated Resource Plan, Docket No. E002/RP-24-67, Appendix E, page 6.
[207] Note that the number is negative because it represents a reduction in the forecast.

Chart A4-34 Solar - Incremental



Similar to what was observed for BE, the overall expansion in behind-the-meter generation incremental can be justified by both an increase in the number of customers relying on this generation (the increase in the intra-year volatility) and no big changes in overall behavior (observed by the overall inter-year generation pattern[208] being similar across the years). Although the Company does not explicitly discuss all the assumptions behind the forecast, it mentions the assumption used to create the behind-the-meter distributed solar sensitivity by saying "We created the High solar adoption sensitivity using a combination of lower installation cost and higher savings."

The remaining solar generation that affects the forecast are solar gardens integrated to the Company's system. The Company divides these into two components Solar large commercial and industrial (LCI) and Other Solar. Solar LCI **[TRADE SECRET DATA HAS BEEN EXCISED].**

[208] Accounting for the differences in scale.

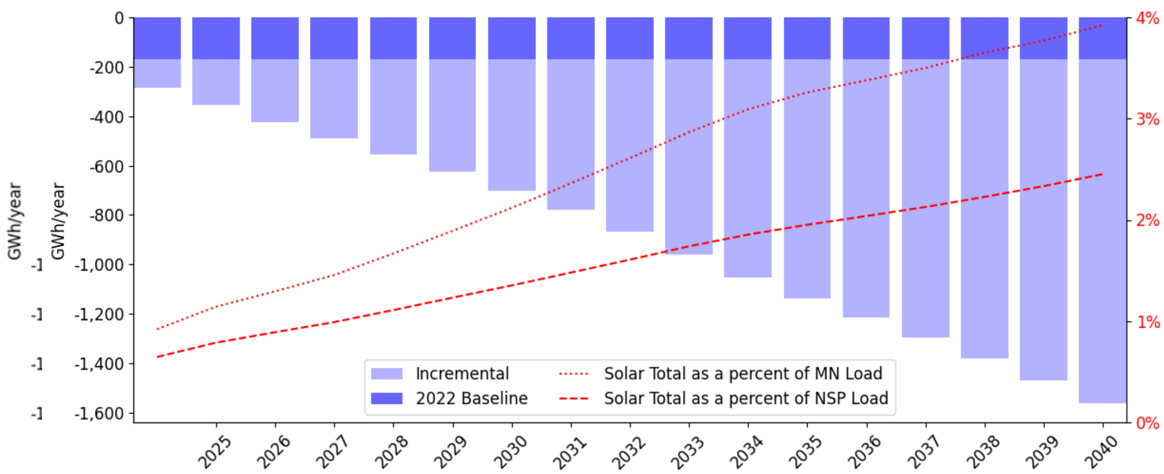
Chart A4-35 Solar - Other

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Finally, the Department considered the whole contribution of behind-the-meter distributed solar generation aggregating by year.

Chart A4-36 Aggregated Solar – Incremental plus Baseline (yearly)



Over the whole forecast period, behind-the-meter generation does not represent more than 3 percent of the system's energy. [209] Although total energy grows over the forecast period, the yearly growth rate decreases going from 24.6 percent from 2024 to 2025 to 6.3 percent from 2039 to 2040. Moreover, the annualized growth rate for the 2024-2040 period is 11 percent. The Department notes that, similar to BE, this growth rate is greater than the total system load annualized growth rate. The Department does not provide a summary graph of LCI and Other LCI solar generation because they represent a smaller portion of Xcel's energy requirements.

[209] Net of all solar effects: 2022 baseline, incremental, LCI, and Other LCI.

The Department analyzed Solar Generation's contribution to NSP's energy forecast and concludes it is reasonable for IRP purposes. Although no major concerns were found by the Department, before providing a final recommendation, the Department recommends the Company in reply comments:

- Provide the assumptions used to create the forecast for Solar Incremental.

5. LCI—Data Centers

The Department evaluate the load in response to prospective customers for data centers in the Minnesota jurisdiction.

Chart A4-37 LCI – Data Centers

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department analyzed LCI – Data Centers' contribution to Xcel's energy forecast and agrees with the Company that the actual load depends on which projects will go through and which will not. Although no major concerns were found by the Department, before providing a final recommendation, the Department recommends the Company in reply comments:

- Provide an updated overview of **[TRADE SECRET DATA HAS BEEN EXCISED]**
- Discuss whether new prospective customers have approached the Company and, if so, provide energy requirement (including timeline) data regarding these potential additions as well as the likelihood of each of those additions.

6. EV

The Department analyzed Xcel's forecast of Electric Vehicles energy requirements. In all five jurisdiction EV energy load is expected to grow over the forecast period.

In obtaining the energy requirements for each jurisdiction, the Company **[TRADE SECRET DATA HAS BEEN EXCISED]:**

- **[TRADE SECRET DATA HAS BEEN EXCISED]**

[TRADE SECRET DATA HAS BEEN EXCISED]

The Company **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Department evaluated the Company's forecasting models, and the underlying assumptions, and did not identify any major sources of concern. However, before providing a final recommendation, the Department recommends the Company in reply comments:

- Explain why the Company **[TRADE SECRET DATA HAS BEEN EXCISED]**.[210]
- Explain why the Company **[TRADE SECRET DATA HAS BEEN EXCISED]**.

The model used to forecast MDV and HDV energy consumption is simpler, so the Department discusses it below.

a. Cumulative Energy

The Department evaluates the cumulative energy, provided in response to Information Requests No. 8 and No. 43. The Company computes energy consumption for light-duty, medium-duty, and heavy-duty vehicles and the Department analyzed each of these.

[210] As noted in EIA Electric Power Monthly, electricity prices differ across states and within sectors.

i. LDV

[TRADE SECRET DATA HAS BEEN EXCISED]

Chart A4-38 LDV Cumulative Energy Consumption

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

ii. MDV and HDV

Unlike the approach to forecast energy consumption for LDV, the approach used by the Company to forecast MDV and HDV energy consumption is less involved. **[TRADE SECRET DATA HAS BEEN EXCISED].**

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Chart A4-39 MDV Cumulative Energy Consumption

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Chart A4-40 HDV Cumulative Energy Consumption

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

b. Incremental Energy

Unlike the cumulative energy consumption discussed so far, the forecast **[TRADE SECRET DATA HAS BEEN EXCISED].** To evaluate this data, the Department **[TRADE SECRET DATA HAS BEEN EXCISED].**Below is a table that accounts for **[TRADE SECRET DATA HAS BEEN EXCISED]:**

Table A4-1 HDV Difference between Cumulative and Incremental Data

[TRADE SECRET DATA HAS BEEN EXCISED]

The data on the table should be interpreted as follows: **[TRADE SECRET DATA HAS BEEN EXCISED]**

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Chart A4-41 Energy Consumption by Jurisdiction (monthly) Energy Consumption

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Following this, the Department analyzed **[TRADE SECRET DATA HAS BEEN EXCISED].**

Chart A4-42 Aggregated Energy Consumption (yearly)

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department analyzed EVs' contribution to Xcel's energy forecast and, although the Department does not have any major concerns about the assumptions made by the Company, it recognizes EV energy consumption growth rate is relevant as well as the contribution to Xcel's system energy requirements. Hence, EVs should be particularly monitored by the Company. Before providing a final recommendation, the Department recommends the Company in reply comments:

- Provide historical percent growth for previous year (if data is available).
- Provide the source of all the data present on 24-0067 DOC-043_MDV and HDV EV Forecast TRADE SECRET IN ENTIRETY.xlsx sheet Base.
    - Explain why, **[TRADE SECRET DATA HAS BEEN EXCISED]**.
- Explain the differences between **[TRADE SECRET DATA HAS BEEN EXCISED]** which the Department could not map to the data provided.

K. PEAK LOAD AND 8760 PROCEDURE

To determine the monthly peak demand and, consequently, the yearly peak demand, the Company relied on a process called the "8760". In general terms, this process maps the monthly energy load, measured in MWh (or a multiple of it, such as GWh), into hourly energy demand, measured in MW (or a multiple of it). The name "8760", hence, derives from modeling all 24 hours of 365 days in a year.[211] To implement this procedure, the Company rely on a software called MetrixLT[212] a third-party proprietary software to which the Department does not have access. As a result, the Department is not able to replicate Xcel's results. The analysis provided by the Department takes into consideration the inputs provided to the software and the outputs of the software.

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[211] Leap years include a 366th day and, consequently, 24 more hours.
[212] https://na.itron.com/products/metrixlt

First, the Department considered the step-by-step of the "8760" procedure:

1. Energy requirements are determined for every component of the forecast:
    a. Base energy:
        i. The five jurisdictions are considered: Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. These components are discussed in section Base Energy above.
    b. Beneficial Electrification:
        i. Residential and Business.
    c. Demand-side Management:
        i. DSM Incremental for Minnesota and South Dakota;
        ii. DSM Forecast for Minnesota;
        iii. DSM before 2024 or after 2036 programs for Minnesota; and
        iv. DSM 2022 Baseline for Minnesota and South Dakota are modelled under Base Energy.
    d. Solar
        i. Solar Incremental;
        ii. Total Solar;[213] and
        iii. 2022 baseline behind-the-meter distributed generation is modeled under Base Energy.
    e. Electric Vehicles
    f. Data Centers
2. For each component above, the hourly profile of a typical year is created.[214]
3. The typical year hourly profile is extended to every year in the forecast period.
    a. This step accounts for elements such as holidays, e.g., Thanksgiving or Christmas, to guarantee the yearly profiles are consistent with the observed energy demand.
4. The output of the "8760" procedure consists of scaling the input hourly profiles for each year of the forecast, taking into consideration the energy requirements forecast.
    a. In other words, the input profiles represented a typical hour-by-hour energy demand taking into consideration historical energy requirements.
    b. Scaling this profile taking into consideration the energy requirements forecast, means adjusting the hourly demand so that a new hourly profile is produced that satisfies:
        i. The hourly demand for any year in the forecast, when summed for all hours and days, is equal to the energy requirement forecast for that year.
        ii. Consistency with historical energy demand since the procedure scales a typical year.
5. To obtain total hourly demand, the hourly demand for each component is aggregated.
    a. Minnesota Solar: Since 2022 Baseline Solar is modelled under Base Energy, and Solar Incremental and Total Solar are modelled separately, when adding Solar Incremental to total hourly demand and subtracting Total Solar from it, the effect of behind-the-meter generation is netted out. Only LCI Solar and Other Solar effects remain.
    b. Minnesota DSM: Since 2022 Baseline DSM is modelled under Base Energy, and DSM Incremental and DSM Forecast are modelled separately, when adding DSM Incremental to total hourly demand and subtracting DSM Forecast from it, the only remaining effect is DSM Historical.[215] Beyond that, DSM before 2024 and after 2036 programs are also included.
6. The annual peak demand consists of obtaining the highest demand among all hours and days in that year.

The Department also evaluated the input and output hourly profiles and did not find any elements that are concerning. Although the demand is different (as a result of the scaling by a growing energy load forecast), the most relevant patterns are present across the years (because the procedure is based on a typical year). Moreover, because the Company modelled each component by its own hourly profile, the Department

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[213] Recall, Total Solar is defined as 2022 Baseline Solar plus Solar Incremental.
[214] These profiles use inputs from different departments inside the Company.
[215] Recall that DSM Historical plus DSM Forecast is equal to DSM 2022 Baseline plus DSM Incremental.

concludes the computation of the system hourly profile forecast is more realistic than assuming a single profile and scaling based on total energy requirements. This is particularly relevant because it takes into consideration the specificities of each component's hourly profile, and the further we advance into the forecast, the more relevant some components become, and the weight of their profiles into the system peak demand becomes more evident.[216]

The Department analyzed the "8760" procedure and agrees with the Company that this approach contributes to a realistic forecast. The Department concludes it is reasonable for IRP purposes and has no objection to it for this IRP.

Table A4-2 Annualized Growth Rate (2024-2040)

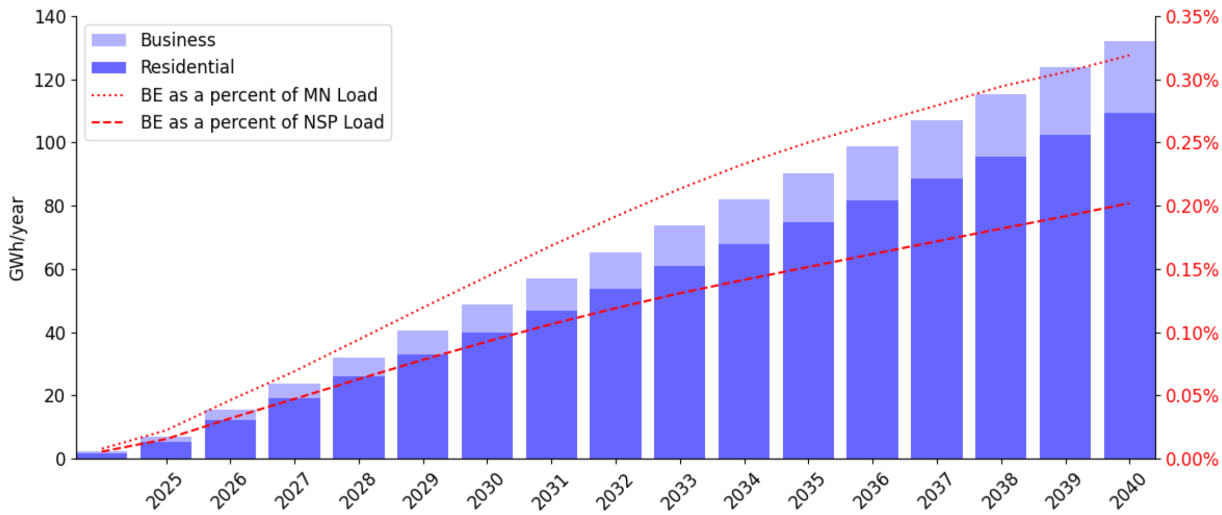
Month	BE Residential	BE Commercial
Jan	29.87%	29.87%
Feb	30.06%	30.06%
Mar	30.08%	30.08%
Apr	29.39%	29.39%
May	28.79%	28.79%
Jun	25.27%	25.27%
Jul	20.92%	20.92%
Aug	26.39%	26.39%
Sep	28.15%	28.15%
Oct	29.87%	29.87%
Nov	29.93%	29.93%
Dec	29.89%	29.89%

The Department notes, across all months and sectors, the lowest annualized growth rate is 20.92 percent, which is considerably higher than the whole system energy load annualized growth rate of 2.4 percent.

[216] Xcel Energy Integrated Resource Plan, Docket No. E002/RP-24-67, Appendix E, page 6 the Company highlights this:

> The resulting peaks largely align with the Company's old monthly modeling process for the first few years of the forecast timeframe. However, adoption of rooftop solar generation eventually pushes summer peaks later into the evening, and increased EV penetration with charge management programs moves peaks to 1:00 a.m. by the early 2040s.

Chart A4-43 Aggregated BE (yearly)



However, the Department acknowledges the relevance of BE to the whole system energy is small adding up to less than 1 percent by the 2040.

In summary, the Department analyzed BE's contribution to Xcel's energy forecast and concludes it is reasonable for IRP purposes. Despite the concerns raised above, its impact on the whole forecast is small, hence it is not a component of concern. However, before providing a final recommendation, the Department recommends the Company in reply comments:

- Provide the assumptions used to create the forecast for BE residential and business.
- Explain how the 2024-2026 Energy Conservation and Optimization Triennial Plan goals are translated into energy load assumptions.
- Explain what drives the difference in growth pattern between BE residential and business.

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Xcel Energy		Information Request No. 1
Docket No.:	E002/RP-24-67	
Response To:	Minnesota Public Utilities Commission	
Requestor:	Sean Stalpes	
Date Received:	March 28, 2024	

Question:

Topic: Load Forecast

Resource Plan Chapter 1 – Page 7 of 15 cites large new data centers, electric vehicles, and beneficial electrification as contributors to a relatively higher average annual energy growth rate than Xcel's last IRP. Figure 1-3 on the same page marks this divergence.

Please provide a table which isolates the annual GWh of energy attributable to data centers, EVs, and beneficial electrification (i.e., each source reported as a separate column or row) assumed in each year of the energy forecast. Include the associated peak demand impact for data centers, EVs, and beneficial electrification as well as the number of data centers and total EVs in the baseline forecast.

Response:

Please refer to Attachment A to this response, provided in live Excel spreadsheet format, for annual energy, peak-coincident demands, and counts for large new data centers, electric vehicles, and beneficial electrification.

Attachment A is marked "Not-Public" as it includes Trade Secret information pursuant to Minn. Stat. § 13.37, subd. 1(b). The information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 2.

Preparer:	Benjamin Levine
Title:	Energy Forecasting Analyst
Department:	Load Forecasting and Analysis
Telephone:	(651) 558-1923
Date:	April 10, 2024

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Northern States Power Company

Docket No. E002/RP-24-67
MPUC Information Request No. 1
Attachment A - Page 1 of 1

Annual GWh Energy Forecast for 2024 thru 2055
Data Centers, Electric Vehicles, Beneficial Electrification

	Energy Requirements (MWh)			Peak Coincident Impact			Count	
	DC	EV	BE	DC	EV	BE	DC	EV
	[Trade secret data begins			[Trade secret data begins			[Trade secret data begins	
2024		130,870	2,419		19.48	0.21		54,485
2025		232,232	7,000		34.46	0.43		69,830
2026		369,411	15,341		53.75	0.70		90,071
2027		555,099	23,682		80.14	1.03		116,735
2028		797,658	32,023		113.46	1.31		151,804
2029		1,112,575	40,364		200.41	1.88		197,558
2030		1,520,296	48,705		269.35	2.24		260,329
2031		2,055,674	57,046		358.08	2.66		346,137
2032		2,792,922	65,386		478.77	3.18		461,994
2033		3,666,622	73,727		616.02	3.49		585,184
2034		4,637,296	82,068		764.91	3.56		720,512
2035		5,657,733	90,409		914.58	3.99		853,954
2036		6,640,516	98,750		1,053.37	4.48		985,234
2037		7,628,195	107,091		1,188.14	4.96		1,114,966
2038		8,625,621	115,432		1,318.82	5.47		1,243,303
2039		9,641,315	123,772		1,447.29	5.73		1,371,859
2040		10,669,592	132,113		1,571.79	5.75		1,499,804
2041		11,687,708	140,454		1,689.29	6.13		1,626,181
2042		12,692,870	148,795		1,799.50	6.66		1,750,386
2043		13,679,288	157,136		1,901.69	7.20		1,871,438
2044		14,645,195	165,477		1,995.85	7.60		1,989,283
2045		15,602,348	173,818		2,083.96	7.36		2,106,758
2046		16,546,211	182,159		2,164.87	7.87		2,220,977
2047		17,464,796	190,499		2,237.46	8.25		2,331,005
2048		18,350,196	198,840		2,300.83	9.06		2,435,587
2049		19,210,791	207,181		2,356.83	9.67		2,537,676
2050		20,058,836	215,522		2,879.38	7.39		2,638,434
2051		20,903,915	223,863		7,733.27	5.96		2,749,591
2052		21,749,631	232,204		8,047.48	6.72		2,860,832
2053		22,595,347	240,545		8,361.71	7.29		2,972,073
2054		23,441,063	248,886		8,675.94	7.93		3,083,314
2055		24,286,779	257,226		8,990.17	8.61		3,194,555
	Trade secret data ends]			Trade secret data ends]			Trade secret data ends]	

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Xcel Energy		Information Request No.	9
Docket No.:	E002/RP-24-67		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Sean Stalpes		
Date Received:	October 9, 2024		

Question:

Page 8 of 12 of the Settlement Agreement states that Xcel "shall file evidentiary support for the Settlement Agreement by October 25, 2024."

9.a. Describe, in detail, what types of evidentiary support the filing will include.

9.b. In addition to the narrative explanation requested above, please explain whether Xcel will include (and if not, why not):

1. Technical reliability analyses, including the reliability analysis discussed at the October 5, 2023, Commission meeting.

2. Additional EnCompass modeling. If the Company is submitting additional EnCompass modeling, please provide:

   - A list of all scenarios and sensitivities Xcel is running, such as;
     - individual, non-Xcel bids;
     - combinations of non-Xcel bids;
     - scenarios with and without one or both of the Xcel bids; and
     - any updated inputs and assumptions since Xcel's February 2024 Initial Filing.

9.c. Which load forecast (e.g., Spring/Fall 2024) is the base forecast for the updated modeling, if any? If the Company is using an updated forecast, please explain any differences, particularly with regard to the variables listed below, between the Initial Filing forecast and the updated forecast:

- Solar
- Demand-Side Management
- Beneficial Electrification
- Electric Vehicles
- Large Commercial & Industrial Customers

If Xcel will use the same forecast as the one used in the Initial Filing, explain any changes and trends that have occurred since the Initial Filing, based on the company's most recent internal data.

<u>Response:</u>

The Company provides the following information:

A. The October 25, 2024 evidentiary support filing will include information demonstrating that the Settlement Agreement is in the public interest. This information will include, among other things: analysis of the reasonableness of the Five-Year Action Plan; updated capacity expansion modeling to support the selection of bids from Docket 23-212; and an evaluation of the bids selected from Docket 23-212 using the framework and resource attributes approved by the Commission's November 3, 2023 Order.

B. The October 25, 2024 evidentiary support filing will include reliability analyses, including the transmission/system stability analysis discussed at the October 5, 2023 hearing, and capacity expansion modeling demonstrating that selecting the identified bids from Docket 23-212 is in the public interest. The Company will provide the requested details about capacity expansion modeling in the October 25, 2024 evidentiary support filing.

C. The updated capacity expansion modeling that will be provided in the October 25, 2024 evidentiary support filing is based upon the modeling provided with the initial IRP filing in Docket 24-67 on February 1, 2024. The forecast for February 1, 2024 IRP filing is the Fall 2023 vintage.

We have taken this approach 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.

The Settling Parties did not evaluate any subsequent forecasts in reaching the Settlement Agreement, so they are not relevant to consider at this time. The Company notes, however, that the test year sales forecast filed on September 27, 2024 in Docket 24-320 indicates a higher level of average growth over the forecasting period than the Fall 2023 vintage forecast.

Preparer:	Christopher Shaw
Title:	Director, Resource Planning & Bidding
Department:	NSP Resource Planning
Telephone:	(612) 330-7974
Date:	October 15, 2024

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Xcel Energy		Information Request No.	2
Docket No.:	E002/CN-23-212 & E002/RP-24-67		
Response To:	Minnesota Office of the Attorney General		
Requestor:	Katherine Hinderlie		
Date Received:	November 4, 2024		

Question:

Reference: Company response to PUC IR 9 in docket no. E002/RP-24-67.
The Company states in its response to question 9c that the "test year sales forecast filed on September 27, 2024 in Docket 24-320 indicates a higher level of average growth over the forecasting period than the Fall 2023 vintage forecast."

If in its response, the Company references filings in any docket with the PUC, the Company must provide the following: (1) the PUC Docket number; (2) the date of filing; (3) the document ID; (4) the document title; and (5) the specific page of the filing for references to PDFs and specific tab and line for references to spreadsheets.

A. Does the test year sales forecast filed in 24-320 use the same updated capacity expansion modeling numbers and assumptions that are used in the October 25, 2024 evidentiary support?

B. If the answer to Part A above is anything other than an unqualified confirmation, explain why the Company uses different load forecasts for different proceedings.

C. If the answer to Part A above is anything other than an unqualified confirmation, does the Company plan to update the load forecast in 24-320 to match the Company's IRP proceedings?

Any responsive documents must be provided in their unlocked native format with all formulas and links intact.

Response:

A. The Company understands that inquiry Part 2.A. above is requesting information about the sales forecasts used for different proceedings, and not a comparison between sales forecasts and capacity expansion modeling.

For clarity, sales forecasts are an input into capacity expansion modeling, but they are not the same thing.

The Company's load and sales forecasts are updated twice annually in spring and fall and leverage the most current available information on: general economic/demographic trends, rooftop solar adoption, large industrial customer operations, beneficial electrification, demand side management, and electric vehicle adoption.

The 2024 Resource Plan (Docket No. E002/RP-24-67) was developed in late 2023/early 2024 and uses the Fall 2023 sales and load forecast. The 2025 Electric Rate Case (Docket No. E002/GR-24-320) was developed in the August-October 2024 timeframe and uses the most recent sales forecast, which is the Fall 2024 sales forecast. As such, the 2025 Electric Rate Case does not use the same forecast assumptions as the initial Resource Plan's analysis, i.e. the forecast referred to in the Company's response to MPUC IR 9 (Docket No. 24-67).

B. The 2024 Resource Plan relied on the most recent forecast at the time it was filed. The 2025 Electric Rate Case also relied on the most recent forecast at the time it was filed. This is consistent with the Company's historical treatment of resource plans and rate case filings.

The October 25, 2024 evidentiary support filing in the 2024 Resource Plan and the Firm Dispatchable Proceeding (Docket No. E002/CN-23-212) is based on the sales forecast used for the 2024 Resource Plan initial filing, the Fall 2023 sales and load forecast. The Company used the Fall 2023 sales and load forecast to ensure that the underlying analysis for the 2024 Resource Plan was not changed during the proceeding, and the same forecast was used for the Firm Dispatchable Proceeding to ensure consistency while reviewing the Settlement Agreement.

Further, as explained in the October 25, 2024 filing, using the same forecasting for the 2024 Resource Plan and the Firm Dispatchable Proceeding is consistent with specific directives given by the Commission during the October 5, 2023 hearing. The Commission has consistently expressed a preference that we should use consistent modeling across related dockets.

The Company did not use the Fall 2023 forecast for the 2025 Electric Rate Case because that proceeding is distinct from the other two proceedings, a new and materially different forecast was available, and because it is important that rates be based on the most recent forecasting available during the test year.

C. No. As noted above, the Company's 2025 Electric Rate Case uses the most current forecast vintage available. It would not be reasonable to base forward-looking utility rates on forecasting from Fall 2023 when the Fall 2024 forecast is available.

Preparer:	Ben Levine	Christopher Shaw
Title:	Sr. Energy Forecasting Analyst	Director, Resource Planning & Bidding
Department:	Load Forecasting and Analysis	NSP Resource Planning
Telephone:	N/A	(612) 330-7974
Date:	November 14, 2024	

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

March 15, 2024

—Via Electronic Filing—

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

RE: REPLY COMMENTS – COMPLETENESS
PRAIRIE ISLAND NUCLEAR GENERATING PLANT CERTIFICATE OF NEED
DOCKET NO. E002/CN-24-68

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the March 8, 2024 Comments of the Department of Commerce, Division of Energy Resources (Department) and Citizens United for Responsible Energy (CURE), regarding completeness of the Company's Application for a Certificate of Need for Additional Dry Cask Storage at the Prairie Island Nuclear Generating Plant Independent Spent Fuel Storage Installation (Application) filed with the Minnesota Public Utilities Commission on February 7, 2024.

We appreciate parties' review of our Application and provide references or updates to the information as requested by the Department below, as well as a response to the comments of CURE. We also thank the Department of Commerce, Energy Environmental Review and Analysis (DOC-EERA) staff for its February 29 letter updating that it will prepare an environmental impact statement (EIS) for the proposed expansion, anticipating that process to be completed in approximately one year.

A. Completeness - Additional Information

1. *Minn. R. 7855.0270 F—a quantification of the manner by which these [conservation] programs affect or help determine the applicant's forecast of demand;*

The Company's 2024-2040 Upper Midwest Integrated Resource Plan (Docket No. E002/RP-24-67) is the basis of the Prairie Island Certificate of Need Application. Section F, Appendix F of the IRP states that NSP modeled future energy efficiency programs as a supply side resource. There was no direct application of future energy efficiency programs to the demand or energy forecast on the demand side in the IRP analysis, and therefore no "manner by which these [energy efficiency] programs affect or help determine the applicant's forecast of demand."

Regardless of whether energy efficiency is modeled on the supply or demand side, 1 MWh of DSM savings results in a 1 MWh reduction in energy required from conventional generation sources, and its effects were considered in the IRP, which is the basis for the present Application.

> *2. Minn. R. 7855.0600 A (3)—a physical description of the facility, including: its design capacity in cubic meters;*

A physical description of the facility is contained in Chapter 8 of the Application, including the requested additional design capacity of 1,200 fuel assemblies. As noted in the Application, Chapter 10, Table 1, the volume of a fuel assembly is 0.158 cubic meters. The additional capacity would then be 189.6 cubic meters.

> *3. Minn. R. 7855.0600 B(1)—data regarding design and construction of the facility, including: if known, the complete name and business address of the engineer and firm that would be responsible for the design of the facility;*

Currently, Xcel Energy is using Orano TN for the new technology. While it is anticipated that Xcel Energy would continue to use this technology during the period of extended license, if approved, there is currently no contract with Orano to perform the ISFSI expansion.

The Company, for the current operating license, is in contract with Orano TN. Orano TN is the Orano subsidiary in charge of nuclear logistics, formerly known as TN Americas. Please see the contact information below:

TN Americas LLC
Columbia Office
7160 Riverwood Drive
Columbia, MD 21046

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Project Manager
TN Americas LLC
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Known design details are included in Chapter 8 of the Application.