APPENDIX F

MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

MISO LRTP TRANCHE 2.1 PORTFOLIO REPORT

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Chapter 2: Regional / Long Range Transmission Planning

2.1 Overview

Under the Reliability Imperative's Transmission Evolution pillar, MISO is transforming how it plans for and manages the grid of the future, given all the complex changes underway. As part of this effort, Long Range Transmission Planning (LRTP) develops backbone regional projects to ensure the transmission system is reliable, economic and compliant in the future based on state and utility policy and goals, projected conditions and industry trends. This is accomplished while demonstrating the transmission portfolio provides benefits in excess of costs and value that is consistent with MISO's Tariff criteria. LRTP tackles needs and issues that are not easily addressed in cyclical planning processes like MISO's MTEP, which focuses on more near-term needs. Instead, it looks at a long-range (roughly 20- to 40-year) view of the system and provides a roadmap or vision to address those future issues, while also guiding near-term transmission planning.

From a transmission planning perspective, LRTP looks comprehensively at the MISO region in collaboration with stakeholders. While its resulting portfolios enable a reliable and efficient grid based on forecasted resources, they are not intended to resolve every issue associated with precise siting of future generation or load. As a result, LRTP portfolios are "least-regrets" to plan for an uncertain future based on the needs reflected in policy and member plans that are current at the time of modeling and analysis.

The overall LRTP effort is large and complex, unlike any effort MISO or any other organization has undertaken in the history of the grid. It takes a long time to plan for comprehensive regional solutions, especially when managing against a great deal of uncertainty. Additionally, LRTP has to be conducted over the course of rapid evolution as business plans, federal and state energy/environmental policies and other dynamic factors that affect the region's transmission needs continually change.

Tariff Requirements

Categorized as Multi-Value Projects (MVPs) under MISO's tariff, LRTP solutions must meet the following requirements: enable the transmission system to deliver energy reliably and economically, in support of documented energy policy mandates or laws; provide multiple types of economic value with a benefit-to-cost ratio of 1.0 or greater; or address at least one reliability issue and provide at least one type of transmission-based economic value. Additionally, an MVP cost allocation methodology must be applied—one that spreads costs footprint-wide on a load-ratio share basis, or spreads costs to a subregion only if benefits are primarily provided to that single subregion.

History

Long-term transmission planning was not new to MISO when LRTP launched in 2020. MISO's initial regional, long-term study began in 2008 to address the integration of renewable energy required by state Renewable Portfolio Standards. It resulted in the Multi-Value Project (MVP) portfolio of projects, which was approved in 2011 and fully constructed by 2024.

In 2019-2020, MISO began to formulate a strategy for LRTP. After cities, states, large commercial and industrial corporations and utilities started setting aggressive renewable and decarbonization goals, MISO members asked MISO to quickly move on long range transmission planning to align with their goals, preferences and investment decisions. In its own studies, like the Renewable Integration Impact Assessment (RIIA), MISO gained insight on significant system issues which would result from the continuing transition of the resource portfolio towards much higher weather-based renewable resources. Paramount to RIIA's findings was the fact that greater penetrations of renewable resources required new transmission to ensure system reliability. Additionally, the transfer capability realized because of this transmission buildout would provide better regional connectivity and thereby reduce the amount of generation capacity that would be needed to meet resource goals.

The job of LRTP is to enable a reliable generation fleet as planned by MISO Members and states. Based on RIIA and the Futures which had been recently updated, MISO knew the industry drivers and high level issues which informed the development of a conceptual, indicative roadmap (see Figure 2.1: Indicative Roadmap). Among other things, the roadmap is an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures. It was contemplated by MISO planning staff as an extension of the existing grid that could provide logical connections that increase connectivity, close gaps between subregions and support a more resilient grid by enabling more transfers of bulk power flows. The roadmap is not a plan, but provides a basis to guide conversations and consider solutions to expected transmission issues. Although solutions in the roadmap may not ultimately meet the necessary requirements to become projects in MTEP Appendix A, the roadmap provided and continues to provide a foundation from which to work.

Because of the magnitude of the needs and the study efforts required to determine solutions, MISO is approaching this large endeavor in tranches, beginning with a focus on the Midwest for Tranches 1, 2.1 and 2.2, moving later to the South region in Tranche 3 and the Midwest-South connection in Tranche 4. In its initial plan, MISO envisioned two tranches for the Midwest but during Tranche 2 planning, recognized the needs of the Midwest should be addressed in three phases. As a result, Tranche 2 was renamed 2.1 and Tranche 2.2 was added.

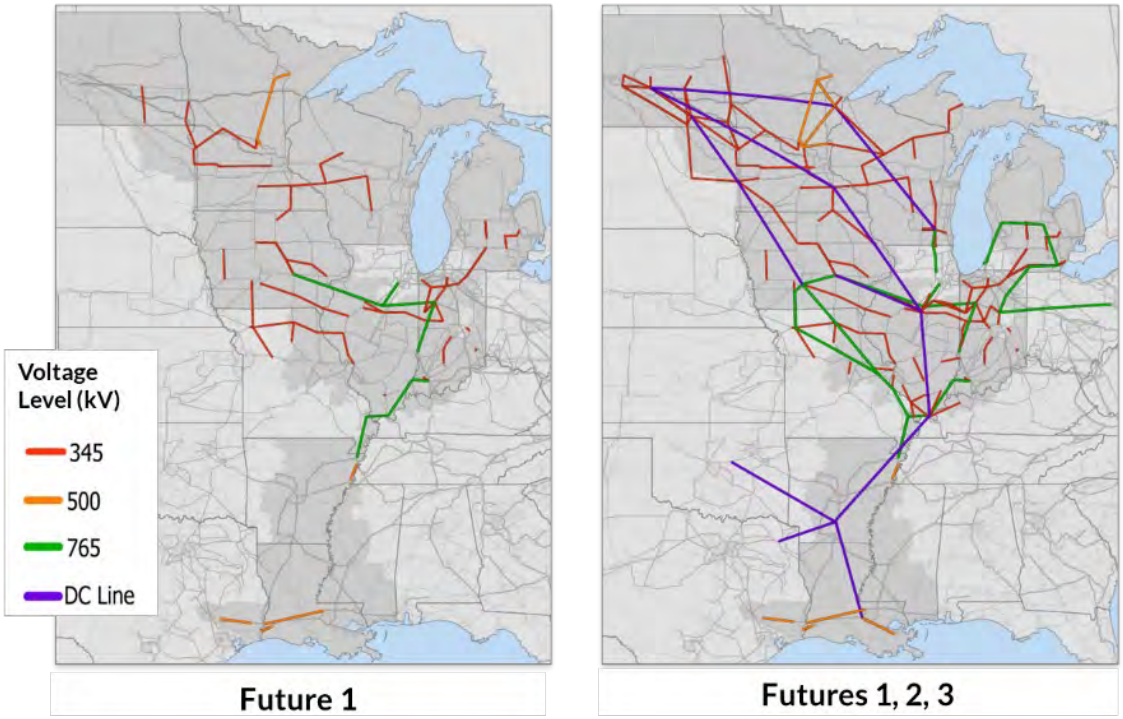


Figure 2.1: Indicative Roadmap

Tranche 1

Approved in July 2022 as part of MTEP21 Appendix A, the Tranche 1 portfolio totals $10.3 billion, consists of 18 projects spread across the entire MISO Midwest subregion and benefits multiple states, MISO members and customers. Planning for Tranche 1 began in 2020 following the development of new Futures Series 1 that reflected policy changes and the plans of states, utilities, and members. Tranche 1 solutions addressed approximately 30% of issues that were identified. Analysis was based on Future 1 and a Multi-Value Project (MVP) cost allocation approach will spread the costs of projects pro-rata to load across the MISO West, Central and East regions (Midwest subregion). A wide range of value will be provided, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

With a Tariff requirement to provide benefits that are commensurate with costs, the full portfolio has a benefit-to-cost ratio of 2.6 - 3.8, which is well in excess of costs, and a benefit-to-cost ratio of at least 2.1 for every MISO zone. MISO's planning maximized the use of existing rights-of-way, which helped reduce the typical challenges in the regulatory process stemming from siting and acquisition of new rights-of-way.

As of July 2024, many projects are well into regulatory approval processes, with MISO supporting constructing Transmission Owners in these efforts. MISO will monitor the status of these projects through the build phase and utilize its variance analysis process to deal with any costs or schedule changes that exceed certain, established criteria, and other project scope or construction challenges that could put at risk getting the projects in service.

2.2 The Planning Process

The magnitude of change planned for the future is now more significant than it was just a few years ago when MISO developed Tranche 1. It requires prompt action to address the fast pace of transformation occurring in the industry. To ensure MISO identifies a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs, a rigorous analysis by MISO with stakeholder engagement was conducted.

For Tranche 2.1, MISO followed its iterative seven-step process to build models, identify issues and test potential solutions, with over 40,000 staff hours invested in the study. Stakeholders were engaged in the process, with more than 300 meetings in various formats and forums, numerous one-on-one discussions, email exchanges and more. A reliability study whitepaper, economic study whitepaper, business case analysis whitepaper, models, scenarios and all key data inputs and analysis results were posted and reviewed by stakeholders. Additionally, formal and informal feedback was received and considered throughout the process, and appropriate updates were implemented based on feedback.

Models focused on Future 2A from the 1A series represented credible system conditions with likely and possible dispatch patterns determined following a data-driven process. Steady state, transfer and transient stability analyses were performed to ensure transmission system performance is reliable and adequate before and after contingencies (disturbances) occur. Economic analyses[1] were performed to evaluate congestion, generation curtailment, regional price separation and overall costs to serve load and to understand the impacts to overall Adjusted Production Cost savings.

To consider opportunities with existing and emerging technologies, MISO reviewed impacts of transmission technology concepts with stakeholders at the Planning Advisory Committee in 2023, discussing 345 kV, 765 kV, High Voltage Direct Current (HVDC) and Grid Enhancing Technologies (GETs). This presentation focused on high-level approaches with technology considerations and the potential impact of thermal and absolute limits, given factors like MW per mile cost and loading limits. For many of the new transmission line needs identified in LRTP Tranche 2.1, the necessary line mileages and power transfer requirements suggested that a 765 kV backbone would be the optimal choice at this stage. Grid Enhancing Technologies tend to work best when they are used to solve local issues, and were considered and selected for certain underbuild projects. Static synchronous series compensator technology was selected for one of the underbuild solutions as a flow control solution.

MISO also conducted robustness testing to determine the potential impact of key projects already approved or under consideration after LRTP power flow models were completed in October 2023. This assessment looked at select MTEP23 and MTEP24 projects, the JTIQ projects and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project, and determined these projects do not negate the need for the Tranche 2.1 portfolio. Additionally, MISO received nearly 100 alternative solutions from stakeholders representing 47 solutions. After the evaluation process, some alternatives were incorporated into the portfolio.

In its final analysis and consideration of stakeholder feedback, MISO concluded the Tranche 2.1 portfolio boosts reliability and economic value, enabling member fleet transitions, load growth and regional power

[1]Consists of utilizing production cost models that simulate chronological dispatch for an entire year (8760 hours). For additional information please refer to MISO Economic Planning Whitepaper.

transfer within MISO, when geographic diversity must be relied upon to help manage dispatch flexibility during a range of operating conditions.

Seven-Step Process

Through a seven-step iterative process (Figure 2.2: MISO's 7-Step Process), MISO plans, assesses, evaluates and repeats steps as necessary to ensure a least-regrets plan. It begins with development of the Futures with stakeholders, based on a minimum 20-year horizon because transmission can take 8 to 12 years to identify, site and develop. MISO forecasts and sites generation resources, as well as load and energy growth. MISO then analyzes the ability of the transmission system to perform reliably and safely in delivering resources economically to load, recognizing member and state goals across the entire footprint.

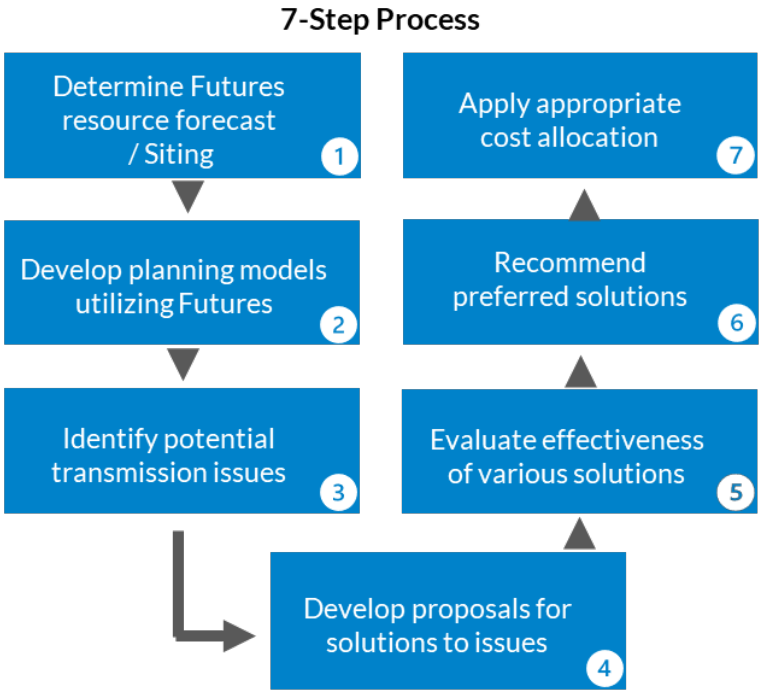


Figure 2.2: MISO's 7-Step Process

From there, MISO develops a conceptual long-range vision of the transmission system that could be needed to meet the Futures scenarios, with a focus on an incremental, subregional buildout based on the needs of each area. As solutions are identified, MISO considers the value of various transmission options in terms of reliability, economic and other factors.

Before choosing solutions to identified issues, guardrails are applied in several scenarios to show reliability and economic value considering how any subregional upgrades may fit into the conceptual long-term plan so MISO doesn't make shorter-term design decisions that would make the future development more costly — for example, effective use of right-of-way — constructing for higher voltages and operating at a lower voltage where that makes sense.

LRTP's focus is on regional transmission solutions, rather than resolving all localized issues. MISO recognizes some issues will be more appropriately addressed by annual MTEP reliability planning and

generator interconnection processes. The LRTP planning process and the reliability component of the NERC TPL annual reliability planning process have related, but distinct objectives. The NERC TPL annual reliability planning process is a compliance-based planning process that ensures the transmission system is planned to address reliability needs in the short-term (i.e., five-year planning horizon, etc.) and relies on known and committed inputs. LRTP is focused on regional and long-term issues that require regional and long-lead solutions. It is not designed to replace the shorter-term generator interconnection and annual reliability planning processes, but instead focuses on broad regional issues that are not sensitive to changes in input assumptions as well as long lead solutions that significantly reduce life cycle costs in the long-term costs and require advanced planning to implement.

Stakeholder Engagement

MISO could not complete this work without stakeholder input. Its transmission planning is conducted through a stakeholder process. In addition to regular stakeholder meetings, MISO provides other opportunities to encourage and ensure strong engagement, such as stakeholder feedback requests.

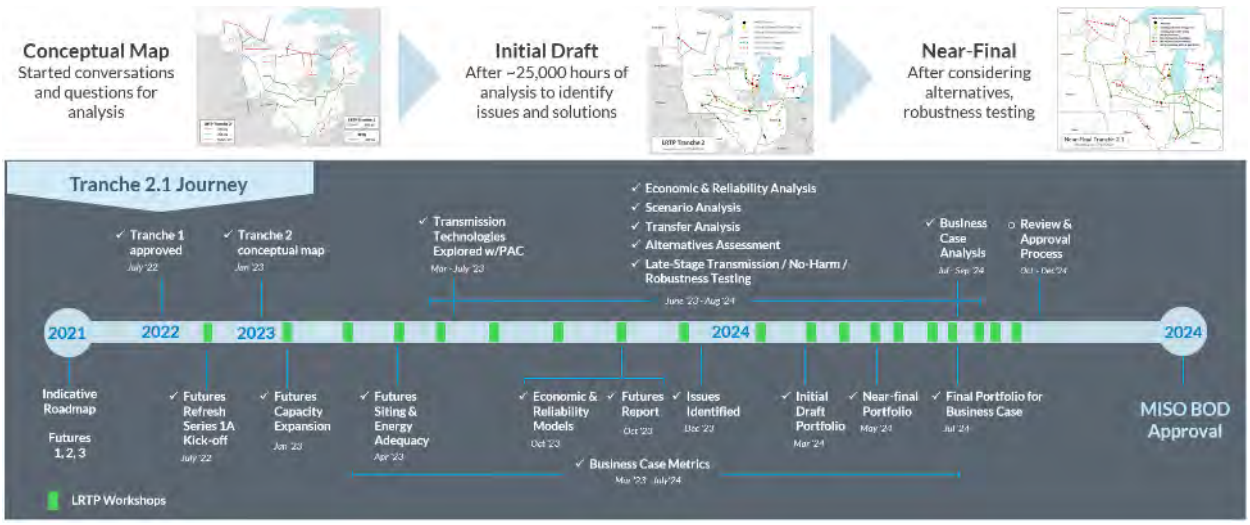


Figure 2.3: Tranche 2.1 Journey

From Planning Advisory Committee (PAC) meetings that analyze identified issues and proposed solutions, to deep dives in LRTP workshops, and so much more, there have been at least 300 meetings – both internal and external – to arrive at the Tranche 2.1 portfolio. With strong interest in LRTP, workshops averaged 275 participants and multiple other meetings and in-depth discussions were held. Among these various stakeholder meetings, MISO utilized both its public Stakeholder Feedback Tool and its LRTP email to elicit much of the feedback received and inform the inputs, scope and metrics for the Long Range Transmission Panning process. MISO reached out to Stakeholders 10 times across two years for Formal/Informal feedback thru the Feedback Tool; this combined with oral feedback received at LRTP workshops to shape the processes and portfolio. An example of feedback from the Feedback Tool and LRTP email includes:

- The Futures and Siting process was informed by 500+ stakeholder revisions impacting the inputs of the process

- MISO received significant stakeholder feedback and used that feedback to implement changes to the reliability and economic models throughout multiple months
- Stakeholder feedback informed the transfer scenarios selected as part of the scope
- Feedback was instrumental in informing the business case metrics

After sharing its rationale for planning approach, analysis and key decisions, MISO is confident it has developed a least-regrets, robust portfolio.

Step 1: Establish Futures and Siting

LRTP's planning begins with forward-looking planning scenarios called Futures, which capture a range of economic, political, and technological possibilities over a twenty-year period, provide potential resource mixes, and appropriately bookend future uncertainty. The Futures are based on member data, stakeholder input, state and federal policy, and technical and economic data like the DOE's National Renewable Energy Lab (NREL) Annual Technology Baseline. MISO defined three Futures which co-optimize several parameters to minimize total costs in achieving member goals, including peak demand plus reserve margin, annual energy, decarbonization goals and renewable portfolio standards/clean energy goals.



Figure 2.4: MISO Futures

MISO Futures

To develop Futures, MISO follows a rigorous, stakeholder-driven process to bridge the gap between what members plan for the future and the generation needed to get there. The original Futures are referenced as Series 1 (Futures 1, 2 and 3). The refreshed Futures, called Series 1A (Futures 1A, 2A and 3A) were initiated in July 2022. They provided the basis for the Future 2A resource expansion, which began in January 2023 with stakeholder engagement and included 500 siting changes based on feedback. Energy adequacy analysis was completed in April 2023 and was followed by capacity expansion modeling, siting, and production cost

modeling handoffs development for Futures 1A and 3A for MISO (and the three external areas modeled). Initial screening analyses was conducted in Summer 2023.

MISO posted the Series 1A Futures Report in Fall 2023 and then continued to conduct various screening analyses of the resource mix for the portfolio through January 2024. For Tranche 2.1, MISO determined Future 2A is most aligned with an optimized, least-cost expansion that meets member goals and Future 1A is an appropriate low-end bookend for the business case analysis.

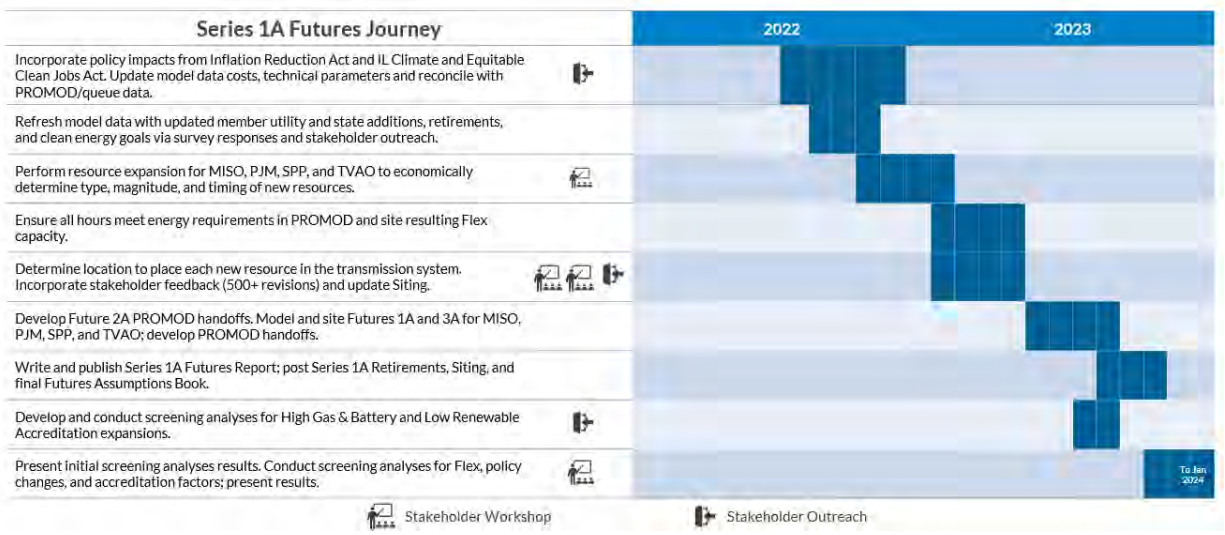


Figure 2.5: Series 1A Futures Journey

The Futures are periodically refreshed with key data inputs to help ensure the most accurate forecasts are used in planning. Subsequent refreshes will be driven by the timing and pace of planned new generation based on policy, load and other drivers of change.

Resource Expansion

Since MISO is not an integrated resource planner, MISO Futures reflect resource plans announced by member utilities and states. MISO is obligated to reflect and define a resource expansion that aligns with these plans. As such, transmission planning works to ensure the energy planned by members can be delivered to where it's needed. Additional future resources beyond member plans are required to meet projected load, policy objectives, and reserve margins. To bridge this gap, MISO performs an economic resource expansion analysis, which forecasts the additional resources to meet system needs at lowest cost.

For more than a decade, MISO has utilized a transmission-less, non-chronological resource modeling tool for transmission planning analysis. MISO develops a least-cost resource expansion with total costs linked to key assumptions, which grounded the Futures. Several notable outcomes from these key assumptions on Future 2A include:

- **Generation Additions and Retirements:** For additions, 54% of the F2A expansion originates from member-planned resources. For retirements, MISO used member data and applied age-based retirement assumptions in cases for which no feedback was provided on generator retirement dates. For example, member data directly provided approximately 77% of coal retirements.

- **Load:** MISO benchmarked its load forecast with McKinsey & Company in 2022 and found load projections fell within Future 2A and Future 3A with annual energy similar to Future 3A.
- **Incentives:** The Inflation Reduction Act provides various incentives for battery, solar, hybrid and wind, which lower their respective overall costs through investment or production tax credits.
- **Resource Type Cost Modeling**: Resource operations and maintenance (O&M) costs are offset by incentives (Inflation Reduction Act), with wind costing the lowest and hybrid and battery the highest.
- **Decarbonization Goals:** 75% of MISO load is served by members with ambitious decarbonization and/or renewable energy goals.
- **Battery Storage Assumptions:** By utilizing excess energy for charging, battery storage plays an important role in the Futures expansion to minimize the overall resource fleet cost. Future 2A includes 11 GW of member-planned battery and 20 GW of model-built battery, for a total of 31 GW of 4-hour lithium-ion battery.
- **Accreditation:** Capacity accreditation was based on the approved 2022 Planning Resource Auction and shifts over time based on the Renewable Integration Impact Assessment (RIIA)

A full list of the Futures assumptions is included in the Futures Refresh Assumptions Book.

Resource Siting

Futures development culminates in a siting process that maximizes resource availability and accommodates member goals. After the expansion, siting analysis ensures these resources can be built in needed areas. MISO followed a stakeholder-approved siting process which was covered in the Series 1A Futures Report and Futures Refresh Assumptions Book. As part of this process, MISO sited model-built resources to address the following:

- Local/regional Renewable Portfolio Standards (RPS) and decarbonization goals
- 80/20 split between Generator Interconnection (GI) queue and Vibrant Clean Energy (VCE)/Greenfield Sites for renewable resources, with:
    - Up to 80% of Wind, Solar, or Hybrid sited at Active Definitive Planning Phase (DPP) 1, 2, or 3 Generator Interconnection (GI) Queue or Tranche 1-enabled sites
    - Remaining ~20% sited at VCE-identified areas with renewable potential
- Each Local Resource Zone (LRZ) meeting its Local Clearing Requirement (LCR) and Planning Reserve Margin Requirement (PRMR)
- Capacity sited at 5-year milestone intervals (2027, 2032, 2037, 2042)

Once the expansion was determined, MISO worked with stakeholders to determine appropriate resource sites, including over 500 revisions based on extensive stakeholder feedback:

- Made significant modifications to the sited wind across the MISO footprint, including:

- Moved all preliminary sited MISO South model-built onshore wind to MISO Midwest (primarily North Dakota and South Dakota)
- Moved ~60% of member-planned onshore wind in MISO South to SPP as a planned external resource
- Moved wind in Wisconsin and northern Minnesota to North Dakota and South Dakota

- Situationally re-sited capacity at provided/preferred buses:
    - Redistributed solar and solar hybrid to include more of these resources in MISO South and Wisconsin
    - Re-sited thermal capacity from MN and IL to locations provided by stakeholder feedback
- Redistributed Demand Response and distributed generation photovoltaic (DGPV) resources over additional sites
- Incorporated additional member-planned resources, primarily energy storage and Reciprocating Internal Combustion Engines (RICE)
- Reduced offshore wind due to a 54% reduction of the Wind Energy Area (WEA) affecting the size and availability of Bureau of Ocean Energy Management (BOEM) leasing sites near LA and TX.

Energy Adequacy and PROMOD Analysis

An example that demonstrates managing uncertainty through MISO's comprehensive, iterative process is how MISO assessed energy adequacy during analysis to arrive at Future 2A. An energy adequacy analysis ensures the grid can be operated reliably, meeting energy needs during all hours with the forecasted resource mix—an important step given the increase in intermittent resources. Through planning, analysis revealed an energy shortfall during what MISO has called the twilight hours—at sunset and sunrise—when wind output is typically low and solar output is unavailable.

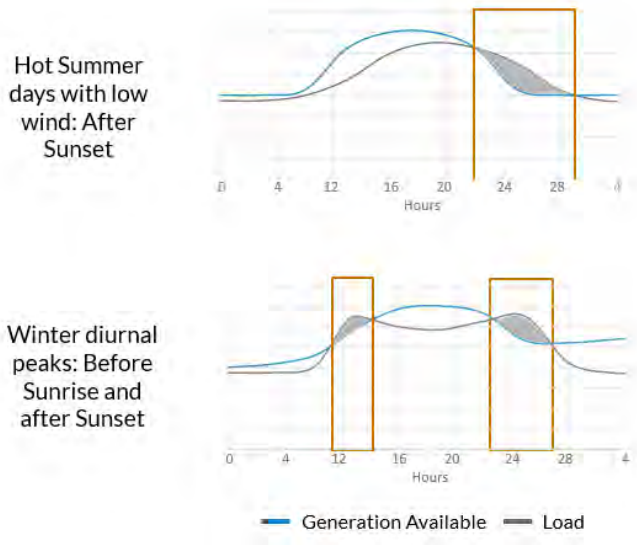


Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units

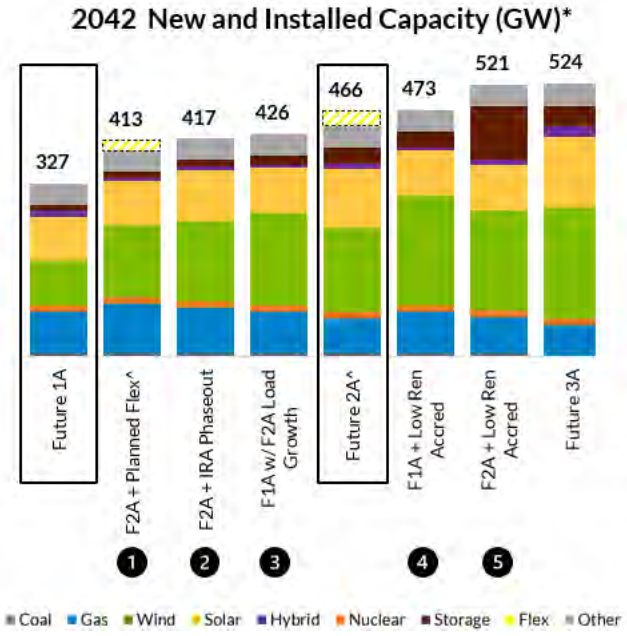
PROMOD, a production cost modeling tool providing hourly (annual) chronological security-constrained unit commitment and economic dispatch, identified generation shortfalls for three to four hours per day during twilight hours (before sunrise or at sunset) in up to 26 days of the modeled year, with a maximum shortfall of 29 GW in a single hour. To address this energy shortfall, 29 GW of supplemental low- or no-emitting, high availability resource additions, referred to as Flex for Flexible Attribute Units, were needed to ensure energy adequacy during these time periods. This is reflected in the shaded areas of both graphs in Figure 2.6: Energy Adequacy Analysis for Flexible Attribute Units.

These "Flex" units represent potential generation that is highly available, highly accredited, low- or non-carbon-emitting and long in duration. Flex resources could be, but are not limited to the following: Reciprocal Internal Combustion Engine (RICE) units, long-duration battery (>4 hours), traditional peaking resources, combined cycle with carbon capture and sequestration, nuclear Small Modular Reactors (SMRs), green hydrogen, enhanced geothermal systems, and other emerging technologies.

Low-End Bookend

MISO's LRTP processes define a robust portfolio of transmission to achieve the energy goals of MISO states and members under a range of conditions. Part of this robustness is achieved through ensuring the models used in scenarios appropriately bookend future uncertainty and capture potential resource mixes. The Resource Expansion results drive the selection of transmission solutions.

As such, MISO conducted multiple screenings assessing the impact of different changes on the resource mix and validated Futures 2A and 1A as appropriate bookends. Many of the screens performed showed resource mixes similar to Future 2A; as a result, MISO proceeded with Future 1A as the low-end bookend.



	Screening	Details
1	Future 2A + Planned Flexible Attribute Units	Inclusion of 29 GW of Flexible Attribute units as planned gas units
2	Future 2A + Inflation Reduction Act Phaseout	Assumed phaseout of Inflation Reduction Act provision after 2030
3	Future 1A + Future 2A Load	Expansion using F1A goals and retirement assumptions and F2A load growth
4	Future 1A + Low Renewable Accreditation	F1A with wind and solar resource receiving 5% capacity credit
5	Future 2A + Low Renewable Accreditation	F2A with wind and solar resource receiving 5% capacity credit

Figure 2.7: Futures Low-End Bookend

Step 2: Develop Planning Models Utilizing Futures

Reliability Models

MISO built 10-year, and 20-year reliability models based on Future 2A for LRTP reliability analysis. As part of this analysis, MISO tested transmission reliability under likely and possible dispatch with a focus on the worst credible conditions from the system point of view, while recognizing that local conditions may vary.

A set of base models were used to assess the impact of variable renewable and hybrid generation and other system conditions. These broad base models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus providing the platform to perform a wide range of reliability studies.

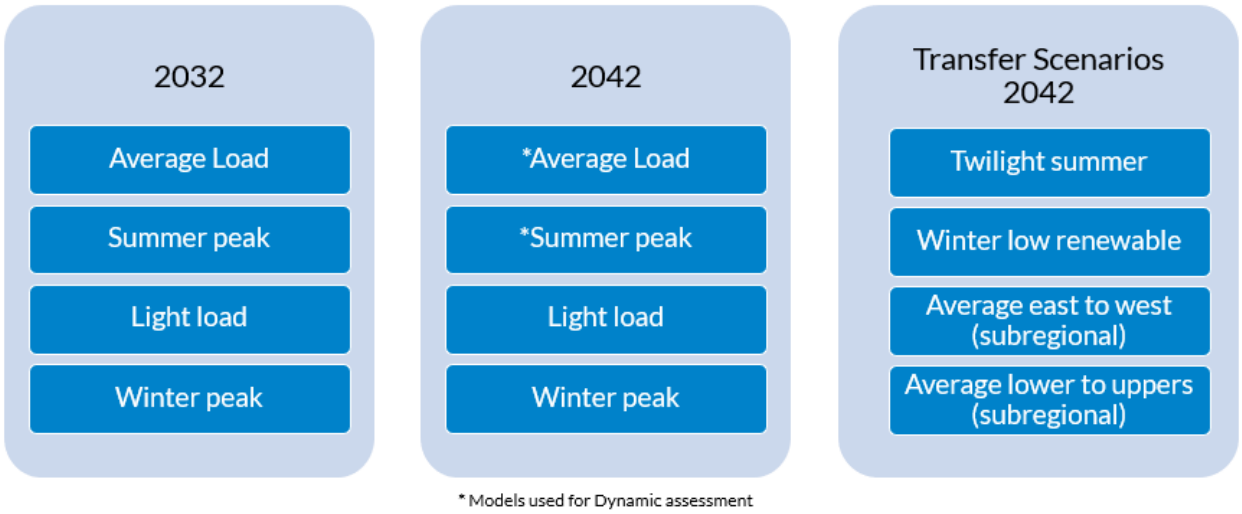


Figure 2.8: Core Models used in Reliability Assessment

Core models were determined via load points on the MISO annual load duration curve (see *Figure 2.9: Overview of load levels in Future 2A, Table 2.1)*. After selection of these load points, coincident output from wind and solar resource profiles were used to derive a credible dispatch for the given scenario. Figure 2.9 shows an overview of load levels in Future 2A, informing the selection of reliability models. To the right, the load duration curve is shown, highlighting the four desired load levels for the core models. The left shows a series of indicative daily load shapes and how they map to the load duration curve. These power flow models provided the basis for steady state, dynamic, voltage stability and additional scenarios. A more comprehensive explanation of reliability models and analysis is available in a MISO Reliability Study Whitepaper.

Core cases	Renewable and storage dispatch methodology	Reason for inclusion
Case 1: Summer Peak Load • Represents summer peak demand which is the highest load on the annual load duration curve	• High coincident renewable output in the summer between 90% and 100% of the annual peak demand • Storage off	• Test the ability to reliably serve load via variable renewable energy and conventional resources
Case 2: Winter Peak Load • Represents winter peak demand	• High coincident renewable output in the winter between 90% and 100% of the annual winter peak demand • Storage discharging at 50% nameplate	• Local/Regional/System load profile and peak is different from the summer case • Test ability of renewables to reliably serve load considering load profile diversity • Test system ability to export to Manitoba Hydro
Case 3: Average Load • Represents typical system conditions within 70-80% on the load duration curve	• High coincident renewable output between 70% and 80% of the annual peak demand • Storage charging at 60% nameplate	• Assess system ability to move power and reliably serve load during the annual maximum coincident wind/solar, which is likely to occur during this timeframe • Peak variable renewable energy case is essential to evaluate dynamic performance
Case 4: Light Load • Represents lowest 10% on the load duration curve	• High coincident renewable output to test ability of the system to absorb reactive power • Storage charging at 60% nameplate	• Assess system conditions during low load, moderate wind, and zero solar output

Table 2.1: Core models

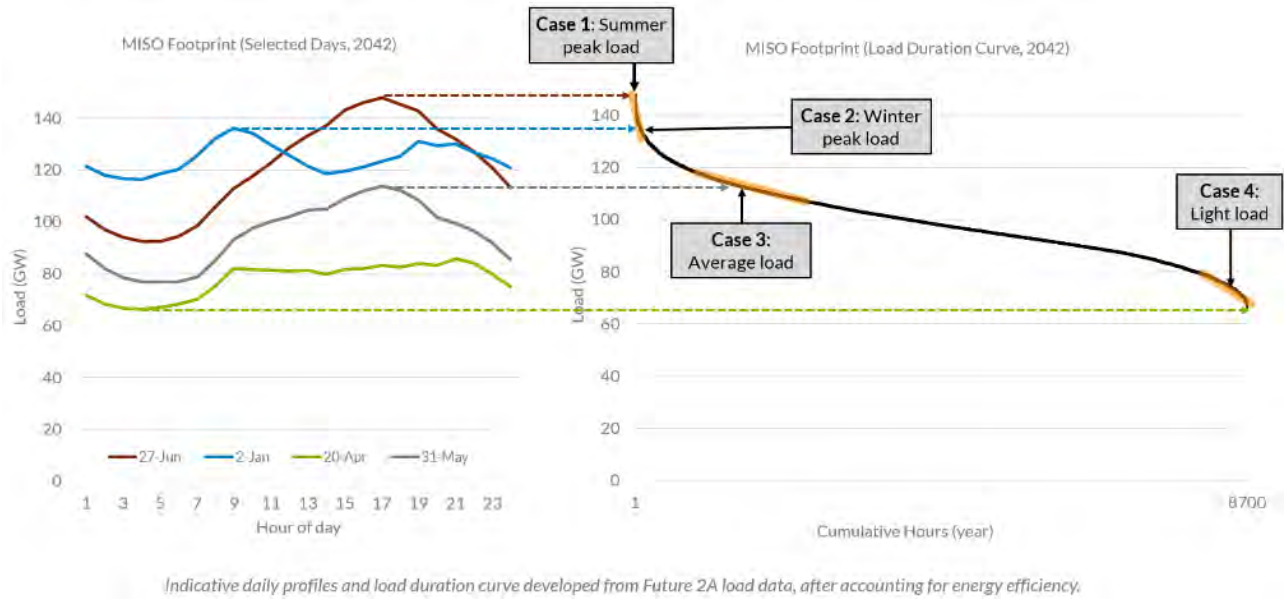


Figure 2.9: Overview of load levels in Future 2A

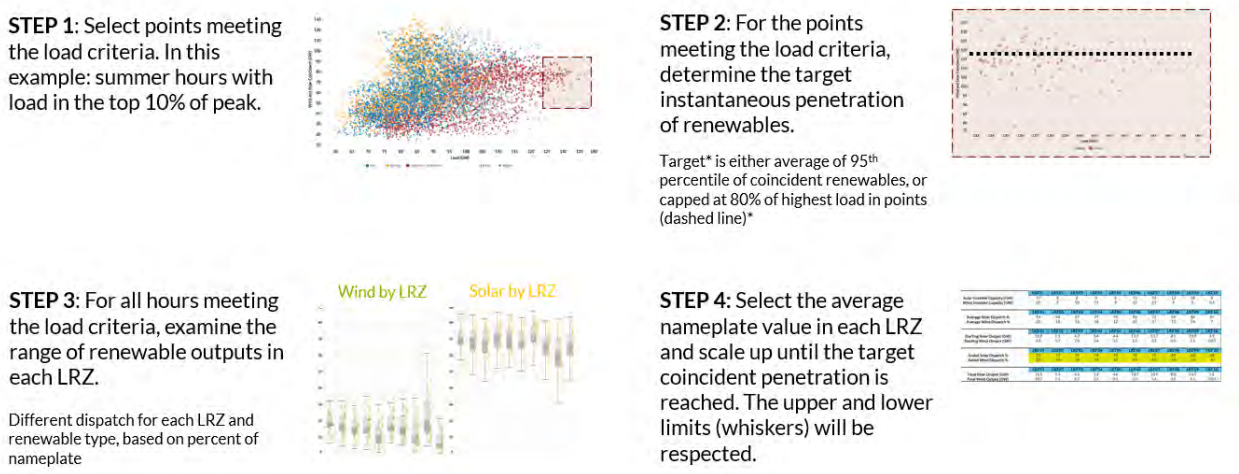


Figure 2.10: Overview of renewable dispatch methodology. This 4-step process provided a target variable dispatch for wind and solar resources specific to each LRZ. This served as a basis in the dispatch each of the core models.

Typically, powerflow models with high instantaneous penetration of renewable energy are challenging to solve. Furthermore, the retirements and additions from Future 2A represent a steep change from the starting models of MTEP22. Inverter Based Resources are modeled with a reactive power max (Qmax) and reactive power min (Qmin) at +/- 0.95 Power Factor based off the Power Generation (Pgen) of the unit. The units will adjust their reactive output within those limits to hold the scheduled voltage at the designated voltage-controlled bus Point of Interconnection (POI).

MISO has solved high renewable models through the Renewable Integration Impact Assessment (RIIA) and through building study models for the Definitive Planning Process (DPP) (i.e., interconnection queue). The goal of a power-flow model is to obtain a stable combination of voltages angle and magnitude information for each bus in a power system for specified load, generator, and topology conditions. Due to the nonlinear nature of this problem, to obtain a solution that is within an acceptable tolerance, the following issues may be experienced:

- The maximum real or reactive mismatch at any bus in the system exceeded
- The voltage magnitude and angle difference between buses too big or unknown
- The maximum number of iterations exceeded, etc.
- Voltage collapse and/or divergent solution

To solve the models, many methods may be required, such as:

- Additional fictitious reactive support devices
- Adjustment of model parameters including tap settings and voltage-controlled buses
- Localized generation curtailment if case approaches instability

- Model review to identify and rectify modeling issues

For each case MISO provided a summary of issues identified and methods (solutions) used to ensure modes are within acceptable tolerance. Once models were solved, the addition of fictitious resources, transmission lines, reactive resources or other model tweaks were re-examined for necessity and removed from the case to the extent possible.

Economic Models

MISO built 10-year, 15-year and 20-year economic models based on Future 2A for LRTP economic analysis. As part of this analysis, economic modeling utilizes PROMOD, a chronological security-constrained unit commitment and economic dispatch tool which applies a wide variety of operating constraints. Within the PROMOD model, Futures assumptions around load, generation, and fuel costs are incorporated up to a 20-year time horizon along with transmission grid topology and constraints to assess future transmission needs.

The economic model produces a unit commitment and security-constrained economic dispatch while optimizing production costs. The analysis allows simulation of all 8,760 hours in a year, not just the peak hour. The economic study model encompasses multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus allowing the model to perform a wide range of economic analysis.

Economic modeling and analysis rely on a 10-step process that starts with a core "No-Futures" model and ends with a "Final" economic model for portfolio development as shown in Figure 2.11. Throughout this process, MISO allows for touchpoints with stakeholders to incorporate feedback on models and flowgates, transmission issues and the portfolio, and to coordinate with the MISO reliability teams to sync issues and solutions across study work.

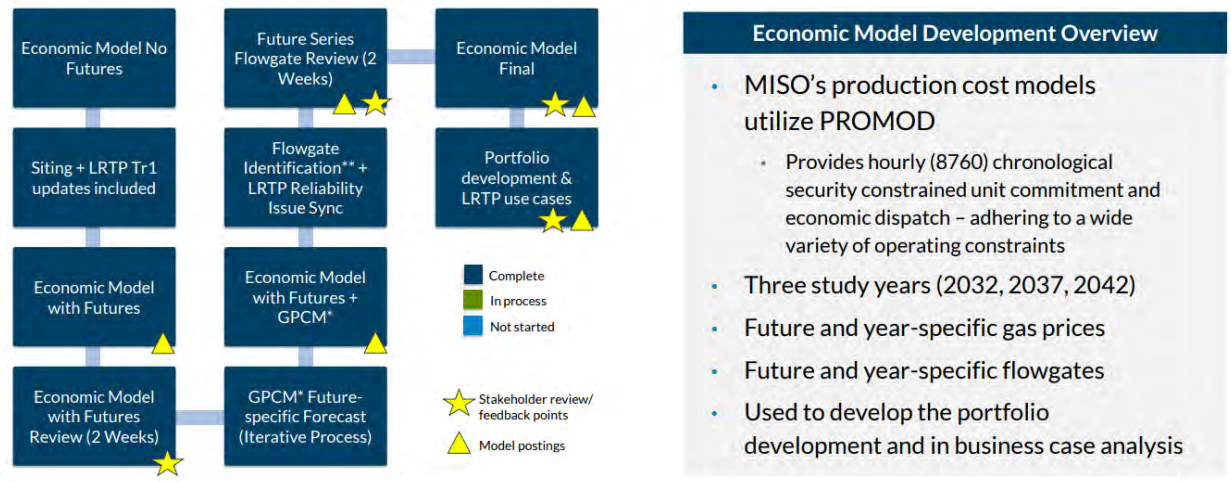


Figure 2.11: Economic Modeling 10-Step Process

Each of the economic production cost models include chronological Future- and year-specific assumptions for multiple regions to identify economic constraints and test potential solutions (See Figure 2.12: Economic Model Development Study Years).



Figure 2.12: Economic Model Development Study Years

Economic Model No Futures

The Economic model building process starts with developing the base economic model without any Futures assumptions. This requires compiling Hitachi-released generation and fuel data, resource utilization data, and transmission topology for the MISO footprint and neighboring entities. The Series 1A No Futures model includes:

Base Economic Data	What's included
Hitachi PROMOD Releases	o Fall 2021 – generator updates and economic data o Spring 2022 – coal price updates o 11.5.1 engine
Neighboring Entities Data	o SPP generator additions and economic data o PJM generator additions and economic data
Resource Utilization	o Generators with signed GIA additions o Attachment Y Retirement updates
Powerflow Model	o MTEP22 - 2032 Summer Peak Powerflow model with updates o LRTP Tranche 1 Projects o 2032 Winter Peak Powerflow model ratings
Natural Gas Price	o Q2 Henry Hub 2022 natural gas prices

Table 2.2: Economic Model No Futures Inputs

Economic Model with Futures

After finalizing a set of Futures with an energy adequacy validation process, that set is fully incorporated into the economic model, resulting in the Economic Model with Futures. Once an economic model with Futures is created, the database is made available to stakeholders who have completed the necessary non-disclosure documents with MISO. As part of this process, MISO looks to stakeholders to provide feedback on transmission ratings, generator attributes, and any other discrepancies identified within the database provided. Economic Planning works with stakeholders to update model data and address potential modeling concerns as needed.

Gas Price Forecasting

The Economic model includes estimated gas prices calculated using a Gas Pipeline Competition Model (GPCM) process. The GPCM models the physical and market systems of gas pipeline networks to forecast natural gas production, pipeline and storage utilization, deliveries, and prices at different locations across the North American gas market. By completing this process after the incorporation of Futures assumptions, the gas prices reflect the impact of changing gas demand levels. The 'Economic Model with Futures' is used in an iterative process to reach convergence between gas prices and gas burns within the associated PROMOD model as seen in Figure 2.13.



Figure 2.13: GPCM iterative process

Flowgate Identification

The MISO Flowgate Identification process has been developed and refined over time through multiple MTEP economic studies. Flowgate Identification requires multiple tools, including and not limited to PROMOD and PROMOD Analysis Tool (PAT), and requires multiple iterations to identify transmission constraints to construct the PROMOD event file (See Figure 2.14: Economic Flowgate Identification Process I). PROMOD utilizes an event file as instructions on what elements to monitor and what constraints to include in a run. Due to the size and complexity of a PROMOD model, not all transmission can be included in the event file. The Flowgate Identification process produces an event file that captures likely predicted binding flowgates for the economic analysis while still allowing the PROMOD model to solve. Additional criteria for flowgate identification is detailed in Figures 2.15, 2.16 and 2.17.

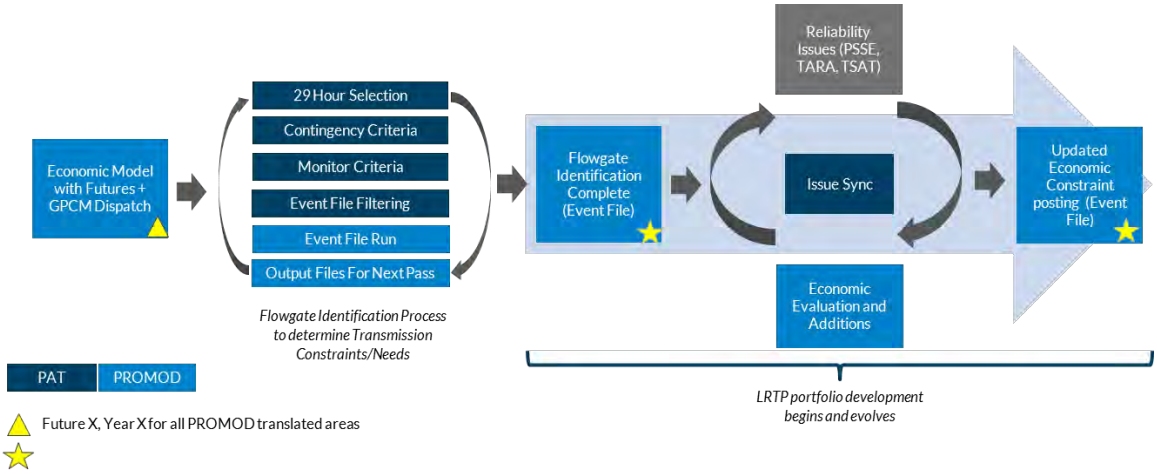


Figure 2.14: Economic Flowgate Identification Process I

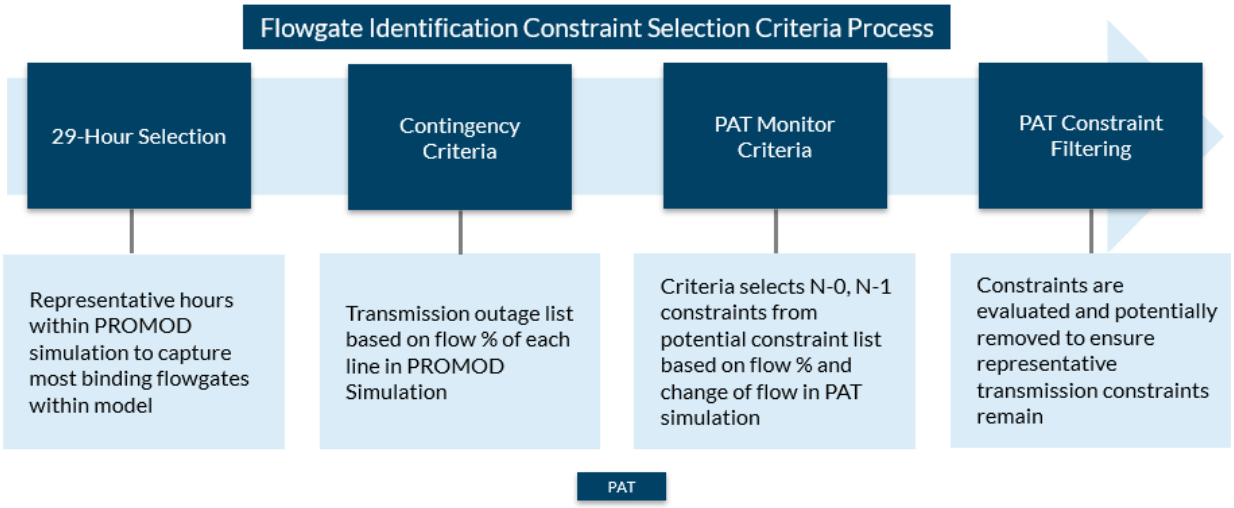


Figure 2.15: Flowgate Identification Constraint Selection Criteria Process II

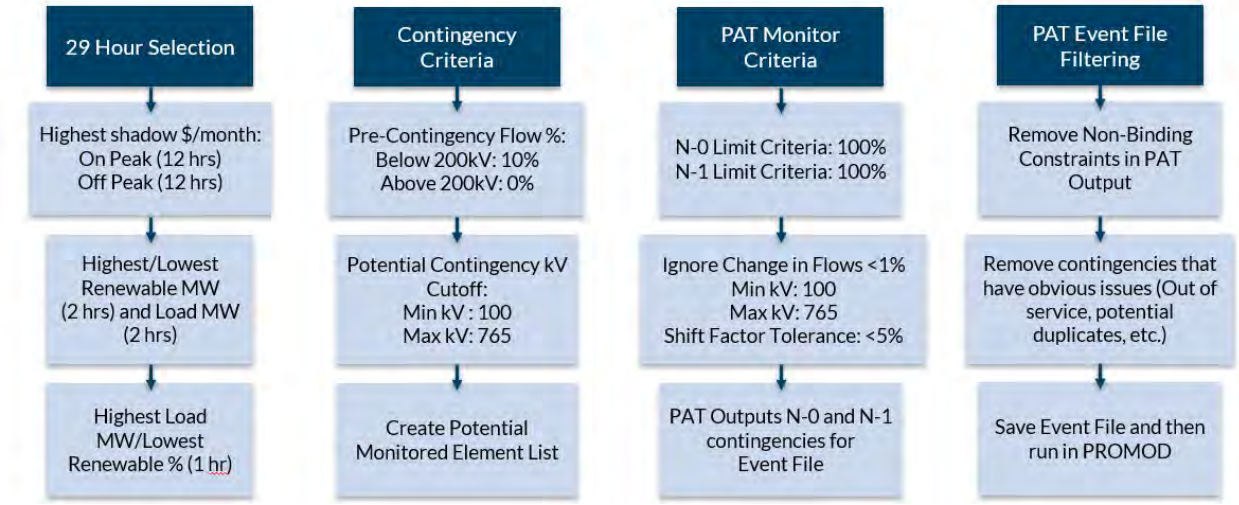


Figure 2.16: Flowgate Identification Constraint Selection Criteria Process III

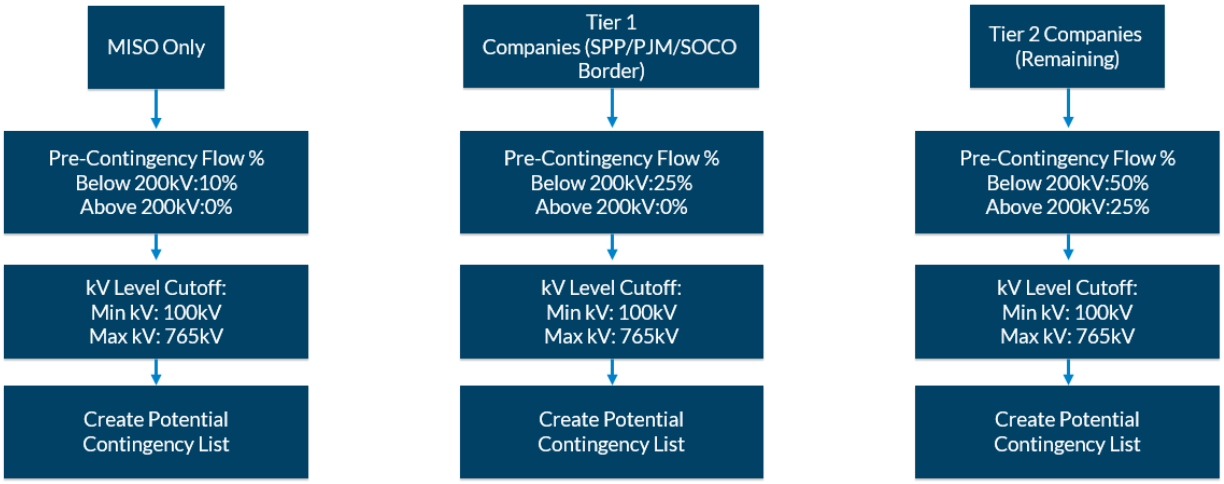


Figure 2.17: Flowgate Identification Constraint Selection Criteria Process IV

Step 3: Identify Transmission Issues

Step three involves performing reliability and economic analysis to identify transmission issues. The purpose of reliability analysis is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 2A scenario in the 10-year and 20-year time horizons. Economic analysis identifies issues like congestion, generation curtailment, widespread price separation, and price to serve load. The reliability analysis and economic analysis are iterative processes that are coordinated with each other to determine cost-effective and reliable solutions.

Tranche 2.1 work focused on resource changes contemplated by Future 2A. Key reliability and economic issues provided the foundation to develop Tranche 2.1 as a no-regrets and stand-alone first step towards the transmission required to enable Future 2A.

Economic and reliability analysis showed significant congestion across the Midwest, with widespread price separation and generation curtailment, along with significant levels of overload on lower and higher voltage equipment and decreased reactive support across the system. Also, the addition of generation located further away from load requires longer-distance transmission lines, and the lower stability limits of these lines increase stress on the system. Similar results were seen in the economic analysis with the widespread locational marginal price separation due to lack of a regional high-voltage backbone. Results also revealed opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion.

Reliability Analysis

The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. It is important to understand that the Tranche 2.1 portfolio was designed to enable the grid of the future and

was not designed to resolve all identified issues. Consequently, there remain unresolved overloads, voltage violations and non-converged contingencies in the Tranche 2.1 reliability models. To the extent an issue is local and caused by a specific driver, LRTP may not resolve it. The two most common examples of local issues from specific drivers would be local generator interconnection issues and local load growth issues. If the specific siting of a Futures resource causes an issue that would not exist if the siting was relocated to a different bus within the local area, that tends to suggest that the issue is local and specific to siting of the resource, and should be addressed by the generator interconnection process if and when that specific site is pursued by an interconnection customer. Likewise for local load growth, to the extent the load growth was relocated to another bus or set of buses within the local area, if the issue persists, this suggests it might be a regional issue. If the issue is resolved or changes, this would suggest it is an issue related to load growth that the annual MTEP reliability planning process has not yet detected based on a much shorter planning horizon, and is best addressed in the future via the annual reliability planning process. As part of the MISO reliability analysis process, engineers have conducted a thorough review of the study results to ascertain if specific issues tend to be more local in nature, as described above, or more regional in nature.

Furthermore, LRTP is not a NERC compliance study, whereby every issue identified must have an appropriate mitigation measure according to NERC standards and requirements. Some issues identified in the LRTP analysis were local in nature and will be addressed in other planning processes, such as the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty.

Additionally, MISO conducted transient stability analysis to determine the degree to which the proposed LRTP portfolio improved system performance related to angular stability. MISO also utilized Safe Loading Limits (SLL) calculated based on the St. Clair methodology as an additional metric to assess the improvement in overall stability and voltage performance of the system. Unlike thermal limits, safe loading limits decrease as line length increases for Extra High Voltage transmission lines; thus, safe loading limits are a good general metric to assess the overall improvement in angular stability performance.

Reliability analysis ensures the transmission system can reliably serve load under various system conditions and dispatch patterns.

- Assess transmission line loading and voltages for a wide variety of system events called “contingencies”
    - Example of a contingency: a line trips offline to clear a fault
    - At a minimum, performance is evaluated against applicable contingency events and planning criteria
    - This study included 55k single initiating events and 100k multiple contingency events

Transmission projects may be identified to:

- Ensure transmission system performance is reliable and adequate before and after contingencies occur
- Enable high regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty

Reliability analysis included several different types of simulations, each targeting different information about performance. Multiple iterations were performed to build models, identify issues and test potential solutions.

Name	Description	Timeframe	Tools
Steady-state	Determines if transmission facilities remain within safe design limits (line loading and voltage) following disturbances	• One operating point (instant) • 5+ min after a system disturbance	Powerflow (PSS/E, TARA)
Transient stability	Determines if the system will experience uncontrolled loss of load or generation following disturbances; focus on voltage and frequency performance	• 0-30 seconds following a system disturbance	Dynamics (PSS/E, DSA)
Transfer analysis	Assesses impact of various system conditions, dispatch patterns and intra-regional power transfer limits; focus on line loading and voltages	• One operating point (instant) • 5+ min after each change	Transfer analysis (PSS/E, TARA)

Table 2.3: Description of reliability study components for LRTP 2.1 study

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the four base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP single element (NERC Category P0, P1, P2, P4, P5, and P7) contingency events and selected multi-element (NERC Category P3, P6) events. Facilities in the Midwest subregion were monitored for steady state thermal loading in excess of 90% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria. For Extra High Voltage lines that are longer than 50 miles, loading levels were also assessed utilizing the Safe Loading Limit (SLL) metric.

Transfer Analysis

MISO utilized core models and built another set of models called 'transfer scenarios/models' utilizing transfer techniques to test for robust performance under varying dispatch patterns. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another), these new models were created and added to the set of study models. These additional 'transfer scenarios/models' can be utilized for any further analysis like the core models. The LRTP transfer study includes four transfer scenarios (20-year models) to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

MISO leverages its extensive geographic footprint and diverse resources to ensure that the system remains reliable in the future. Transfer analysis helps assess system performance, particularly concerning subregional internal import and export capabilities during high regional power transfer scenarios. These scenarios arise when geographic diversity becomes crucial in managing dispatch volatility and resource uncertainty to serve anticipated load. Generation patterns are expected to significantly shift between day and night, as well as seasonally. Therefore, the ability of load in one area to be supported by generation from a remote area will become increasingly important for ensuring ongoing system reliability.

To better evaluate the need for system flexibility, assess project effectiveness under broader assumptions, and understand the impact of locational variability in resource profiles, additional transfer scenarios were developed. MISO utilized core models and built another set of models called 'transfer scenarios/models'

utilizing transfer techniques. Once the appropriate transfers (MWs flow from one area to another and/or from one fuel type to another) are added to the core models, these new models were created and added to the set of study models. These additional 'transfer scenarios/models' can be utilized for full contingency analysis similar to the core models.

- East to West Transfer Scenario, derived from 2042 Average Model, highlights the bi-directional nature of the system with flows reversing as system conditions change. 18 GW of excess wind and solar in Local Resource Zones (LRZs) 4-7 is exported into LRZs 1-3 as they experience lower renewable output.
- Lowers to Uppers Scenario, derived from 2042 Average Model, highlights the importance of accessing resources in lower Central regions (hours where WI and MI will rely on imports). Additional excess wind from LRZs 4-6 exports into LRZ 2 (reached limit of 0.8 GW beyond the initial 4.2 GW import) and LRZ 7 (reached limit of 3.6 GW beyond the initial 5.8 GW import) as they experience lower renewable output.
- Winter Peak Low Renewable Scenario, derived from 2042 Winter Model, captures multi-day periods of low renewable output expected to occur during early morning hours and regional winter freeze. Winter low renewable scenario dispatches down solar, wind, and batteries. All conventional resources and demand response resources are dispatched to their maximum nameplate capacity. This scenario represents the lowest renewable scenario of all core models and additional scenarios with an objective to test reliance on conventional local resources to support load during winter freeze that historically occurred on MISO system.
- Twilight Summer Scenario, derived from 2042 Summer Model, captures the ability of conventional resources to meet demand during sunset. Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. All conventional resources and demand response resources are dispatched up. Batteries are assumed unavailable since this scenario represents a multi-day low renewable scenario and batteries are not able to recharge.

Initially MISO scoped to build a fifth West to East Scenario, derived from 2042 Average Model, which highlights system limitations of output in the West. This scenario was removed from the final list as heavy West to East Bias was already present in core models and while attempting to further increase West to East flows only achieved a 2% increase in dispatch of wind nameplate percentage in LRZs 1 and 3 before voltage collapse i.e., 1.5 GW of excess wind in LRZs 1 and 3 exports into LRZs 2 and LRZs 4-7 as they experience lower renewable output.

The scope for transfer scenarios were initially presented at the LRTP workshop in August 31, 2023 and needs or issues presented at the LRTP workshop January 26, 2024. Each core model and additional transfer scenarios have supporting information such as imports/ exports from each zone with all material posted on MISO Sharefile. In addition, all results and system performance under various contingencies are posted as well.

Dynamic Assessment

With the increasing integration of renewable energy sources, dynamic assessment is essential for managing the variability and uncertainty introduced into transmission systems. This assessment evaluates how the system performs under different system conditions and dispatch patterns, ensuring that transmission networks can meet future energy demands while maintaining stability and reliability.

In the LRTP Tranche 2.1 dynamics analysis, the focus was on comparing the dynamic performance of the system with the final portfolio against a base case scenario without the portfolio. The LRTP dynamic models were constructed from the steady-state power flow models, ensuring that the topology and dispatch align with these models.

For transient stability analysis in Tranche 2.1, MISO evaluated the system's performance using the 2042 Summer Peak and 2042 Average Load core models. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

MISO monitored key factors such as Transient Stability Index (TSI), first swing transient stability, angular oscillations, damping characteristics, and voltage recovery for dynamic disturbances applied to the models, comparing the performance of scenarios with and without the portfolio.

Voltage and Reactive Support

As more renewable energy sources are integrated into the grid, reactive support becomes increasingly crucial for managing their variable output and maintaining system stability. Reactive power helps keep voltage levels within acceptable limits, which is vital for the stable operation of the power system. It improves efficiency, reduces losses, and enables transmission lines to carry more power without exceeding thermal limits, effectively increasing their transfer capability.

MISO has adopted a more conservative approach during model building and criteria selection for future Inverter-Based Resources (IBR), with their reactive capabilities determined by their output i.e. +/- .95 Power Factor based on output at the time and system needs. MISO used default acceptable steady-state thermal and voltage limits, as well as post-contingency voltage deviation and transient voltage response criteria established by each Transmission Owner (TO) or Transmission Planner (TP). For issues affecting multiple TO/TP footprints, the most conservative planning criteria among the relevant TOs/TPs will apply. If a TO/TP does not specify voltage criteria, the MISO criteria outlined in Appendix K of the BPM-020 Transmission Planning Business Practice Manual will be used by default.

Economic Analysis

Economic analysis requires a market-type dispatch reflective of MISO Futures modeling and planned topology set by the MTEP powerflow model in order to evaluate potential future transmission inefficiencies. MISO's economic analysis process relies on the production cost modeling software PROMOD to identify and address economic issues caused by these inefficiencies.

PROMOD dispatches generation to meet load for every hour over the course of the year based on the constraints and assumptions included in the model. Constraints like key flowgates identified in the Flowgate Identification process, and assumptions for battery dispatch, as detailed in MISO's Series 1A Battery Modeling Whitepaper, increase the complexity of PROMOD runs and analysis.

To understand the impact of these constraints and assumptions, economic analysis occurs throughout the study process. MISO completes PROMOD runs and assesses outputs through each stage of the study process to review model accuracy, address dispatch assumptions, identify issues, and find transmission solutions. The Economic Modeling, Futures Energy Adequacy, and Alternatives Analysis sections provide details on how PROMOD was utilized in various stages of the Tranche 2.1 process. Additional critical components of the economic analysis process are detailed below.

Economic Metrics

The metrics in Table 2.4 are calculated from PROMOD outputs and used by MISO's Economic Planning team to assess the economic impact of proposed projects.

Economic Metric Name	Description	Use
Congestion Measure ($/MW)	An indication of the production cost savings opportunity from relieving transmission congestion	• Identifying most constrained transmission elements • A reduction in Congestion Measure for a constraint or group of constraints indicates a more optimal regional dispatch
Curtailment (MWh)	A measure of the total amount of energy from renewable sources which cannot be delivered economically	• Reduction of curtailment at a single generator improves that unit's financial viability • Reduction of total curtailment in a region indicates that transmission investments enable additional renewable generation
Load LMP ($/MWh)	The Locational Marginal Price (LMP) is the market price to purchase energy from a market. Load Weighted LMPs are expressed as an average price weighted by energy each hour and at each delivery point and are indicative of the price of energy in a region	• A price separation in Load LMPs across a region indicates that transmission is limiting efficient dispatch, resulting in overall higher production costs
Adjusted Production Cost (APC) ($)	A measure, by company, of the costs to serve demand, considering the effect of purchase and sales	• Evaluating the combined measure of the operating cost of companies within MISO
Adjusted Production Cost Savings ($)	APC Savings are seen when APC decreases from one model to another (i.e., Reference Case – Change Case). A company sees APC Savings when they dispatch lower cost generation, purchase power at a lower load LMP, or sell power at a higher Gen LMP	• Evaluating portfolio benefits in the Business Case
Generation Enablement (MW)	A Distribution Factor (DFAX) based methodology to determine which Future Series Model Built resources are enabled by regional transmission to connect to the system	• Future Series Model Built resources with ≥5% DFAX are considered enabled

Table 2.4: Economic Metrics

Congestion Measure

Economic congestion is assessed using "Congestion Measure" ($/MW), which is calculated by multiplying the annual Average Annual Shadow Price ($/MW/hr) of a transmission constraint by the number of annual Binding Hours (hr/yr) in which congestion at that constraint is observed. Congestion Measure approximates the annual savings for the next additional MW that could flow if that constraint was relieved. It is used as an indicator of the magnitude of economic opportunity from relieving individual transmission constraints, and when summed over all the constraints in a region, it measures whether a project or set of projects has relieved congestion in that region.

Curtailment

Curtailment is a measure of the amount of energy (MWh) which is available from non-thermal generators (generally Wind, Solar, and Hydro), but cannot be dispatched and delivered economically primarily due to two reasons: transmission constraints and/or competition between abundant renewable resources to serve load, when available resources exceed load.

A reduction in Curtailment is generally seen when transmission constraints that limit the output of non-thermal generating resources are relieved by transmission investments. Curtailment may be caused by any constraint in a PROMOD case, and not all Curtailment will be caused by transmission congestion.

Load Weighted Locational Marginal Price (Load LMP)

Price to serve load is presented using Load-weighted Locational Marginal Prices ($ / MWh) or Load LMPs. LMPs represent the marginal cost at a given location to deliver one additional MWh of energy in a given hour. A Load LMP represents the marginal cost to deliver one additional MWh of energy within a given region and over a given period of time. It is computed as the weighted average of LMPs using the hourly and locational distribution of demand energy as weighting factors.

Adjusted Production Cost

Adjusted Production Cost (APC) is a measure of the cost to serve load by company and is utilized to capture the differences in production costs between two models. This metric is used in portfolio development to identify and compare economic benefits across alternatives as well as in the Business Case to project 20-year APC savings.

Adjusted Production Cost Savings

Additional details on APC Savings can be found in MISO's Business Case Metrics Methodology Whitepaper under the section on Congestion and Fuel Savings. MISO's APC calculation methodology is described in detail the MISO APC Methodology Whitepaper.

Generation Enablement

Distribution Factor (DFAX) analysis is the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located, determining the amount of generator impact on facility loading. In this analysis, Future Series Model Built resources are considered enabled if they have a DFAX ≥5% against reliability constraints that are addressed by regional transmission.

Reliability and Economic Analysis Results

The total resource expansion for Future 2A in the Midwest subregion provided the starting point in identifying transmission issues and anticipated Tranche 2.1 solutions. Regional analysis identified key system issues under Future 2A, providing a foundation from which to develop transmission concepts into a draft portfolio. As part of the 7-step process, the economic and reliability analysis identified potential transmission issues.

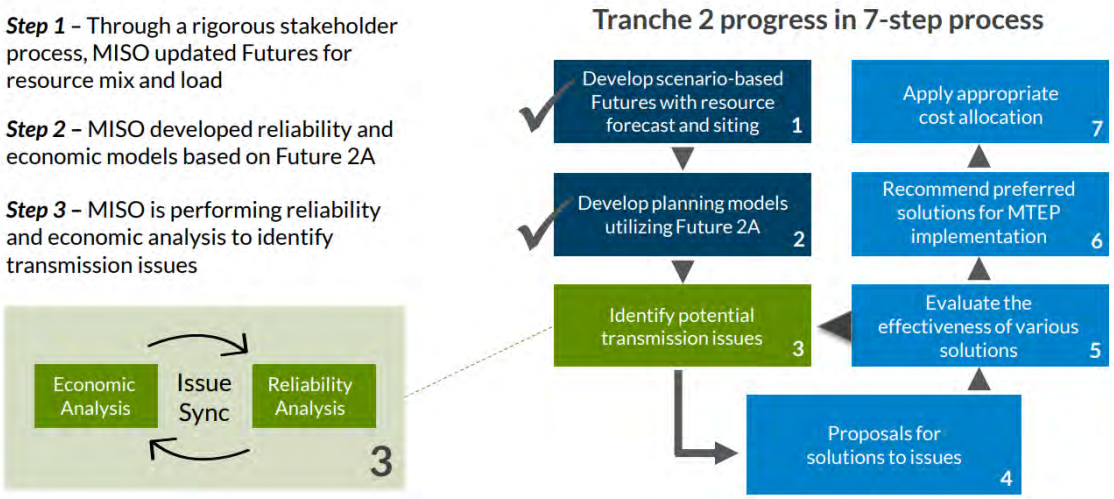


Figure 2.18: Economic and Reliability Transmission Issue Identification

The initial constraints discussed in the December 2023 LRTP workshop (economic and reliability) shaped the Tranche 2.1 portfolio. The economic analysis showed needs for MISO West, Central and East. Severe congestion was driven by high renewable penetration and load that lacked high-voltage regional transmission support to alleviate existing transmission. Similarly, the reliability analysis pointed to the need for significant transmission system enhancements. Both the economic and reliability analysis indicated significant transmission issues through the Midwest region (See Figure 2.19: Summary of Reliability and Economic Issues) and pointed to the need for a high voltage regional transmission backbone, including:

- Severe wide-area congestion across the MISO Midwest subregion
- Wide-area economic price separation between the West and East/Central regions
- Significant generation curtailment due to severe economic congestion on numerous lines
- Significant levels of overloads and voltage violations on High Voltage (HV) and Extra-High Voltage (EHV) equipment throughout the footprint
- With the changing resource fleet and decrease in reactive support, system is stressed with the expected results of lower stability limits of longer distance transmission lines
- Substantial increase in voltage angle difference between sending and receiving end as power is traveling a longer distance to reach load
- Multifold increase in system losses due to long-distance transfer and stressed transmission system

This analysis drove the development of transmission solutions for a draft portfolio.



WEST

- 20% of the facilities were found to be overloaded
- Annual curtailments exceeded 40%
- Energy losses over transmission lines increased from 2.5% to 11%

CENTRAL

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission enabled transfer of regional power
- Needs were refined through transfer sensitivities and multi-element contingencies

EAST

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission supported daily and nightly import / exports

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

kV	Unique overloads	Max loading%	Unique needs	Binding hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Figure 2.19: Summary of Reliability and Economic Issues

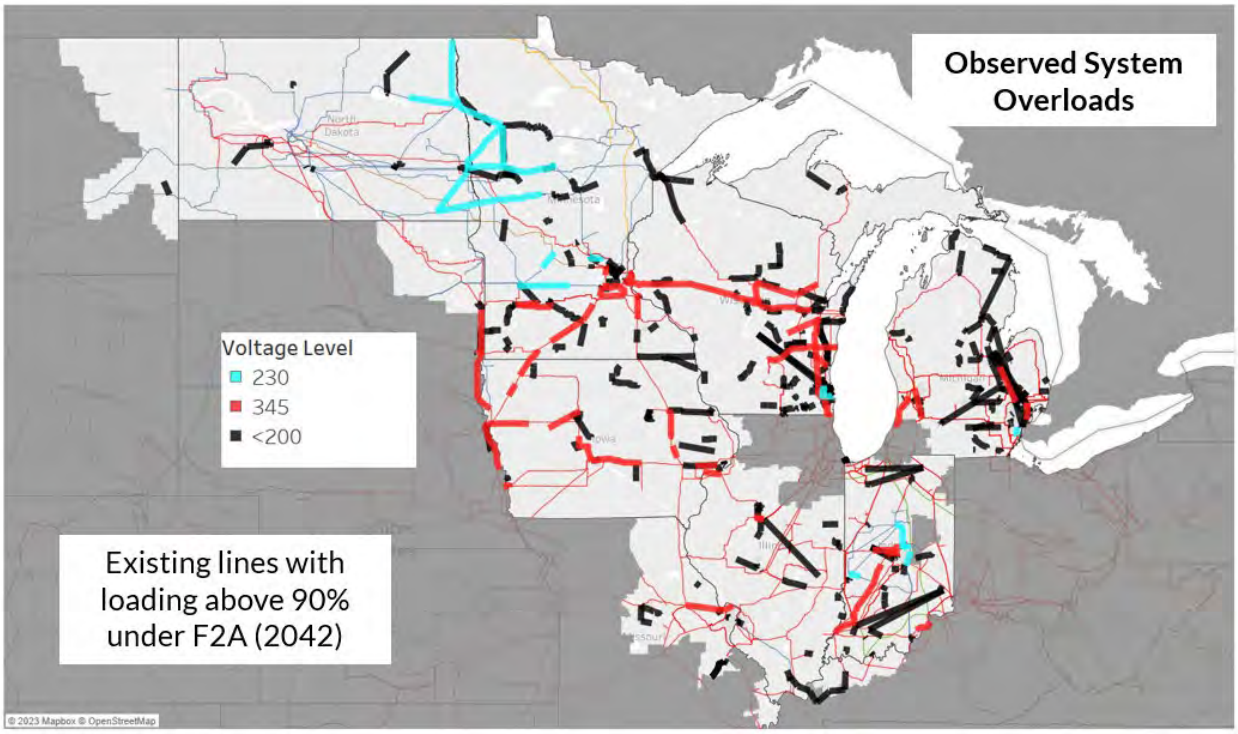


Figure 2.20: MISO Midwest subregion map showing thermal constraints observed by voltage level

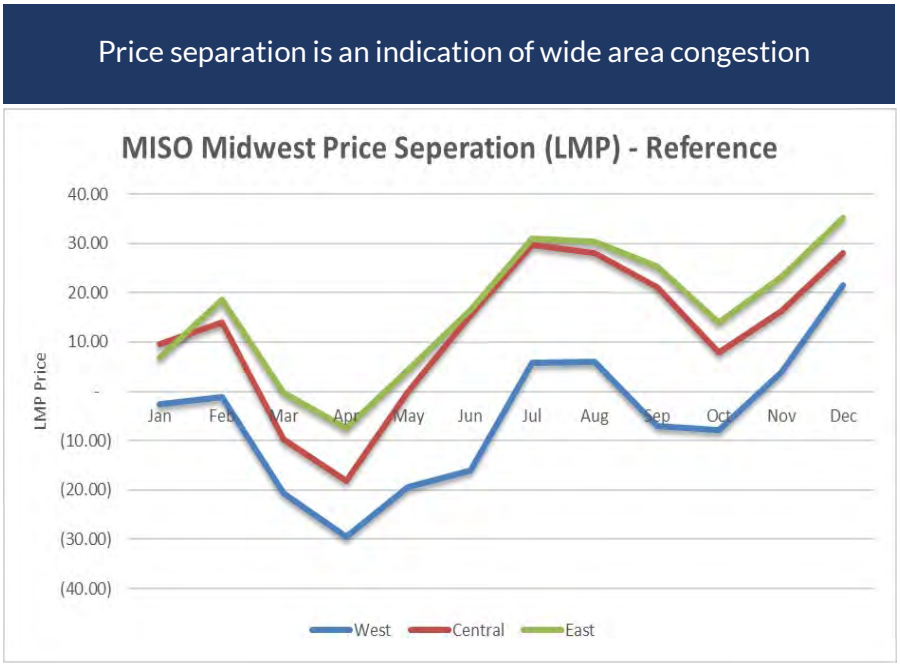


Figure 2.21: Figure 2.23: MISO Midwest Price Separation

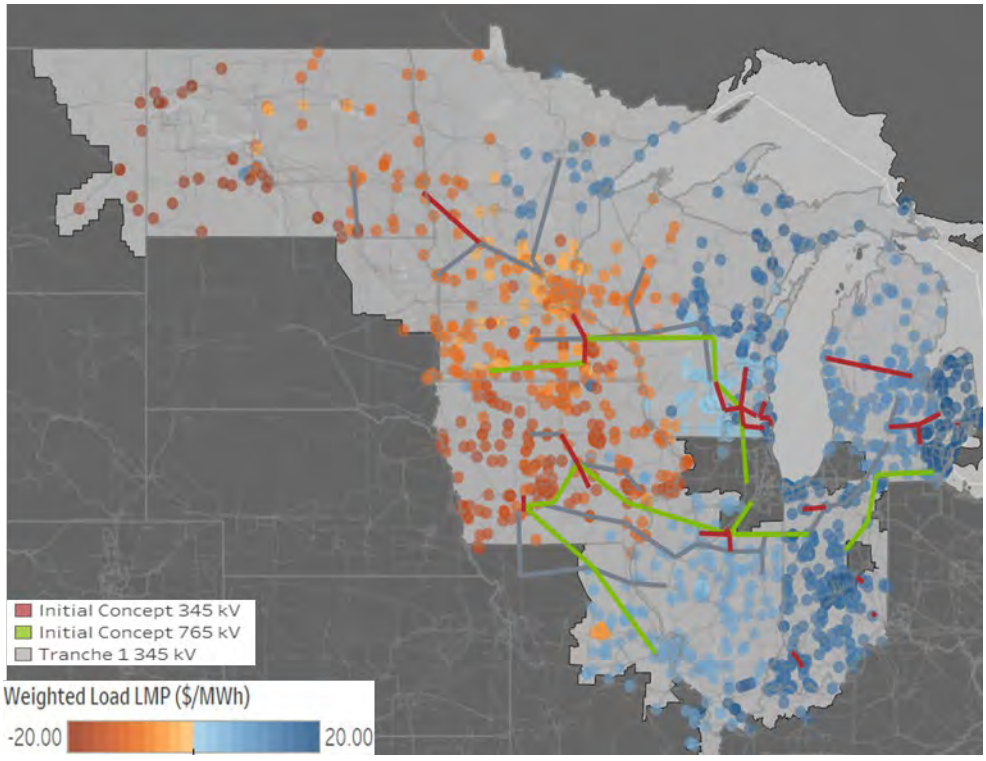


Figure 2.22: Pre-Portfolio LMP Map

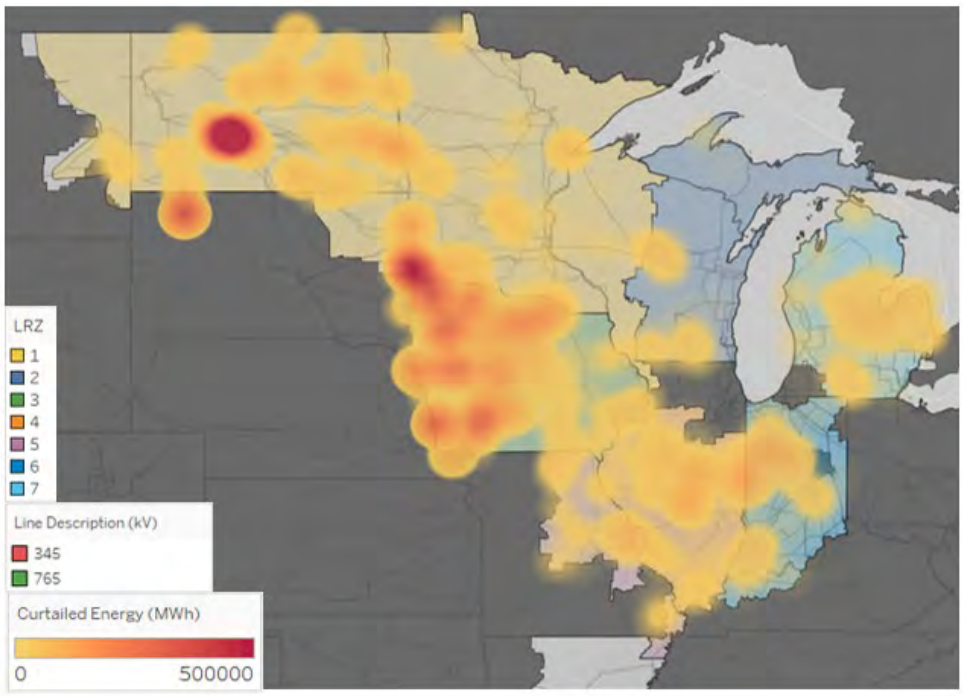


Figure 2.23: MISO Midwest Generation Curtailments Pre-Portfolio

West Region

The West region shows the need for higher voltage transmission facilities to support large power transfers and deliver generation from remote areas to load centers. MISO noted significant overloads and curtailments. Twenty percent of facilities are overloaded, curtailments exceed 15% and energy losses over transmission lines increase from 2.5% to 11%. This is also an area where line losses increase as the existing system attempts to deliver power from the Future 2A resource mix.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	66	206	28	1,000-4,000
230	41	208	17	150-4,100
<200	496	263	76	50-6,000

Table 2.5: West Region – Reliability and Economic Issues

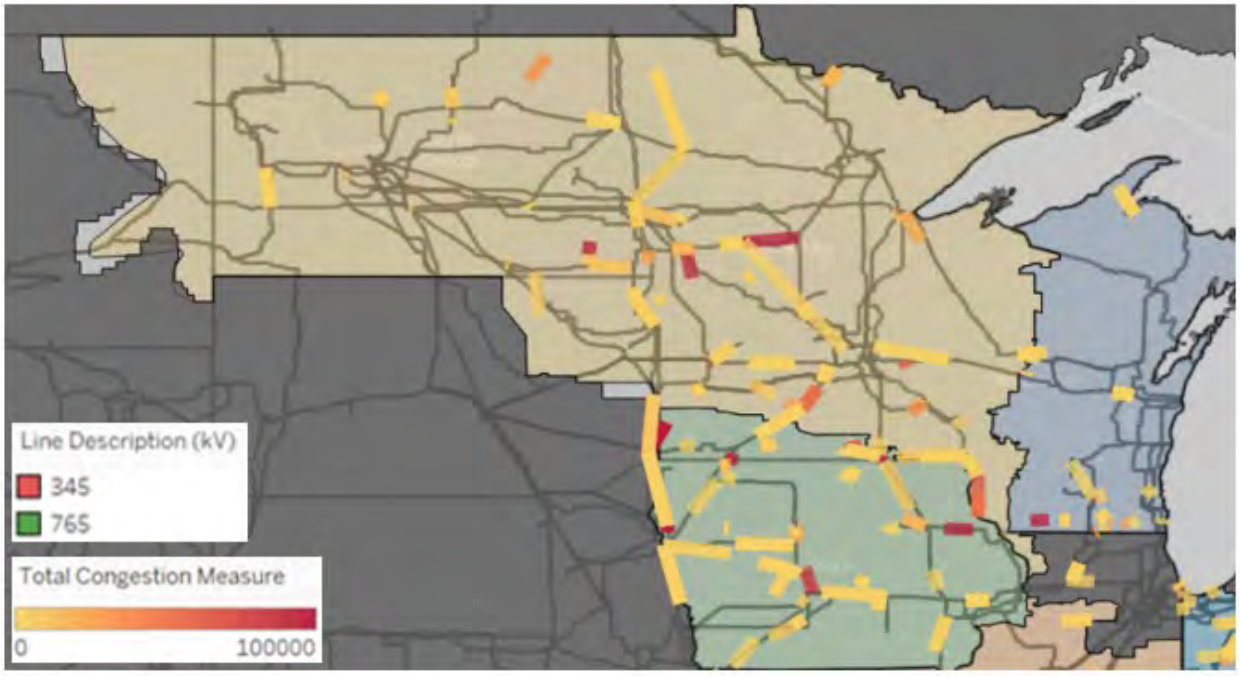


Figure 2.24: Reference Case: Economic Congestion (West)

Central Region

Transmission in the Central region will be key to enabling system transfers and supporting high transfer scenarios between the East and West regions. In the base Future 2A power flow cases, MISO sees 10% of facilities exhibiting overloads. In addition to these overloads, MISO expects that enabling resources in the West region will increase regional transfers into and through the Central region. MISO also has seen historically that the Central region is highly impacted by different transfers and weather patterns that it needs to consider. Multi-element contingencies will also have a large impact on this region and drive additional needs.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	21	171	23	11-2,500
230	13	142	5	25-960
<200	158	191	53	20-2,560

Table 2.6: Central Region – Reliability and Economic Issues

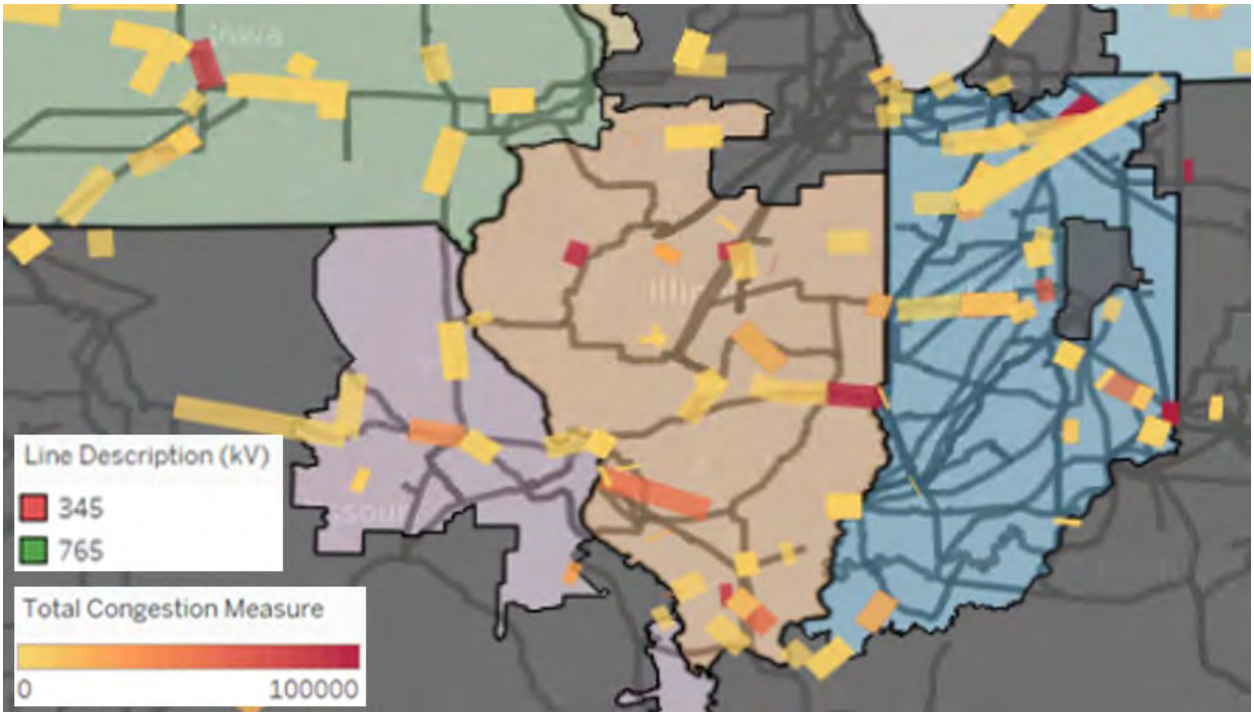


Figure 2.25: Reference Case: Economic Congestion (Central)

East Region

The East region's transmission solutions will need to consider transfer limits as changes to the resource mix create the need to enable increased imports and exports to and from the state. MISO sees more overloads (10% of facilities) and curtailment issues (annual curtailments exceed 15%), and especially the impacts of the resource fleet evolution in different import and export patterns between day and night. There is excess capacity during the day with solar resources, but imports will be needed during night hours.

	RELIABILITY ISSUES		ECONOMIC ISSUES	
kV	Unique overloads	Max loading %	Unique Needs	Binding Hours
345	7	113	3	60-135
<200	159	223	42	10-2,400

Table 2.7: East Region – Reliability and Economic Issues

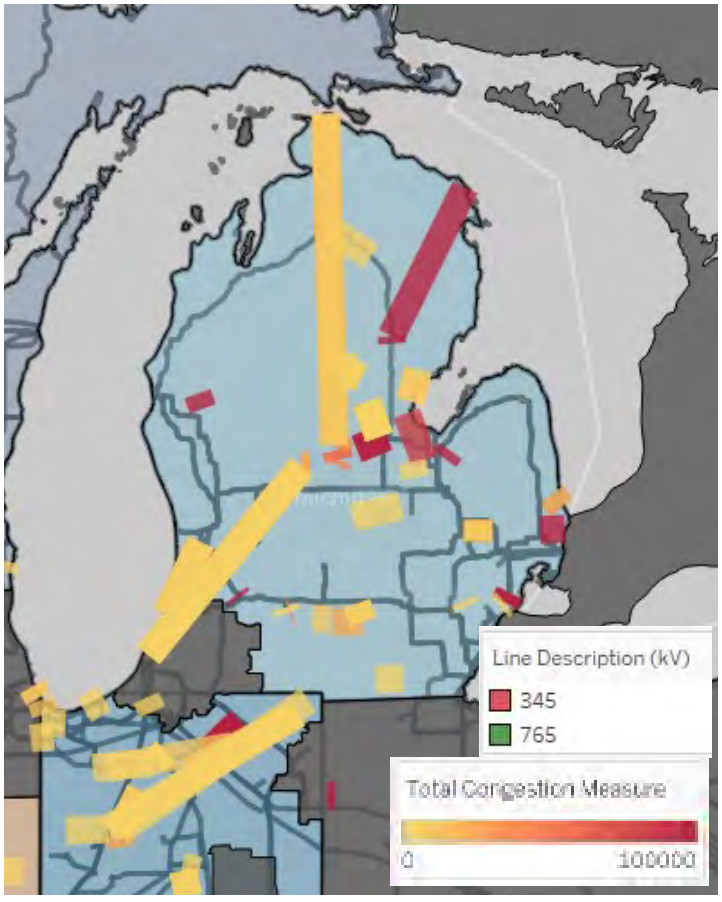


Figure 2.26: Reference Case: Economic Congestion (East)

Step 4: Propose Solutions

As MISO understood the impacts of member plans throughout the planning process, conceptual ideas were developed for what the potential transmission solutions may be. In January 2023, MISO shared a hypothetical roadmap taking concepts from its initial long-term roadmap shared in 2021. This map continued to be refined focusing on a 765 kV regional solution accounting for a future with more remote resources, and where safe loading limits and absolute limits will become more relevant. Absolute limits and Safe Loading Limits decrease as line length increases. As discussed in March PAC material (March 8, 2023), some considerations of the performance of 765 kV include:

- Transmission Limits including Safe Loading Limits and Absolute Limits,
- Cost per MW-Mile, and
- Land-Use per MW-Mile.

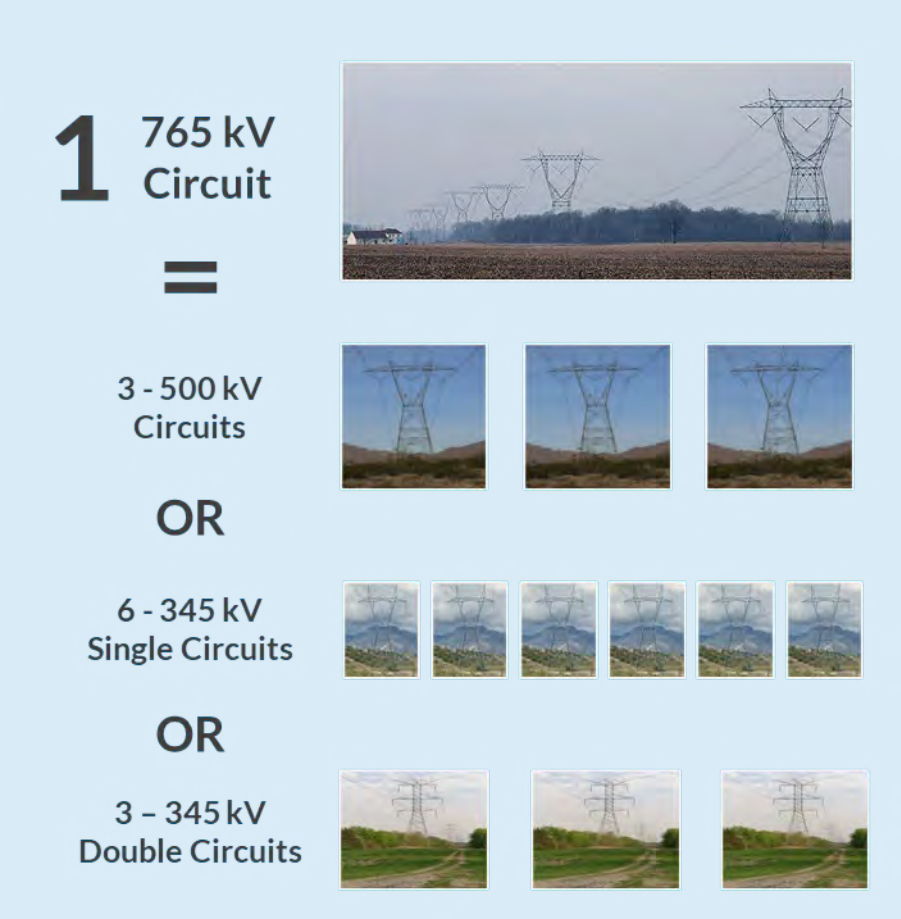


Figure 2.27: Land-Use Evaluation per Transmission Voltage

When considering the per MW-mile capability of 765 kV and 345 kV lines, 765 kV has much higher loading capability than 345 kV, particularly for longer distances. For Tranche 2.1, 50% of the proposed 765 kV facilities are more than 120 miles long. At 120 miles, the Safe Loading Limit of a 345 kV line is less than 1,000 MVA and 765 kV is 4,500 MVA. The loadings observed on the Tranche 2.1 765 kV facilities range between 2,000 and 4,000 MVA.

The cost per MW-mile of a 765 kV line is generally 33% to 50% of the cost per MW-mile of 345 kV or 500 kV lines. This implies a long distance, well utilized regional transmission system would cost much less if it incorporated a substantial amount of 765 kV transmission. Conversely, it would be much more costly to develop the required regional transmission system using only 345 kV transmission, and substantially even more cost to develop the system slowly and incrementally using sub-Extra High Voltage transmission only.

Given 345 kV is a legacy voltage, a hybrid regional solution making significant use of both 765 kV and 345 kV facilities is the optimal solution. If transmission upgrades were facilitated incrementally using 138 kV lines in place of 765 kV, the cost would be 12 to 18 times higher for 138 kV incremental transmission upgrades than it would be for 765 kV on a cost per MW-mile basis.

In addition to lower cost, a 765 kV line requires less land-use on a per MW-mile basis than 500 kV or 345 kV. The land use in acres per MW-mile required for 765 kV is less than 25% to 67% of the land use required in acres per MW-mile for the equivalent 345 kV alternative, and about 33% of the land use required in acres per mile for 500 KV.



Figure 2.28: Progress of Portfolio Development

Refining Solutions

Robustness Testing

A key objective of robustness testing is to identify key projects that were either approved or in the process of approval subsequent to the finalization of LRTP power flow models in October 2023, which may have a material impact on the anticipated Tranche 2 portfolio. The second main objective is to perform an assessment with and without key projects and identify areas that may result in MISO modifying, adding to, or removing transmission facilities in the LRTP portfolio.

- **Removals:** Tranche 2 projects or segments may be considered for removal and replacement by key projects. Evaluate areas where the reliability impact provided by key projects and Tranche 2.1 projects overlap or duplicate independently.
- **Modifications:** Tranche 2.1 projects or segments may be considered for modifications. Evaluate areas whether issues addressed by key projects and Tranche 2.1 projects are closely related and if modifying Tranche 2.1 transmission facilities could optimize the reliability impact of both.

- **Additions:** Consider potential adverse effects on the system resulting from the inclusion of key projects, while also considering constraints that may be local in nature that are better resolved in annual MTEP reliability planning and the generator interconnection processes.

If initial robustness testing results in a reliability impact such as need for removal, modification or addition, then further testing may be conducted utilizing some or all of the remaining core reliability cases and additional transfer scenarios that represent various system conditions and dispatch patterns to better understand the impacts of all projects and system changes.

Key Projects

Tranche 2 robustness testing refers to a process for reviewing the impact of system changes, specifically key projects, that were either approved or under consideration following the completion of LRTP power flow models in October 2023 which may affect the anticipated Tranche 2 portfolio. Each key project that is identified for robustness testing is analyzed in detail by looking at the relevant system conditions and contingencies with and without key projects. Performance of projects, effectiveness in resolving identified needs, or any new criteria violations is documented during the testing process.

MISO completed an assessment on the impact of select MTEP23 and MTEP24 projects, the JTIQ projects, and the Grain Belt Express (GBX) Merchant High Voltage Direct Current project. The MISO-SPP Joint Targeted Interconnection Queue Projects facilitate the integration of new resources by optimizing the transmission infrastructure required across regional boundaries. The JTIQ and Tranche 2.1 projects, being electrically close, complement each other. JTIQ projects do not negate the need for the Tranche 2.1 portfolio. The GBX project does not prompt any required modifications to the Tranche 2.1 portfolio located within its solution area. There is a noticeable reduction in overloads and lines loadings on monitored flowgates with addition of the Tranche 2.1 portfolio.

Eligible projects

In Tranche 2, the powerflow core models were built from the MTEP22 topology (including LRTP Tranche 1 approved projects) with load, generation, and siting information from Future 2A. After much collaboration and engagement with stakeholders, powerflow models were finalized in October 2023. These models used best-known information at the time of completion. Key projects were selected from the following categories for robustness testing:

- MTEP23 portfolio of projects approved by MISO's Board in December 2023
- The Transmission Connection Agreement (TCA) for the GBX Merchant HVDC project was accepted by FERC in February 2024
- JTIQ projects, subject to FERC approval and MISO Board approval
- MTEP24 portfolio of projects to be approved by MISO's Board in December 2024

Generally, projects on the 230 kV system and above that are electrically close to identified issues and transmission facilities shown on the March 4th portfolio map would qualify to be tested. It is important to highlight that if any of the key projects from MTEP23, MTEP24, JTIQ, or Grain Belt Express have a material impact on the anticipated Tranche 2.1 portfolio, that impact will be detected in the robustness testing. Based on the criteria described above, MISO identified several projects for Tranche 2.1 robustness testing, listed below:

Key projects eligible for robustness testing	Category	PSSE Area Number[2]
P23026 – New South-Central Illinois Transmission Expansion	MTEP23	357, 361
P50106 – Big Cedar Interconnection	MTEP24	627, 635
Bison – Hankinson – Big Stone South 345	JTIQ	600, 608, 613, 615, 620, 627, 633, 635, 661
Lyon Co. – Lakefield 345		
Raun – S3452 345 kV		
Auburn – Hoyt 345 kV		
Grain Belt Express with projects as identified in Transmission Construction Agreement	MHVDC	356, 357, 330, 333

Table 2.8: Summary of Key projects eligible for robustness testing

MISO's initial screening used the LRTP 20-year out average load model, developed for Tranche 2.1 reliability assessment with Future 2A assumptions. Models are described in detail in the Reliability Study Whitepaper.

The 2042 LRTP Average Load Case represents typical system conditions within 70-80% on the load duration curve. This scenario is the most stressed case because it has 100% renewable penetration, meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. To better assess the impact of key projects, MISO ran all single initiating events, i.e., contingencies, on the following four scenarios first, then supplemented results with two additional scenarios incorporating the outcome of the alternative analysis (Key projects shared at the May 13, 2024 LRTP workshop and additional study material is posted on MISO Sharefile:

Models with March 2024 Initial Proposed Portfolio Results:

1. The 2042 LRTP Average load case (i.e., most stressed LRTP case)
2. The 2042 LRTP Average load case + LRTP T2.1 anticipated portfolio of projects
3. The 2042 LRTP Average load case + key projects
4. The 2042 LRTP Average load case + key projects1 + LRTP T2.1 anticipated portfolio

Models with May 2024 Near-Final Proposed Portfolio Results:

1. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio
2. The 2042 LRTP T2.1 Average load case with Alternatives Portfolio + key projects

At a high level, the process diagram below best illustrates robustness testing. The diagram refers to the models used for robustness testing and key projects were presented in May.

[2] Key projects are electrically far away from each other and grouped by location (PSSE Areas #) to focus more closely on their impact.

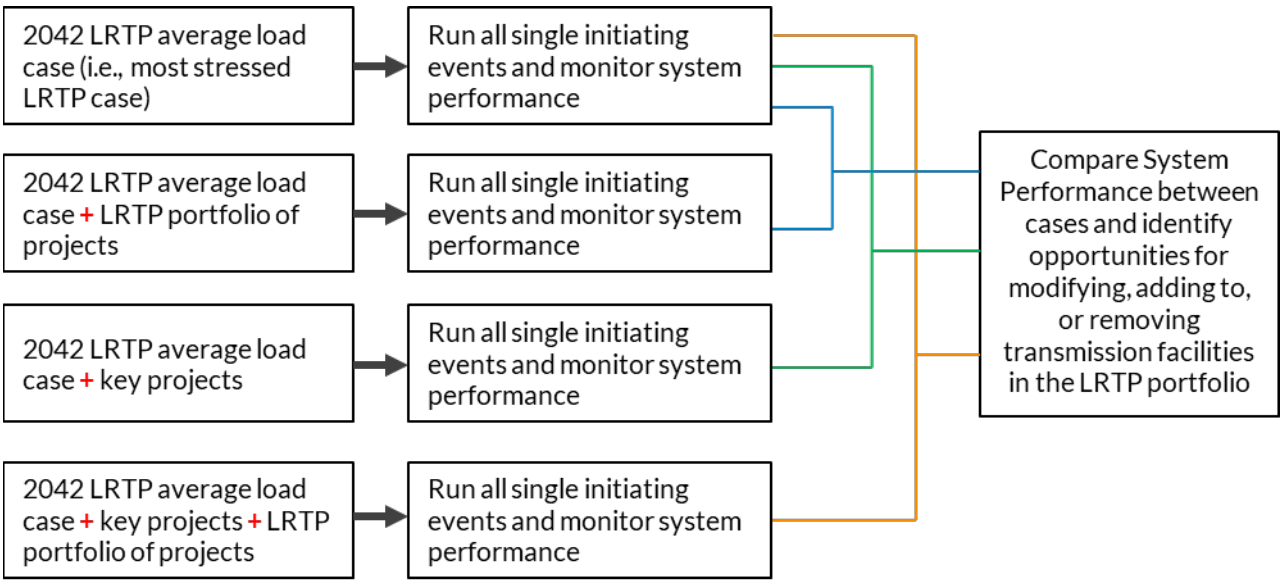


Figure 2.29: Models used in robustness testing

To gauge the impact of key projects more accurately, MISO first evaluated all single-initiating events using four scenarios from the March 2024 Initial Proposed Portfolio. Then this analysis was enhanced by incorporating two additional scenarios featuring alternative projects from the May 2024 Near-Final Proposed Portfolio. Key projects were shared at the May 13, 2024, LRTP workshop.

Project P23026: New South-Central Illinois Transmission Expansion and Project P50106: Big Cedar Interconnection:

Robustness testing assessment reinforces the projects' alignment with local needs, consistent with their MTEP justification. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. More information about the projects, local needs and robustness evaluation can be found at the June 10, 2024, LTRP workshop.

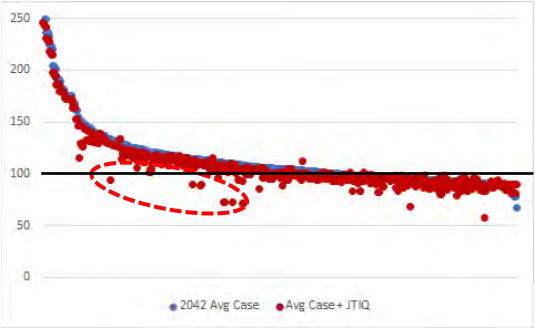
JTIQ Projects

The MISO-SPP Joint Targeted Interconnection Queue Projects enable interconnection of new resources by optimizing transmission needed for interconnection across the seams. JTIQ projects have a positive impact on reducing overloads and loadings on monitored flowgates; consistent performance was observed with the March and May portfolios. JTIQ and LRTP Projects are electrically close, serving to complement rather than compete with one another. No Tranche 2.1 project areas have been pinpointed for addition, removal, or modification of projects required due to a very limited reach.

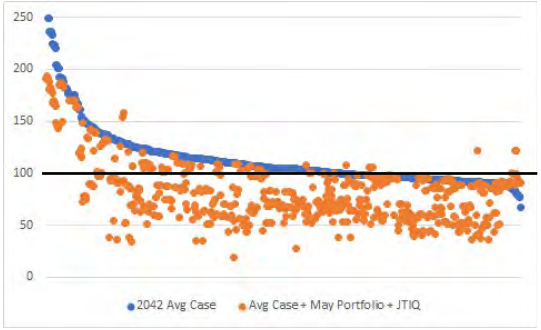
Models with May 2024 Near-Final Proposed Portfolio Results

Out of about 700 monitored flowgates, only a handful (highlighted in red circles in Figure 2.30) were considered for modification. The positive impact of JTIQ on monitored flowgates is noteworthy, yet it doesn't possess the comprehensive scope and robustness needed to entirely substitute or modify sections within the LRTP portfolio. There's a clear synergy among multiple local flowgates; JTIQ and LRTP portfolio

combined resolved non-converged events, enabled transfer of power, and bolstered the overall system strength.



- Flowgate loading in the Avg Case with and without JTIQ
- Red demonstrates JTIQ reduces loadings on some monitored flowgates versus the Avg Case without JTIQ



- Flowgate loading in the Avg Case with and without JTIQ + near-final proposed portfolio
- Orange demonstrates JTIQ and near-final proposed portfolio complements each other, further reducing flowgate loading

Figure 2.30: Flowgate loading in the Average Case with and without JTIQ vs Flowgate loading in the Average Case with and without JTIQ + near-final proposed portfolio

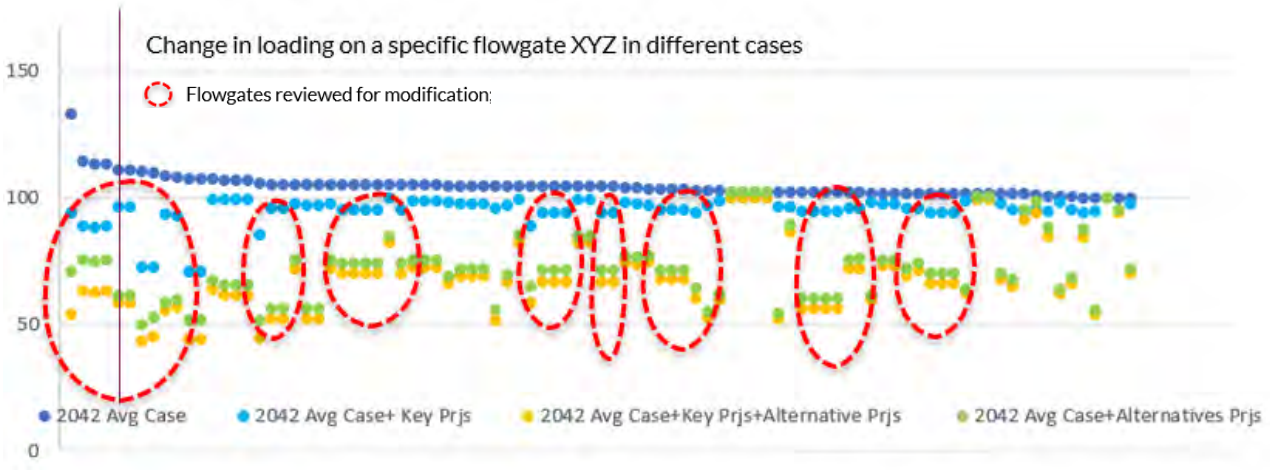


Figure 2.31: Flowgates considered for modification

Grain Belt Express (GBX)

Merchant HVDC Transmission Line with projects as identified in Transmission Connection Agreement (TCA). MISO appropriately modeled key transmission projects eligible for robustness testing to ensure a least-regrets, robust portfolio.

- Transmission line(s) modeled with appropriate characteristics.
- Grain Belt Express (GBX) modeled as a single 1.5 GW generator injection at the MISO Point of Interconnection (POI) and a single 1.0 GW generator injection at the AECI POI.

- Modeled MISO network upgrades associated with the injection.

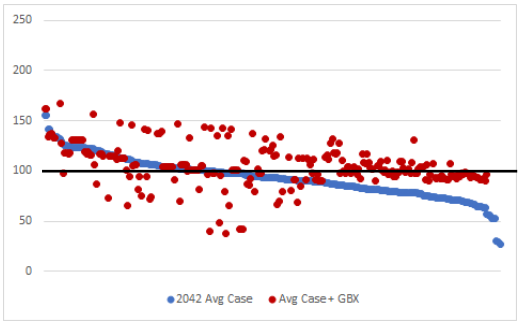
- Dispatch:
  - Injection of 1.5 GW (GBX) into the MISO system was balanced with renewables across MISO Midwest system scaled down to balance load/losses with generation.
  - Injection of 1.0 GW (GBX) into the AECI system was balanced with output reduced by 1.0 GW from the oldest coal units.

All Network Upgrades identified in the Transmission Connection Agreement (TCA) were added (Click here for a detailed list of all connection facilities and necessary upgrades specified in the TCA):

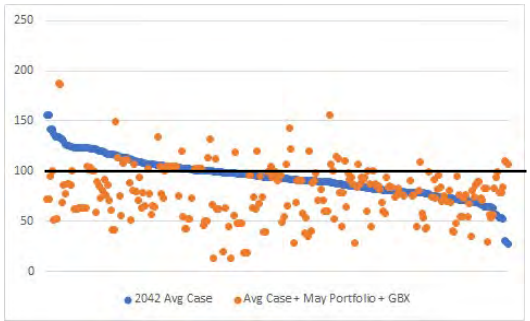
- New Burns-Montgomery 345 kV lines (2X)
- Rebuild Big Creek-Warrenton 161 kV line
- Rebuild Belle Tap Gasco Tap 138 kV line
- Rebuild Belle Tap-Meta Tap 138 kV line
- Rebuild Bland- Gasco Tap 138 kV line
- Rebuild Miller-Meta Tap 138 kV line
- Rebuild Warrenton-Montgomery-3 161 kV line

Models with May 2024 Near-Final Proposed Portfolio Results

Grain Belt Express (GBX) 1.5 GW injection further stressed the system; GBX 1.5 GW injection performance with the May portfolio still closely mirrors the March portfolio, no Tranche 2.1 project areas have been pinpointed for addition, removal, or modification. The near-final Tranche 2.1 projects strengthen the system and have a positive impact on reducing overloads and loadings on monitored flowgates.



- Flowgate loading in the Avg Case with and without GBX
- Red demonstrates GBX increases loadings on some monitored flowgates and reduces loadings on others versus the Avg Case without GBX



- Flowgate loading in the Avg Case with and without GBX + near-final proposed portfolio
- Orange demonstrates GBX + near-final proposed portfolio reduces stress for some flowgates

Figure 2.32: Flowgate loading in the Average Case with and without GBX vs Flowgate loading in the Average Case with and without GBX + near-final proposed portfolio

The near-final Tranche 2.1 proposed portfolio posted in May significantly reduces overloads/loadings on monitored flowgates when compared to the 2042 Avg Case + GBX without the near-final proposed portfolio demonstrating enhanced reliability for the MISO Midwest subregion, enabling member plans for fleet transition, load growth and regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty.

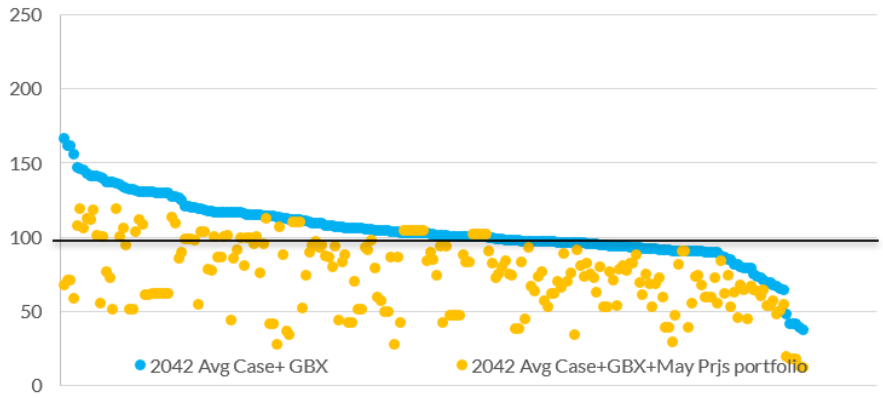


Figure 2.33: Flowgate loading in the Average Case with GBX vs. Flowgate loading in the Average Case with GBX + near-final proposed portfolio

Alternatives Analysis

Analysis of alternatives was performed and 97 projects representing 47 solutions were received from stakeholders. Not all these solutions were evaluated as MISO focused on alternatives that are more closely aligned with the same issues and needs that drove the solutions for this portfolio, various alternatives were similar in location and ones that are likely to be constructed in a timely manner. Additionally, some solutions were evaluated along with variations of alternatives developed by MISO staff, and some projects addressed more local versus regional needs and are more suited for the annual MTEP reliability planning and the generator interconnection processes. **Based on alternative analysis, MISO made additions to the portfolio in MN, IA, IN, ND, SD, MI and replacement in MO.**

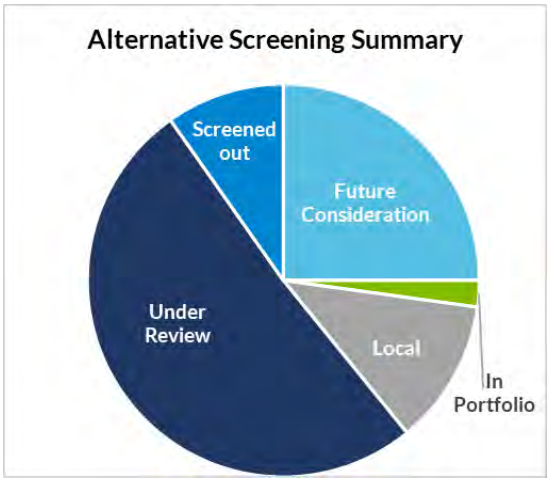


Figure 2.34: Alternative Screening Summary

Process

Alternative solutions were reviewed within key considerations.

- Does it align with the initial portfolio?
- Does it contribute to the objectives of Tranche 2.1?
- Is it focused on regional needs considering historic and new transfer patterns across the Midwest?
- Does it contribute to resolving and/or further mitigating identified issues in the subregion or region?
- Does it cause other potential issues?

Additionally, the following decision factors also guided analysis:

- If an alternative solution was identical or close to solutions already in the initial concept, there was no need to test the alternative solution. However, minor adjustments could be considered as appropriate.
- If an alternative solution was additive to the initial concept, MISO could recommend the project be resubmitted as an alternative in a future planning process.
- MISO could create a new alternative by combining components of one or more alternatives, and potentially combine them with initial solution concepts.
- Some alternative solutions could be screened out for several qualitative reasons, such as alignment with overall objectives and concept, constructability, permitting risk, local rather than regional focus, and other various reasons.

Of the 97 alternative solutions submitted, 47 passed the threshold for analysis.

- 97 alternative solutions were submitted by 32 entities
    - 21 Transmission Owners
    - 8 Transmission Developers
    - 3 Transmission Dependent Utilities
- Most included multiple facilities
- Alternatives recommended replacements and additions
- There were common facilities among multiple solutions

Analysis Decisions for Alternatives

- Under Review: Alternative or variations will be considered for Tranche 2.1
- Future Consideration: May be considered as possible solutions in future planning initiatives including, but not limited to, future LRTP initiatives

- In Portfolio: Represent proposed facilities already included in the March Tranche 2.1 initial proposed portfolio
- Local: Mainly resolving local issues
- Screened Out: Will not be considered in the current Tranche 2.1 based on initial screening

Alternative Analysis Results

MISO grouped the 47 alternatives into six studies for engineering analysis to understand system performance. Reliability analysis focused on the alternative performance compared to the March 4, 2024, draft portfolio (presented at March 15, 2024, LRTP workshop) with supplemental information from the base model (without portfolio) and transfer scenarios. Economic analysis focused on the alternative compared to the March 4th draft portfolio and reference case model (without portfolio). Details were provided via Sharefile.

No.	Alternative Description	Location	Recommendation
1	Maple River – Cuyuna 345	ND/MN	Add to portfolio
1	Big Stone South – Brookings – Lakefield 765	SD/MN	Add to portfolio
1	Lakefield – East Adair 765	MN/IA	Add to portfolio
1	Reynolds – Sullivan 765	IN	Do not add to portfolio
2	Denver – Nelson Road 345	MI	Add to portfolio
2	Goss – Sabine 345 ***Replaces: Oneida – Sabine Lake 345***	MI	Do not add to portfolio
3	Brookings – Chisago Co. – Highway 22 – Paddock – Plano 765 ***Replaces: Lakefield – Pleasant Valley – North Rochester - Jefferson Co – Plano 765***	SD/MN/ WI/IL	Do not replace project in portfolio, keep original
4	Milan – Sumpter 345	MI	Do not add to portfolio
4	Duff – Culley – Reid 345, AB Brown 2nd XF, Culley 2 XFs	IN/KY	Add to portfolio
4	Iron Range – St. Louis – Arrowhead 345	MN	Add to portfolio
4	Big Stone S – Hazel Creek – Blue Creek 345	SD/MN	Do not add to portfolio
5	Montgomery – Sioux – Stallings 345, Kingdom – Bland – Labadie 345	MO/IL	Do not add to portfolio
5	St. John – Burr Oak 345	IN	Do not add to portfolio
5	Lehigh – Twinkle 345	IA	Add to portfolio
6	Maywood – Belleau – MRPD- Sioux, MRPD – Bugle - Roxford/Gateway) 345 + XFs ***Replaces: East Adair –Timber Branch – Labadie 765***	MO/IL	Replace project in portfolio

Table 2.9: Project grouping for alternative analysis

Alternative 1 - New 765kV from South Dakota through Minnesota into Iowa and North Dakota 345kV outlet into Northern Minnesota and evaluation of southern Indiana 765 kV

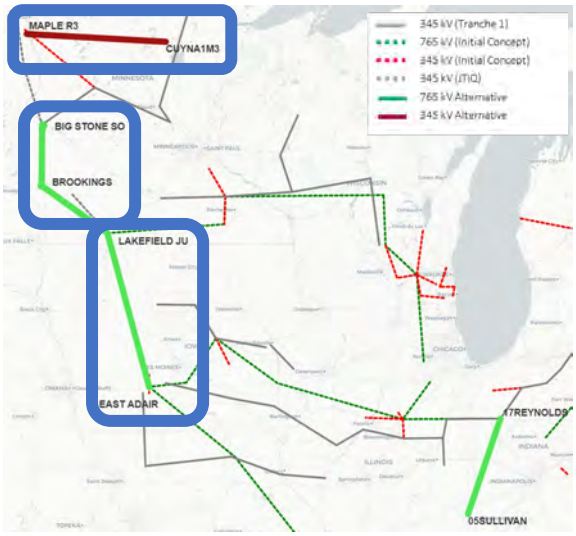


Figure 2.35: Map shows selected Alternative 1 projects in blue boxes

Alternative 1 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 3 project proposals to add in MN/SD/ND/IA
    - Maple River – Cuyuna 345
    - Big Stone South – Brookings County –Lakefield Junction 765
    - Lakefield – East Adair 765
- 1 project proposal to add in IN
    - Reynolds – Sullivan 765
- No projects from initial portfolio replaced or removed

Alternative 1 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.

- 765 kV from South Dakota through Minnesota into Iowa increased delivered energy from North Dakota, South Dakota, Minnesota, Iowa and is added to the portfolio.
- 765 kV from Lakefield to Adair completed a redundant loop configuration for the 765 kV projects, allowing greater reliable use of other portions of the proposed 765 kV system and is added to the portfolio.
- 345 kV from North Dakota to Minnesota improved North Dakota exports and is added to the portfolio.

- Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio.

Maple River – Cuyuna 345; Big Stone South – Brookings – Lakefield 765; Lakefield – East Adair 765

Overall, Alternative 1 curtails approximately 7.5 GWh less renewable energy than the Initial draft portfolio, reduces congestion on Iowa flowgates, improves North Dakota exports, and facilitates a more economical dispatch for MISO Midwest resulting in higher Adjusted Production Cost Saving over the initial portfolio. The projects resolve reliability constraints and reduce loading stress across all reliability models. Negative percentage indicates a decrease in curtailments.

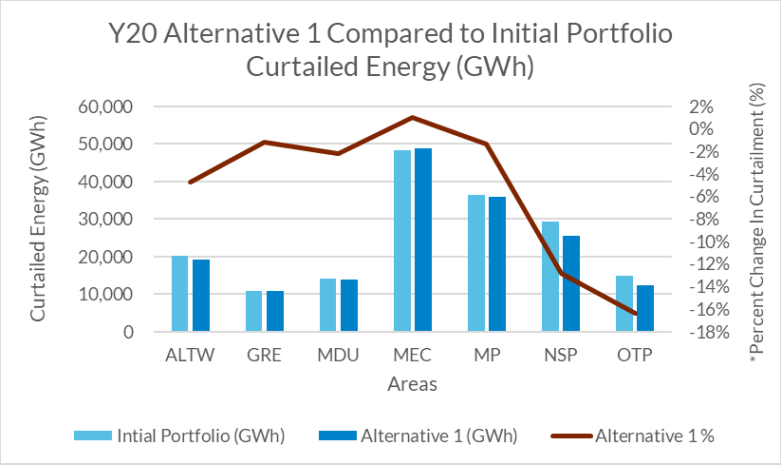


Figure 2.36: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1

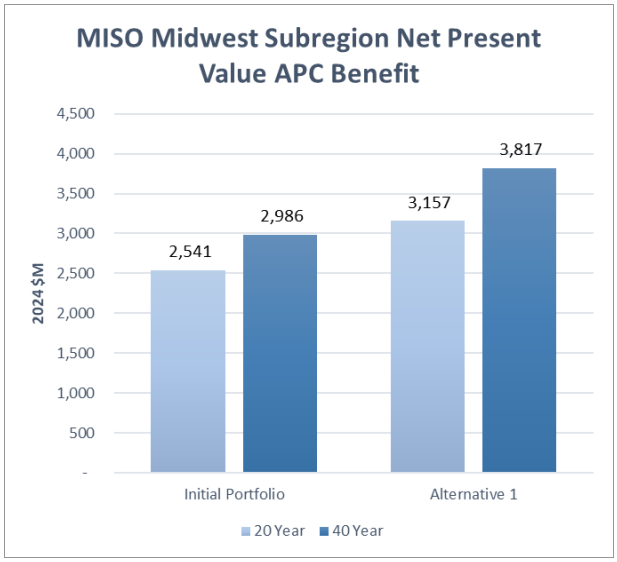


Figure 2.37: Midwest Subregion Net Present Value APC Benefit

Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

The new 765 kV from South Dakota through Minnesota into Iowa and North Dakota 345 kV outlet into Northern Minnesota unlock additional economic value by reducing renewable curtailment. The 765 kV extension into South Dakota provides greater transmission capacity and a direct regional outlet for strong wind resources in that area.

The 765 kV connection between Lakefield Junction and East Adair creates a redundant 765 kV loop between Minnesota, Wisconsin, Iowa, and Illinois, which allows the other portions of that loop to be reliably used at higher capacities. This increases the overall capacity of the 765 kV network to deliver renewable resources across the region. The redundant configuration is more successful at relieving congestion both near Lakefield Junction where the 765 kV station functions as an on-ramp for resources, and across central Wisconsin which would otherwise be sensitive to contingency flows for the loss of the 765 kV corridor between Rochester MN and Southern Wisconsin.

The 345 kV segment in Northern Minnesota improves the system's ability to move renewable resources from Western Minnesota and North Dakota towards load centers in Northern Minnesota and provides congestion relief for the line with the greatest Reference case Congestion Measure in Northern Minnesota.

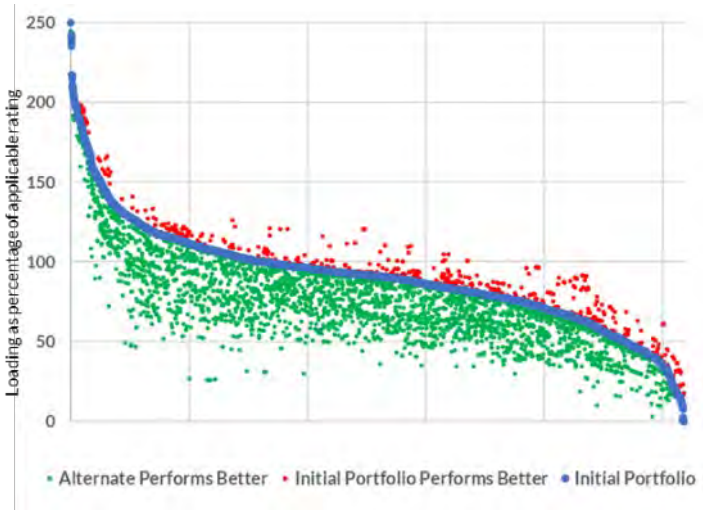


Figure 2.38: Scatter plot showing Alternative 1 performance as compared to Initial Portfolio

Each dot on this plot shows loadings observed from alternative projects for each monitor elements and contingency pair for all core models. Loadings observed in initial portfolio models are used as reference in blue font (blue dots make a smooth line as loadings are sorted in descending order). Loadings observed from alternative projects are shown in red (harming) and green (helping) fonts. More green dots suggest that alternative is helping in reducing the loading stress in the region, whereas redder means that alternative increased loading stress on the system. Blue line overlapping red and green dots means that alternative has little or no impact.

Additional data is provided in the May 29, 2024, LRTP workshop demonstrating other impactful considerations from alternative analysis. For the added projects there were a significant number of 138 and

230 kV facilities that were impacted, the primary voltages of facilities in the area. There were also some 161 and 345 kV facilities impacted.

Reynolds to Sullivan 765 kV

Reynolds – Sullivan 765 did not result in significant congestion relief without additional support and therefore was not selected to be added to the portfolio. Minimal constraints were resolved in the steady state analysis and in some situations additional constraints were created. Southern Indiana 765 may be reviewed further in later tranches with a continuous 765 kV path.

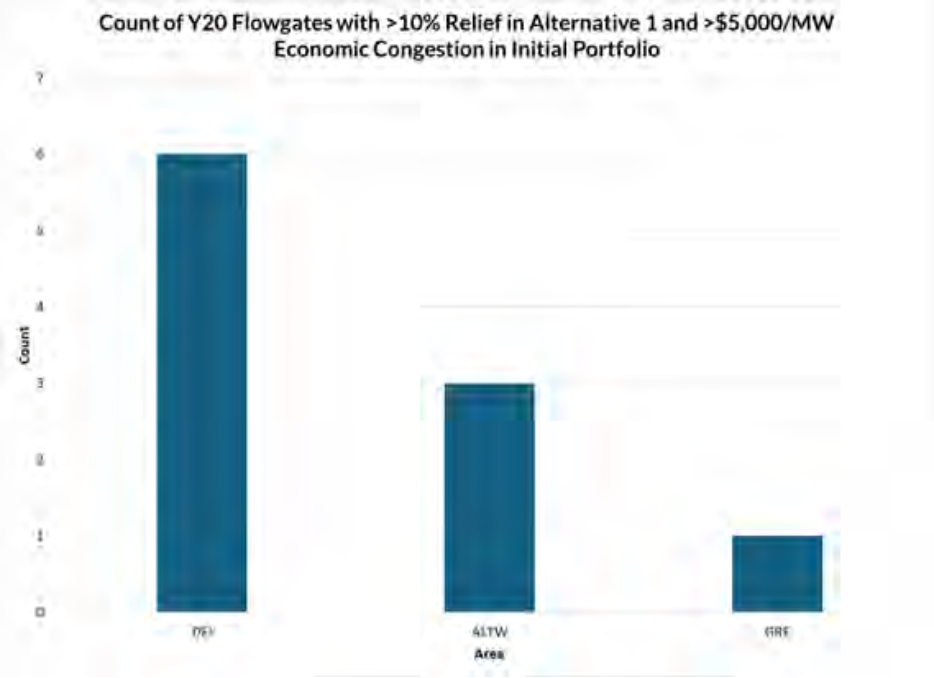


Figure 2.39: Count of Year 20 Flowgates with Congestion Relief for Alternative 1

This graph shows the number of Year 20 flowgates with greater than 10% congestion relief by Alternative 1 which had greater than $5,000/MW congestion measure in the initial portfolio.

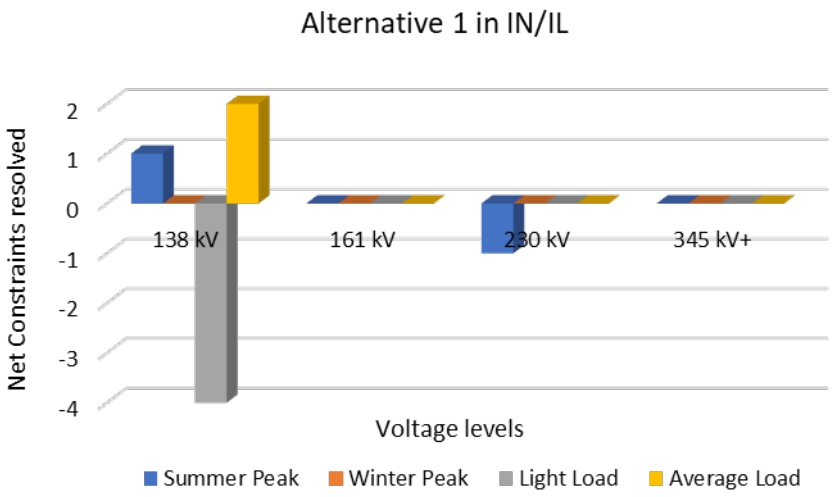


Figure 2.40: Figure: Indiana and Illinois Constraints resolved by Voltage level by Alternative 1 Indiana project

This graph shows the number of net constraints (monitor element and contingency pairs) resolved (= constraints resolved minus new constraints created) by Alternative 1 by voltage kV level and by core models. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 2 - New 345 kV in Michigan connecting proposed Tranche 2 facilities with Tranche 1

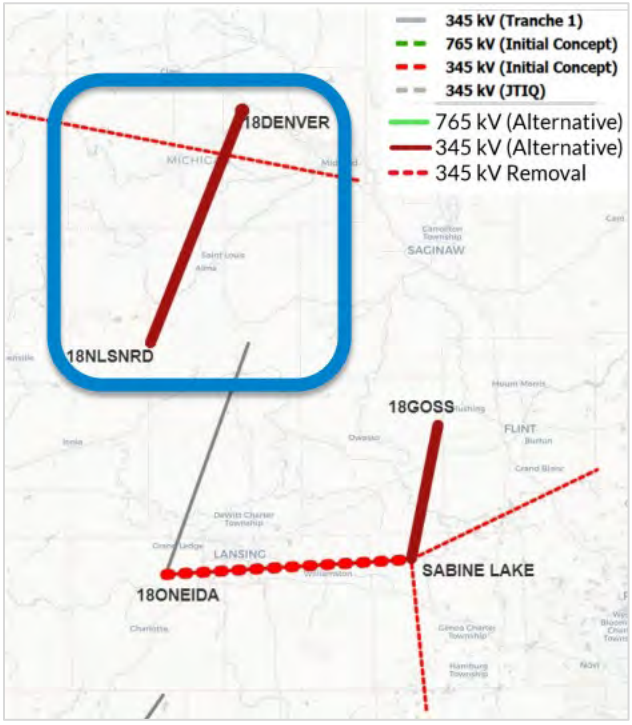


Figure 2.41: Map shows selected Alternative 2 projects in blue boxes

Alternative 2 adds four projects to the portfolio and unlocks generation in the West as a complement to existing and 765 kV paths in the initial draft portfolio.

- 2 project proposals to add in MI
    - Denver – Nelson Road 345
        - New Denver Substation
        - Two 345/138 transformers at Denver
    - Sabine Lake – Goss 345
- 1 project proposal to replace in MI
    - Oneida – Sabine Lake 345 (replaced by Sabine – Goss 345 in this Alternative)

Alternative 2 facilitates Future 2A fleet change by improving economic congestion relief, resolving constraints and reducing loading stress across all reliability models and providing more production cost savings for the MISO Midwest.

- 345 kV from Denver – Nelson Road resolves constraints and provides significant congestion relief on Michigan flowgates and is added to the portfolio.
- 345kV from Sabine Lake – Goss 345 did not show significant congestion relief over the initial portfolio and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Denver – Nelson Road 345 kV

Alternative 2 Denver to Nelson Road resolves constraints (especially in Summer Peak models) and reduces loading stress across all models by increasing the connectivity of the proposed Tranche 2 Ludington to Tittabawassee 345 kV line. This alternative adds a tab to the proposed 345 kV line at Denver and adds a 345 kV line from Denver to the Tranche 1 Nelson Road substation.

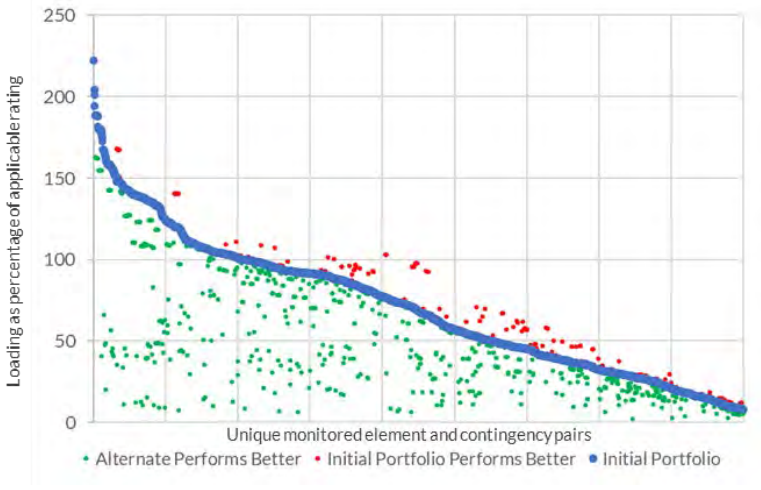


Figure 2.42: Scatter plot showing Denver-Nelson Road 345 kV performance as compared to Initial Portfolio

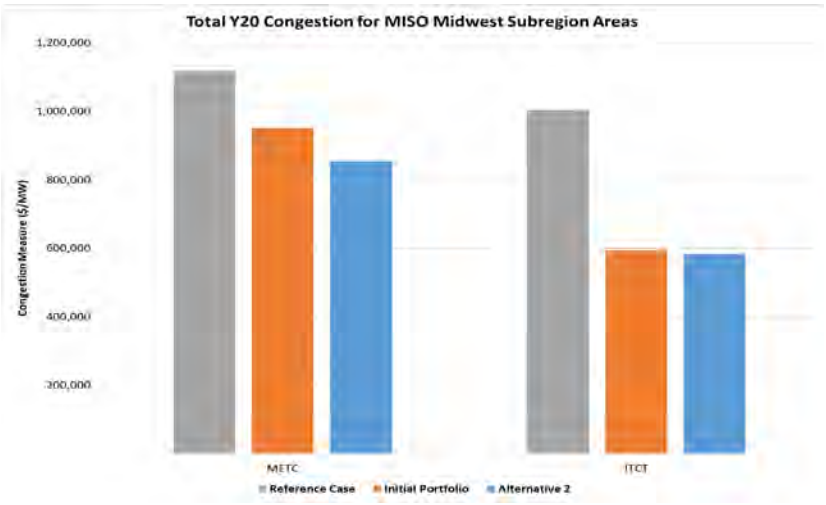


Figure 2.43: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 2

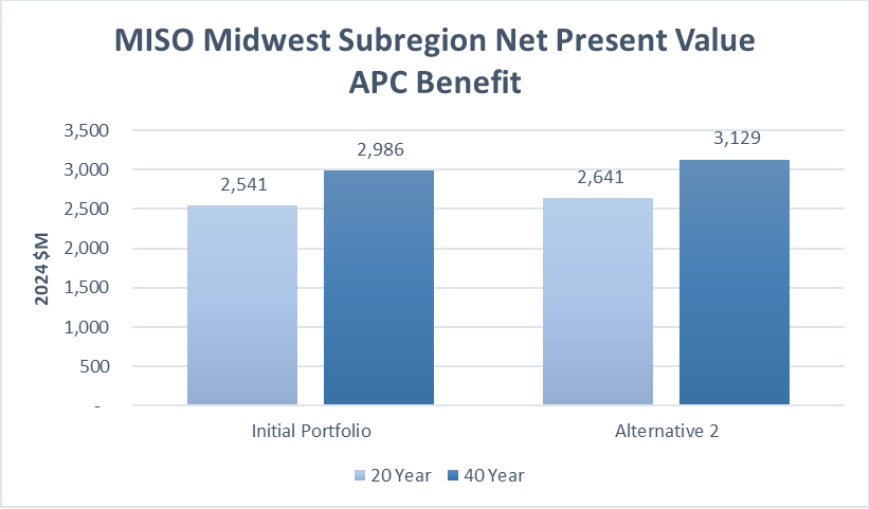


Figure 2.44: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Results based on analysis performed during portfolio definition. Results are not inclusive of all portfolio value and final results are expanded on by the business case analysis.

Goss – Sabine Lake 345 kV

The Goss to Sabine Lake 345 kV replaced a proposed Tranche 2 Oneida to Sabine 345 kV facility. This facility resolved a few constraints while stressing other system elements in the reliability analysis. In the economic analysis, Goss – Sabine Lake 345 kV did not show significant congestion relief over the initial portfolio. Therefore, this alternative was not selected to be added to the portfolio as a replacement for Oneida – Sabine Lake 345 kV.

Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 3 - Replacement of Lakefield Junction to Plano 765 kV projects in Minnesota and Wisconsin by moving the starting location to Brookings heading north of Twin Cities to Chisago onto Wisconsin Highway 22 to Paddock and retaining same end point at Plano 765

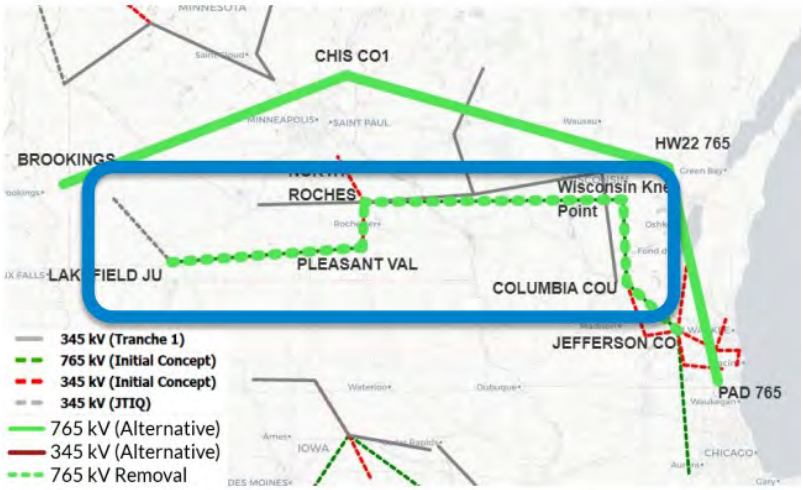


Figure 2.45: Map shows selected initial portfolio projects in blue boxes, Alternative 3 projects were not selected

Alternative 3 replaces the entire 765 kV project in MN/WI/IL with a configuration that is north of twin cities and is approximately 200 miles longer.

- 1 project proposal to add SD/MN/WI/IL
    - Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV
- 1 project removed in MN/WI/IL
    - Lakefield Junction – Pleasant Valley – North Rochester – Jefferson Co – Plano 765 kV
        - electrically comparable to the final configuration of LRTP projects 24, 26, 30, and 31
- Multiple 345 kV changes (additions and removals) in Wisconsin were incorporated with this alternative (not shown on map)

Alternative 3 targeted the same constraints as Alternative 1, but Alternative 1 outperformed Alternate 3 on the loading stress reduction metric, curtailed energy, congestion relief, and production cost savings.

- 765 kV from Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 showed marginal or mixed results in improving congestion relief over Alternative 1 and resolved a few constraints while stressing other system elements and therefore was not selected to be added to the portfolio.

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV

Brookings County – Chisago Co. – Highway 22 – Paddock – Plano 765 kV, in Alternative 3, showed marginal improvements in economic congestion compared to Alternative 1, but did not facilitate Future 2A fleet

change as well as Alternative 1. Alternative 3 had mixed results on reducing congestion in Wisconsin; reducing congestion in some areas and aggravating it in others. Compared to Alternative 1 and the initial draft portfolio, Alternative 3 did not enable as much renewable generation in the area curtailing approximately 8 GWh more renewable energy than Alternative 1.

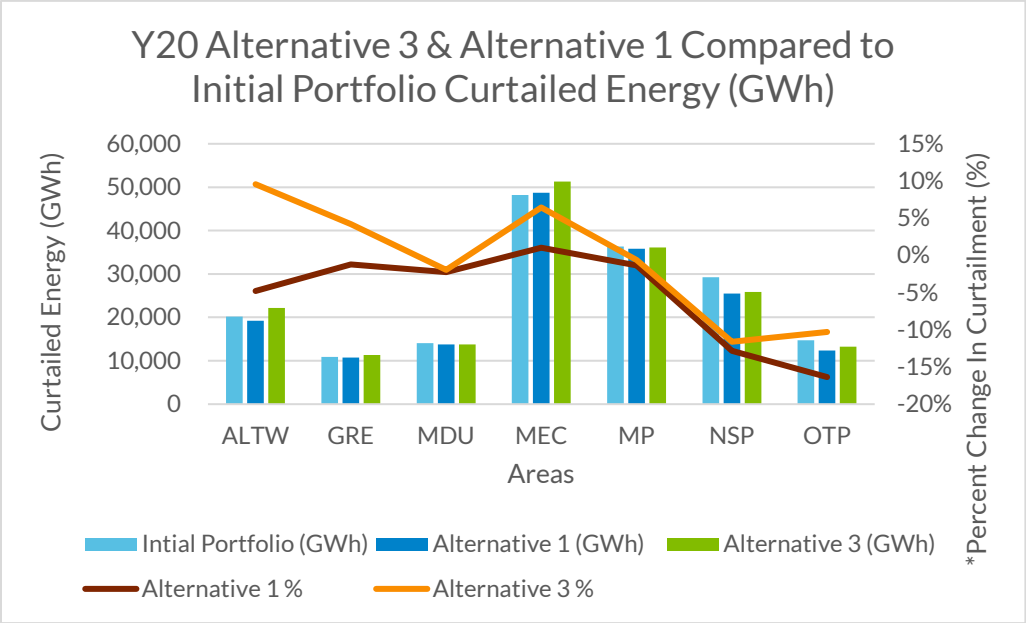


Figure 2.46: Year 20 Curtailed Energy for Initial Portfolio vs. Alternative 1 vs. Alternative 3

Alternative 3 had lower Adjusted Production Cost Savings as compared to Alternative 1 and the initial draft portfolio.

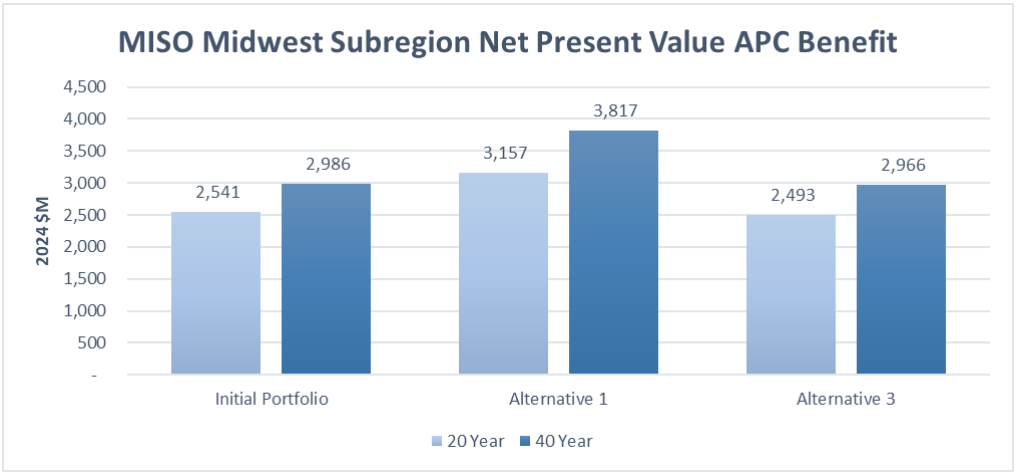


Figure 2.47: Initial Portfolio vs. Alternative 1 vs. Alternative 3 Adjusted Production Cost Savings

Alternative 3 was considered looking at the impacts of the MN area facilities and the WI area facilities considering the local areas that were impacted and comparing those reliability results.

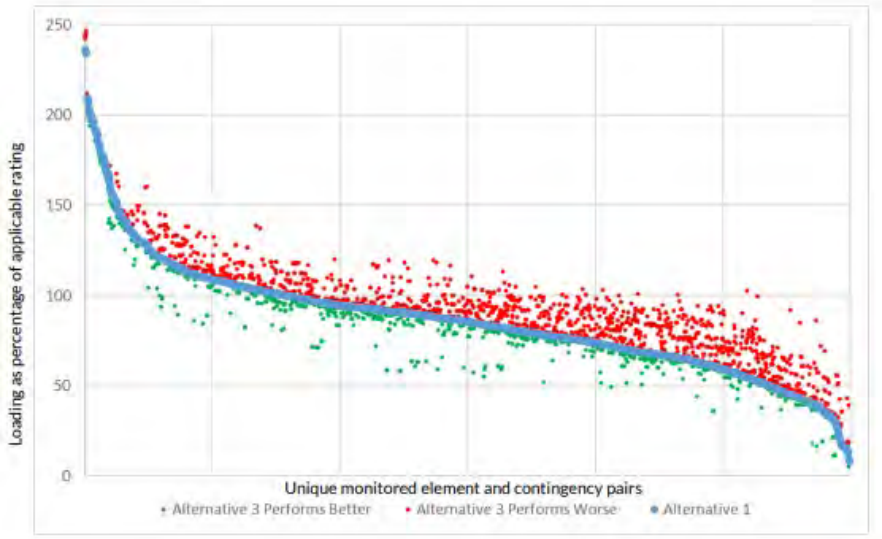


Figure 2.48: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio with Alternative 1 in MN

Alternative 1 overall performed better for the Minnesota area than Alternative 3 due to better connecting the portfolio to the rest of the MISO region, allowing for more connections to Iowa since it traverses south of the Twin Cities. Alternative 1 also benefits more from Tranche 1 345 kV portfolio in the area as well.

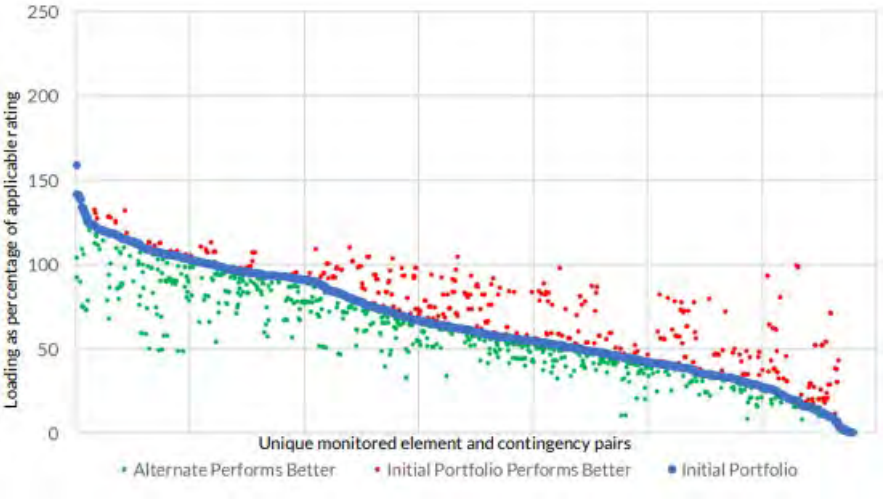


Figure 2.49: Scatter plot showing Alternative 3 performance as compared to Initial Portfolio in WI

For Wisconsin, the results were inconclusive whether incorporating the alternative resolved more violations, as both violations were created and resolved. The result was retaining the original Wisconsin portfolio in this area. Alternative 3 was not selected to move forward, instead a combination of the proposed facilities in this area with the Alternative 1 additions (Big Stone to Brookings County 765 kV and Lakefield Junction to East Adair 765 kV). Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 4 - Add northern MN outlet from Tranche 1 facilities and add Southern IN reinforcements enabling interstate transfers. Evaluates Michigan 345 kV project proposal

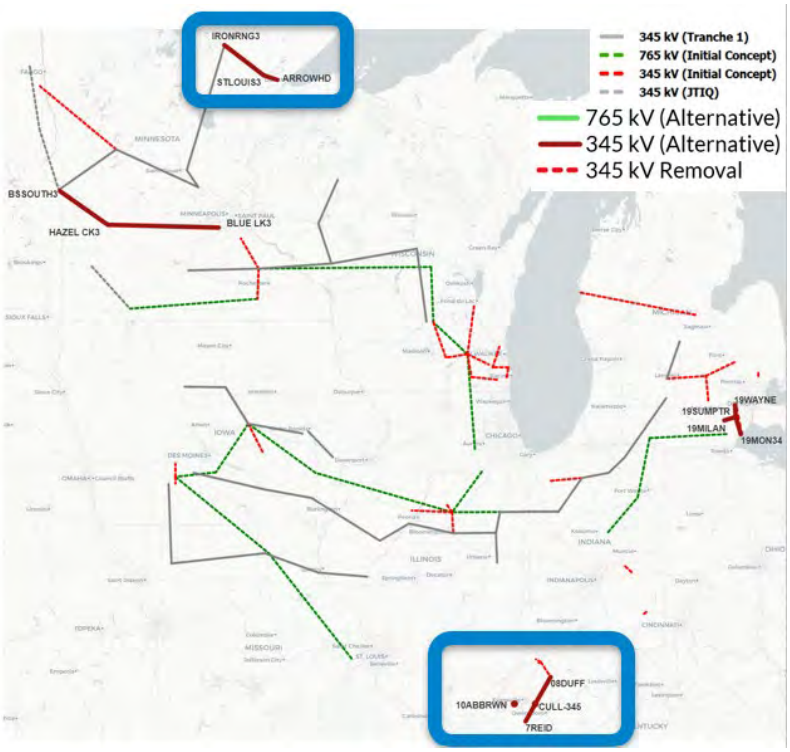


Figure 2.50: Map shows selected Alternative 4 projects in blue boxes

Alternative 4 adds four projects to the portfolio in Michigan, Indiana/Kentucky, Southern Minnesota and Northern Minnesota.

- 2 project proposals to add in MN
    - Iron Range – St Louis Co. – Arrowhead 345 kV (Northern MN)
    - Big Stone South – Hazel Creek – Blue Lake 345 kV (Southern MN)
- 1 project proposal to add in IN/KY
    - Duff – F. B. Culley – Reid EHV 345 +A. B. Brown 345/138 XF (1) and F. B. Culley 345/138 kV XFs (2)
- 1 project proposal to add in MI
    - Milan – Sumpter 345
- No projects from initial portfolio replaced or removed

Select projects within Alternative 4 facilitates Future 2A fleet change by increasing the deliverability of renewable energy and providing more production cost savings for the MISO Midwest.

- 345 kV in Northern Minnesota resolved constraints, reduced loading stress and improved economic congestion in Northern Minnesota and is added to the portfolio.
- 345 kV in Southern Indiana reduced loading in the area and supports interstate transfers and is added to the portfolio.
- 345 kV in Southern Minnesota resolved similar constraints in the region as Alternative 1 with mixed results observed on the loading reduction metric and was not selected to be added to the portfolio.
- Milan – Sumpter 345 kV had minimal economic impact in Michigan and had minimal impact on transmission facilities in the area therefore was not selected to be added to the portfolio.

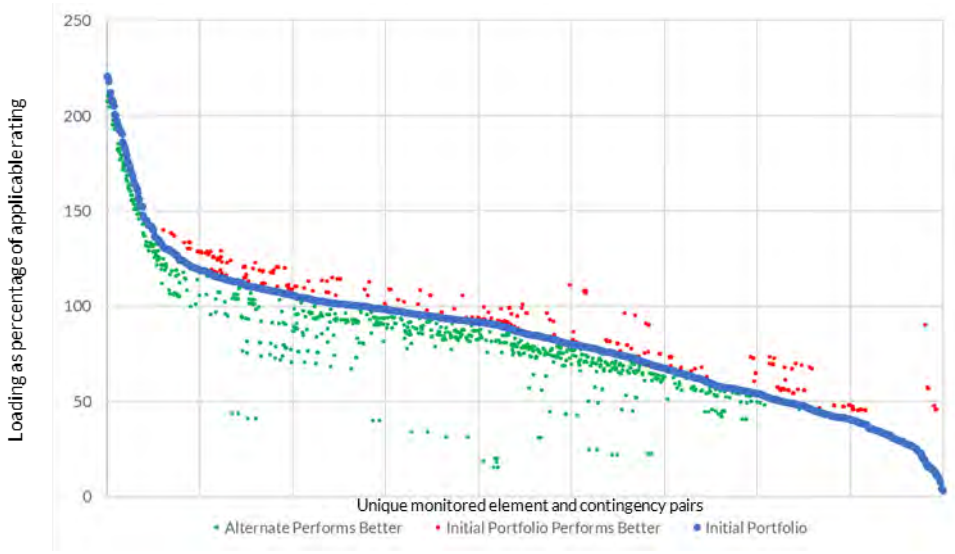


Figure 2.51: Scatter plot showing Iron Range- Arrowhead 345 kV performance as compared to Initial Portfolio

Alternative 4 in Northern Minnesota resolves constraints and reduces loading stress for the majority of impacted flowgates with healthy base case loading on the project in all models.

Iron Range – St Louis Co. – Arrowhead 345 kV provides additional congestion relief in Northern Minnesota in Iron Range and south of Duluth.

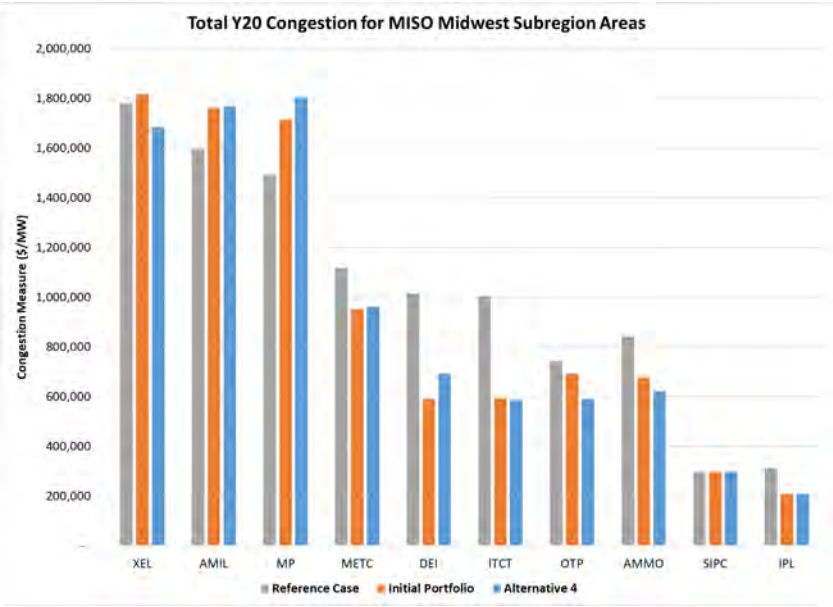


Figure 2.52: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (MN)

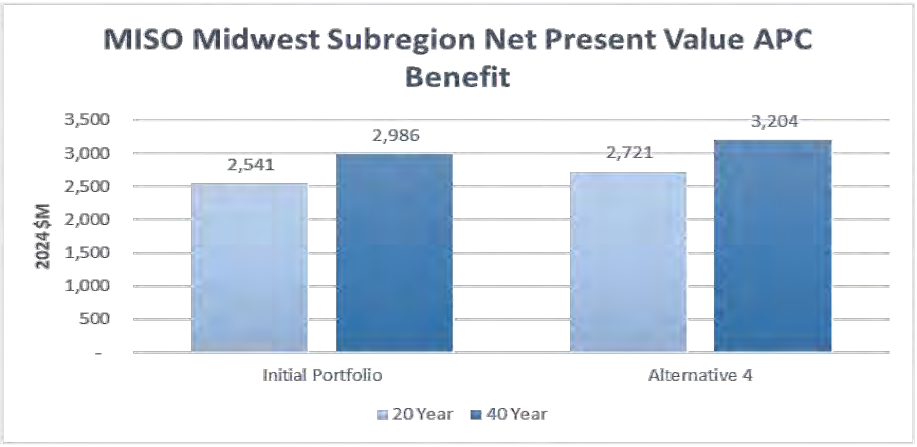


Figure 2.53: Initial Portfolio vs. Alternative 4 Adjusted Production Cost Savings

The Northern Minnesota 345 kV also shows economic value due to congestion relief and increases the Adjusted Production Cost Savings for the Midwest subregion as compared to the initial portfolio.

Duff – F. B. Culley – Reid EHV 345, A. B. Brown 2nd Transformer, F. B. Culley 2 Transformers

Alternative 4 project in Indiana resolves key constraints in the region and assists in reducing the loading on system elements in Southern Indiana. In addition, loading reductions occurred on constraints in additional transfer scenarios to enable regional flows.

Duff – F. B. Culley – Reid EHV 345 and A. B. Brown and Culley transformer alternative resulted in an overall downward trend in congestion in Indiana. Congestion reduction supports transfer capability in MISO Central and 345 kV facilities provided economic value for southern Indiana, Illinois and Kentucky.

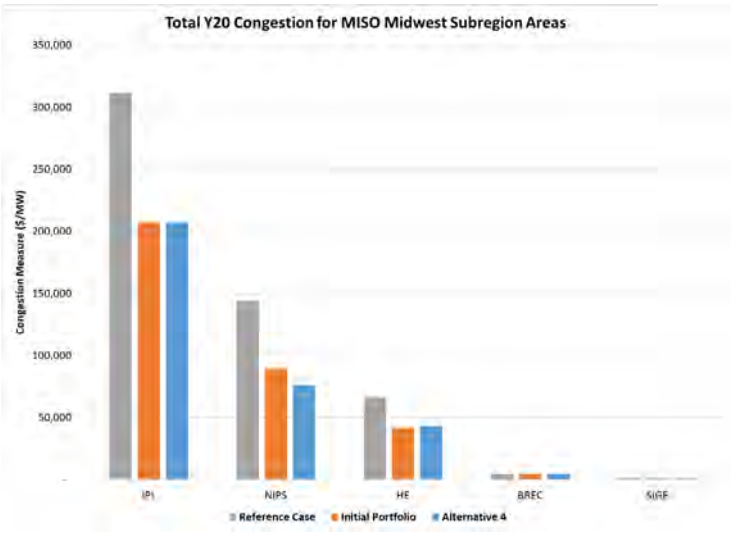


Figure 2.54: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 4 (IN)

Big Stone South – Hazel Creek – Blue Creek 345 kV

The Alternative 4 Southern Minnesota project resolves constraints in the region; however, these are similar constraints to those resolved by Alternative 1; mixed results were observed on the loading reduction metric. 345 kV Southern MN addresses similar constraints as Alternative 1, therefore was not selected for the final portfolio.

Milan – Sumpter 345 kV

Alternative 4 project in Michigan had minimal impact on transmission facilities in the area from a reliability analysis. In addition, the Milan – Sumpter 345 kV project had minimal economic impact for Michigan. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 5 - Central IA additional source to the proposed Twinkle 765 kV substation

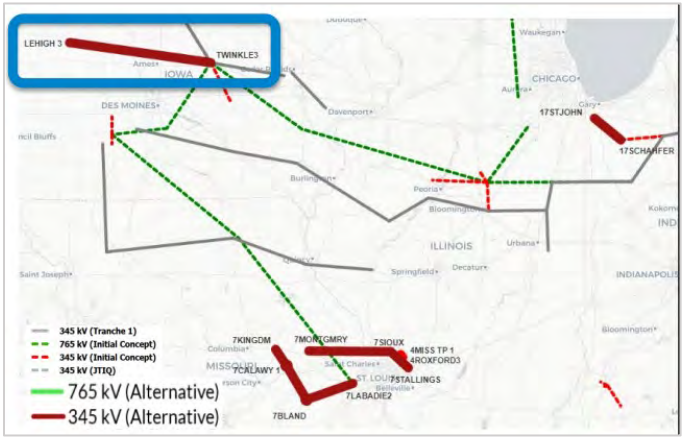


Figure 2.55: Map shows selected Alternative 5 projects in blue boxes

Alternative 5 adds three projects to the portfolio in Indiana, Missouri and Iowa

- 1 project proposal to add in Indiana
    - St. John – Burr Oak 345
- 2 project proposals to add in Missouri
    - Montgomery – Sioux – Stallings 345
    - Kingdom City – Bland – Labadie 345
- 1 project proposal to add in Iowa
    - Lehigh – Twinkle 345
- No projects from initial portfolio replaced or removed

Alternative 5 facilities build upon Tranche 1 and proposed Tranche 2 facilities in central Iowa further facilitating Future 2A and high voltages.

- 345 kV line from Lehigh to Twinkle further connected Tranche 1 Marshalltown 345 kV outlets (Marshalltown and Twinkle are same location) providing additional sources for the 765 kV outlet under contingency operation. This project was added to the portfolio.
- 345 kV facilities proposed in MO; Montgomery to Sioux to Stallings and Kingdom City to Bland to Labadie, resulted in minimal impact on transmission facilities in the area and was not selected to add or modify the portfolio.
- 345 kV line in northern Indiana St. John to Burr Oak 345 kV was considered and only impacted one constraint, resulting in no addition or modification to the portfolio.

Lehigh – Twinkle 345 kV

Alternative 5 in Iowa provides an additional source to the proposed Twinkle 765 kV substation, with healthy loadings confirming its utilization. The Lehigh -Twinkle 345 kV provided support to the 765 kV network and a marginal impact to the overall Adjusted Production Cost Savings as compared to the original portfolio.

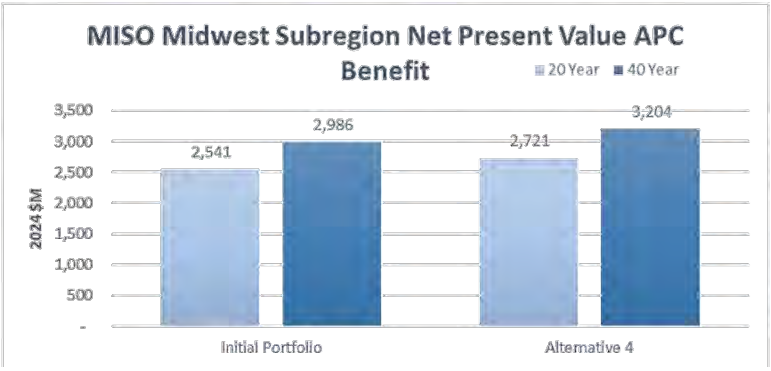


Figure 2.56: Initial Portfolio vs. Alternative 5 Adjusted Production Cost Savings

Montgomery – Sioux – Stallings 345, Kingdom City – Bland – Labadie 345 kV

Alternative 5 in Missouri has minimal impact on transmission facilities in the area. This project resolved high voltage constraints and assisted in reducing loading stress in the area. The Missouri area projects showed minimal congestion relief or economic value over the initial portfolio.

St. John – Burr Oak 345 kV

Alternative 5 in Indiana has minimal impact on transmission facilities in the area. The St. John – Burr Oak 345 kV project showed minimal congestion relief or economic value over the initial portfolio.

Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

Alternative 6 - Replace 765 kV proposed in MO with 345 kV projects connecting to Tranche 1 facilities

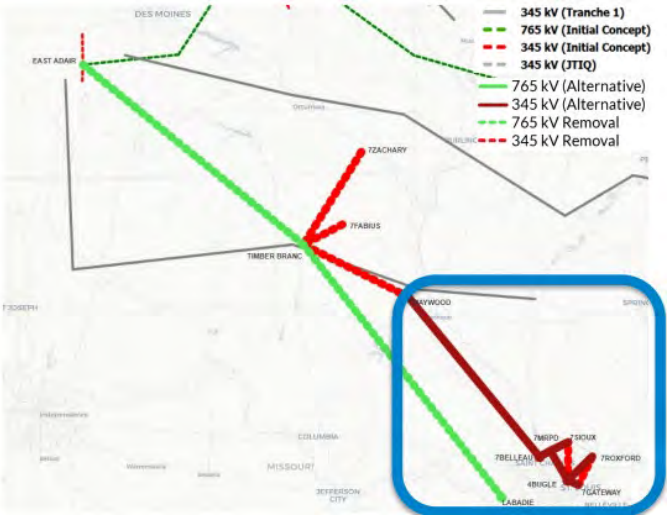


Figure 2.57: Map shows selected Alternative 6 projects in blue boxes

Alternative 6 replaces the 765 kV project in IA/MO with 345 kV projects in the St. Louis metropolitan area in Missouri.

- 1 project proposal to add in MO
    - Maywood – Belleau – MRPD- Sioux, MRPD – Bugle –Roxford /Gateway) 345
- 1 project removed in IA/MO
    - East Adair (IA) – Labadie 765 kV

Alternative 6 facilities build upon Tranche 1 and enables regional flows and removes 765 kV facilities into MO that may be reviewed further in later tranches with a continuous 765 kV path.

- 345 kV facilities in Missouri resolved constraints in MISO Central, reduced loadings in the Missouri area and provided economic value while enabling interstate transfers and was added to the portfolio.

- 765 kV from Iowa to Missouri did not result in significant congestion relief without additional support and was removed from the portfolio.

Maywood – Belleau – MRPD- Sioux, MRPD – Bugle -Roxford/Gateway) 345 kV + XFs

The 345 kV facilities reduced congestion supporting transfer capability in MISO Central.

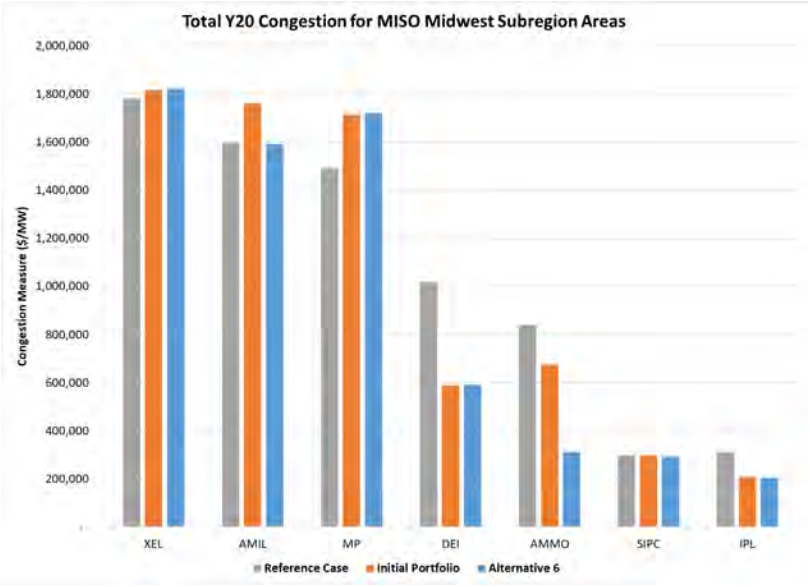


Figure 2.58: Year 20 Congestion Measure for Reference Case vs. Initial Portfolio vs. Alternative 6

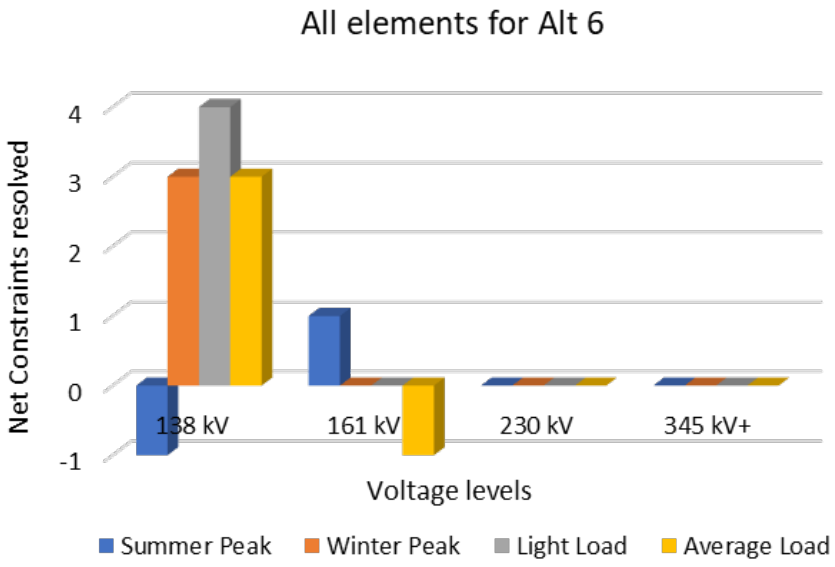


Figure 2.59: Constraints resolved by Voltage level by Alternative 6 project

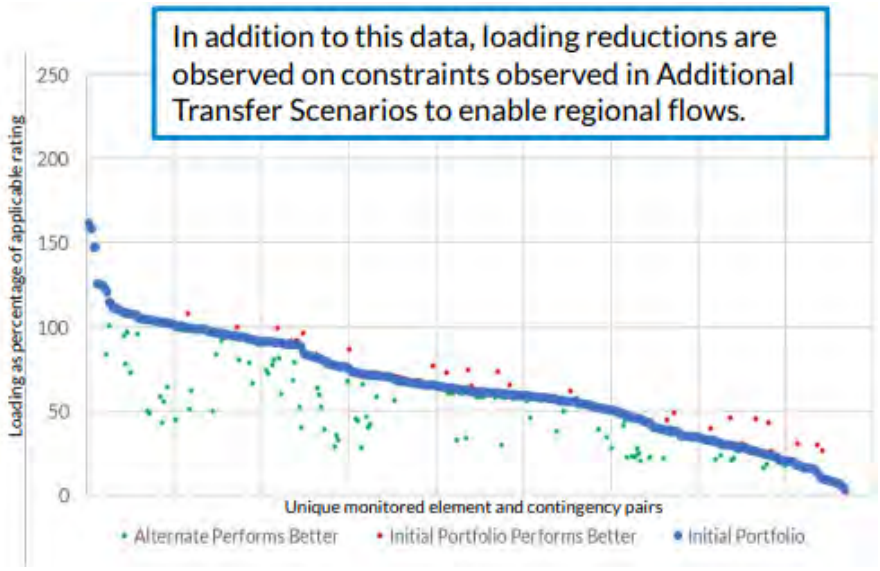


Figure 2.60: Scatter plot showing Alternative 6 performance as compared to Initial Portfolio

The Iowa - Missouri 765 kV line did provide economic value but did not result in significant congestion relief without additional support and may be reviewed further in later tranches with a continuous 765 kV path. Additional explanation and detailed results are available at the May 29, 2024, LRTP workshop.

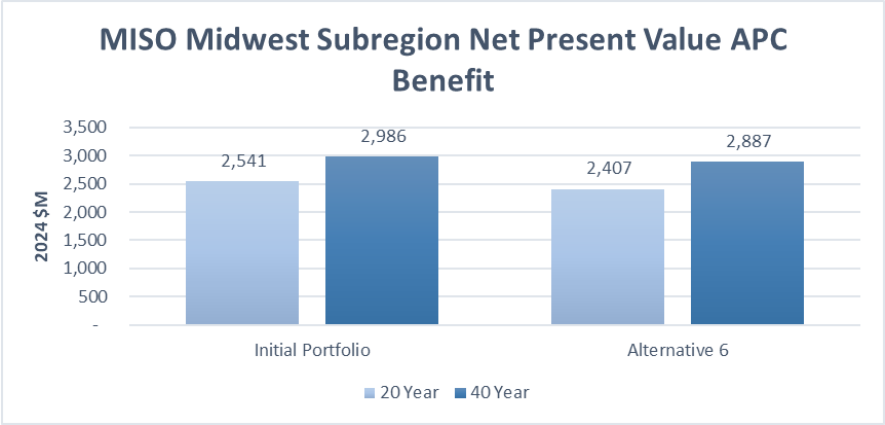


Figure 2.61: Initial Portfolio vs. Alternative 1 Adjusted Production Cost Savings

Refine Solutions

After identifying the issues that would be addressed in Tranche 2.1, and performing the above alternatives assessment, MISO developed a near-final portfolio of solutions to resolve those issues based on results from reliability and economic analysis using the criteria, data, tools and methodology described in the prior sections of this document and in the economic and reliability study whitepaper.

Tranche 2.1 portfolio includes 24 projects across the MISO Midwest subregion, estimated at $21.8 billion. The projects are targeted to go in service from 2032 to 2034. The least-regrets, robust portfolio provides the following:

- Facilitates a more economical dispatch for MISO Midwest resulting in $8.1B in Adjusted Production Cost (APC) savings
- Reduces economic congestion for MISO Midwest by 29.5%
- Reduces MISO Midwest curtailment by 11.2% (27.1M MWh)
- Decreases MISO Midwest load serving costs and reduces price separation
- Resolves more than 60% of >200 kV constraints for single initiating and multiple element contingency events
- Paired contingency (P3/P6) analysis shows on average more than 70% of thermal violations are resolved for all voltage levels
- Reduces the majority of the loadings below Safe Loading Limits
- Enables regional power transfer within MISO when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty

Step 5: Evaluate and Justify Solutions

Total Reliability Results

Analysis with twelve reliability models representing various system conditions and dispatch patterns helped MISO better understand system performance with and without LRTP portfolio of projects. MISO monitored flow on lines and voltage at substations with and without the LRTP portfolio of projects. To better assess the impact and severity of overloads and voltage violations across multiple lines and substations, MISO utilized industry-standard ranking criteria known as Severity Indices. The severity index formulation is a modified Contingency Severity Index (CSI) from Siemen PTI's PSS/MUST. This approach enables straightforward comparisons of overall system performance across various models, rather than focusing solely on specific monitored elements or contingency pairs.

The Thermal Severity Index provides an overview of the performance of the Tranche 2.1 portfolio taking into consideration the magnitude of thermal and voltage violations, respectively, from the contingency analysis. The Thermal and Voltage Severity Index values calculated for the Tranche 2.1 portfolio point to significant improvement in the overall system performance.



Figure 2.62: Thermal Severity Index and Voltage Severity Index with and without the Tranche 2.1 portfolio

Large Angular separation across the Midwest subregion was noticed while building models, as power was being transferred via longer, inefficient routes leading to increased risk of angular separation and instability, and increased losses. The Tranche 2.1 portfolio reduces angular separation across the MISO transmission system in the most stressed case by 47°, showing that power can take more direct paths from resources to load, enabling additional flexibility during outages.

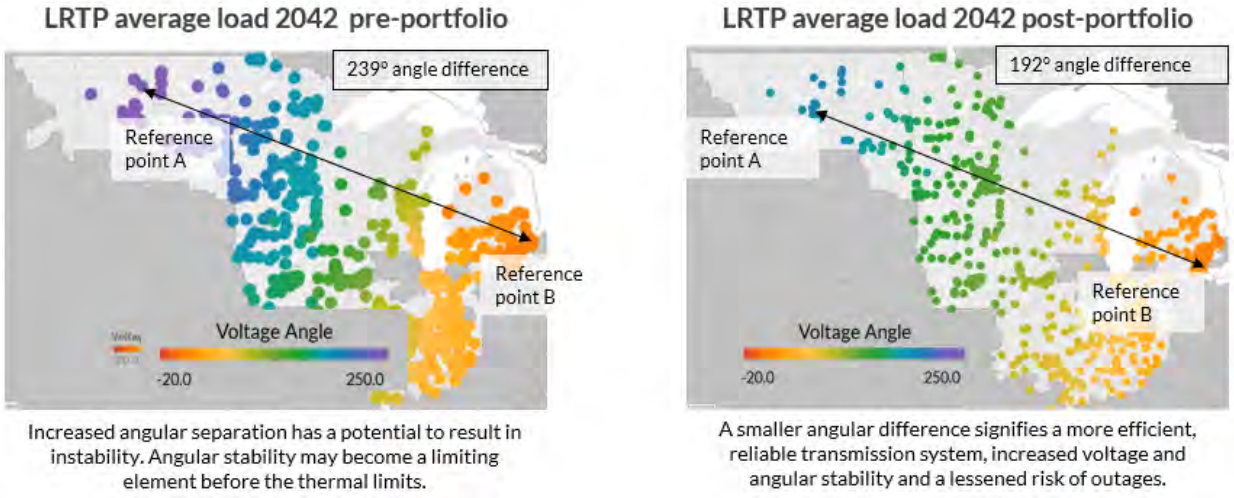


Figure 2.63: Angular separation with and without the Tranche 2.1 portfolio

Voltage and Reactive Support

Maintaining optimal loading levels is essential for reliable operation and effective voltage regulation in (Extra High Voltage) EHV transmission lines. When EHV lines operate below their Surge Impedance Loading (SIL), they generate reactive power, functioning as a source or reactive power that can alleviate voltage

issues elsewhere in the grid. To enhance system reactive support and reduce reliance on other voltage support devices, MISO intentionally planned the system to increase the SIL of regional lines when practical (e.g., use of 765 kV options and high-SIL 345 kV options for very long 345 kV lines), thus providing substantial reactive power capability from the regional transmission system under most conditions. Since regional flows are lower during summer peak conditions, which is the time when reactive power demand from loads tends to be highest, the lower regional flows that typically occur in the summer (because a much greater percentage of the generation output in summer is local) allow for even more reactive power capability from the regional lines, decreasing the need for local voltage support equipment during these conditions.

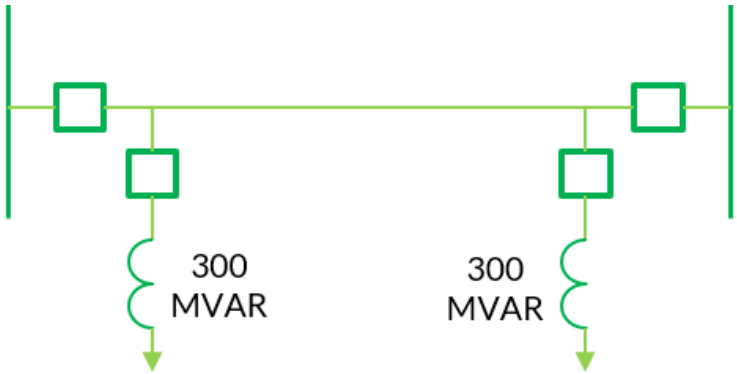


Figure 2.64: Default 765 kV line configuration includes line-side switchable shunt reactors to manage high voltages and mitigate Ferranti Effect during switching

To better manage high voltage issues and allow for greater flexibility, the default 765 kV line configuration includes line-side switchable 300MVAr shunt reactor banks at each terminal to control high voltages and mitigate the Ferranti Effect during switching. The reactor banks can also be switched off by operators when line flows exceed the SIL and it is necessary to maintain acceptable voltage levels in the area.

The LRTP Tranche 2.1 portfolio addressed most of the voltage violations. The average 765 kV N-0 loadings in the core cases are as follows:

- Summer Peak: 33.7% of Surge Impedance Loading
- Winter Peak: 50.1% of Surge Impedance Loading
- Average: 60.1% of Surge Impedance Loading
- Light Load: 58.7% of Surge Impedance Loading

Due to the Surge impedance loading of 2440 MW for 765 kV, the 765 kV system is providing substantial reactive power, particularly in the summer peak case where voltage support is most needed. This substantially reduces the need for other voltage support devices.

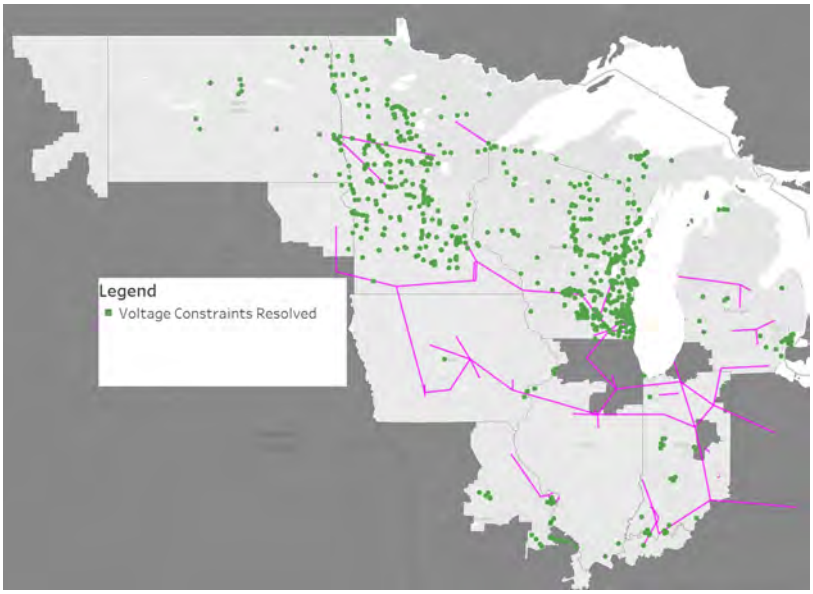


Figure 2.65: Green dots represent a voltage constraint observed in core models and is mitigated by the final portfolio

Since reactive support is inherently local—given that reactive power cannot be transferred over long distances—the remaining low and high voltage issues, along with overloaded transmission lines due to local load growth and specific generation interconnections, will be addressed through various shorter-term planning processes. These include the annual MTEP reliability planning and the generator interconnection processes, as specific load and generation locations are identified.

Dynamic Assessment

The portfolio enhances the overall stability of the system as demonstrated by a significant reduction in the number of transient voltage violations, low damping violations and relay trip violations. The 2042 average load case represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and 100% renewable penetration meaning that all MISO load is being served by renewables and is the most severe case due to the required transfers of generation across long distances to serve load. The 2042 summer peak model represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

The Transient Stability Index (TSI) is an industry acceptable metric used in TSAT (Transient Security Assessment Tool) which assesses the severity of each disturbance. A higher TSI for a disturbance represents a more stable system response. The Tranche 2.1 portfolio resolved a vast majority of transient voltage violations for the 2042 AVG model and boosts the system performance in the 2042 SUM model. Approximately 90% of transient voltage violations were resolved in the 2042 AVG stability model, and 30% of transient voltage violations were resolved in the 2042 SUM peak stability model.

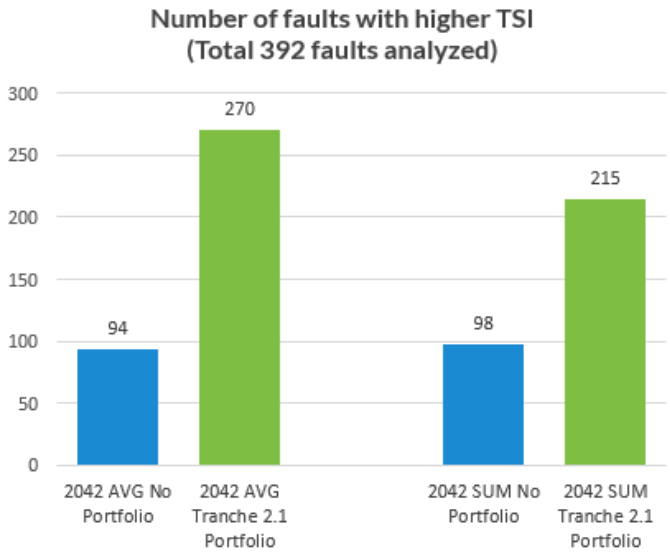


Figure 2.66: Transient Stability Index with and without the Tranche 2.1 portfolio

Many of the remaining transient voltage violations will have better resolution through site specific dynamic parameter tuning, and through the annual MTEP reliability planning and the generator interconnection planning processes. The portfolio resolved all the low damping violations and reduced the total number of relay violations.

Transfer Analysis

East to West Transfer Scenario underscores the portfolio's flexibility to accommodate significant shifts in generation during low renewable output in the West, while also highlighting the bi-directional nature of the system, with flows reversing as conditions change.

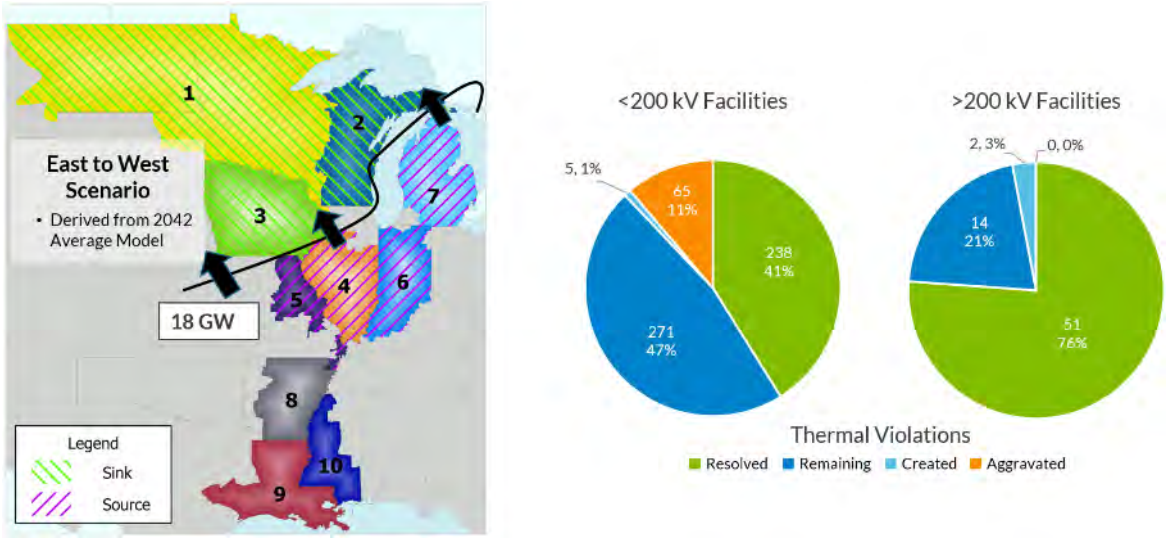


Figure 2.67: East to West Transfer results summary with the Tranche 2.1 portfolio

All reliability core models had natural direction of flows from West to East based on data from future hourly profiles; however, there were a number of hourly profiles where flow was in the East to West direction. To cover this credible scenario, MISO utilized the data from Futures to build an East to West scenario. In the East to West transfer an additional 13% unique limiting elements were observed beyond the unique limiting elements in the core models (average load, summer peak, light load, and winter peak). The LRTP 2.1 portfolio resolves more than 75% of all 200 kV and above constraint violations observed in the East to West scenario.

The Lowers to Uppers Scenario highlights the flexibility of the portfolio to accommodate increased output in the Central Region and reliably deliver power to other MISO Regions.

Studying this scenario introduced an additional 6% unique limiting elements beyond the core models. The LRTP Tranche 2.1 portfolio resolves 70% of all 200 kV and above constraint violations observed in this scenario.

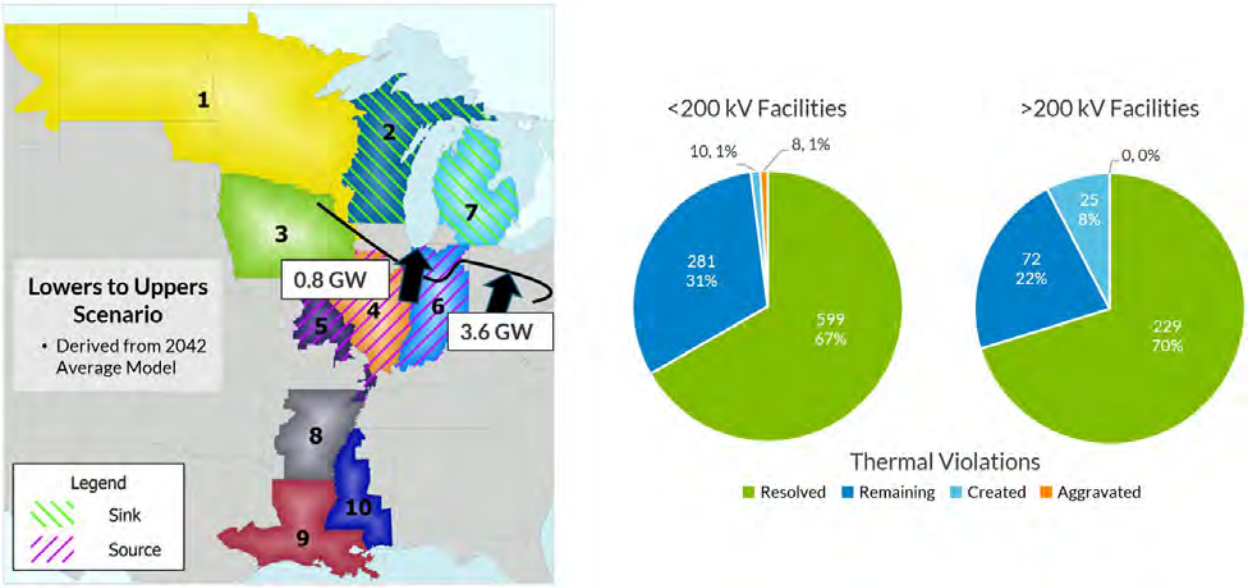


Figure 2.68: Lowers to Uppers Scenario results summary with the Tranche 2.1 portfolio

The Winter Peak Low Renewable scenario captures multi-day periods of low renewable output, particularly during early morning hours and regional winter freezes. The LRTP portfolio enables reliance on conventional local resources to reliably support load during winter events that have historically impacted the MISO system.

This scenario represents the lowest renewable scenario of all core models and additional scenarios. All conventional resources are dispatched to their maximum nameplate capacity. Studying this scenario introduced an additional 48% unique limiting elements beyond the unique limiting elements in the core models. LRTP Tranche 2.1 portfolio resolves 52% of all 200 kV and above constraint violations observed in this scenario.

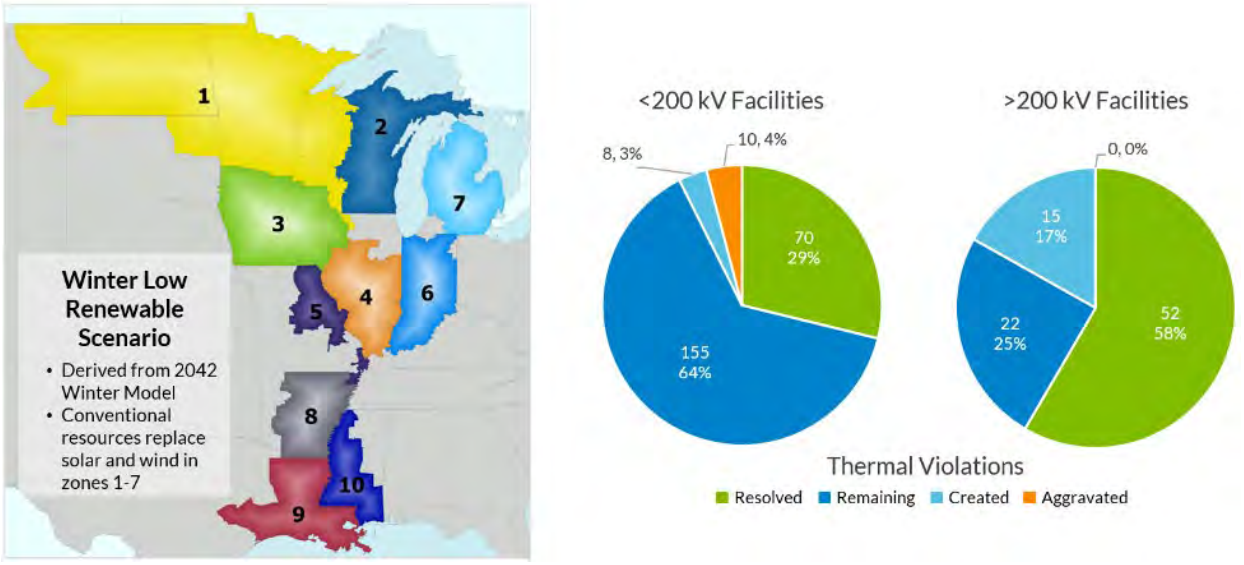


Figure 2.69: Winter Peak Low Renewable Scenario results summary with the Tranche 2.1 portfolio

The Twilight Summer Scenario demonstrates a large increase in reliability on the 200 kV and above system as the resource mix transitions during sunset at peak load.

The Twilight scenario dispatches down solar and wind resources to 10% of nameplate capacity. In this scenario, batteries are assumed unavailable. Studying this scenario introduced an additional 20% unique limiting elements beyond the unique limiting elements in the core models. The LRTP Tranche 2.1 portfolio resolves 72% of all 200 kV and above constraint violations observed in this scenario.

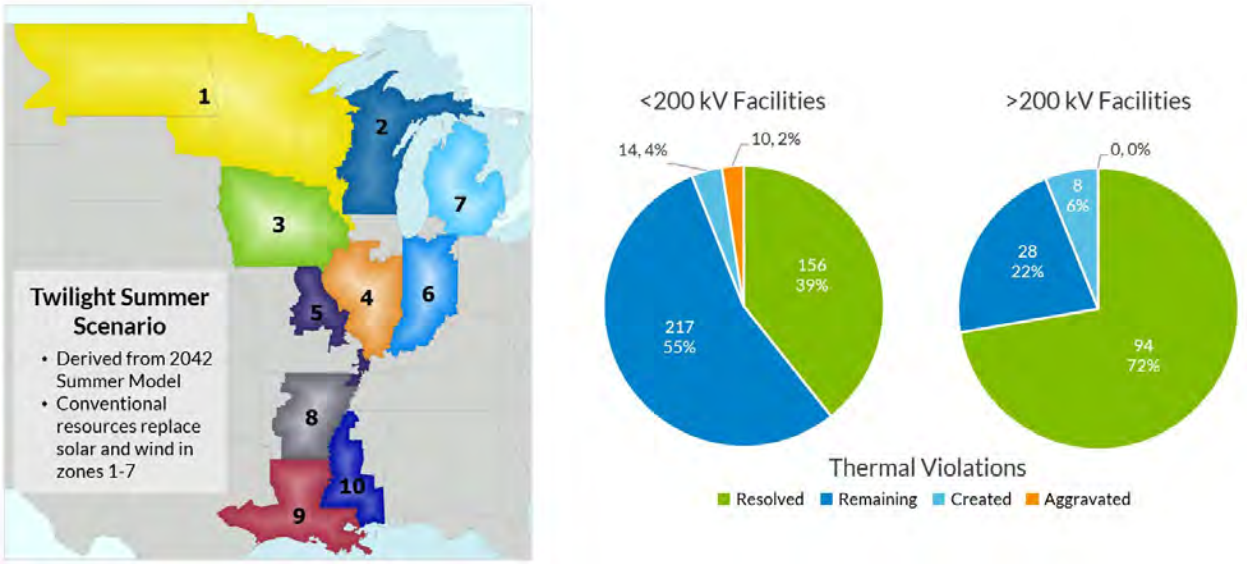


Figure 2.70: Twilight Summer Scenario results summary with the Tranche 2.1 portfolio

Total Economic Results

Analysis with annual economic models represent various system conditions and dispatch patterns helped MISO better understand system performance with and without the LRTP portfolio of projects. Unless otherwise indicated, the measures described in this section were derived from the 2042 Future 2A PROMOD models. The Tranche 2.1 portfolio enhances the economic value for the MISO Midwest subregion and enables member plans for fleet transition and load growth. The economic analysis revealed the Tranche 2.1 portfolio:

- Reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5%
- Reduces curtailment in the MISO Midwest subregion by 27.1M MWh (11.2%), improving access to more economic generation
- Supports the MISO Midwest subregion by reducing price separation across the subregions and decreasing system cost to serve load
- Facilitates a more economical dispatch for MISO Midwest resulting in $8.1B in Adjusted Production Cost (APC) savings
- Provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement

Congestion Measure

Transmission congestion is quantified through "Congestion Measure" ($/MW) and is calculated by multiplying annual Average Shadow Price ($/MW/hr) by Binding Hours (hr/yr). A reduction in Congestion Measure demonstrates that the most congested transmission constraints in a region have been relieved, and that the effects of congestion throughout the region have been reduced.

The Tranche 2.1 portfolio reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5% including:

- West Region sees a 25.5% ($2.0M/MW) reduction in economic congestion
- Central Region sees a 33.9% ($2.0M/MW) reduction in economic congestion
- East Region sees a 31.7% ($0.9M/MW) reduction in economic congestion

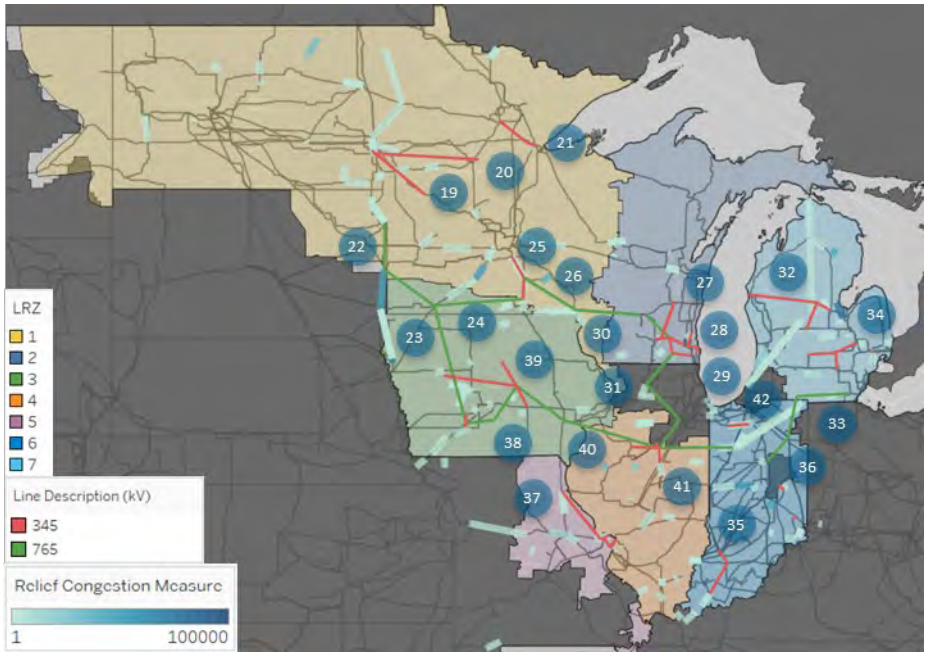


Figure 2.71: Change Case: Year 20 Economic Congestion Relief

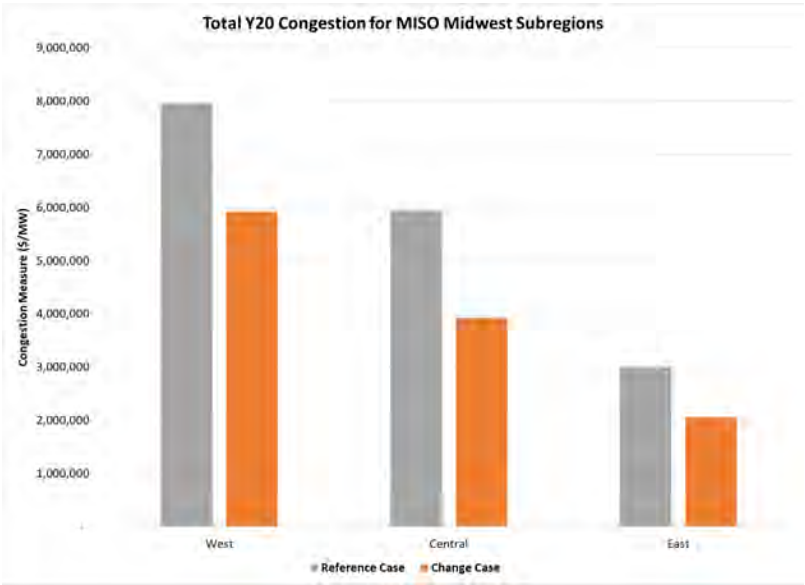


Figure 2.72: Reference and Change Case Year 20 Economic Congestion

MISO Subregion Y20 Congestion Measure by LRZ					
Region	**LRZ**	**Reference Case ($/MW)**	**Change Case ($/MW)**	**Reduction ($/MW)**	**Reduction (%)**
West	LRZ1	6,032,037	5,054,985	977,052	16.2%
	LRZ2	1,109,215	345,145	764,070	68.9%
	LRZ3	811,109	526,642	284,467	35.1%

MISO Subregion Y20 Congestion Measure by LRZ					
Region	**LRZ**	**Reference Case ($/MW)**	**Change Case ($/MW)**	**Reduction ($/MW)**	**Reduction (%)**
	West	7,952,361	5,926,772	2,025,589	25.5%
Central	LRZ4	1,972,466	1,698,381	274,085	13.9%
	LRZ5	1,277,548	563,671	713,877	55.9%
	LRZ6	2,688,959	1,661,564	1,027,395	38.2%
	Central	5,938,973	3,923,616	2,015,357	33.9%
East	LRZ7	3,000,363	2,050,593	949,770	31.7%
	East	3,000,363	2,050,593	949,770	31.7%
MISO Midwest	**Total**	**16,891,697**	**11,900,981**	**4,990,716**	**29.5%**

Table 2.10: Year 20 Congestion Reduction with LRTP Tranche 2.1 by Percentage

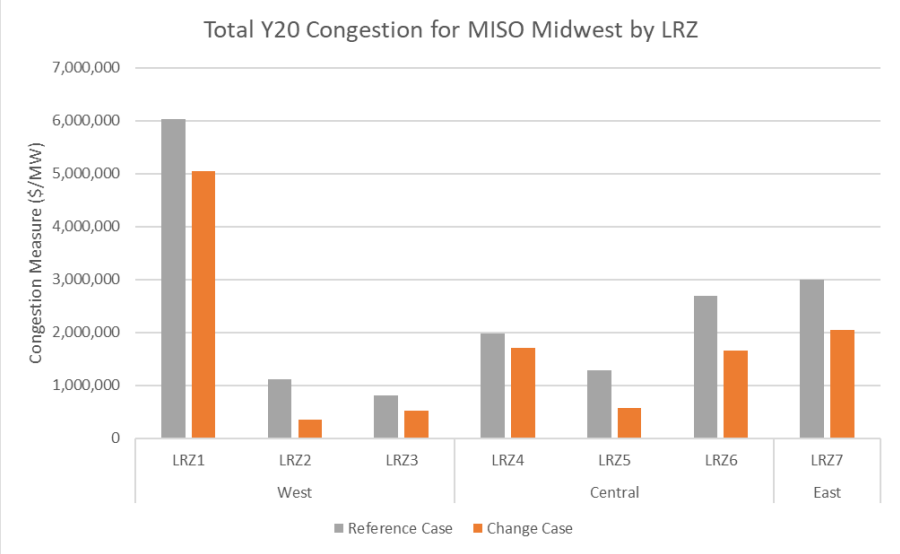


Figure 2.73: Year 20 Congestion with and without LRTP Tranche 2.1 by Local Resource Zone

Curtailment

Curtailment is due to many factors, including congestion and deliverability within MISO Midwest, which are substantially addressed with Tranche 2.1 transmission. Other curtailment is caused by competition and limited interregional export capacity and opportunity, which is outside the scope of this current effort to address.

Between the 2042 Reference case (without Tranche 2.1 transmission) and the 2042 Change case (with Tranche 2.1 transmission), the Tranche 2.1 portfolio reduces curtailment and improves access to more economic generation.

Curtailment in PROMOD is a measure of the available energy from renewable resources which are unable to deliver due to transmission constraints. Curtailment relief demonstrates the Tranche 2.1 portfolio will boost deliverability of additional generation, facilitate the Future 2A fleet change, and drive APC lower by reducing purchase and sales costs.

The Tranche 2.1 portfolio reduces generation curtailment across the MISO Midwest subregion 11.2% (27.1M MWh) including:

- West Region sees a 16.1% (31.6M MWh) reduction in curtailment
- Central Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- East Region sees marginal increase in curtailment, primarily due to increased competition from dispatch of more economical units within the Midwest subregion
- Overall, curtailment for the MISO Midwest subregion reduces from 33.7% to 29.9% in Year 20.

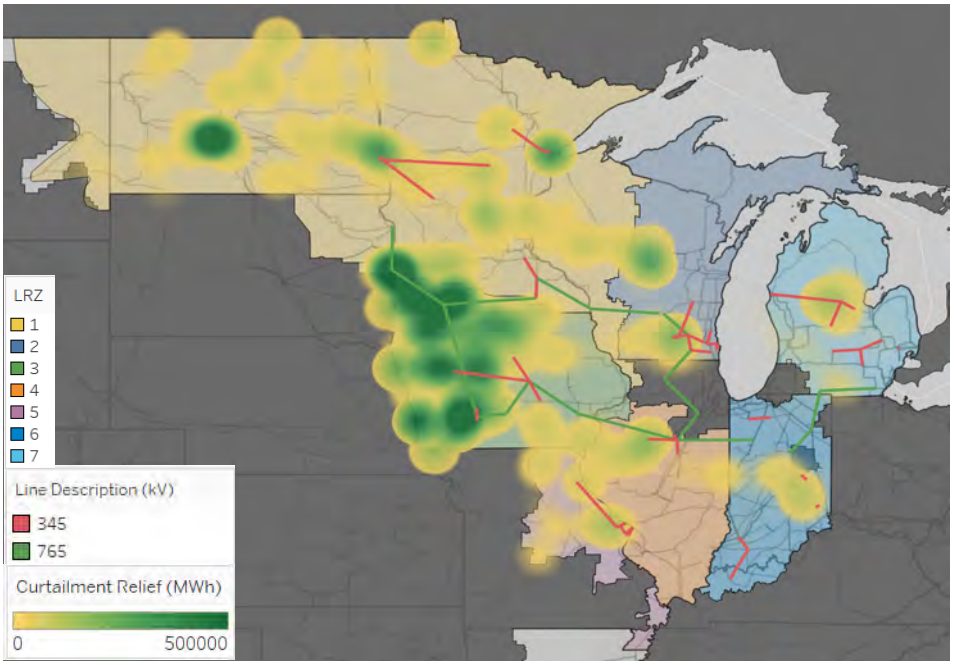


Figure 2.74: Change Case: Curtailment Energy Relief

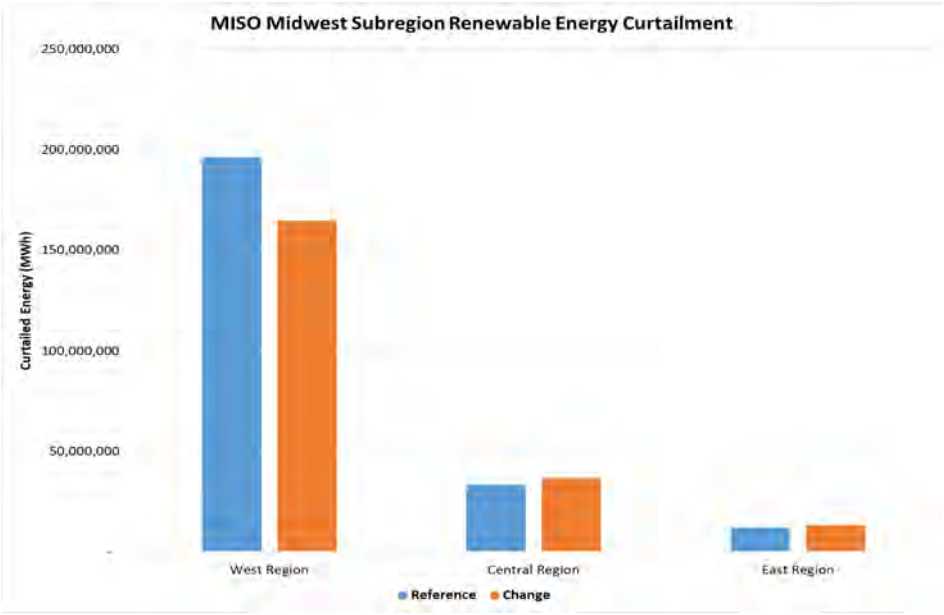


Figure 2.75: Reference and Change Case: Year 20 Curtailment Energy

Load Weighted Locational Marginal Price (Load LMP)

The portfolio supports the MISO Midwest subregion by reducing price separation across the subregion and decreasing system cost to serve load. Cost to serve load is represented by Load Weighted LMP ($/MWh). The difference in prices between portions of the MISO Midwest subregion indicates that transmission constraints are limiting the efficient dispatch of lower cost resources. With Tranche 2.1 transmission included, the separation between these regions' prices decreases. Load Weighted LMPs decrease for each of the West, Central and East regions, with the greatest reductions seen in regions where Reference case prices are the highest.

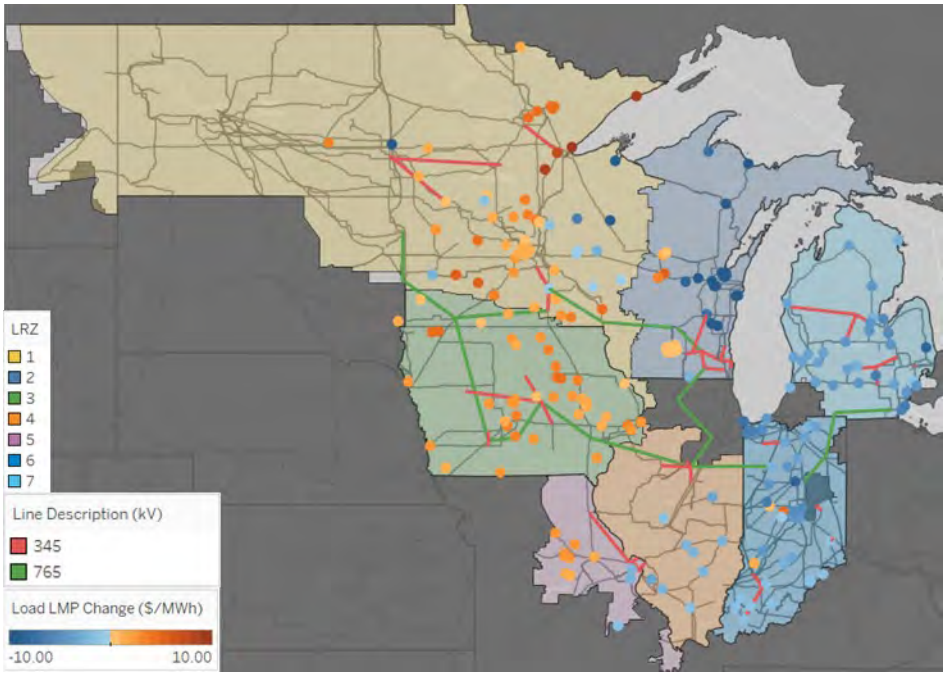


Figure 2.76: Change Case: Load LMP Price Reduction

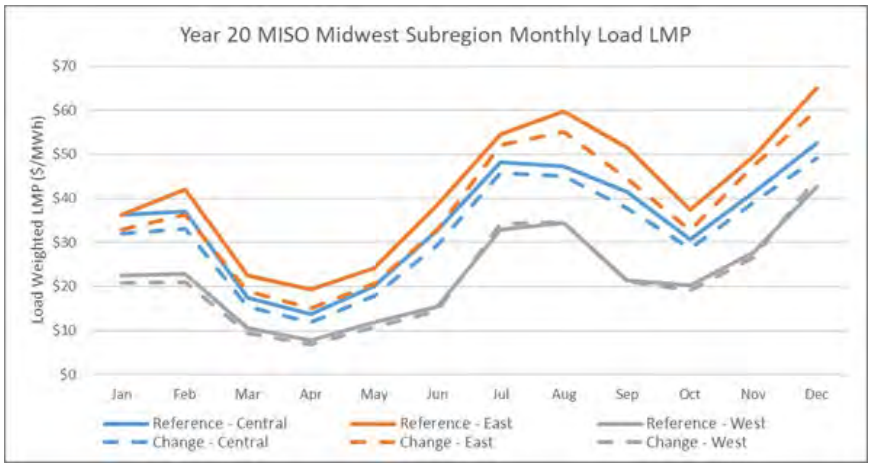
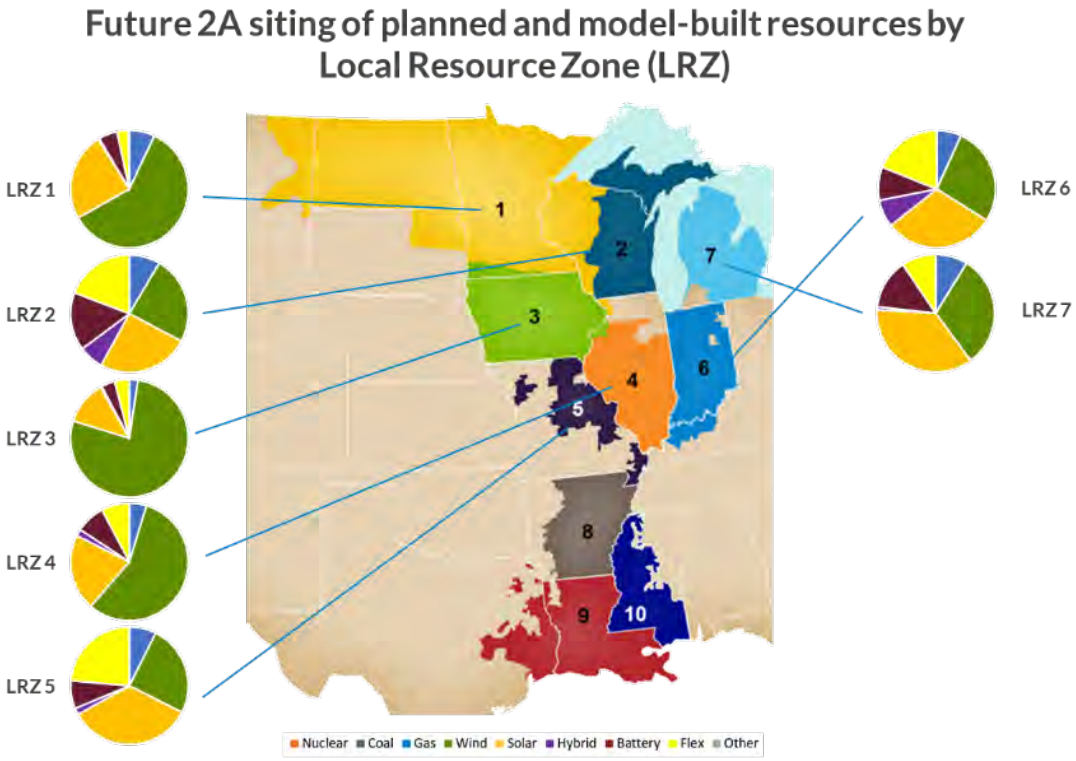


Figure 2.77: Reference & Change Case: Year 20 Load LMP Price

Generation Enablement

Tranche 2.1 provides a robust regional backbone supporting 115.7 GW of Future 2A resource enablement in addition to the 20.1 GW of generation previously enabled with Tranche 1 transmission. To date, the MISO Long Range Transmission Plan Tranche's support 135.8 GW of resource enablement.



Generation Enabled by Resource Type (GW)	
Storage	15.4
Gas & Flex	16.9
Solar	14.1
Hybrid	1.2
Wind	68.1
Total	**115.7**

Generation Enabled by Local Resource Zone (GW)	
LRZ 1	32.1
LRZ 2	9.5
LRZ 3	27.4
LRZ 4	16.1
LRZ 5	2.8
LRZ 6	16.6
LRZ 7	11.2
Total	**115.7**

Figure 2.78: LRTP Tranche 2.1 Future 2A Generation Enablement

West Region – Reliability and Economic Results

Results of transmission solutions in the West Region include the following:

- The Northern Minnesota group provides outlets to North Dakota generation, resolves constraints in this area and connects to Tranche 1 lines
- Congestion in Northern Minnesota is reduced
- Increased generation outlets in North Dakota, South Dakota and Minnesota shift congestion to new flowgates, which are addressed through underbuild
- The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support
- The Minnesota-Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin
- Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network
- The Wisconsin-Illinois 765 kV project assists serving load centers in the region and provides contingency support by connecting to the West – East 765 kV path through Iowa and Illinois

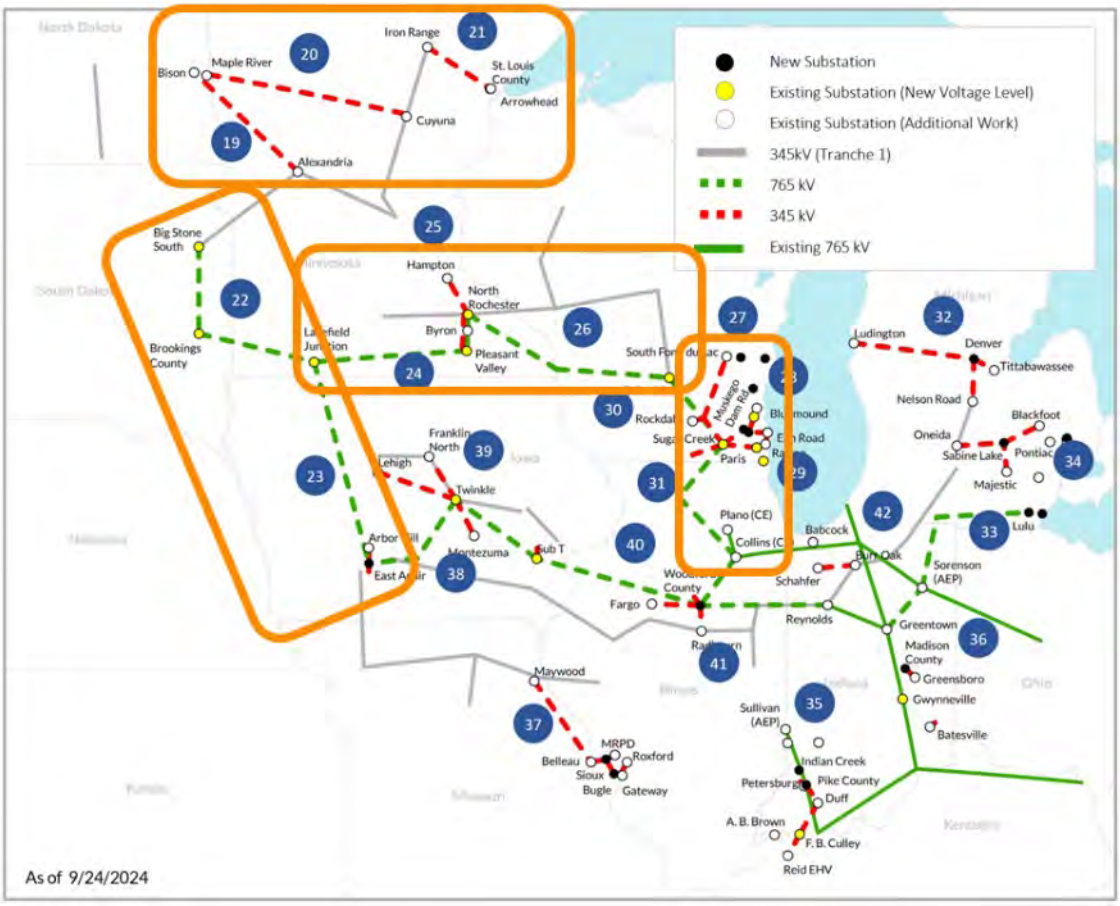


Figure 2.79: West Region Project Groups

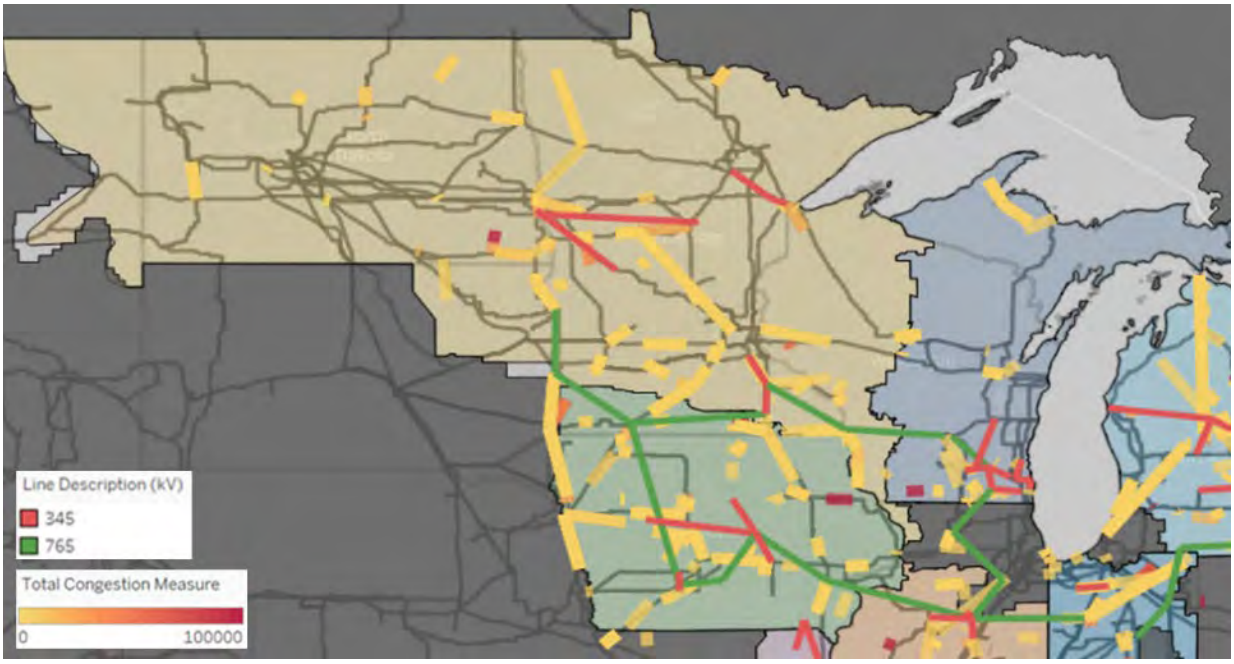


Figure 2.80: Change Case Economic Congestion - West

LRZ 1 – North Dakota and Minnesota

The LRTP Tranche 2.1 portfolio resolves most of the reliability violations on all voltage levels. The Tranche 2.1 portfolio reduces curtailments in LRZ1 by 13.2 % (15.5 M MWh) as illustrated in Figure 2.82 and reduces congestion throughout LRZ1 by 16.2% (977 k$/MW). The curtailment reductions are seen in the areas of greatest base case curtailment, which can be seen in Figure 2.83. Based on the identification of relieved constraints, 32.1 GW of generation is enabled in LRZ 1.

The load serving costs annual Load LMP, moves towards a regional norm, as regional transmission better connecting west and east regions allows a more efficient dispatch of resources (cost to serve load is represented by Load Weighted LMP ($/MWh)). This narrows the MISO Midwest subregion price disparity with a slight increase of $1.87/MWh. Transmission enables greater access for generator exports, allowing renewable generation to offset higher cost generation in other regions. While overall congestion in LRZ1 decreases, generation enabled by new transmission shifts some congestion to new flowgates. The constraints that see increased congestion due to these shifts are associated with more localized issues, or with individual loads or generators and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.

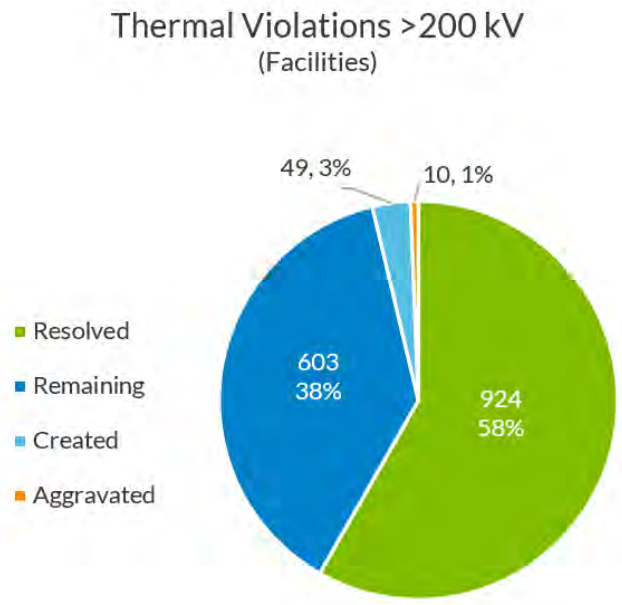


Figure 2.81: Thermal constraint resolution for LRZ1

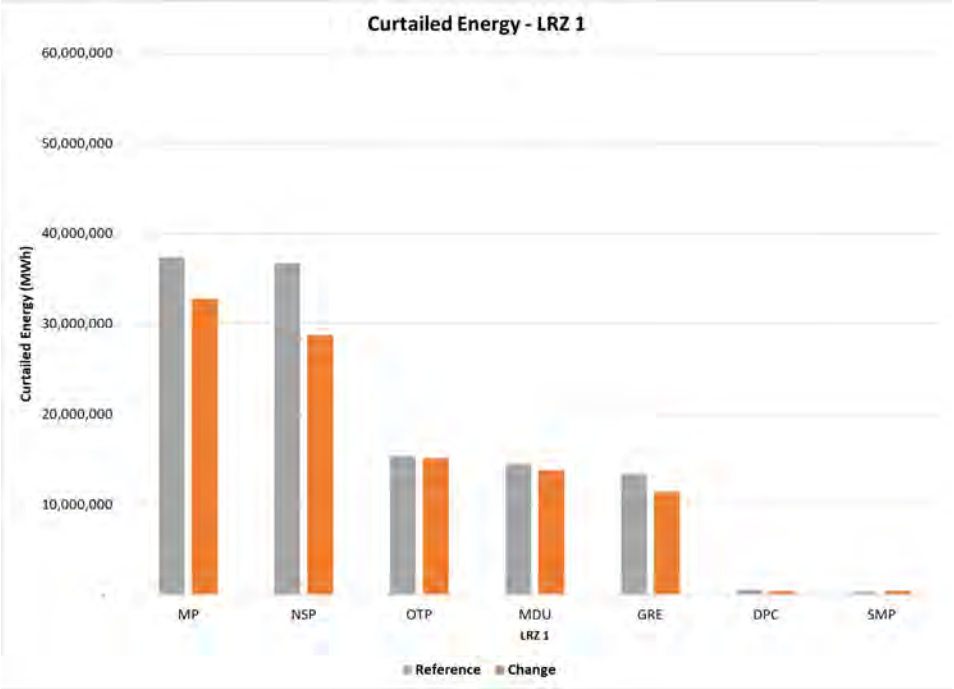


Figure 2.82: Curtailed Energy - LRZ 1

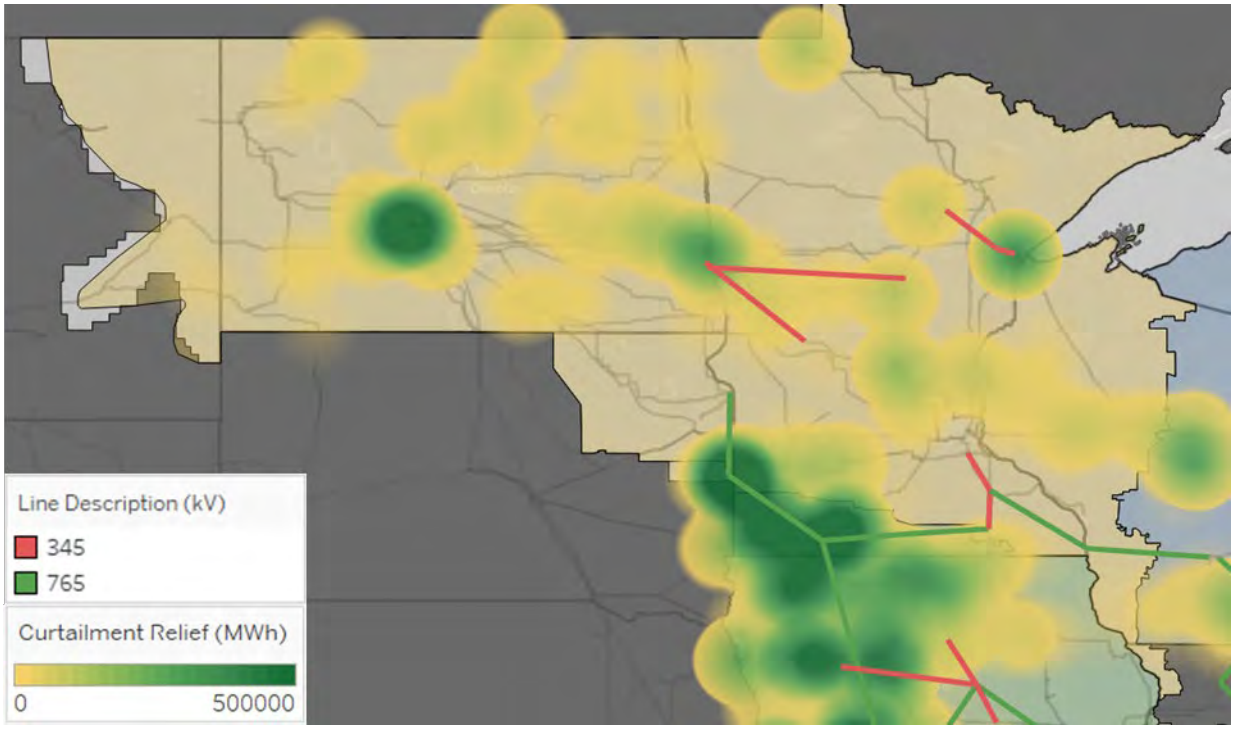


Figure 2.83: Change Case Curtailment Relief – LRZ 1

Bison - Alexandria 345 kV (Project 19), Maple River - Cuyuna 345 kV (Project 20), and Iron Range – St. Louis County - Arrowhead 345 kV (Project 21)

The 345 kV projects in Northern Minnesota (indicated by the dashed red lines in the map below) resolve more than 50% of the constraint violations for both the 200 kV above and below systems. The Northern Minnesota group provides outlets to North Dakota generation, resolves constraint violations in this area and connects to Tranche 1 lines. Congestion in Northern Minnesota is reduced and the increased generation outlet in North Dakota, South Dakota and Minnesota shifts congestion to new flowgates, which are addressed with the portfolio.



Figure 2.84: Northern Minnesota LRTP Tranche 2.1 projects

There is a significant reduction in the loadings in Northern Minnesota because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The criteria for selecting these lines was a combination of the number of violations resolved as well as the degree of reduction in loadings. The third column shows the highest loading for these elements in the models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The top resolved facilities are also displayed geographically in the figure below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[MP] Badoura-[GRE] Hubbard 230 kV	138	84
2	[GRE] Hubbard–[OTP] Erie Jct 230 kV	121	78
3	[OTP] Erie Jct-[OTP] Audubon 230 kV	124	83
4	[OTP] Wahpeton-[MRES] Fergus Falls 230 kV	124	84
5	[GRE] Silver Lake-[MRES] Fergus Falls 230 kV	107	74
6	[MPC] Maple River–[MPC] Winger 230 kV	124	66
7	[OTP] Wahpeton-[MPC] Frontier 230 kV	110	51
8	[MP] Riverton-[GRE] Wing River 230 kV	123	74

#	Element	Initial Worst Loading %	Final Worst Loading %
9	[GRE] Silver Lake-[GRE] Henning 230 kV	104	68
10	[MP] Hibbard – [MP] Winter St. 115 kV	243	97
11	[MP] Dahlberg – [MP] Stinson 115 kV	211	Reconfigured
12	[XEL] Sheyenne – [WAPA] Fargo 230 kV	130	56
13	[XEL] Sheyenne – [OTP] Maple River 230 kV	114	51
14	[MP] Fairmount Park – [MP] Winter St. 115 kV	259	95
15	[MP] Fairmount Park – [MP] Stinson 115 kV	230	74
16	[OTP] Wilton – [OTP] Scribner 115 kV	126	86
17	[OTP] Wilton Tap – [OTP] Scribner 115 kV	123	86
18	[OTP] Solway – [OTP] Wilton Tap 115 kV	114	81
19	[XEL] Wakefield – [XEL] Stockade Tap 115 kV	111	90
20	[MP] Arrowhead – [MP] Gary 115 kV	123	74

Table 2.11: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

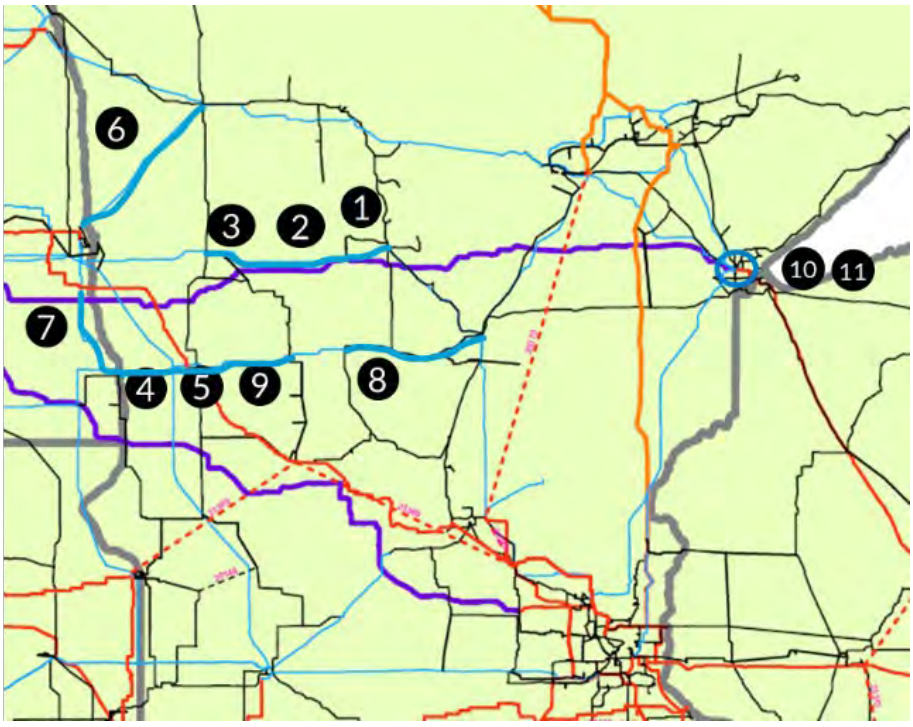


Figure 2.85: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Northern Minnesota

Projects in Northern Minnesota increase deliverability of resources from North Dakota, South Dakota and Western Minnesota towards load centers in Northern Minnesota and down towards the Twin Cities. These projects reduce congestion overall, and reduce congestion on the most heavily congested flowgate in LRZ1. The increase in energy delivery shifts the dispatch throughout LRZ1, and some congestion shifts to different flowgates associated with more localized issues. Table 2.12 shows top relieved flowgates ranked by congestion measure relief for projects 19, 20, & 21. The combined congestion measure impact for flowgates assessed for projects 19, 20, & 21 is shown in Figure 2.86.

Y20 Top Relieved Flowgates - Projects 19, 20, & 21			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 1117: [MP] HIBBARD - [MP] WNTR ST 115 kV 1	1,621,984	876,000	745,984
Event 270: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	158,693	-	158,693
Event 192: [MP] LONG PR7 - [GRE] GRE-LTLSKTP7 115 kV 1	454,591	329,864	124,727
Base Case: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	112,246	-	112,246
Event 1033: [MP] AITKNMN7 - [GRE] GRE-AITKIN 7 115 kV 1	47,573	-	47,573
Event 586: [GRE] GRE-INMAN 4 - [GRE] GRE-WINGRIV4 230 kV 1	64,442	24,550	39,892
Event 1355: [MP] CLOQUET7 - [MP] CANOSIA7 115 kV 1	58,902	19,317	39,585
Event 1391: [NSP] CASS CO7 - [NSP] REDRIVR7 115 kV 1	38,318	-	38,318
Event 1045: [MP] FLDWDTP7 - [MP] MDWLNDS7 115 kV 1	31,812	-	31,812
Event 592: [NSP] SHEYNNE4 - [OTP] LAKE PARK T4 230 kV 1	40,486	11,028	29,457

Table 2.12: Top Relieved Flowgates – Projects 19, 20 & 21

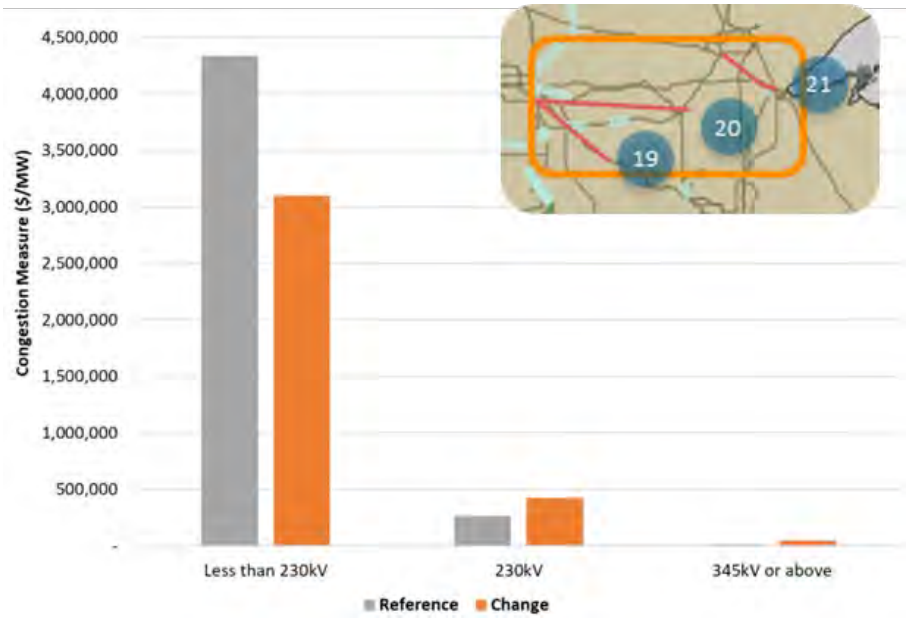


Figure 2.86: Congestion Measure for Projects 19, 20, and 21

Lakefield Junction - Pleasant Valley - North Rochester 765 kV (Project 24), Pleasant Valley - North Rochester - Hampton Corner 345 kV (Project 25), and North Rochester – Columbia 765 kV (Project 26)

The portfolio resolves most constraints in Southern Minnesota and Western Wisconsin, especially on 200 kV and above facilities. The Minnesota -Wisconsin West – Wisconsin East project assists transfer of power into load centers in Minnesota and Wisconsin.

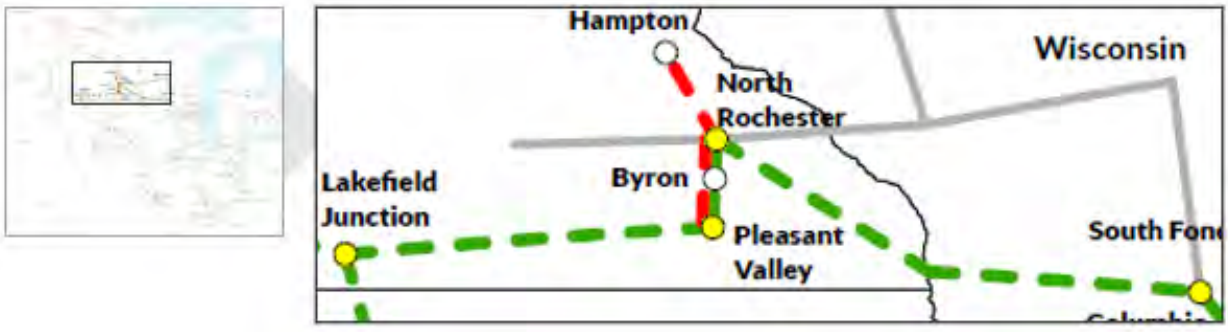


Figure 2.87: Southern Minnesota and Western Wisconsin LRTP Tranche 2.1 projects

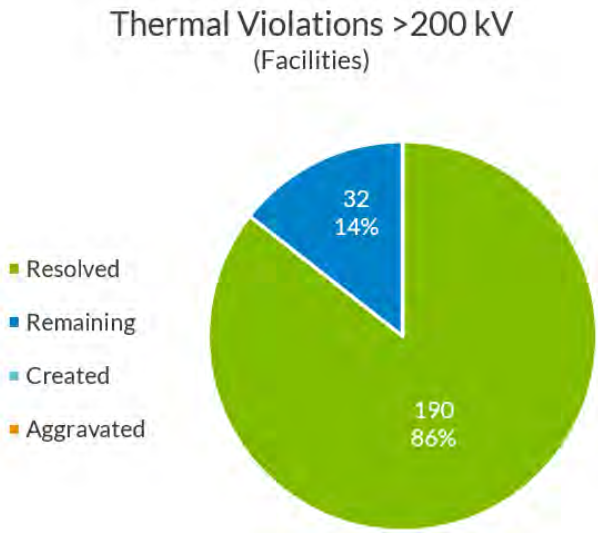


Figure 2.88: Thermal constraint resolution for Southern Minnesota and Western Wisconsin

There is a significant reduction in the loadings in Southern Minnesota and Western Wisconsin because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The North Rochester-Byron and Byron-Pleasant Valley lines, which are labeled as reconfigured, still exist in the portfolio models and have been upgraded to higher ratings as part of a single-to-double circuit rebuild and are no longer overloaded anymore. The locations of the top 10 lines are shown on the map below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[XEL] Helena–[XEL] Hampton Corner 345 kV	162	75
2	[XEL] AS King–[XEL] Eau Claire 345 kV	133	75
3	[XEL] Prairie Island–[XEL] N. Rochester 345 kV	123	90
4	[XEL] Helena–[XEL] Scott Co. 345 kV	127	98
5	[XEL] Wilmarth–[XEL] Crandall 345 kV	123	66
6	[XEL] Wilmarth–[XEL] Sheas Lake 345 kV	113	81
7	[XEL] N. Rochester–[XEL] Byron 345 kV	110	Reconfigured
8	[XEL] Helena–[XEL] Sheas Lake 345 kV	105	72
9	[XEL] Eau Claire–[ALTE] Arpin 345 kV	116	71
10	[XEL] Byron–[XEL] Pleasant Valley 345 kV	114	Reconfigured
11	[XEL] Wilmarth–[XEL] Huntley 345 kV	108	73
12	[XEL] Tremval – [MGE] North Madison 345 kV	112	67
13	[XEL] Jump River – [WPS] Gardner Park 345 kV	108	67
14	[ALTW] Emery – [MEC] Floyd 161 kV	120	83
15	[MP] Gordon – [MP] Hawthorne Tap 161 kV	135	22
16	[ALTW] Barton – [ALTW] Lime Creek 161 kV	121	91
17	[WPS] Cassel – [WPS] Wien 115 kV	130	79
18	[XEL] Minnesota Valley – [XEL] Redwood Falls 115 kV	125	82
19	[WPS] Sunnyvale – [WPS] Cassel 115 kV	134	79
20	[DPC] Wabaco – [DPC] Kellogg 161 kV	151	96

Table 2.13: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

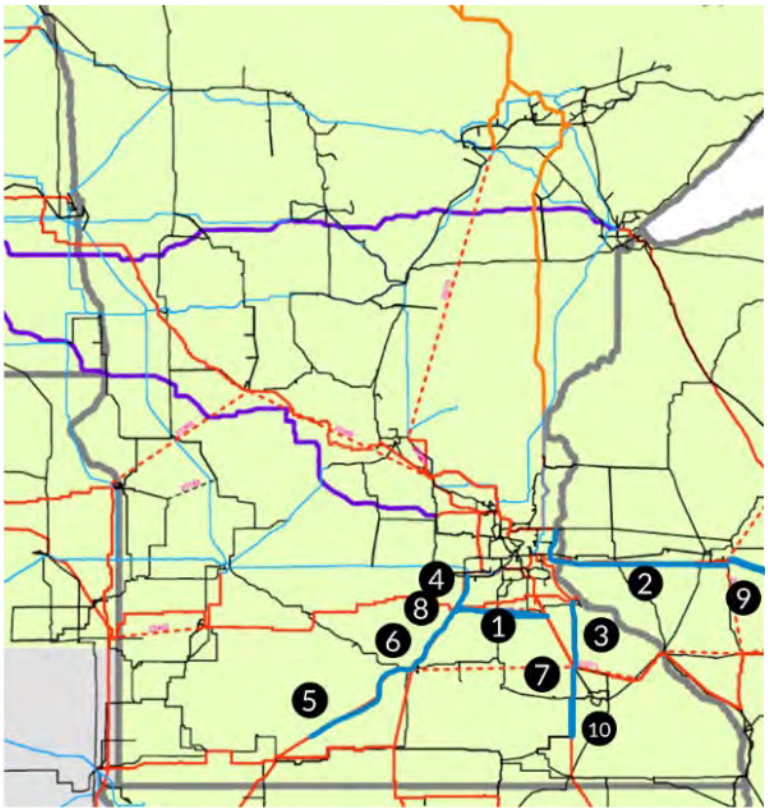


Figure 2.89: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Minnesota and Western Wisconsin

Projects in Southern Minnesota and Wisconsin enable substantially more renewable delivery, particularly from the Eastern Dakotas, Southwestern Minnesota, and Northern Iowa – locations with some of the strongest wind resources. This is aided through the loop configuration of the other Tranche 2.1 765 kV west-to-west path which increases the amount of power that can reliably flow over 765 kV facilities. Overall congestion in this area remains flat even as energy delivery increases. The additional enabled resources shift the patterns of congestion to new and different flowgates. Table 2.14 shows top relieved flowgates ranked by congestion measure relief for projects 24, 25, and 26. The combined congestion measure impact for flowgates assessed for projects 24, 25, and 26 is shown in Figure 2.90.

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Top Relieved Flowgates	**Congestion Measure ($/MW)**		
	Reference	**Change Case**	**Total Relief**
Event 130: [SMP] RUTLAND5 - [ALTW] FOX LK 5 161 kV 1	85,064	720	84,343
Event 146: [NSP] BLUE LK3 - [NSP] SCOTTCO3 345 kV 1	49,404	13,732	35,672
Event 32: [NSP] BLUE LK3 - [NSP] HMPT CNR3 345 kV 1	55,518	26,597	28,922
Event 587: [ALTW] BARTON5 - [ALTW] LIME CK L2 5 161 kV 1	34,899	15,532	19,367
Event 143: [NSP] ADAMS 3 345kV - [ALTW] ADAMS 5 161 kV 9	26,860	8,666	18,194
Base Case: [DPC] ALMA 5 - [DPC] KELLOGG 5 161 kV 1	18,347	1,254	17,093

Y20 Top Relieved Flowgates Ranked by Cong, and 26estion Measure Relief - Projects 24, 25, & 26			
Event 1443: [NSP] WILMART3 - [ALTW] HUNTLEY3 345 kV 1	10,423	50	10,372
Event 255: [NSP] BRIGGS RD 5 - [NSP] TREMVAL5 161 kV 1	5,248	210	5,038
Event 250: [MEC] WEBSTER5 - [MEC] SUB T FD 5 161 kV 1	4,729	0	4,729
Event 78: [NSP] WILMART3 - [NSP] SHEAS LK3 345 kV 1	4,807	188	4,619

Table 2.14: Top Relieved Flowgates – Projects 24, 25, & 26

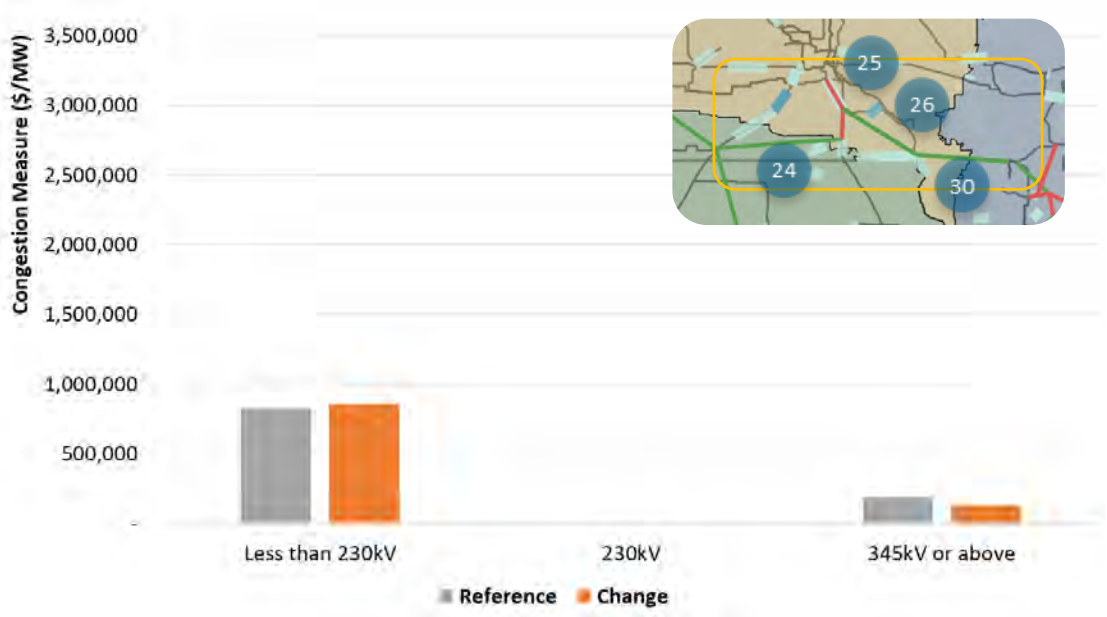


Figure 2.90: Congestion Measure for Projects 24, 25, and 26

LRZ 2 – Wisconsin

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations across all voltage levels in LRZ2. The Tranche 2.1 portfolio reduces congestion throughout LRZ2 by 68.9% (764 k$/MW) and reduces curtailments in LRZ2 by 26.9% (1.4M MWh) enabling 9.5 GW of generation. Load serving costs decrease year-round and throughout LRZ2, by an average of $7.67 / MWh as shown in Figure 2.93.

Reductions in curtailment follow the geographic pattern of initial curtailment and are observed in corridors relieved by the 765 kV regional path, seen in Figure 2.92. The 765 kV pathway moves regional flows off lower voltage facilities, supports economic congestion reduction and significantly relieves top binding constraints. Congestion in LRZ2 is driven by regional loop flow, which is more easily relieved through 765 kV paths. The Tranche 2.1 facilities reduce congestion due to loop flow and access to additional lower cost renewables in the West. Increased access to low-cost resources from neighboring LRZs significantly reduces Load LMPs.

Thermal violations remaining on >200 kV facilities are a result of splitting of the existing lines, and their overloads are less severe than the original overloads. For example, some of the new violations are attributed to the splitting of two lines. The highest loading on one of the lines was 156% in the core models and decreased to 109% in the portfolio models. Similarly, the other facility was loaded at 119% in the core

models and decreased to 102% in the portfolio models. The 345/230 kV transformers are fully relieved in the core models, and the new violations are limited to the transfer scenarios specific to new resource units to load and it is more appropriate for these issues to be addressed by the annual MTEP reliability planning and the generator interconnection processes.

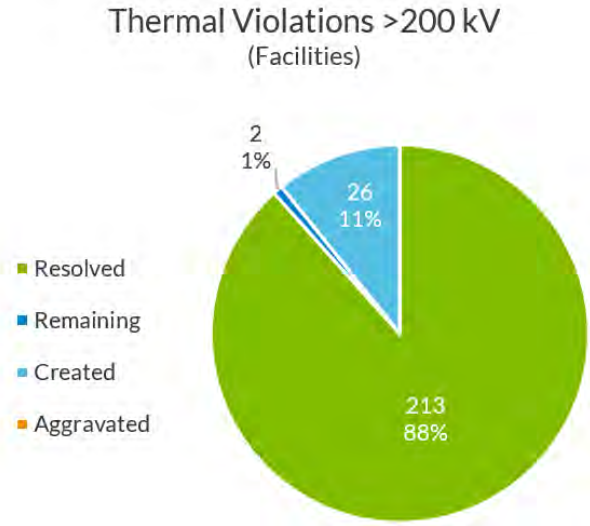


Figure 2.91: Thermal constraint resolution for LRZ2

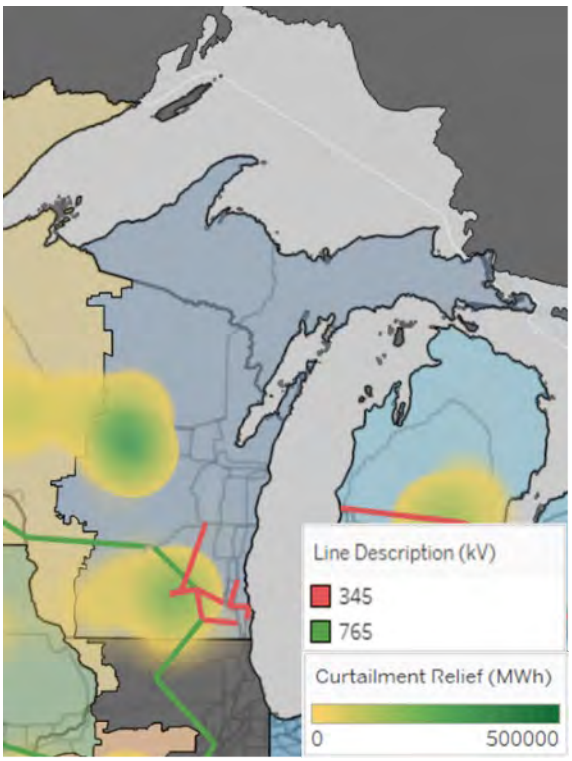


Figure 2.92: Change Case: Curtailment Relief for LRZ 2

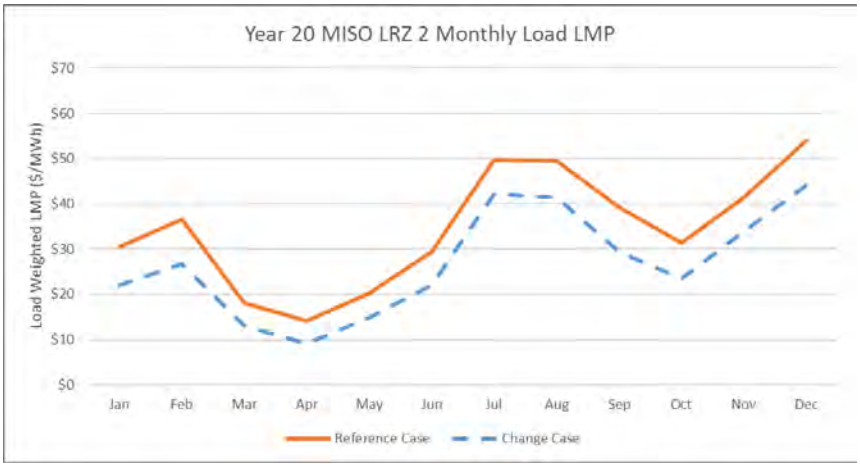


Figure 2.93: Comparison: Monthly Load LMP for LRZ 2

Rocky Run – Werner West - North Appleton 345 kV (Project 27), South Fond du Lac – Jefferson - Rockdale and Big Bend - Sugar Creek - Kitty Hawk 345 kV (Project 28), Bluemond - Arcadian -– Muskego Dam Road - Elm Road - Racine 345 kV and Arcadian – Waukesha 138 kV uprate (Project 29), Columbia - Sugar Creek 765 kV (Project 30), and Sugar Creek - Collins 765 kV (Project 31)

The Tranche 2.1 portfolio resolves a majority of the thermal violations across all voltage levels in Southeastern Wisconsin. Congestion in Eastern Wisconsin is reduced by moving regional flows onto the backbone network. Sugar Creek – Collins 765 kV project in Wisconsin and Illinois assists in serving load centers in the region and provides contingency support by connecting the northern 765 kV path to the West – East 765 kV corridors through Iowa and Illinois.

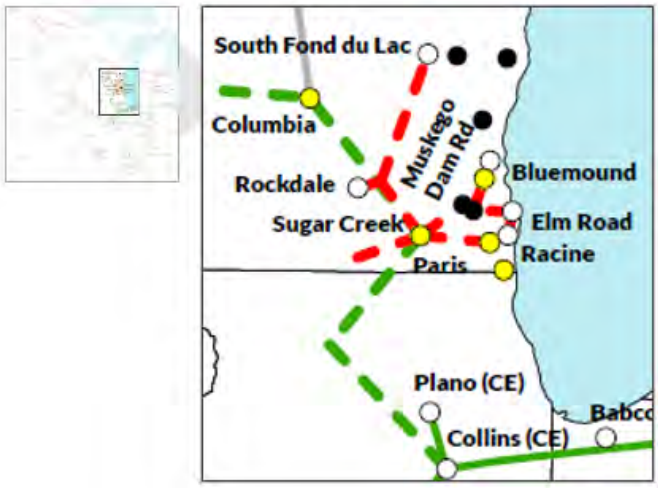


Figure 2.94: Southeastern Wisconsin LRTP Tranche 2.1 projects

Loading stress on several elements across various voltage levels in this region is relieved by the Tranche 2.1 portfolio. The elements with the most reduction in the loadings are shown in the table below. "Reconfigured" means that the circuits have been cut into two or more segments, because of new stations added in between, and thus such circuits no longer exist in the cases with the portfolio.

- The Cypress – Arcadian 345 kV line is now the Cypress - Sheboygan River - Cedar Creek Junction – Arcadian 345 kV line
- The Edgewater - S Fond du Lac 345 kV line is now the Edgewater - Mullet River Junction - Sheboygan River - S Fond du Lac 345 kV line
- The Zion Station - Pleasant Prairie 345 kV line is now Zion Station - Lakeview - Pleasant Prairie 345 kV line
- The Arcadian – Paris – Zion Station e 345 kV line is now Arcadian – Big Bend - Muskego Dam Rd - Elm Rd - Racine - Mt Pleasant - Pleasant Prairie 345 kV line
- The Arcadian – Pleasant Prairie 345 kV line is now the Arcadian – Big Bend – Muskego Dam Road – Paris – Lakeview – Pleasant Prairie 345 kV line.

The map below depicts the top relieved facilities from the table.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[WPS] Rocky Run–[WEC] Werner W. 345 kV	201	56
2	[WEC] Werner W.-[WEC] N. Appleton 345 kV	192	48
3	[WEC] Cypress–[WEC] Arcadian 345 kV	156	Reconfigured
4	[ALTE] Edgewater–[ALTE] S. Fond du Lac 345 kV	119	Reconfigured
5	[WEC] Cypress-[WEC] Forest Jn. 345 kV	138	77
6	[WEC] Cedar Sauk-[ALTE] Edgewater 345 kV	121	56
7	[WPS] Rocky Run–[WPS] Gardner Park 345 kV	113	86
8	[CE] Wempletown-[ALTE] Paddock 345 kV	105	75
9	[CE] Zion Station-[WEC] Pleasant Prairie 345 kV	103	Reconfigured
10	[WEC] Arcadian-[WEC] Pleasant Prairie 345 kV	112	Reconfigured
11	[CE] Zion Energy Center-[WEC] Pleasant Prairie 345 kV	117	52
12	[WEC] Elk Lake Reactor – [WEC] Elkhart Lake 138 kV	148	92
13	[ALTE] N. Lake Geneva – [ALTE] Elkhorn 138 kV	115	93
14	[WEC] Auburn – [WEC] Butternut 138 kV	121	87
15	[ALTE] Sunrise – [WEC] Lakehead 138 kV	117	74
16	[ALTE] Nelson Dewey 161/138 kV Transformer	134	97
17	[WEC] Elkhart Lake – [WEC] Saukville 138 kV	148	80
18	[WEC] Forest Junction – [WPS] Tecumseh Rd 138 kV	122	77
19	[WEC] Esker View – [WPS] Tecumseh Rd 138 kV	122	70
20	[WEC] PM - [WEC] Esker View 138 kV	119	66

Table 2.15: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Eastern Wisconsin

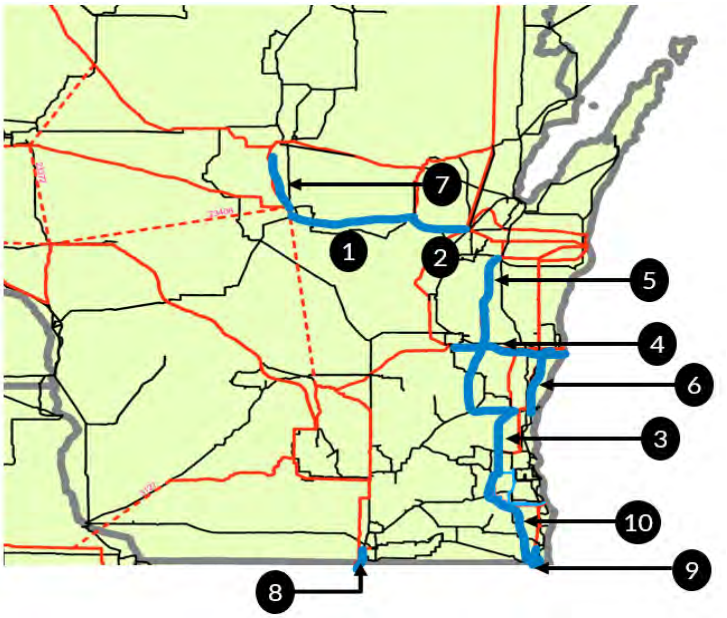


Figure 2.95: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southeastern Wisconsin

The regional backbone projects in and through Wisconsin are successful in moving regional flows off of the local system and onto the backbone transmission, which results in the relief of the majority of congestion seen in LRZ2. The most congested flowgate in LRZ2 is fully relieved by these projects. This congestion relief also allows LRZ2 resources to dispatch more efficiently, reducing curtailment in the zone. Table 2.16 lists the top flowgates relieved by projects 27, 28, 29, 30, and 31 in LRZ 2. Figure 2.96 shows the combined impact for all flowgates assessed with projects 27, 28, 29, 30, and 31.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 27, 28, 29, 30, & 31			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**Reference**	**Change Case**	**Total Relief**
Event 1463: [WPS] ROCKY RUN - [WEC] WERNER W B4 345 kV 1	292,658	-	292,658
Event 94: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	123,330	790	122,541
Base Case: [WEC] JEFRSN5 - [WEC] CRWFSH R 138 kV 1	142,777	29,873	112,904
Event 47: [WEC] BRLGTN1 - [WEC] NLK GV T 138 kV 1	48,790	211	48,579
Base Case: [ALTE] ROE 138 - [WEC] LKHD_CAM_TP 138 kV 1	36,426	-	36,426
Event 22: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	89,452	58,211	31,241
Event 75: [ALTE] NLG 138 - [ALTE] ELK 138 138 kV 1	20,300	398	19,902
Event 361: [UPPC] SILVER RIVER - [UPPC] GREENSTN TAP 138 kV 1	43,144	24,512	18,632
Event 615: [UPPC] PERCH LK - [MIUP] PRESQ IS4567 138 kV 1	36,357	19,733	16,624
Event 92: [WEC] BCR_LNG_TAP - [WEC] BLUFFCRK 138 kV 1	14,126	-	14,126

Table 2.16: Top Relieved Economic Flowgates – Projects 27, 28, 29, 30, & 31

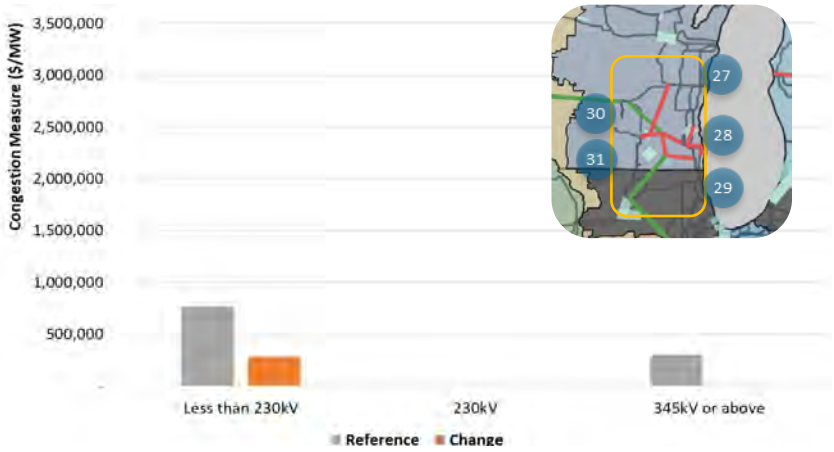


Figure 2.96: Congestion Measure for Projects 27, 28, 29, 30, & 31

LRZ 3 – Iowa

The LRTP Tranche 2.1 portfolio resolves a vast majority of the thermal violations in LRZ 3. For the <200 kV system, 92% of the violations have been resolved with 80% of the violations resolved on the >200 kV system as shown in the two pie charts below. Congestion shown in the reference case is reduced by the LRTP Tranche 2.1 portfolio by 35.1% (284 k$/MW). The strongest economic congestion relief is observed in the West to East oriented elements in Central Iowa and Southern Minnesota. Smaller increases in economic congestion are in Western Iowa, and numerous smaller shifts of congestion are seen as transmission enables Future 2A generation.

The LRTP Tranche 2.1 portfolio reduces curtailments by 20.0% (14.6M MWh) which is demonstrated in Figure 2.99 and enables 27.4 GW of generation. Reduced curtailment generally matches the geography of reference case curtailment, with the largest concentration in Northern and Western Iowa as can be observed from Figure 2.98. Transmission enables greater access for generator exports, reducing costs for purchasing companies. Load LMPs increase slightly by $2.52/MWh, moving towards a regional norm, while narrowing the MISO Midwest subregion price disparity. Overall congestion in LRZ is reduced, as backbone transmission picks up more regional flows.

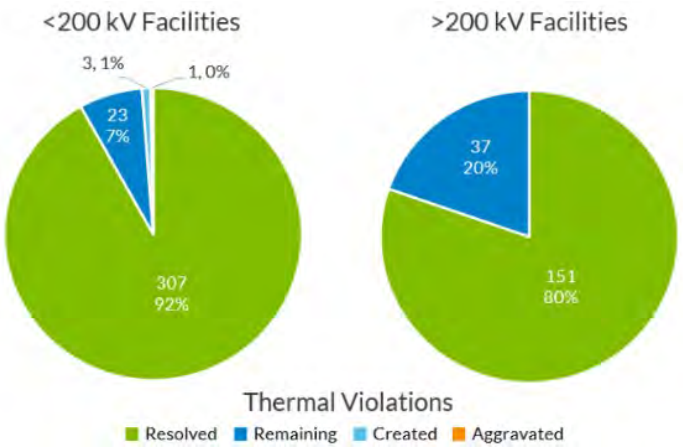


Figure 2.97: Pie- charts showing LRTP Tranche 2.1 resolving a vast majority of thermal violations in LRZ 3

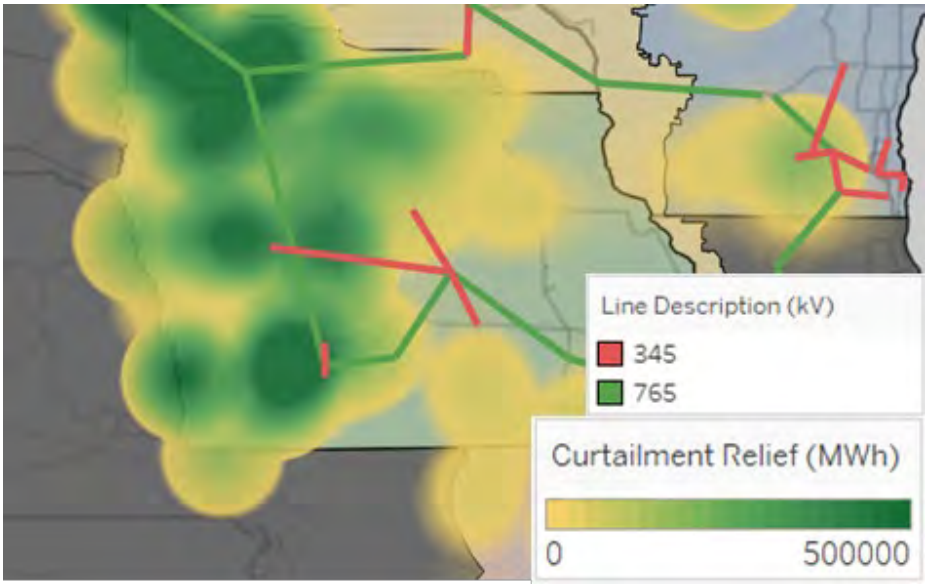


Figure 2.98: Change Case Curtailment Relief – LRZ 3

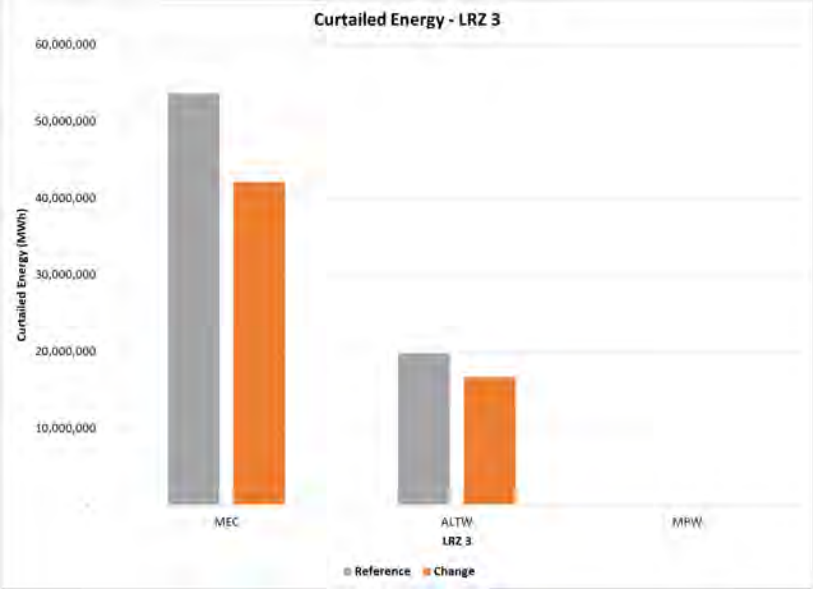


Figure 2.99: Curtailed Energy - LRZ 3

Big Stone South - Brookings County - Lakefield Junction765 kV (Project 22) & Lakefield Junction - East Adair 765 kV (Project 23)

The 765 kV project in northeastern South Dakota , Southwestern Minnesota and Western Iowa provides outlet for generation in South Dakota and also connects both 765 kV west-to-east paths together at the western end to provide contingency support. The reliability impacts of LRTP Tranche 2.1 portfolio, and the Big Stone South- Brookings County- Lakefield Junction -East Adair 765 kV projects have been studied in this section.

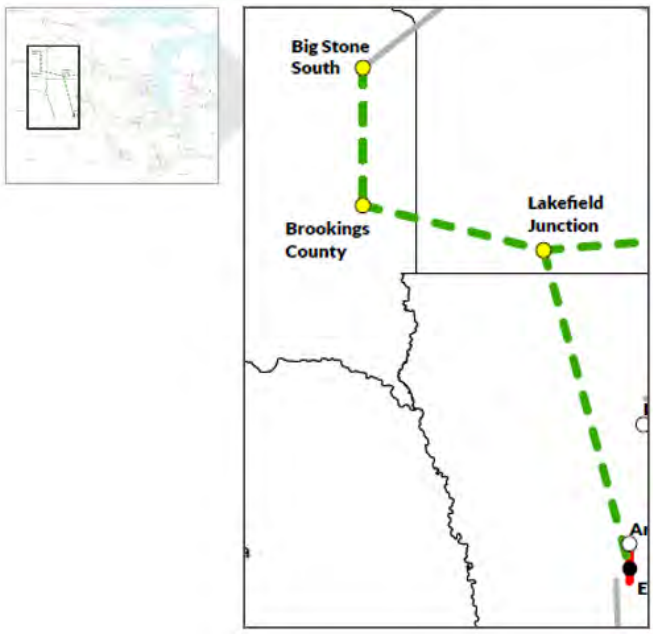


Figure 2.100: South Dakota, Southwestern Minnesota, and Western Iowa LRTP Tranche 2.1 projects

The LRTP Tranche 2.1 portfolio solved the majority of the thermal violations (82%) for the 200 kV+ system as shown below in the pie-chart below. A large number of the unresolved thermal violations for the 200 kV and below facilities are due to local generation siting, and can be better addressed through the annual MTEP reliability planning and the generator interconnection processes.

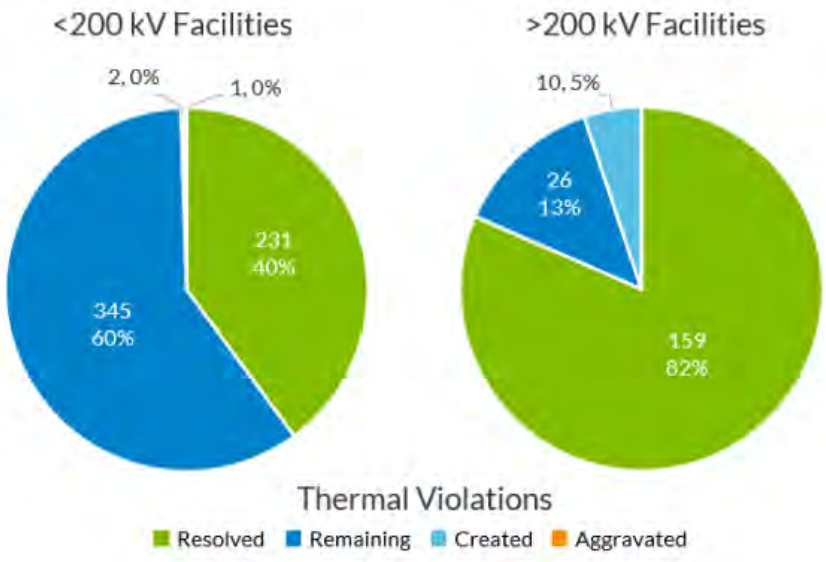


Figure 2.101: Pie-charts showing majority of thermal violations on the 200 kV and above facilities in South Dakota, Southwestern Minnesota, and Western Iowa being resolved by the LRTP Tranche 2.1 portfolio

The table below shows the top twenty limiting elements in the area that had the most impactful resolution in their thermal violations upon portfolio application, the map shows the geographic location of the top

facilities. The elements with overloading as high as 150% across all models and all seasons/scenarios in the pre-portfolio had loading level drop to less than 100% upon application of the portfolio. Notably among them is the Raun- Ida County West 345 kV line which was loaded at 142% of its rated capacity in the Light Load 2042 case. The same element had loading drop to 48% for the Light Load 2042 case upon application of the Tranche 2.1 portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[GRE] Panther-[XEL] McLeod 230 kV	121	81
2	[XEL] Minnesota Valley-[GRE] Panther 230 kV	114	76
3	[XEL] Minnesota Valley-[WAPA] Granite Falls 230 kV	116	75
4	[XEL] Hazel Creek 345/230 kV transformer	112	74
5	[XEL] Split Rock–[WAPA] White 345 kV	122	92
6	[MEC] Raun–[MEC] Ida County West 345 kV	142	48
7	[NPPD] Tekamah -[MEC] Raun 161 kV	147	83
8	[MEC] Raun–[OPPD] Sub 3451 345 kV	114	46
9	[MEC] Ida County West–[MEC] Ida County 345 kV	123	24
10	[AEPW] Southern Hills–[MEC] Booneville 345 kV	109	74
11	[XEL] Swan Lake-[XEL] Stockade Tap 115 kV	108	77
12	[XEL] Split Rock 230/115 kV transformer	119	53
13	[GRE] Kerkhoven Tap-[GRE] Kerkhoven 115 kV	117	77
14	[XEL] Split Rock- [WAPA] Sioux Falls 230kV	143	63
15	[XEL] McLeod 230/115 kV transformer	120	98
16	[XEL] Coon Creek- [XEL] Moore Lake 115 kV	100	97
17	[OTP] Benson-[OTP] Danvers 115 kV	106	77
18	[XEL] Monticello-[GRE] Oakwood 115 kV	103	99
19	[XEL] Brookings County 345/115 kV transformer	113	92
20	[OTP] Formal 230/115 kV transformer	107	99

Figure 2.102: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

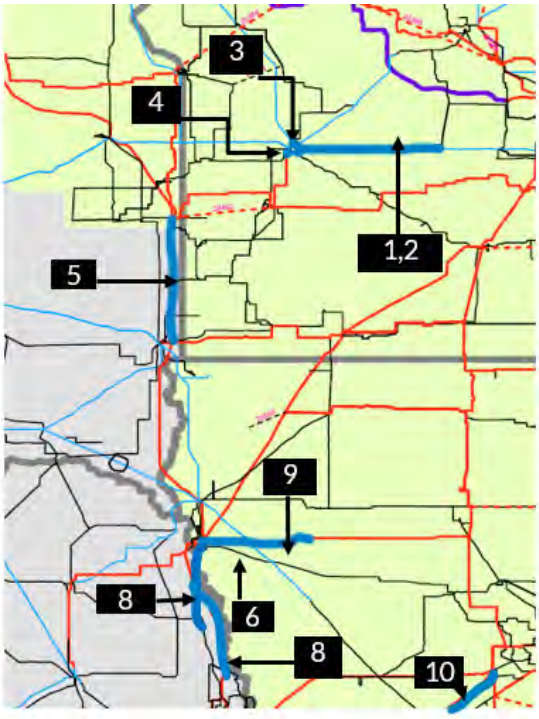


Figure 2.103: Top reliability constraints resolved by LRTP Tranche 2.1 projects in South Dakota, Southwestern Minnesota, and Western Iowa

The LRTP Tranche 2.1 portfolio significantly reduces curtailment and increases energy delivery from LRZ3. The increase in energy delivery shifts the dispatch, with relieved congestion in the western portion of LRZ3 being offset by congestion from new flowgates, many of which represent more localized issues. While the total congestion in the western portion of Iowa slightly increases, congestion throughout LRZ3 decreases, due to the combined contribution of the other transmission backbone system elements. Table 2.17 shows top relieved flowgates ranked by congestion measure relief for projects 22 and 23. The combined congestion measure impact for flowgates assessed for projects 22 and 23 is shown in Figure 2.104.

Y20 Top Relieved Flowgates - Projects 22 & 23			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 42: [NSP] HUC-MCLEOD 4 230 kV - [OTP] HUC-MCLEOD 7 115 kV 1	239,742	114,971	124,771
Base Case: [OTP] BIGSTON4 230kV - [OTP] YBUS770 100 kV 2	15,099	0	15,099
Event 43: [NSP] HUC-MCLEOD 4 230kV - [OTP] HUC-MCLEOD 7 115 kV 1	8,200	-	8,200
Event 392: [OTP] HANKSON4 - [OTP] FORMAN 4 230 kV 1	5,781	-	5,781
Event 53: [OTP] BIGSTON4 - [OTP] BROWNSV4 230 kV 1	6,444	2,873	3,570
Event 375: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	7,970	4,681	3,289
Event 171: [MEC] RAUN 3 - [OPPD] S3451 3 345 kV 1	4,817	2,877	1,940
Base Case: [NSP] BRKNGCO3 345kV - [NSP] BRKNGCO7 115 kV 9	2,068	329	1,739

Y20 Top Relieved Flowgates - Projects 22 & 23			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 45: [OTP] BIGSTON4 230kV - [OTP] BROWNSV4 230 kV 1	2,767	1,404	1,363
Event 70: [NSP] SPLT RK4 - [WAUE] SIOUXFL4 230 kV 1	2,753	1,499	1,253

Table 2.17: Top Relieved Economic Flowgates – Projects 22 & 23

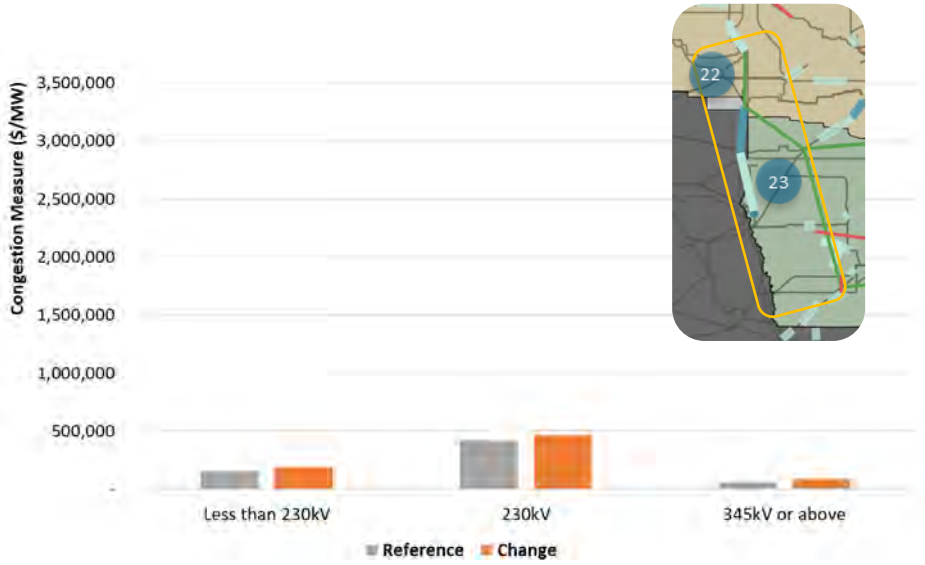


Figure 2.104: Congestion Measure for Projects 22, 23

Central Region – Reliability and Economic Results

- Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7
- Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. The 345 kV project in Missouri resolves numerous constraints in the St. Louis Metro region and enables increased intraregional transfers across the Central Region
- The Southern Indiana/Western Kentucky 345 kV project resolves constraints in the region and enhances West – East transfer capacity across the Central Region
- East Central Indiana upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the Indiana load centers in Central and Southeastern Indiana

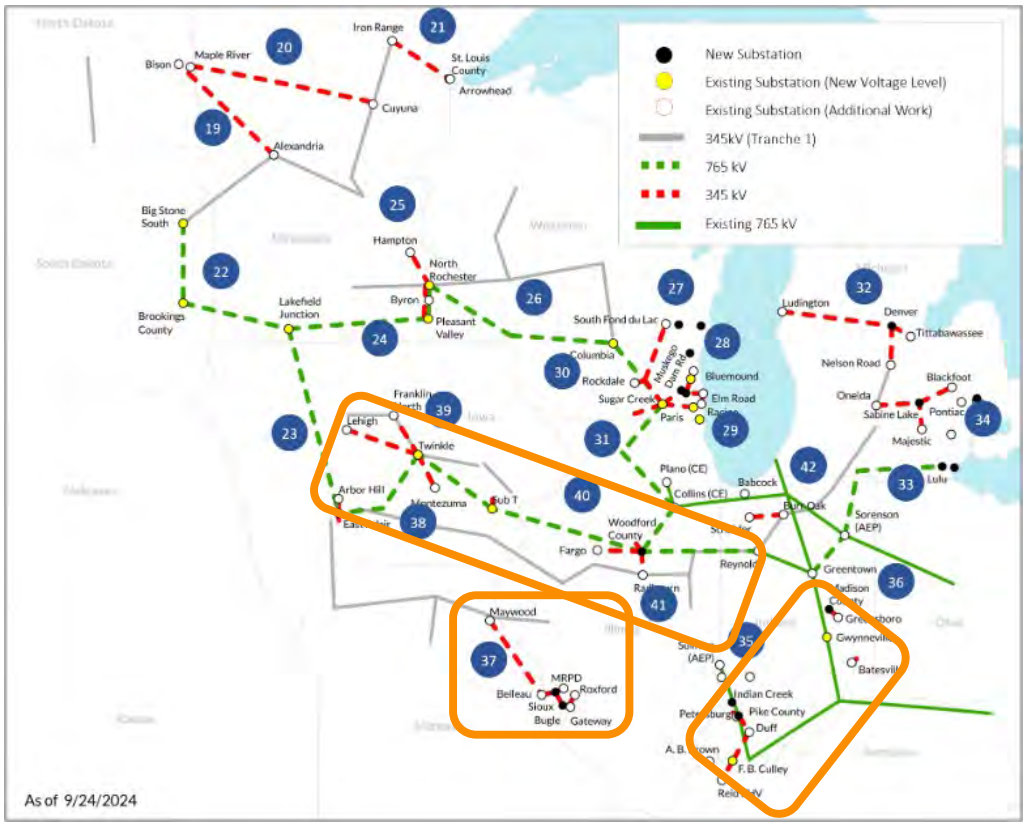


Figure 2.105: Central Region Project Groups

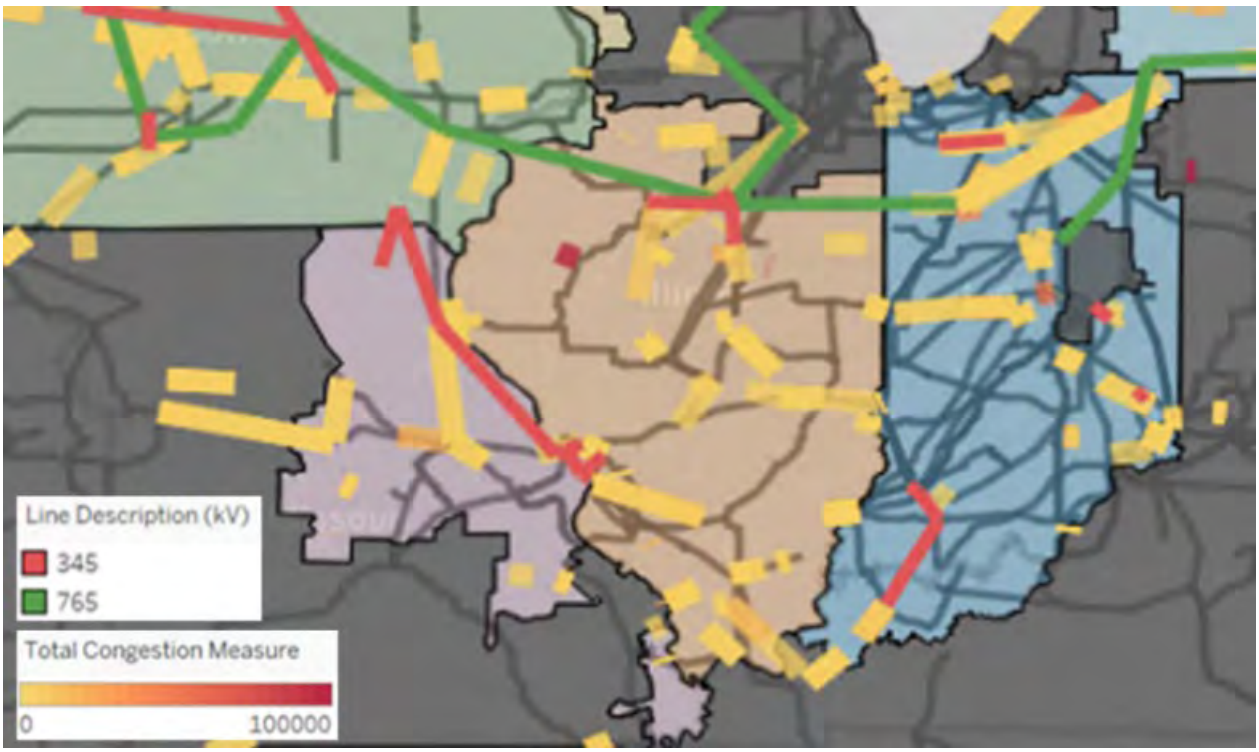


Figure 2.106: Change Case Economic Congestion - Central

LRZ 4 – Illinois

The Tranche 2.1 portfolio resolves most thermal violations on 200 kV and above facilities in LRZ4. For the <200 kV system, more than 50% of thermal violations are resolved. The Tranche 2.1 portfolio reduces congestion in LRZ4 by 13.9% (274 k$/MW) – shown in Figure 2.109 – and enables 16.1 GW of generation in LRZ 4. Load serving costs decrease year-round and throughout LRZ4, by an average of $1.90 / MWh, which is demonstrated in Figure 2.109. Increased exports through transmission expansion allows renewable generation to offset higher cost generation in LRZ4.

Increased access to low cost resources enabled throughout the MISO Midwest subregion drives down Load LMPs in LRZ4 . Curtailment, increased by 1.5M MWh. Change is mainly driven by increased competition with lower cost enabled generation throughout the region. Relief of regional constraints shifts congestion to more localized constraints, resulting in overall reduction in congestion. The remaining under 200 kV reliability issues are specific to local generation or load and may be better resolved through annual MTEP reliability planning and the generator interconnection processes.



Figure 2.107: Thermal constraint resolution for LRZ4

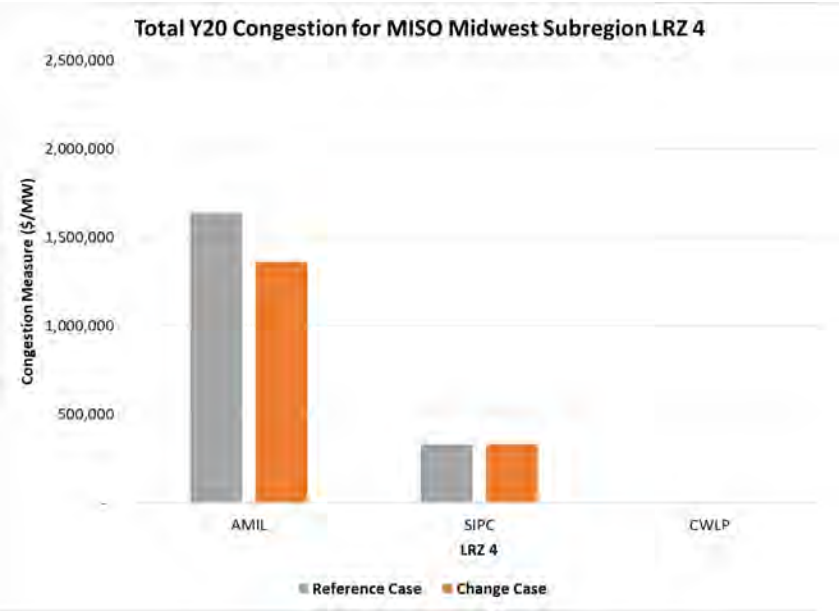


Figure 2.108: Congestion Measure – LRZ 4

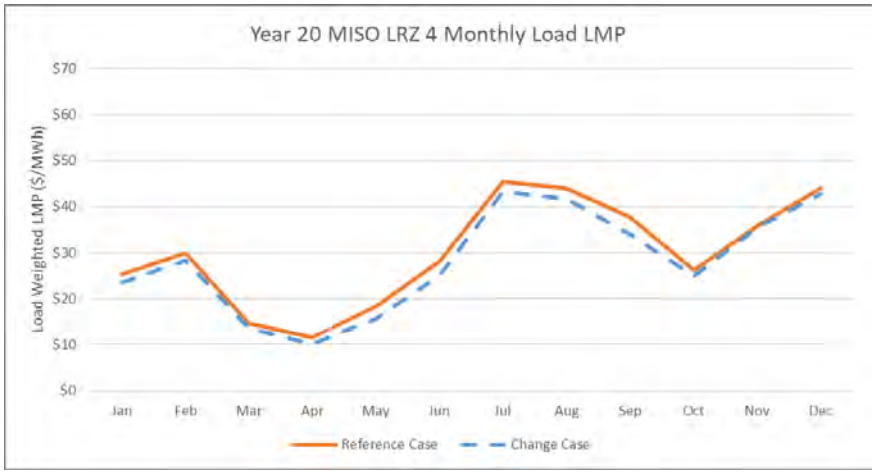


Figure 2.109: Comparison: Monthly Load LMP – LRZ 4

East Adair - Marshalltown - Sub T 765 kV (Project 38), Lehigh - Marshalltown - Franklin North & Montezuma - Marshalltown 345 kV (Project 39), Sub T - Woodford County - Collins & Woodford County - Reynolds 765 kV (Project 40), and Woodford County - Fargo & Woodford County - Radbourn 345 kV (Project 41)

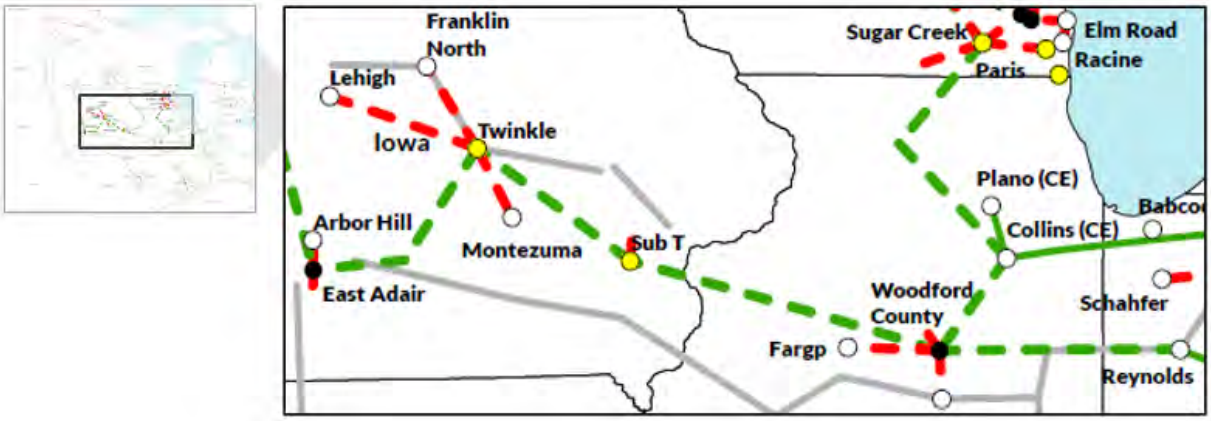


Figure 2.110: Central Iowa and, Illinois and Northern Indiana LRTP Tranche 2.1 projects

Both 765 & 345 kV level projects going West – East from Iowa through Illinois into Indiana provide a regional transfer path that enables generation in LRZ 1, 3, and 4 and supports strong East – West transfers to and from LRZ 6 and 7. Transmission relieves congestion across Central and Eastern Iowa and throughout Illinois, Missouri, and Indiana. Various violations in Central IA and IL are alleviated with the 765 kV facility connecting the western IA 765 to the Indiana 765 kV system. The regional backbone significantly relieves multiple 345 kV facilities while providing transfer capability to various load centers. The top alleviated facilities are in the table and the map shows the top 10 from the list.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ALTW] Hazleton - [ALTW] Arnold 1 345 kV	125	69
2	[MEC] Bondurant- [MEC] Montezuma 1 345 kV	110	56
3	[MEC] Grimes - [MEC] Beaver Crk 1 345 kV	115	60
4	[MEC] Oak Grove - [AMMO] Sub 93 1 345 kV	108	58
5	[MEC] Webster - [MEC] LeHigh 1 345kV	144	62
6	MEC] Morgan Valley - [MEC] TIffin 1 345 kV	103	56
7	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 1	143	65
8	[AEP] Eugene – [AMIL] Bunsonville 345 kV	101	81
9	[AMIL] Tazewell-[AMIL] Maple Ridge 345 kV Ckt 2	141	65
10	[AMIL] Sandburg-[AMIL] Mercer 161 kV	115	69
11	[ALTW] Lasalle – [ALTW] Mitchell County 345 kV	105	57
12	[ALTW] Lasalle – [ALTW] Hazelton 345kV	110	60
13	[MEC] Walcott - [MEC] Sub 92 345kV	105	48
14	[MEC] Hills - [MEC] Sub T 345kV	112	32
15	[AMIL] Hines – [AMIL] Pioneer 138 kV	165	73
16	[ALTW] Hazelton – [ALTW] Dundee 138 kV	124	72
17	[ALTW] Liberty – [ALTW] Dundee 138 kV	115	67
18	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 1	134	36
19	[AMIL] Fargo 345 kV - [AMIL] Fargo 138 kV Xfmr 2	134	36
20	[NIPSCO] Sheffield – [NIPSCO] Wolf Lake	107	97

Figure 2.111: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

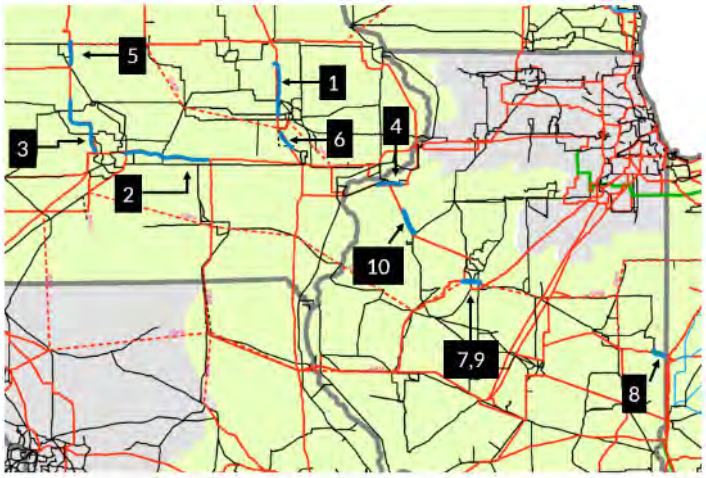


Figure 2.112: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Iowa and Illinois

The corridor of projects between Central Iowa and Northern Indiana supports a more robust exchange of low-cost resources across this region, and from net exporting regions like LRZ3. This results in lower prices in LRZ4. Overall congestion measure is seen to decrease in LRZ4 and along this corridor, with reductions on West/East oriented elements at a wide range of voltage levels. Figure 2.18 shows top relieved flowgates ranked by congestion measure relief for projects 38, 39, 40,and 41. The combined congestion measure impact for flowgates assessed for projects 38, 39, 40, and 41 is shown in Figure 2.113.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 38, 39, 40 & 41			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**Reference**	**Change Case**	**Total Relief**
Base Case: [AEP] 05ALBION - [NIPS] 17NORTHPORT 138 kV 1	908,179	633,175	275,004
Event 660: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 2	216,702	13,734	202,968
Event 3: [DUK-IN] 08WABASH_RIV 345kV - [DUK-IN] 08WAB R 230 kV 1	173,755	11,961	161,794
Event 62: [ALTW] HAZLTON L2 5 - [ALTW] DUNDEE 5 161 kV 1	273,853	148,901	124,952
Event 395: [DUK-IN] 08CHRYS3 - [DUK-IN] 08KOKOMO 138 kV 1	220,813	123,911	96,902
Event 62: [ALTW] LIBERTY5 - [ALTW] DUNDEE 5 161 kV 1	86,730	40,931	45,798
Event 1301: [AMIL] 7TAZEWELL - [AMIL] 7MAPLE RIDGE 345 kV 1	46,211	2,008	44,203
Event 63: [MEC] BONDURANT3 - [MEC] MONTEZUMA 3 345 kV 1	34,589	-	34,589
Base Case: [COMED] MAZON; R - [AMIL] 4CORBIN 138 kV 1	30,507	2,956	27,551
Event 108: [DUK-IN] 08CUYSUB - [DUK-IN] 08CUYUGA 345 kV 1	42,624	18,530	24,094

Table 2.18: Top Relieved Economic Flowgates – Projects 38, 39, 40, & 41

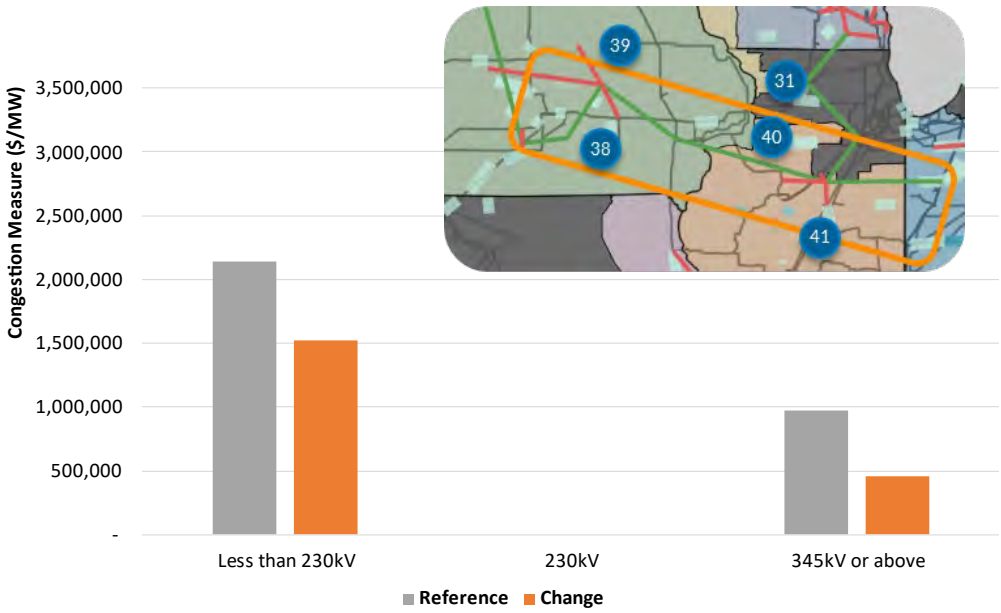


Figure 2.113: Congestion Measure - Projects 38, 39, 40, & 41

LRZ 5 – Missouri

The Tranche 2.1 portfolio resolves all thermal violations for 200 kV and above in LRZ 5. The final portfolio provides relief to the <200 kV system across multiple scenarios. The final portfolio reduces congestion in LRZ 5 by 55.9% (714 k$/MW), shown below in Figure 2.114, by adding another path directly north of congested facilities. The majority of relief comes from the congested [AMMO] Ft Zumwalt-[AMMO] Huster 138 kV line. The new 345 kV line also provides relief to transmission lines facilitating west to east flows.

Load serving costs decrease year-round and throughout LRZ 5, by an average of $2.08 / MWh, as seen in Figure 2.115. Transmission enables greater access to cheaper generation from other parts of the MISO Midwest subregion, and with that increased access and competition, curtailments see minimal change in LRZ 5 (-0.02M MWh). Resolved transmission constraints enable 2.8 GW of generation in LRZ 5.

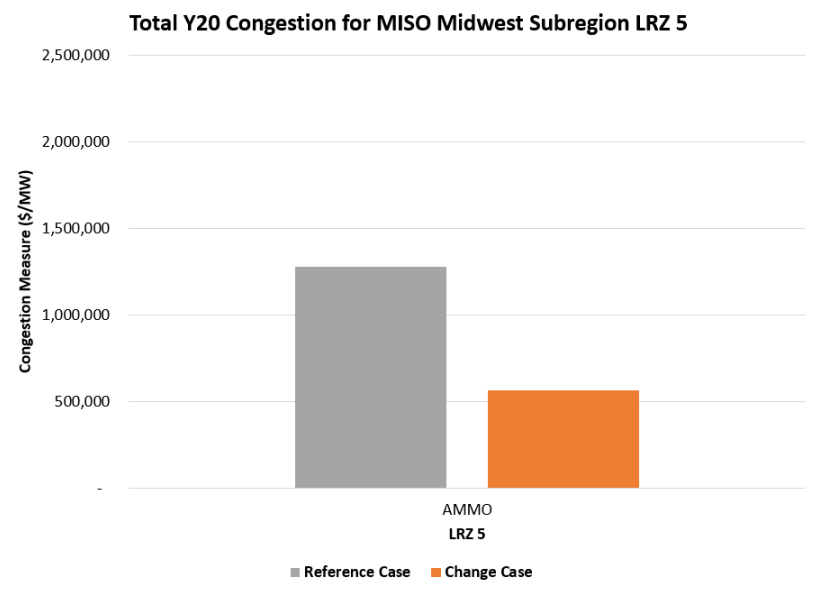


Figure 2.114: Congestion Measure – LRZ 5

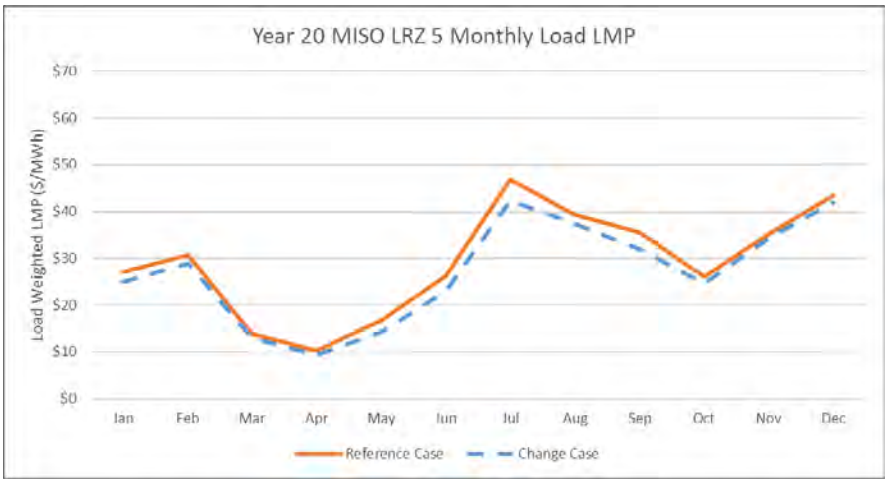


Figure 2.115: Comparison: Monthly Load LMP – LRZ 5

Maywood - Belleau - MRPD - Sioux - Bugle 345 kV (Project 37)

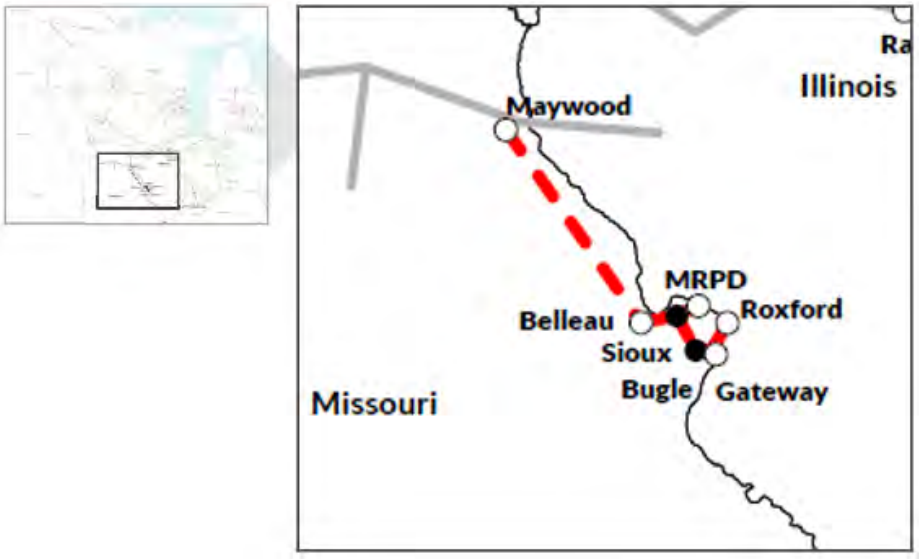


Figure 2.116: Missouri LRTP Tranche 2.1 projects

The 345 kV project in Missouri resolves numerous constraints in St. Louis Metro region and enables increased intraregional transfers across the Central Region. There are five limiting elements <200 kV that were not completely addressed with the addition of the portfolio, see table below. Worth noting, the loading of the elements are relatively the same with and without the portfolio and may be resolved in the annual MTEP reliability planning and generator interconnection processes. The geographically distant constraint, the [AMMO] Overton 345/161 kV transformer loading percent is greatly reduced with the addition of the portfolio.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AECI] Essex – [AMMO] Richland 161 kV	124	124
2	[AMMO[Joachim 345/138 kV transformer	118	114
3	[AMMO] Overton 345/161 kV transformer	128	108
4	[AECI] Big Creek – [AMMO] Warrenton 161 kV	115	112
5	[AMMO] Ester –[AMMO] Rivermines 138 kV	110	109

Figure 2.117: Unresolved constraints in Missouri better suited for resolution in MTEP or queue processes

There were zero areas of LRZ 5 where new system constraints are being introduced. The top 20 facilities mitigated are provided in the table, the portfolio resolved all thermal violations on 200 kV and above facilities in Missouri and nearby Illinois area. The top 10 facilities resolved are geographically represented on the map.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[AMMO] Mason 345/138 kV Transformer	114	92
2	[AECI] McCredie-[AMMO] Montgomery 345 kV	108	65
3	[AMMO] Scarlett-[AMMO] Montgomery 345 kV	103	76
4	[AMMO] Belleau 345/138 kV Transformer	108	49
5	[AMMO] Enon-[AMMO] Montgomery 345 kV	105	71
6	[AMMO] Loy Martin-[AMMO] McBain 161 kV	124	70
7	[AMMO] Apache-[AMMO] California 161 kV	124	71
8	[AECI] Cyrene-[AMMO] Pike 161 kV	128	66
9	[AMMO] Franklin-[AECI] Clover Bottom-[AMMO] Tegeler - [AMMO] Bland 138 KV	110	73
10	[AMMO] Moberly-[KCPL] Salsbury 161 kV	101	99
11	[AMMO] Mason-[AMMO] Schuetz 138 kV	104	69
12	[AMMO] Dorsett-[AMMO] Schuetz 138 kV	105	67
13	[AMMO] Dorsett-[AMMO] Warson 138 KV	100	62
14	[AMMO] Loy Martin-[AMMO] Guthrie 161 KV	112	62
15	[AMMO] Belleau-[AMMO] Fort Zumwalt 138 kV	131	62
16	[AMMO] Fort Zumwalt-[AMMO] McClay 138 kV	121	53
17	[AMMO] Fort Zumwalt-[AMMO] Huster 138 kV	106	48
18	[AECI] Palmyra-[AMMO] Hannibal West 161 kV	105	61
19	[AMMO] Overton 1-[AMMO] Overton 2 161 kV bus tie	111	83
20	[AMMO] McBain-[AMMO] Overton 161 kV	127	97

Table 2.19: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

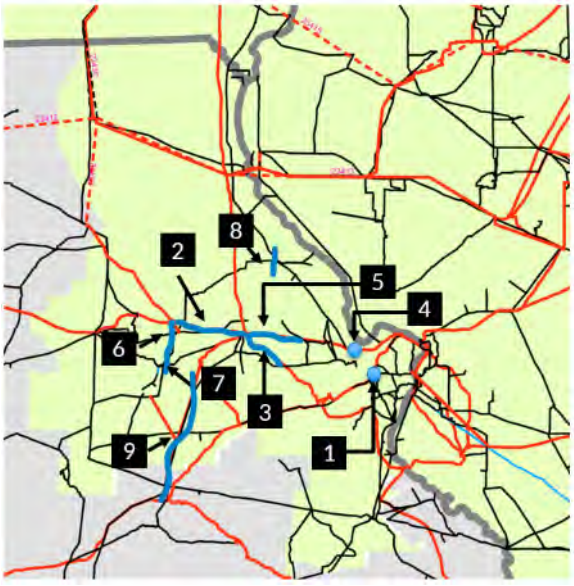


Figure 2.118: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Missouri

Project 37 is located within LRZ 5 and is responsible for the majority of the congestion relief seen in the LRZ. Project 37 reduces congestion in LRZ 5 by adding another path directly north of congested facilities and providing west to east relief. Table 2.20 and Figure 2.119 illustrate this further.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 37			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 539: [AMMO] 4FTZUM_TP 1 - [AMMO] 4HUSTER 3 138 kV 1	697,486	-	697,486
Event 355: [AMMO] 7ENON_TP - [AMMO] 7MONTGMRY 345 kV 1	41,533	12,601	28,932
Event 21: [AMIL] 4MORO - [AMIL] 4LACLEDE NTP 138 kV 1	224,528	196,378	28,150
Event 680: [AMMO] 4ESTHER TP2 - [AMMO] 4RIVMIN 2 138 kV 1	112,531	88,873	23,658
Event 420: [AECIZ] 5FLETCH - [AMMO] 5BR CREEK 161 kV 1	130,809	110,260	20,549
Event 1350: [AMMO] 4WITTNBRG - [AMIL] 4JENKINS 138 kV 1	26,138	12,925	13,213
Event 539: [AMMO] 7BELLEAU 345 kV - [AMMO] 4BELLEAU 1 138 kV 1	10,665	-	10,665
Event 1152: [AMIL] 4CAHOK 1 - [AMIL] 4RIDGE 2 138 kV 1	45,847	37,078	8,769
Event 582: [AMMO] 7MONTGMRY - [AMMO] 7SPENCER 345 kV 1	8,595	-	8,595
Event 324: [AECIZ] 5ESSEX - [AMMO] 5RICHLAND_TP 161 kV 1	16,661	14,253	2,408

Table 2.20: Top Relieved Economic Flowgates – Project 37

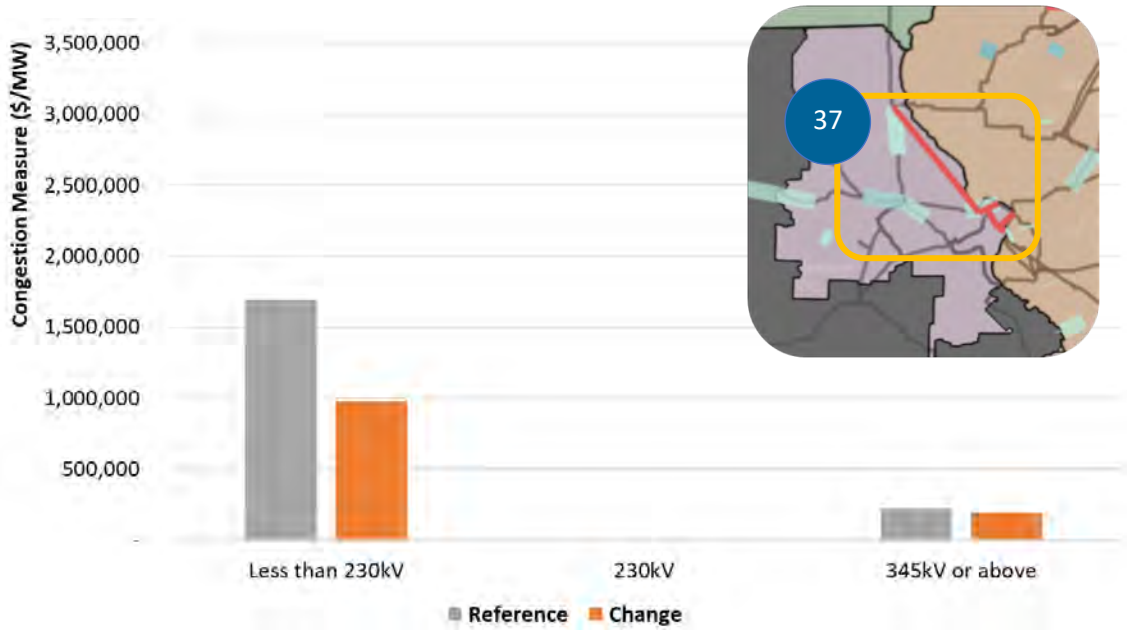


Figure 2.119: Congestion Measure – Project 37

LRZ 6 – Indiana

The Tranche 2.1 portfolio resolves most of the thermal violations in LRZ 6 for 200 kV and above facilities. The Tranche 2.1 portfolio improves transfer capability in Central/Southern Indiana by enabling more power to reach large load centers reliably.

The Tranche 2.1 portfolio reduces congestion evenly across LRZ 6, with all companies seeing congestion relief as shown in Figure 2.120. The portfolio also demonstrates relief throughout LRZ 6 footprint at multiple kV levels. Total congestion in LRZ 6 is reduced by 38.2% (1027 k$/MW). Load serving costs decrease year-round and throughout LRZ 6, as shown in Figure 2.121, by an average of $3.61 / MWh. Increased exports through transmission boost energy transfers while reducing costs for purchasing companies. With increased access to low-cost resources from the larger region, the Tranche 2.1 portfolio sees curtailments in LRZ 6 increase by 0.9M MWh. Relief of transmission constraints enables 16.6 GW of generation.

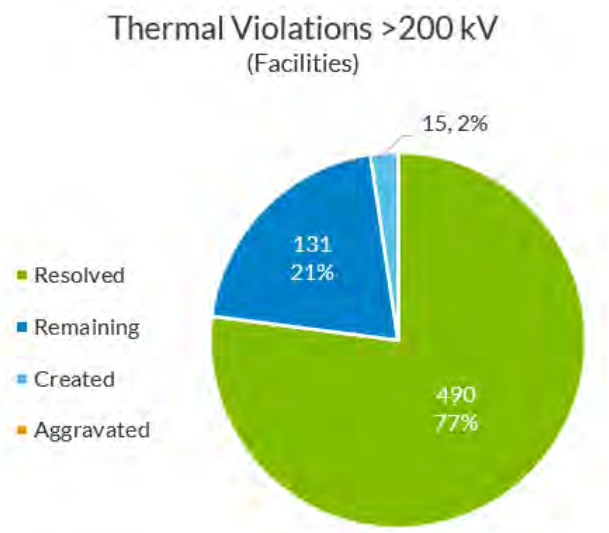


Figure 2.120: Thermal constraint resolution for LRZ6

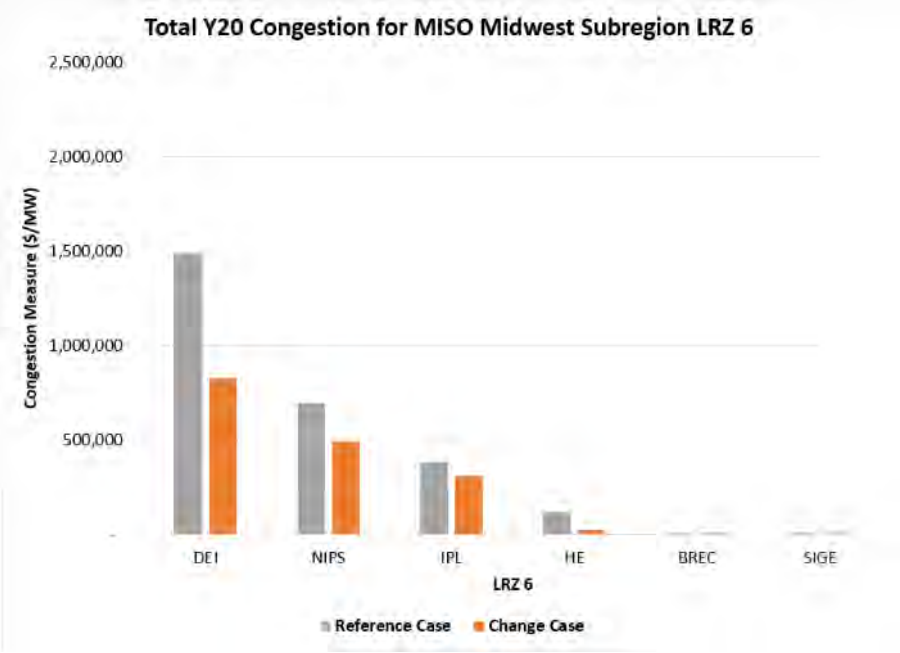


Figure 2.121: Congestion Measure – LRZ 6

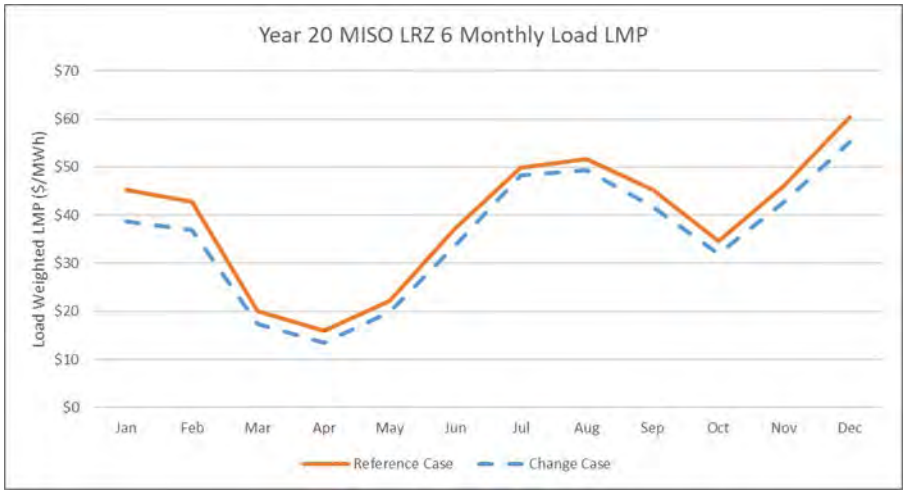


Figure 2.122: Comparison: Monthly Load LMP – LRZ 6

Southwest Indiana – Kentucky (Project 35) and Southeast Indiana (Project 36)

Southern IN/KY 345 kV project resolves constraints in the region and promotes West – East transfers across the central region. Southeast IN upgrades more than double the 345 kV outlet and allows both 765 & 345 kV connections to adequately and reliably transfer remote generation to the IN load centers in Central IN and Southeastern IN.

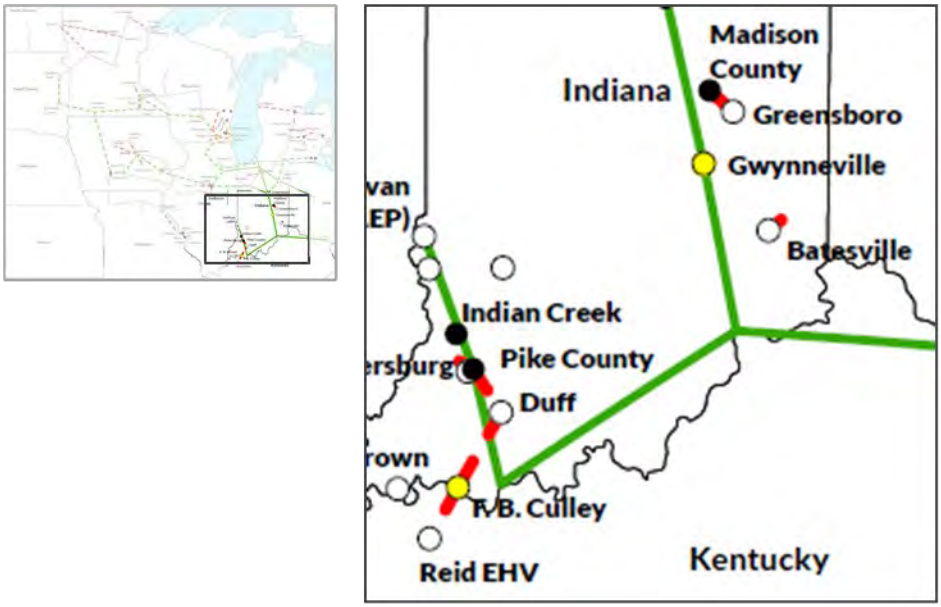


Figure 2.123: Southwest Indiana – Kentucky and Southeast Indiana LRTP Tranche 2.1 projects

There are two main areas of LRZ6 where system constraints were not completely addressed and these areas fall both in Central Indiana, as noted below in tables. The [DEI] Qualitech-[DEI] Whitestown-[IPL] Guion 345 kV and the [DEI] Kokomo-[DEI] Tipton-[DEI]-Carmel 230 kV transmission corridors are both overloaded with the portfolio, though the loading percents have been greatly reduced. The [DEI] Noblesville-[DEI] Madison County-[AEP] Fall Creek 345 kV transmission corridors are showing overloads

with the addition of the portfolio, though the loading percentages have been greatly reduced. Other facilities experienced aggravated loadings and all of the facilities referred to here are attributed to local drivers and better resolved in the annual MTEP reliability planning and the generator interconnection processes.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Qualitech –[DEI] Whitestown –[IPL]Guion 345 kV	168	140
2	[DEI] Kokomo –[DEI] Tipton –[DEI] Carmel 230 kV	143	118
3	[DEI] Noblesville - [DEI] Madison County [AEP] Fall Creek 345 kV	121	107

Table 2.21: Loadings significantly relieved, full resolution better suited for MTEP and queue processes in LRZ6

The top 20 lines with the most reduction in the loadings are shown in the table below. The third column shows the highest loading for these elements in the base models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The Fall Creek – Noblesville 345 kV line listed below as 15 is reconfigured to the Fall Creek to Madison County to Noblesville 345 kV line to accommodate the new 345 kV circuit from Greensboro to Madison County in the Tranche 2.1 portfolio. The locations of the top 10 lines are shown on the map below.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[DEI] Noblesville – [DEI] Durbin 230 kV	105	81
2	[DEI] Hortonville – [DEI] Whitestown 230 kV	106	88
3	[DEI] Nucor – [DEI} Whitestown 230 kV	111	89
4	[DEI]Staunton – [DEI] Wabash River 230	117	79
5	[DEI]Wheatland – [DEI]Edwardsport 345 kV	126	Reconfig
6	[DEI] Gibson– [LGEE] Wheatland 345 kV	107	11
7	[DEI] Speed – [LGEE] Trimble County 345 kV	107	94
8	[DEI] Batesville – [DEI] Hubble – [DEI] Weisburg – [DEI] Wilmington – [HE] Hidden Valley – [DEI] Greendale – [DEO&K] Miami Fort 138 kV	145	55
9	[SIGE] Newtonville – [SIGE] Grandview – [SIGE] Rockville Tap 138 kV	118	69
10	[BREC] Reid – [BREC] Hopkins County – [BREC] Caldwell – [BREC] Barkley HP 161kV – [BREC] Henderson County 161/138 kV transformer	113	79
11	[HE] Decatur – [DEI] Greensburg 138 kV	132	47
12	[DEI] Plainfield – [WVPA] Airport West 138 kV	107	81
13	[DEI] Wabash River 230/138 kV transformer 1B	110	56
14	[DEI] Lapel – [DEI] Noblesville 230	101	82
15	[AEP] Fall Creek – [DEI] Noblesville 345 kV	121	Reconfig
16	[IPL] Guion – [IPL] Pike 138 kV	108	96
17	[IPL] Guion – [IPL] Westlane 138 kV	102	94
18	[IPL] Guion – [IPL] Mill Street 138 kV	108	90
19	[IPL] Guion – [IPL] Tremont 138 kV	103	90
20	[DEI] Vincennces – [DEI] Lawrenceville 138 kV	105	68

Table 2.22: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

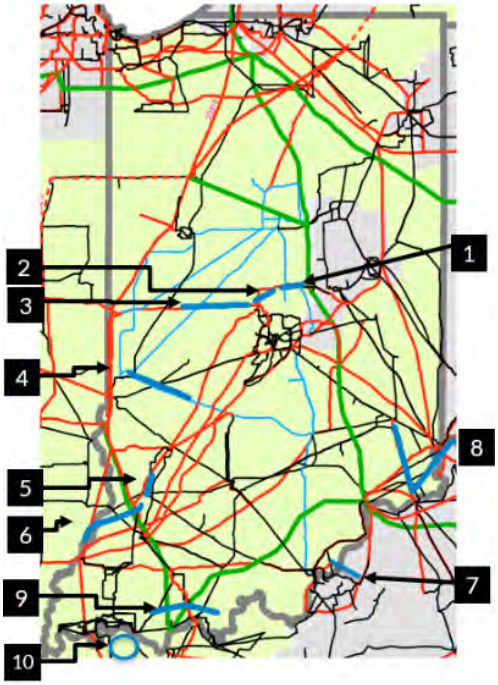


Figure 2.124: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central and Southern Indiana

Projects 35 and 36 provide relief for many lower kV constraints in the mid-southern area of the LRZ, shown below in Table 2.9 and Figure 2.123. They enable more generation to reach the load centers in Central and Southeastern Indiana.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Projects 35 & 36			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 154: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	72,018	-	72,018
Event 246: [DUK-IN] 08WILM J - [DUK-IN] 08WEISBG 138 kV 1	70,780	-	70,780
Event 153: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	70,391	-	70,391
Event 36: [HE] 07DCTRSS - [DUK-IN] 08GRNSBR 138 kV 1	61,494	-	61,494
Event 2: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	58,806	-	58,806
Event 572: [DUK-IN] 08KOK HP - [DUK-IN] 08TIPTN 230 kV 1	55,899	3,382	52,517
Event 167: [IPL] 16GUION - [IPL] 16WSTLAN 138 kV 40	238,760	186,961	51,799
Event 243: [HE] 07HUBBL8 - [DUK-IN] 08BATESV 138 kV 1	39,313	-	39,313
Event 2: [DUK-IN] 08WHITST - [IPL] 16GUION 345 kV 1	142,080	112,538	29,542
Event 1025: [DUK-IN] 08LAFAYE 230kV - [DUK-IN] 99494 YBUS504 100 kV 1	50,262	28,268	21,995

Table 2.23: Top Relieved Flowgates – Projects 35 & 36

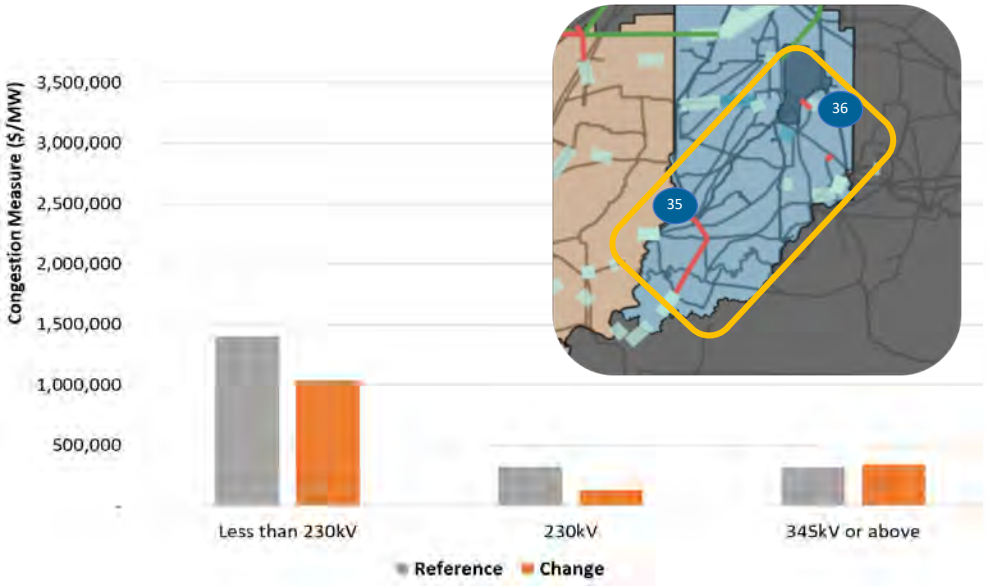


Figure 2.125: Congestion Measure – Project 35 & 36

East Region – Reliability and Economic Results

- Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability
- Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the Eastern load centers
- MI to Northeast IN project supplement the existing connections into Michigan and provide the transfer capability in and out of MI

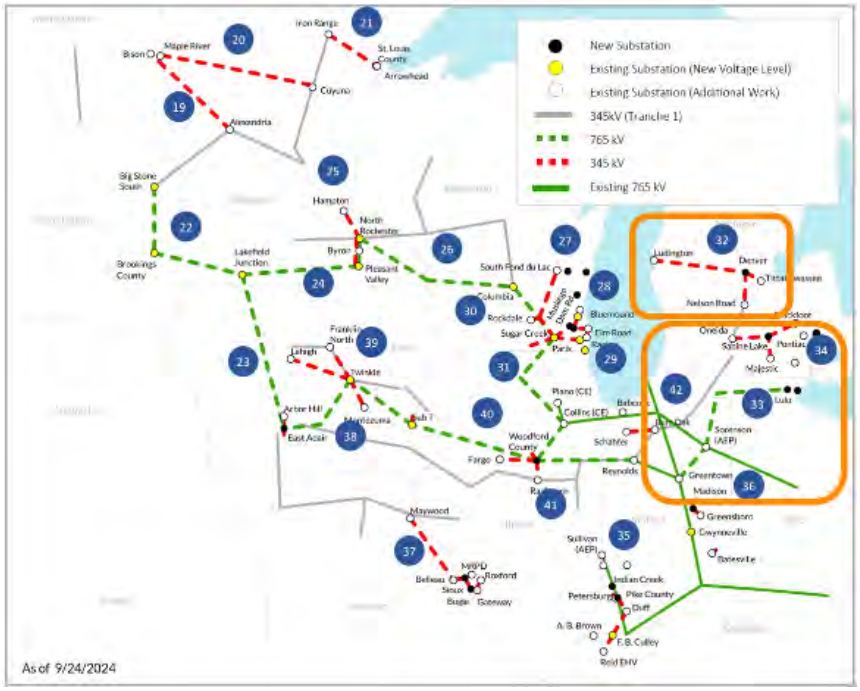


Figure 2.126: East Region Project Groups

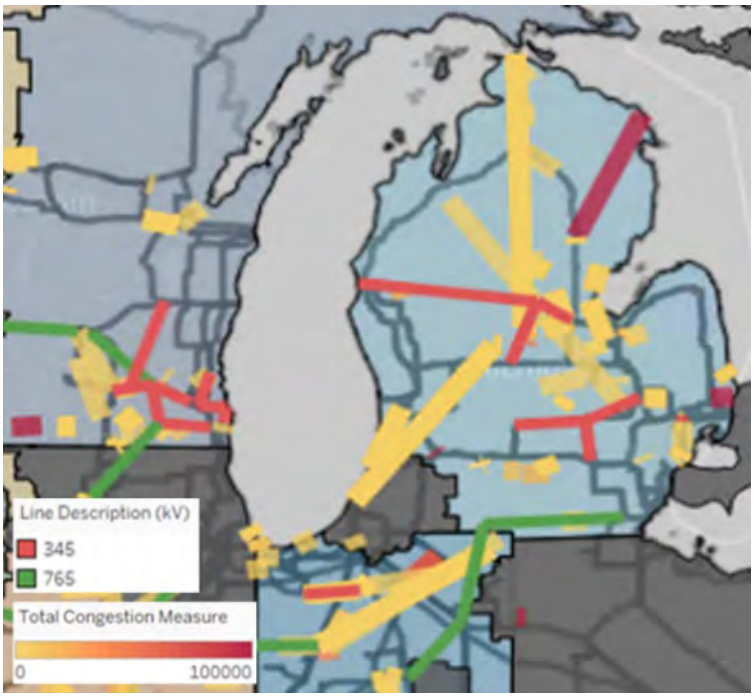


Figure 2.127: Change Case Economic Congestion - East

LRZ 7 – Michigan

For the <200 kV system, 31% of the violations have been resolved. For the >200 kV system, stronger East to West ties are established in the MI footprint. These ties shift flow patterns in the region by allowing access

to remote resources and provide high utilization of new Tranche 2 lines. For the >200 kV system, a majority of the remaining and created violations occur in the twilight, low winter renewable, and lower-upper transfers, where the system is stressed. The remaining reliability issues are specific to local generation sited or load which has better resolution through annual MTEP reliability planning and the generator interconnection processes.

Tranche 2.1 portfolio reduces congestion in LRZ 7 by using regional facilities to relieve local congested areas. Congestion is reduced in LRZ7 by 31.7% (950 k$/MW), and most of the relief is on local constraints near 345 kV additions. Few constraints see increased economic congestion. Both companies see notable congestion relief, as shown in Figure 2.128. Load serving costs decrease year-round and throughout LRZ7 by an average of $3.70 / MWh, generally lowering LMPs in higher cost areas of the state. This is detailed in Figure 2.129. Curtailment reductions are seen in the central part of the LRZ near new transmission, and relief of transmission constraints enables 11.2 GW of generation in LRZ 7. Tranche 2.1 portfolio maintained the relatively low curtailments in LRZ 7, only increasing them by 1.1M MWh. Curtailments, shown in Figure 2.130, improved near the eastern terminus of Project 32. Relief of transmission constraints enables 11.2 GW of generation.

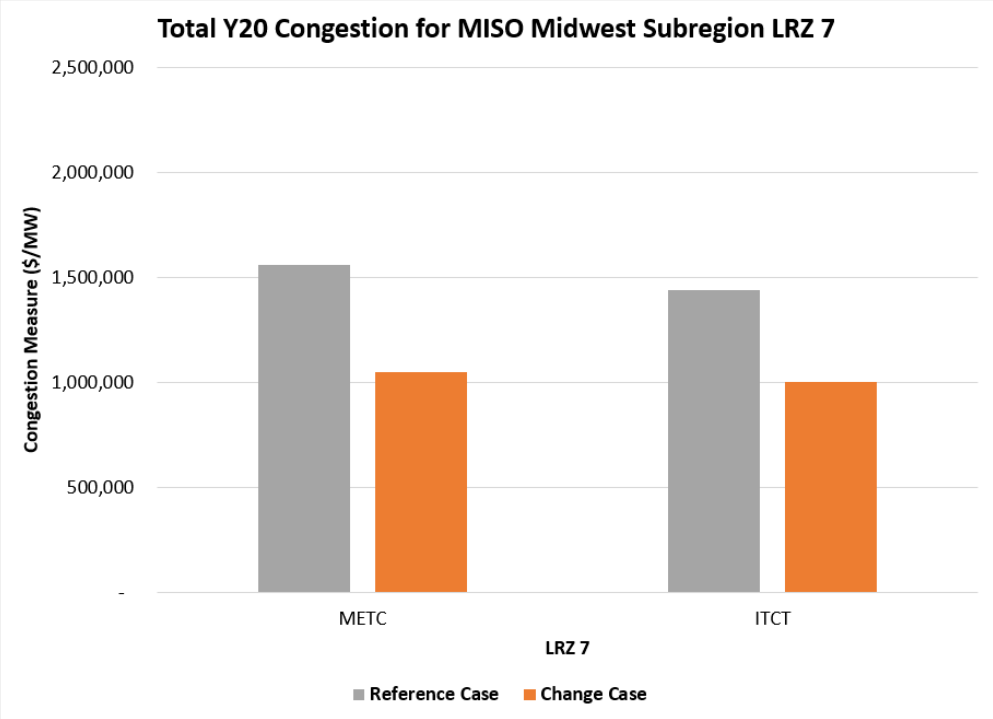


Figure 2.128: Congestion Measure – Project 37

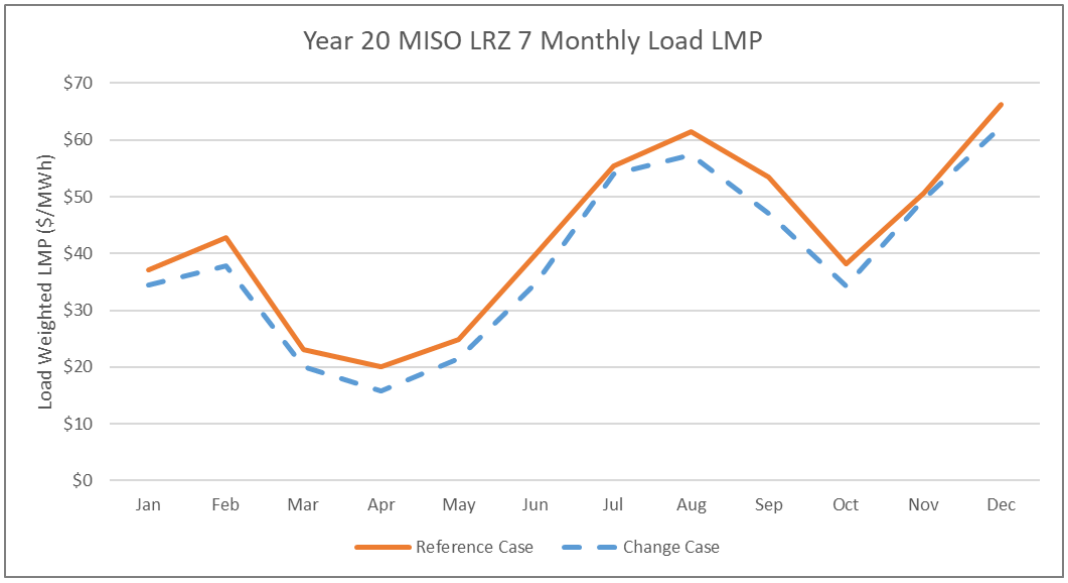


Figure 2.129: Comparison: Load LMP – Project 37

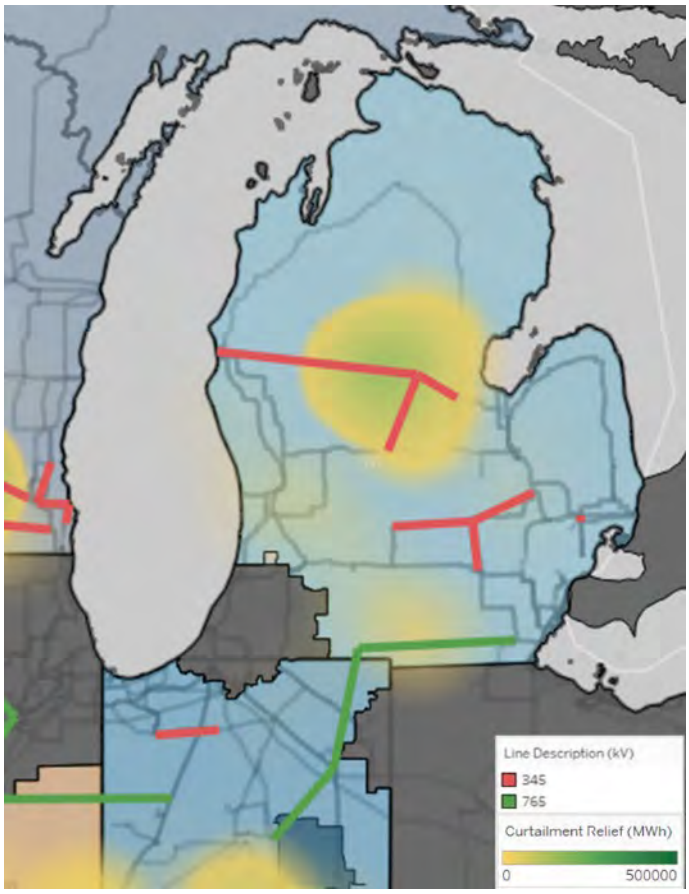


Figure 2.130: Change Case Curtailment Relief – LRZ 7

Ludington - Denver - Tittabawassee & Nelson Road 345 kV (Project 32)

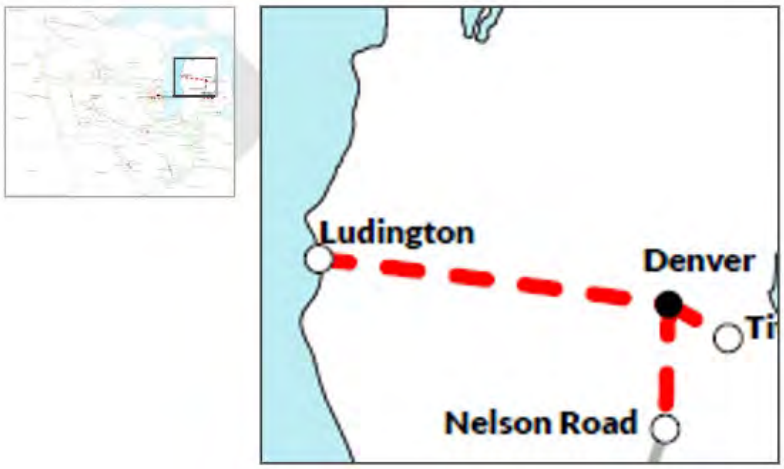


Figure 2.131: Central Michigan LRTP Tranche 2.1 projects

Central MI project assists in unlocking generation in Western and Central MI and connects to Tranche 1 project to allow greater transfer capability. Transmission connects resources from Western MI to load centers in the East, relieving congestion especially near the eastern load centers. The bulk of the identified constraints in Central MI were on the 138 kV line, as this is the predominant voltage in the area. Tranche 2.1 portfolio resolves 37% of thermal violations on 200 kV and below facilities in Central Michigan.

Another key benefit of Central MI projects is aiding the bi-directional nature within the MI system. Ludington Pumped Storage Plant functions as either a significant source of generation, or a significant load to the MI system. This is exhibited by both West to East and East to West flows on the added facilities, respectively. The table shows the most reduction in loadings, while the figure shows the first eight elements.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[METC] Bullock-[METC] Edenville Junction 138 kV	175	34
2	[METC] Bullock-[METC] Salt River Junction 138 kV	193	27
3	[METC] Regal -[METC] Luce 138 kV	186	53
4	[METC] Tittabawassee -[METC] Redstone 138 kV	135	58
5	[METC] Summerton-[METC] Camelot Lake 138 kV	159	9
6	[METC] Camelot Lake Jct -[METC] Salt River 138 kV	160	10
7	[METC] Lewiston-[METC] Plywood Jct 138 kV	115	91
8	[METC] Plywood Jct-[METC] Bagley 138 kV	115	90
9	[METC] Chase -[METC] Mecosta 138 kV	108	93
10	[METC] Hillman -[METC] Airport 138 kV	112	87
11	[METC] Bluegrass Jct -[METC] Summerton 138 kV	131	22
12	[METC] Edenville Junction 138 kV-[METC] Salt River 138 kV	111	13

Table 2.24: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

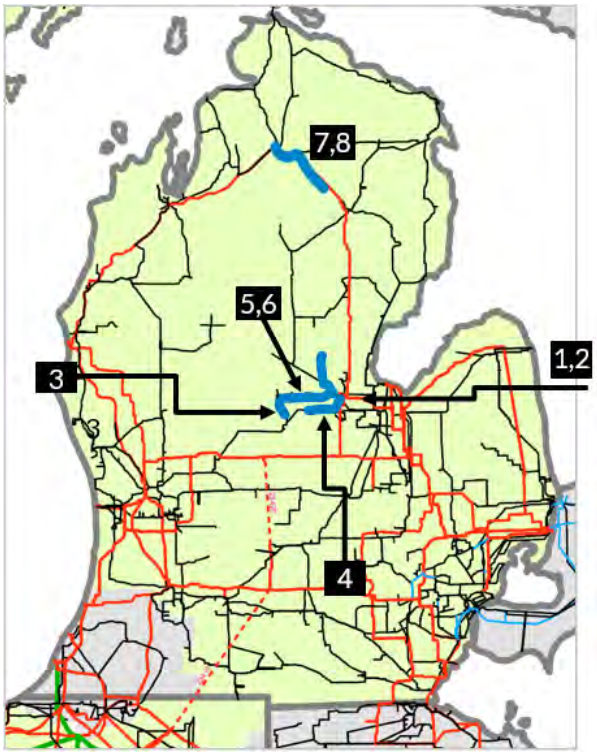


Figure 2.132: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Central Michigan

Project 32 provides congestion relief to lower kV local constraints located in the central part of the LRZ near the project. It does so by pulling flows off of the local system and distributing them more evenly towards surrounding load centers. Table 2.24 and Figure 2.134 illustrate this.

Y20 Top Relieved Flowgates Ranked by Congestion Measure Relief - Project 32			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	**Reference**	**Change Case**	**Total Relief**
Event 627: [CONS] 18BULLOCKW - [CONS] 18SALTRIV 138 kV 1	107,294	-	107,294
Figure	65,165	247	64,918
Base Case: [CONS] 18DEJAJ - [CONS] 18VESTABURG 138 kV 1	55,520	61	55,460
Event 826: [CONS] 18ALMA - [CONS] 18REGAL 138 kV 2	52,867	163	52,704
Event 227: [CONS] 18BULLOCKB - [CONS] 18EDNVLJ 138 kV 1	39,857	-	39,857
Event 9: [CONS] 18HLLMNJ - [CONS] 18AIRPORTW 138 kV 1	28,106	7,124	20,982
Event 529: [CONS] 18CORWTJ - [CONS] 18RONDO 138 kV 1	56,298	36,235	20,063
Event 163: [CONS] 18GALAGR - [CONS] 18GRNWDJ 138 kV 1	15,857	0	15,857
Event 627: [CONS] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	13,502	-	13,502
Event 150: [CONS] 18CAMLTJ - [CONS] 18SALTRIV 138 kV 1	11,583	0	11,583

Table 2.25: Top Relieved Economic Flowgates – Projects 32

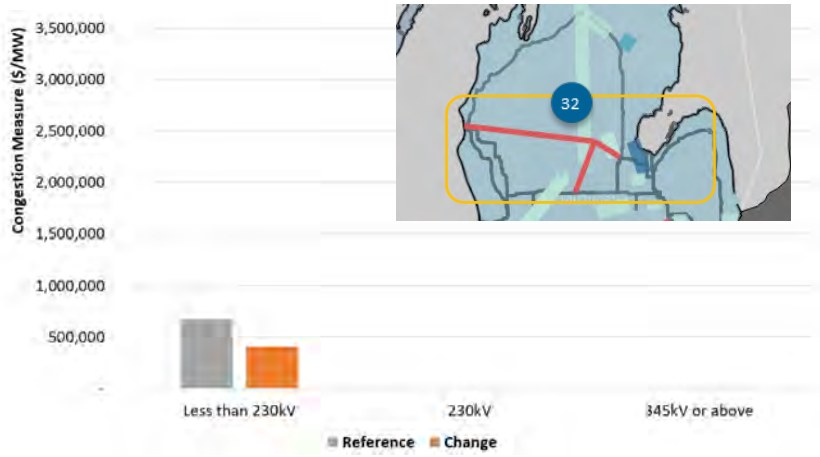


Figure 2.133: Congestion Measure – Project 32

Greentown - Sorenson - Lulu 765 kV (Project 33), Oneida - Sabine Lake - Blackfoot & Majestic 345 kV (Project 34), and Burr Oak – Schafer 345 kV (Project 42)

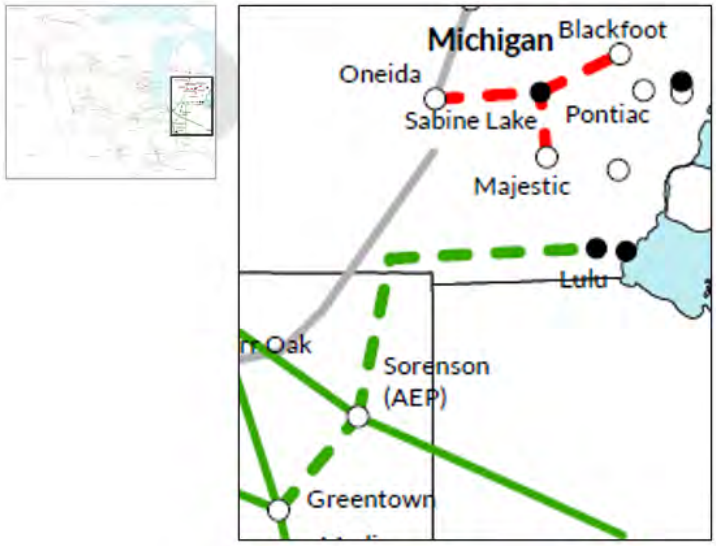


Figure 2.134: Southern Michigan and Northeastern Indiana LRTP Tranche 2.1 projects

The MI to Northeast IN project supplements the existing connections into Michigan and provides the transfer capability in and out of MI. Additionally, the re-configuration near existing Babcock and Burr Oak substations in Northwestern IN strengthen a load pocket that will increasingly rely on support from the rest of the MISO system as local generation retires.

In the average and light load core models, where batteries are charging and solar output is modest to non-existent, MI is importing approximately 5.7 GW. During peak summer and winter cases, MI is exporting approximately 3 GW and 1.6 GW, respectively. Drivers for these large swings can be attributed to a heavy concentration of solar and battery resources in the MI footprint in F2A, coupled with Ludington Pumped Storage Hydro.

The Sorenson to Lulu 765 kV line maintains system reliability as Michigan experiences increasingly large swings in imports and exports. From the constraints resolved map, thermal violations are resolved on the Argenta lines (Western MI) as MWs transfer into or out of the Detroit area (load center) or thumb of MI (generation center) via the Sorenson to Lulu 765 kV line. Additionally, the Oneida - Sabine Lake - Blackfoot & Majestic 345 kV strengthens the pathways into the Detroit area by interconnecting with Tranche 1 facilities. Ultimately these new 345 and 765 kV lines increase the ability of the MI system to handle large generation swings throughout the year. The table shows the most reduction in loadings, while the figure shows the first nine elements.

#	Element	Initial Worst Loading %	Final Worst Loading %
1	[ITCT] Jewell -[ITCT] Bismarck 345 kV	115	54
2	[ATSI] Lallendorf-[ITCT] Monroe 345 kV	117	Reconfigured
3	[AEP] Lemoyne–[ITCT] Maple 345 kV	122	Reconfigured
4	[METC] Oneida 345/138 kV transformer	111	82
5	[METC] Delhi–[METC] Green 138 kV	149	83
6	[METC] College–[METC] Green 138 kV	139	76
7	[METC] Argenta–[METC] Palisades 345 kV 1	108	93
8	[METC] Argenta–[METC] Palisades 345 kV 2	115	99
9	[METC] Argenta –[METC] Meyer 345 kV	102	87
10	[METC] Hagadorn Junction–[METC] Tihart 138 kV	129	68
11	[METC] Hagadorn Junction–[METC] College 138 kV	106	57

Table 2.26: Top Reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan and Northeastern Indiana

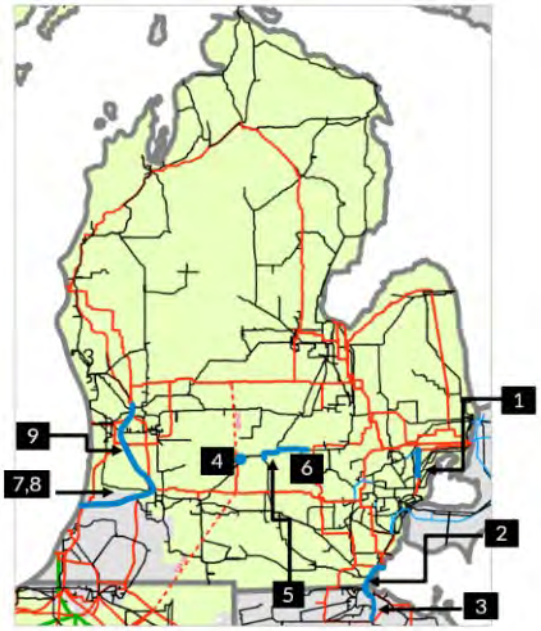


Figure 2.135: Top reliability constraints resolved by LRTP Tranche 2.1 projects in Southern Michigan

Projects 33, 34, and 42 provide relief to lower kV local constraints in the southern and southeastern portions of the LRZ, illustrated in Figure 2.135. Table 2.27 shows the relieved flowgates ranked by congestion measure relief for projects 33, 34, and 42.

Y20 Top Relieved Flowgates - Projects 33, 34 & 42			
	Congestion Measure ($/MW)		
Top Relieved Flowgates	Reference	Change Case	Total Relief
Event 126: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	281,619	166,593	115,026
Event 1156: [DECO] 19BUNCE1 - [DECO] 19FITZ 120 kV 1	131,271	25,320	105,951
Event 1018: [DECO] 19LEE1 - [DECO] 19LHPMPT 120 kV 1	102,215	22,023	80,192
Event 136: [DECO] 19CANIF7 - [DECO] 19HAMTRAMCK6 120 kV 1	315,538	244,547	70,991
Event 1004: [CONS] 18HALSEY - [CONS] GRAND BOC 2 138 kV 1	89,505	24,908	64,596
Event 1124: [CONS] DEAN RD - [CONS] OAKLAND 138 kV 1	41,314	11,652	29,662
Base Case: [NIPS] 17STJOHN - [COMED] CRETE EC ;BP 345 kV 1	30,400	800	29,600
Base Case: [CONS] PLYMOUTH 1 138kV - [CONS] YBUS536 100 kV 12	411,950	382,553	29,397
Event 1114: [DECO] 19CLRDT1 - [DECO] 19PONTC2 120 kV 1	107,992	79,373	28,619
Event 55: [CONS] 18LEONI - [CONS] 18WSHTNJ 138 kV 1	36,842	11,248	25,594

Table 2.27: Top Relieved Economic Flowgates – Projects 33, 34, & 42

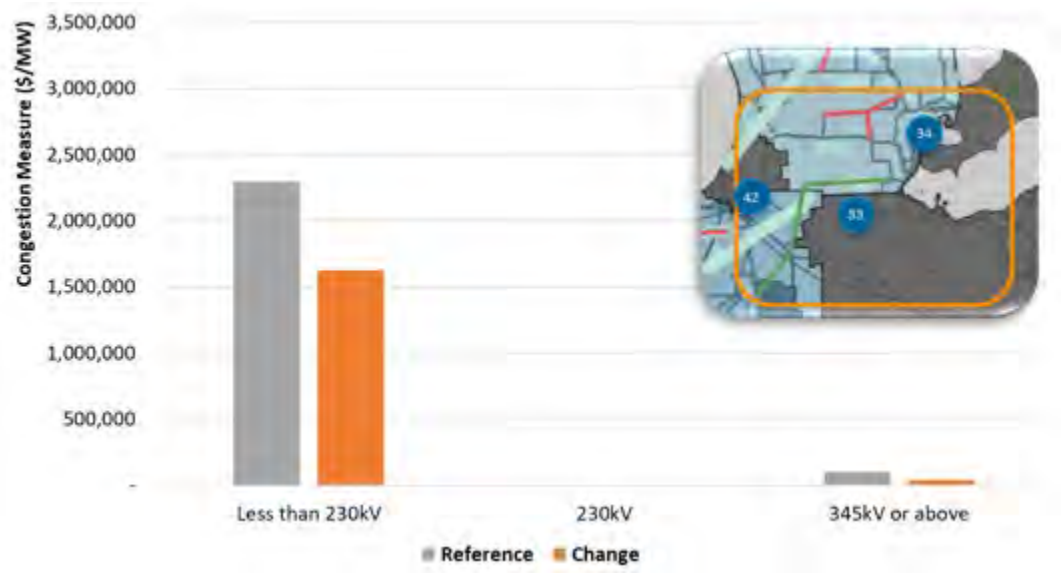


Figure 2.136: Congestion Measure – Project 33, 34 & 36

Business Case Analysis

In accordance with the guiding principles of the MISO transmission planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility criteria are established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

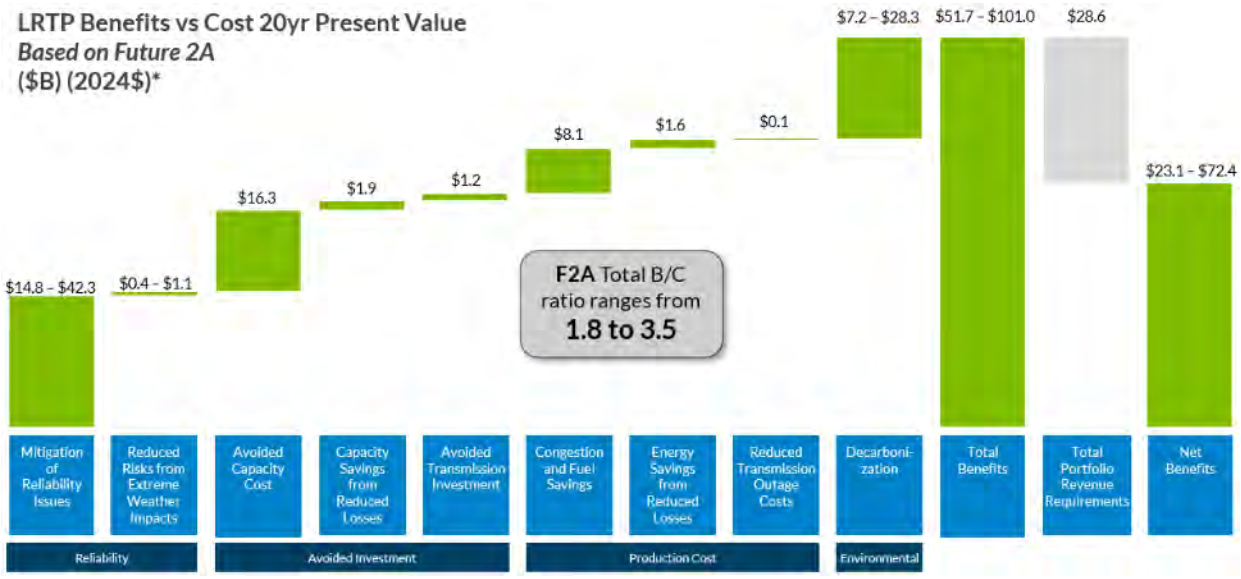


Figure 2.137: Financially Quantifiable Benefits of Tranche 2.1 Portfolio (values as of 11/1/2024).

Guided by the financially quantifiable benefits defined in the tariff for MVP projects, the following benefit metrics were evaluated to determine the amount of value delivered by the Tranche 2.1 Portfolio:

Reliability Benefits	1. Mitigation of reliability issues	Value of alleviating reliability issues which, if unresolved, introduce a risk of unserved load
	2. Reduced risks from extreme weather events	Increases grid resilience and decreases the probability of major service interruptions
Avoided Investment Benefits	3. Avoided capacity costs	Avoids capital costs for local resource builds versus regional expansions defined in Futures
	4. Capacity Savings from Reduced Losses	Value of reducing transmission losses during peak capacity periods
	5. Avoided transmission investments	Avoids the need for facility replacement due to age and condition
Production Cost Benefits	6. Congestion and fuel savings	Enhances market efficiency and provides access to low-cost generation
	7. Energy Savings from Reduced Losses	Lower production costs to serve load with transmission facilities that reduce system losses
	8. Reduced transmission outage costs	Reduced transmission congestion during forced and planned transmission outages
Environmental Benefits	9. Decarbonization	Enables the economical dispatch of renewable resources to help reduce the carbon footprint

Table 2.28: Nine Benefit Metrics used for Tranche 2.1.

Each benefit metric represents a distinct piece of the overall value resulting from the transmission investments. The nine benefit metrics can be grouped into four categories of benefits – reliability (1 and 2), avoided investment (3, 4 and 5), production costs (6, 7 and 8), and environmental (9). The methodologies were developed to define the calculations used to assess the impact of LRTP Tranche 2.1 projects on specific financially quantifiable measures that reflect the value of the investment and are summarized in this report. The details of the methodologies are more fully discussed within the LRTP Tranche 2 Business Case Metrics Methodology Whitepaper.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. Benefits were calculated over a 20-year period as required for MVPs in accordance with the MISO Tariff, starting from the assumed in-service year of 2032, and over a 40-year period to demonstrate the additional value provided by the portfolio over the many decades beyond 20-years the portfolio is expected to be in-service. All benefit values are expressed in 2024 dollars. A discount rate of 7.1 percent is used to calculate the minimum value used to assess the benefit-to-cost ratio and is based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. Benefits are also assessed using a rate of three percent to show how assets perform with a social discount rate that reflects the return a ratepayer would typically receive on a risk-adjusted investment.

While the LRTP Tranche 2.1 Portfolio study has focused on Future 2A, the benefits analysis has also been performed using Future 1A to provide a lower-bookend representation of the value the portfolio provides.

Future 2A Benefit Metric Analysis

Mitigation of Reliability Issues

High-Level Methodology Overview

Traditionally, the NERC TPL standard has been used to ensure the transmission system is planned to be reliable. The NERC TPL standards articulate a minimum level of reliability with which the transmission system must support.

With regard to long-range transmission planning, the objective is to ensure the regional system is reliable and cost effective in the long-term given the many changes that are expected to the resource fleet and load characteristics. In that respect, long-range transmission planning is not TPL compliance-focused, but instead value-focused. LRTP seeks to determine the benefits of reliability improvements associated with long-term projects.

The reliability benefit metric captures where LRTP resolves reliability issues, as defined by instances where the post contingent load under steady state conditions would exceed applicable facility limits after redispatch. The benefit of remediating reliability issues is determined by quantifying the avoided risk of load shedding that would be needed to return the facility within applicable limits and monetizing the value. This load shedding is used as a measure of reliability risk rather than an operating action taken to resolve issues.

Analysis of benefits is performed in a two-step process which applies preventive generation re-dispatch in the first step to mitigate initial overloads followed by a corrective load re-dispatch process to calculate the minimum load shedding to address the contingency violations. This analysis uses the TARA software application to perform an optimal security constrained reliability dispatch for NERC Category P1, P2, and P7 contingencies associated with the LRTP resolved issues.

Thermal overloads identified in each of the core (seasonal) study scenarios for the 2032 and 2042 study years that are relieved by the addition of the LRTP Tranche 2 portfolio, and their associated contingencies are compiled and monitored in the first past generation re-dispatch step. Since seasonal study models are snapshots that reflect a wide range of load and generation dispatch conditions, two dispatch scenarios are created for each of the core study scenarios. The first scenario represents hours with excess renewable availability where renewables are allowed to dispatch in the upward direction. The second scenario represents hours with less renewable availability than modeled where renewables are limited in dispatch to the downward direction.

The unresolved overloads from the generation redispatch step are compiled and monitored in the second pass load redispatch step to calculate load shedding needed to mitigate the remaining thermal overloading. The reduction in load at each bus is calculated and the maximum value for each bus for all contingencies is summed to determine quantity of load shedding needed in each dispatch scenario. The value of this load shedding amount is multiplied by the hours represented by the dispatch scenario and summed to quantify the total risk of unserved energy (in MWh). This value is then multiplied by the Value of Lost Load (VOLL) to monetize the benefit.

$$\text{Benefit} = \sum_{1}^{n} LoadShedMW * VOLL$$

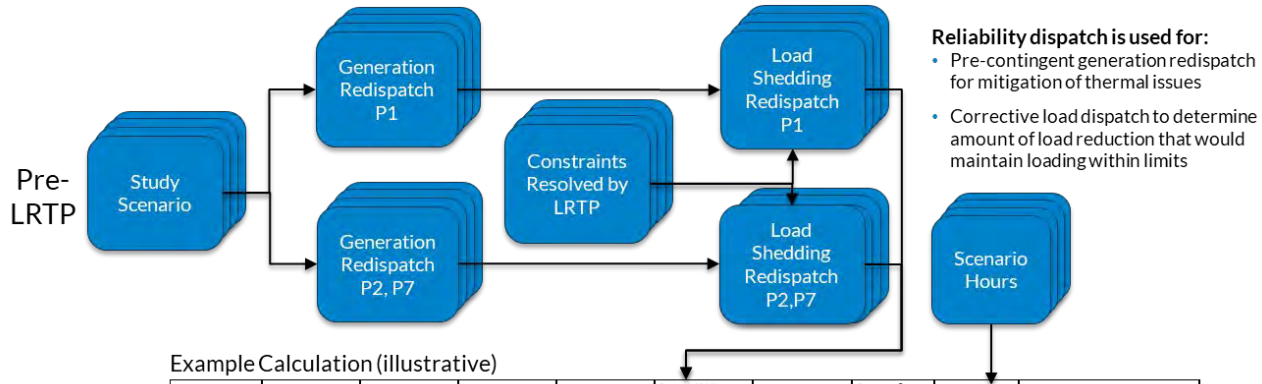
Where

n = dispatch scenario/season

LoadShedMW = amount of load redispatch for each study scenario

VOLL = Value of Lost Load ($3,500/MWh - $10,000/MWh)

Benefits are accrued on a one-time basis for each of the study years (2032 and 2042) and issues identified in the earlier 2032 study year are excluded from consideration in the later 2042 study year. Any reliability issues that are identified are assumed to be mitigated and pose no further risk in the later years to provide a more conservative estimate.



Example Calculation (illustrative)

Model	Redispatch Scenario	Monitored	Contingency	Pre-overload %	Pre-MW Relief Required	Buses	Sum of Max Load Shed MW	Scenario Hours	MWh Benefit
2032sum	up/down	St A- St B	P1_Ctg1	115%	16MW	bus-a bus-b	124	48	5,952
2032avg	up/down	St C - St D	P1_Ctg2	124%	32MW	bus-c bus-d bus-e	46	420	19,320
2032avg	down-only	St E - St F	P1_Ctg3	107%	20MW	bus-f bus-g bus-h bus-i	295	1362	401,790
2032avg	down-only	St G - St H	P2_Ctg4	109%	18MW				
							Load Shedding MWh		427,062

Figure 2.138: Process for Identifying Load Shedding Risk

Results

LRTP Tranche 2.1 projects provide value by proactively addressing numerous thermal overloads that reduces risk of unserved load as indicated in table below and yields $14.8B benefits over a 20- to 40-year period.

Total Unserved Energy Risk by Season (GWh)				
Year	Summer	Winter	Average	Light Load
2032	449	58	2971	278
2042	149	80	400	115

Table 2.29: Avoided by Mitigation of Reliability Issues Benefits Summary of Avoided Unserved Energy

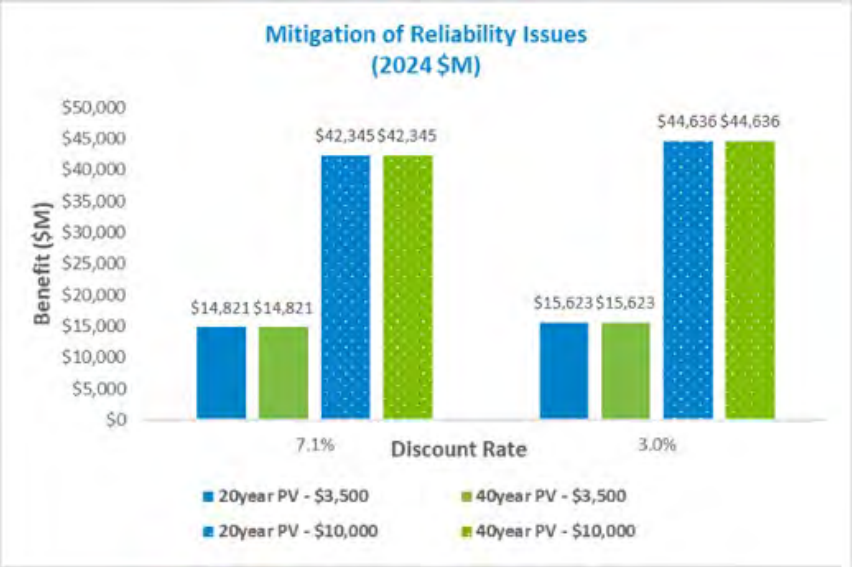


Figure 2.139: Mitigation of Reliability Issues Benefit Value

Reduced Risks from Extreme Weather Impacts

High-Level Methodology Overview

Reduced risks from extreme weather impacts reflects the value of reducing the risk of unserved energy during periods of expected supply deficiency attributed to extreme weather conditions. The increased penetration of variable resources that are reflected in the Futures scenarios, in combination with correlated outages of thermal resources and higher than expected load levels, will increase the risk of supply disruptions due to extreme weather and resulting in more unserved energy. Limited transmission capacity restricts access to resources that are needed to cover capacity shortfalls that can result in greater unserved energy. The addition of the Tranche 2.1 portfolio increases transfer capability to enhance capacity deliverability that reduces the amount of unserved energy.

The analysis uses PLEXOS software to perform probabilistic Loss of Load Expectation (LOLE) simulations using a simplified zonal transmission constraint model to assess the amount of expected unserved energy (EUE) observed in the worst intervals with and without the LRTP Tranche 2.1 portfolio. Hourly simulations are run using 14 weather years of load and renewable generation profiles with 150 samples to reflect the probabilities of forced outages including temperature-dependent correlated outages. Planned maintenance is also accounted for using maintenance outage rates and maintenance frequency. This analysis examines the Conditional Value at Risk (CVaR) to focus on the tails of the risk distribution (i.e. intervals with the highest EUE) which captures the benefits of addressing more extreme risks in a future with high levels of uncertainty and variability in the generation resources. The expected unserved energy metric is used to capture both the duration and magnitude of the loss of load events as a measure of the benefit. A threshold for CVaR is established from the event duration and magnitude and applied to the dataset to select the subset of events in the tail of the risk distribution that are used in the analysis and reflect the top percentage of EUE hours. The benefit metric applies a CVaR(80) target that is used to capture the top 20% of the worst events with greater than 2000 MWh unserved and 4 hour duration.

The reduced risk from extreme weather impacts measures the change in the expected unserved energy (EUE) during the most severe events and uses a VOLL equal to 3,500 $/MWh to monetize the lower end of this benefit and 10,000 $/MWh on the upper end. The economic value, which is applied from year 10, when LRTP transmission is enabled in the planning horizon and accrued every 5 years in accordance with CVaR(80) target,[3] is calculated by the following equation:

$$\text{Economic Value} = \left(\sum_{n=1}^{H} EUE\right) * VOLL$$

Where

EUE is Expected Unserved Energy (MW) in hour n

H is total hourly intervals

VOLL is the Value of Lost Load ($3,500 - $10,000MW/hr)

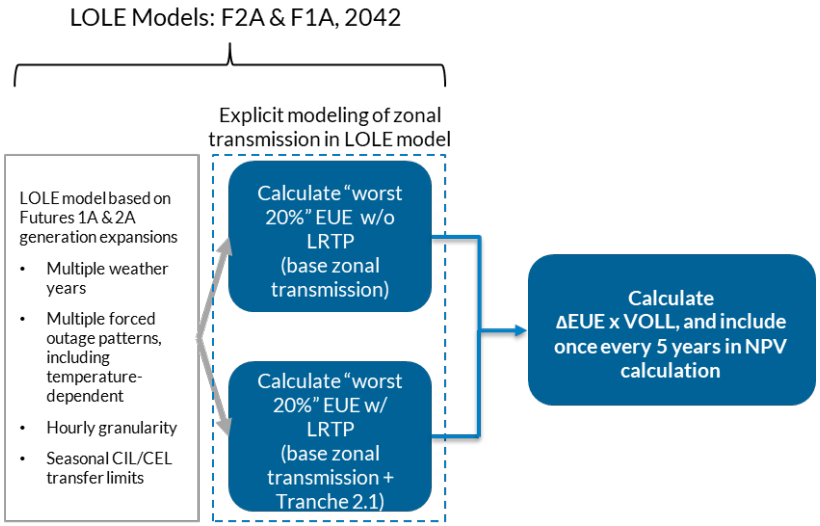


Figure 2.140: Reduced risk from extreme weather Calculation Process

Results

Analysis of the Reduced Risk from Extreme Weather Events benefit indicates that the increased transfer capability provided by the LRTP Tranche 2.1 portfolio improves system performance during extreme weather events. The portfolio provides reduction in Expected Unserved Energy of 37.9 GWh in the top 20% of event hours with the highest Expected Unserved Energy. The Tranche 2.1 portfolio delivers benefits of $394M - $557M over a 20- to 40-year period.

[3] For a CVaR(80), the benefit is applied to year 0, 5, 10, 15, 20 in the 20-yr NPV calculation.

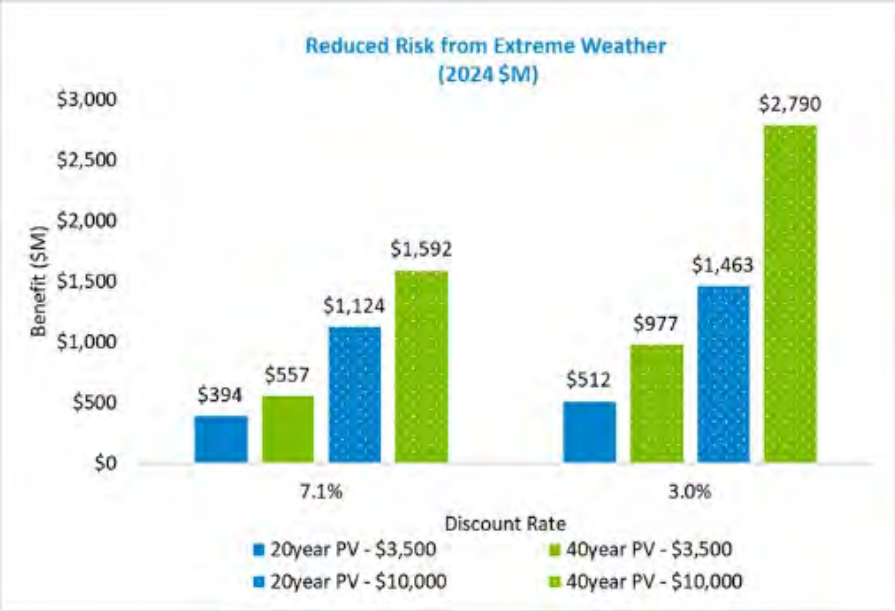


Figure 2.141: Reduced Risk from Extreme Weather Benefit Value

Avoided Capacity Cost

High-Level Methodology Overview

Avoided Capacity Cost (ACC) benefits capture savings in resource investment that result from the increased transfer capability to enable access to a more geographically diverse pool of resources. Transmission constraints limit access to resources elsewhere in the region, requiring more resource investment to meet future capacity needs. The addition of Tranche 2.1 projects alleviates the constraint violations and avoids the need for more capacity above what is included in the Future 2A scenario.

The analysis method first identifies the additional reserve requirement by using a simplified transmission constraint model that represents a change in zonal transmission limits and applies probabilistic Loss of Load Expectation (LOLE) analysis. This determines the additional reserves needed to achieve the same level of LOLE with and without LRTP using a 1-day-in-10-year criterion (0.1 d/y). The probabilistic LOLE analysis is performed with the PLEXOS software and includes the evaluation of 14 weather years of load and renewable generation profiles. Hourly simulations are run with 150 samples to reflect the probabilities of forced outages, including temperature-dependent correlated outages. Planned maintenance is also accounted for, using maintenance outage rates and maintenance frequency.

The LOLE analysis is performed using the 2042 seasonal capacity import/export limits (CIL/CEL) values without the portfolio to compute the LOLE for the modeled resources, and an incremental amount of perfect capacity (or load) is then added until the 0.1 d/y annual LOLE is reached (Seasonal LOLE targets are also applied to the cases). The same analysis is repeated using the seasonal CIL/CEL values with the LRTP portfolio to determine the incremental amount of capacity needed to reach the 0.1 d/y annual LOLE. The difference is calculated as the additional reserves that would be needed without the portfolio, reflecting the impact of the LRTP transmission.

This additional reserve value is then applied as an adjustment to the planning reserve margin (PRM) requirement in an incremental EGEAS resource expansion analysis that determines the amount and types of

resources that are built to meet the added requirements. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in, starting with the assumed portfolio in-service year and increased to the full value in the 2042 study year. The EGEAS expansion for this metric is performed in combination with the Capacity Savings from Reduced Losses (CSRL) metric to reflect the total impact of the LRTP Tranche 2.1 portfolio. The ACC and CSRL components are split out after modeling completes, in proportion to their contribution to the total reserve requirement adjustment in 2042.

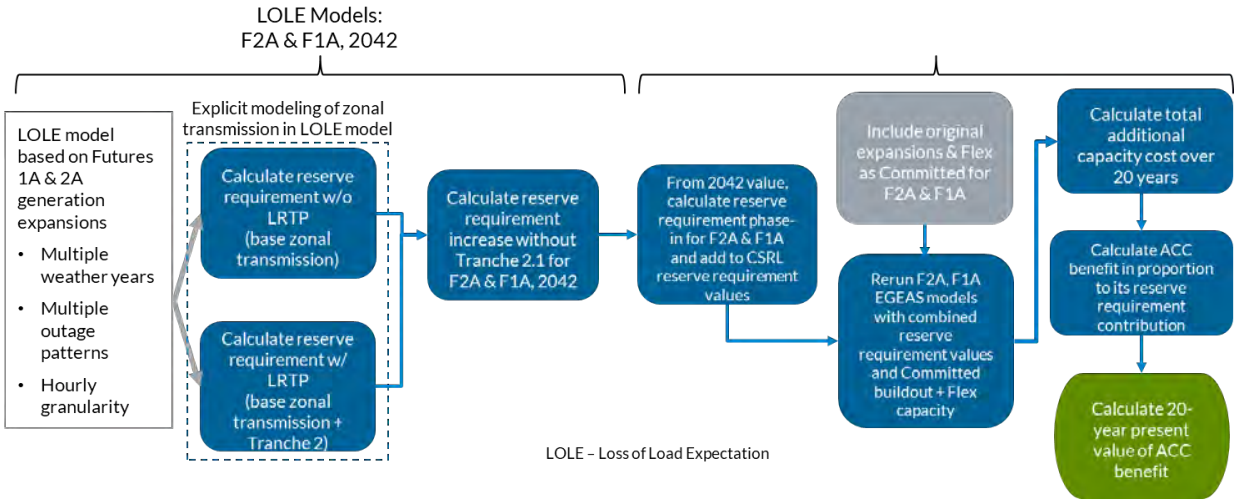


Figure 2.142: Avoided Capacity Costs Calculation Process

Results

Analysis of the Avoided Capacity Costs benefit indicate that the LRTP Tranche 2.1 portfolio increases transfer capability, which enhances resource diversity by allowing access to resources across the region. This provides for a more cost-effective buildout of regional resources and avoids the need for 20.5 GW of capacity that would otherwise be needed in addition to the buildout reflected in Future 2A. The ACC metric delivers benefits of $16.3B – $19.2B over a 20- to 40-year period.

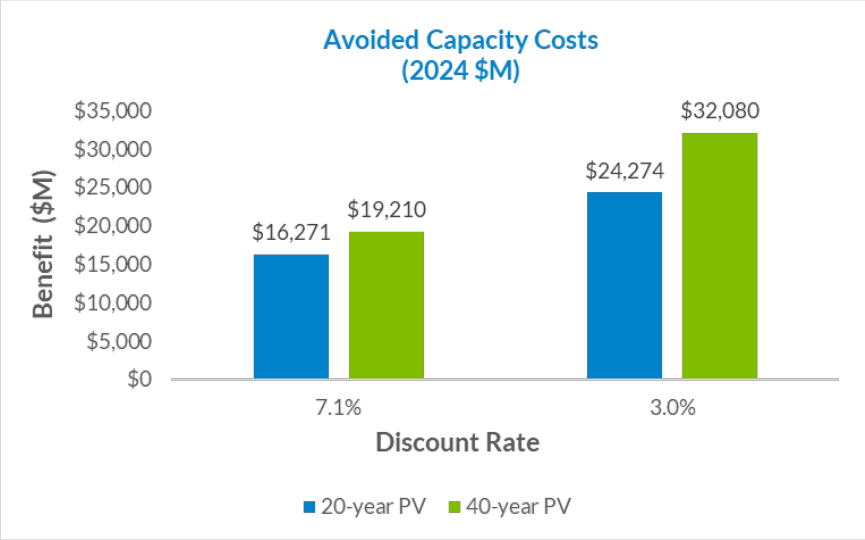


Figure 2.143: Avoided Capacity Costs Benefit Value

Capacity Savings from Reduced Losses

High-Level Methodology Overview

The Capacity Savings from Reduced Losses (CSRL) benefit reflects the capacity savings associated with the reduced losses resulting from the addition of LRTP Tranche 2.1. These projects lower the effective system impedance and redistribute flows to decrease system losses. The adoption of more widely dispersed and remote resources in the future will cause power to flow extensively and over longer distances on the transmission network, producing significant power losses. These losses, occurring during the period with highest capacity requirements, contribute to the need for additional capacity investment. In modeling system requirements for capacity expansion modeling, losses are included in the load forecast data and are held constant when evaluating Avoided Capacity Cost benefits (i.e., the benefit metric does not account for the change in losses with and without LRTP transmission). Capacity Savings from Reduced Losses (CSRL) captures an incremental benefit where LRTP transmission reduces losses in the peak capacity period.

The methodology applied in the calculation of CSRL examines change in losses observed in the reliability power flow models that reflect the various seasonal loading conditions. These reliability power flow cases model both without-LRTP topology (higher losses) and with-LRTP topology (lower losses). The change in losses is calculated using the power flow models that correspond to the season with the peak capacity requirements that determine the capacity investment needed to meet Future 2A needs. For Future 2A expansion, the winter season was determined to have the highest capacity requirements.

The modeling of incremental losses in the EGEAS expansion is reflected as a reserve requirement adjustment to introduce the additional requirements in the resource expansion. While reserve requirement itself is not a function of system losses, it simply serves as mechanism to capture the effects of losses by introducing additional requirements for capacity. The additional reserve requirements for Capacity Savings from Reduced Losses are added to the reserve requirements from the Avoided Capacity Cost metric and applied as a PRM adjustment in an incremental EGEAS expansion. For this additional expansion in EGEAS, model-built and flex capacity from Future 2A is built into the base model as committed capacity. The PRM adjustment is phased in starting in the assumed portfolio in service year and increased to the full value in the

2042 study year. The EGEAS expansion results reflect the total impact of the LRTP Tranche 2.1 portfolio and the components for each metric are split out after the fact in proportion to their contribution to the total reserve requirement adjustment in 2042.

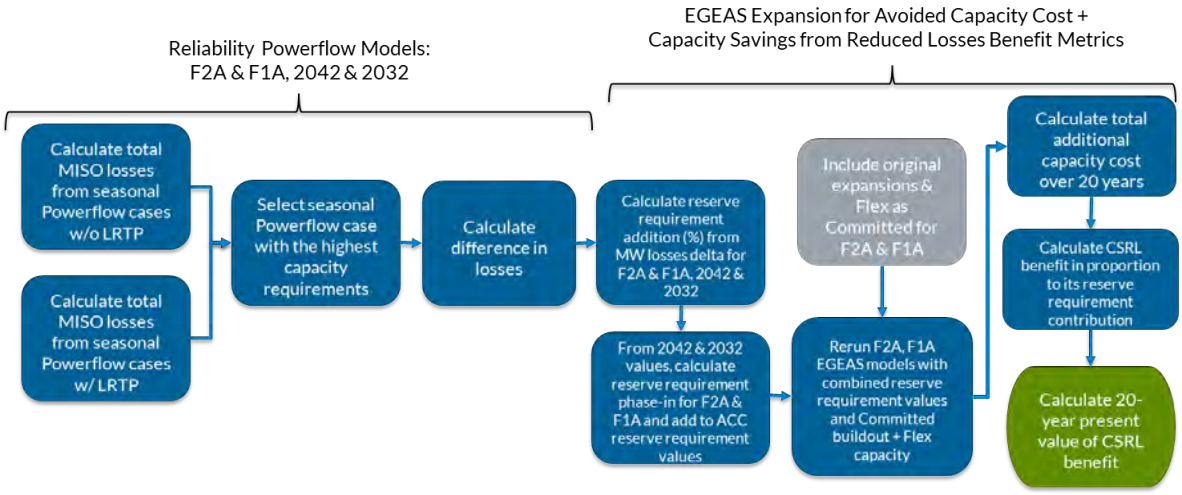


Figure 2.144: Capacity Savings from Reduced Losses Calculation Process.

Results

The lower capacity requirements resulting from the decrease in transmission system losses with the LRTP Tranche 2.1 portfolio avoids the need for 2.3 GW more capacity investment which yields benefits of $1.9B - $2.2B over a 20- to 40-year period.

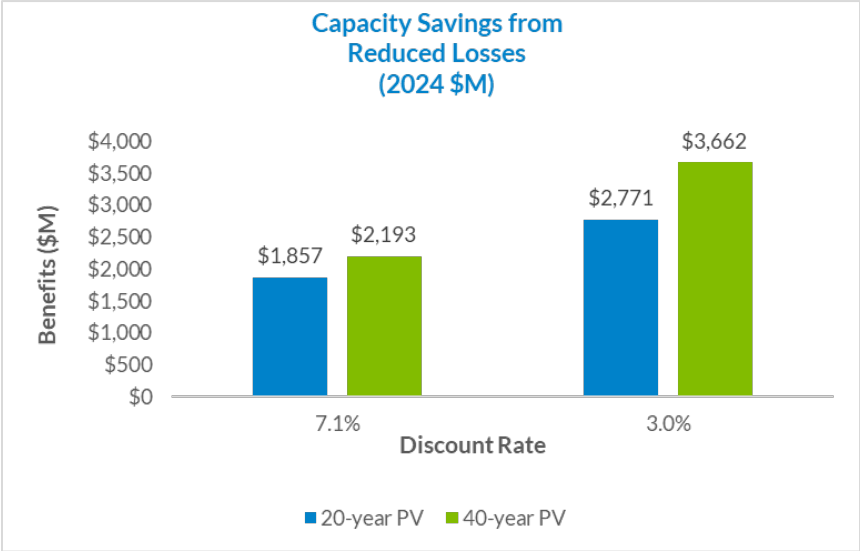


Figure 2.145: Capacity Savings from Reduced Losses Benefit Value.

Avoided Transmission Investment

High-Level Methodology Overview

Avoided Transmission Investment benefits reflect the capital cost savings from eliminating the need for age and condition replacement of existing facilities where LRTP projects reuse existing transmission infrastructure. LRTP projects that require rebuild of existing facilities or co-location of new transmission circuits along the same route as the existing facilities would require installation of new structures and hardware to support both the new circuit as well as the existing circuit and eliminates the need to replace the aging facility later resulting in avoided costs. Candidate facilities for age and condition replacement are identified in the LRTP project scoping effort. These selections are then evaluated for replacement cost except where Transmission Owners have determined that the facilities are ineligible for age and condition replacement due to recent construction or rebuild. Costs are estimated using high level cost estimates derived from the current MISO Transmission Cost Estimation Guide.

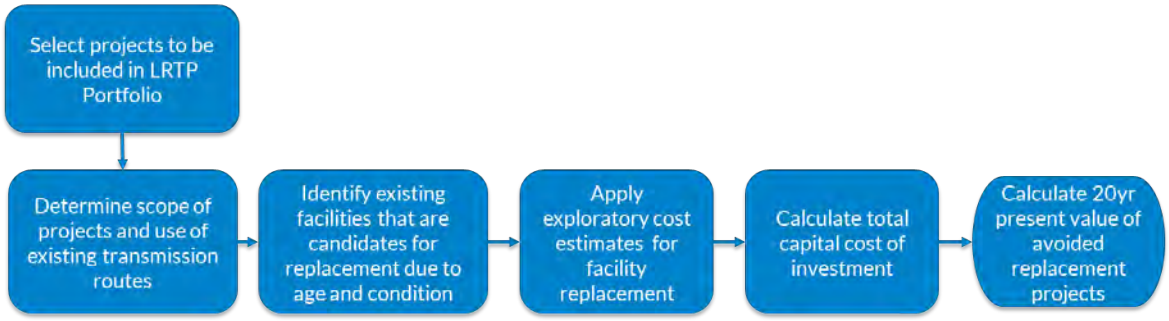


Figure 2.146: Avoided Transmission Investment Calculation Process.

Results

LRTP Tranche 2.1 portfolio avoids the need for replacement of over 700 miles of existing transmission and delivers benefits of $1.2B - $1.8B over a 20- to 40-year period.

Equipment and Upgrade Type	Unit Cost ($M)	Quantity /Miles	Cost ($M)
Transformer Replacement =345	$12.00	0	$0.0
Transformer Replacement <345	$8.40	0	$0.0
Transmission line Replacement =345kV (per mile)	$3.20	178	$569.6
Transmission line Replacement <345kV (per mile)	$1.90	424	$805.6
Transmission double-ckt line replacement = 345 (per mile)	$3.24	30	$97.2
Transmission double-ckt line replacement <345 (per mile)	$2.60	75	$195.0
Transmission triple-ckt line replacement <345 (per mile)	$2.64	1	$1.9
		Total (2024$)	**$1,669.3**

Table 2.30: Summary of Avoided Transmission Investment Benefits

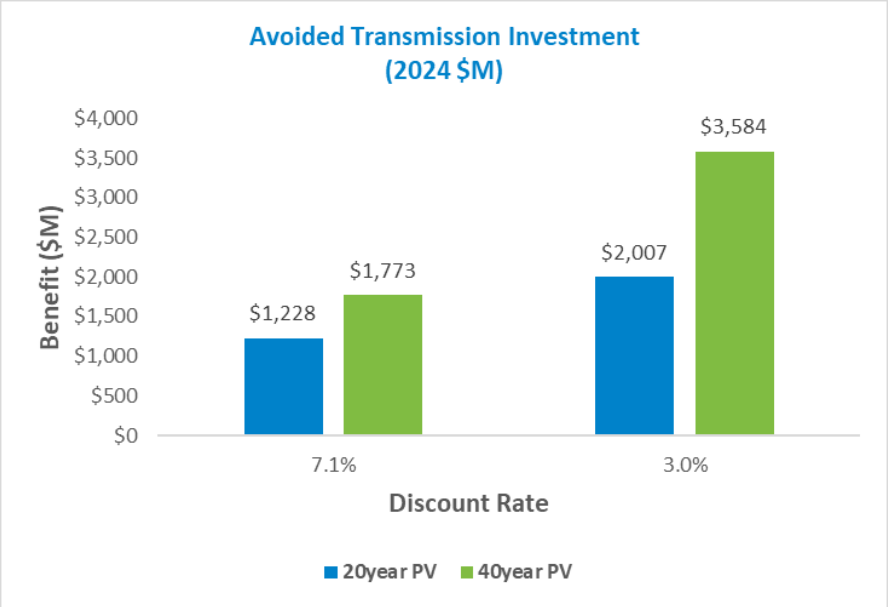


Figure 2.147: Avoided Transmission Investment Benefit Value.

Congestion and Fuel Savings

High-Level Methodology Overview

The congestion and fuel savings benefit reflects production cost savings that are achieved through a more economically efficient dispatch enabled by regional transmission, which reduces congestion and provides access to lower-cost generation. Production cost analysis uses hourly (8760) chronological security constrained unit commitment and economic dispatch, adhering to a wide variety of operating constraints and respecting N-1 contingency conditions. Production cost savings calculations compare the reference case dispatch using a model without the LRTP transmission portfolio to a change case dispatch that incorporates the LRTP transmission portfolio. The addition of LRTP transmission decreases the loading (congestion) on the pre-existing network, alleviating several thermal constraint violations that would otherwise necessitate dispatch of higher-cost resources and facilitates access to lower-cost generation. The difference in production costs between the reference case and change case is thus captured as a benefit provided by the LRTP portfolio.

MISO's production cost models do incorporate Production Tax Credits (PTC) (See MISO Series 1A Futures Report - Inflation Reduction Act) for applicable resources into the security constrained unit commitment and economic dispatch; however, the PTC value is removed from the final congestion and fuel savings value shown for the transmission portfolio.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of adjusted production costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of adjusted production costs (by Cost Allocation Zone) with LRTP transmission for the three study years.

For the three study years, the difference in Adjusted Production Costs with and without LRTP transmission is calculated to produce an annual savings. These yearly values are then used to interpolate or extrapolate annual values for the remaining years within the benefit period.

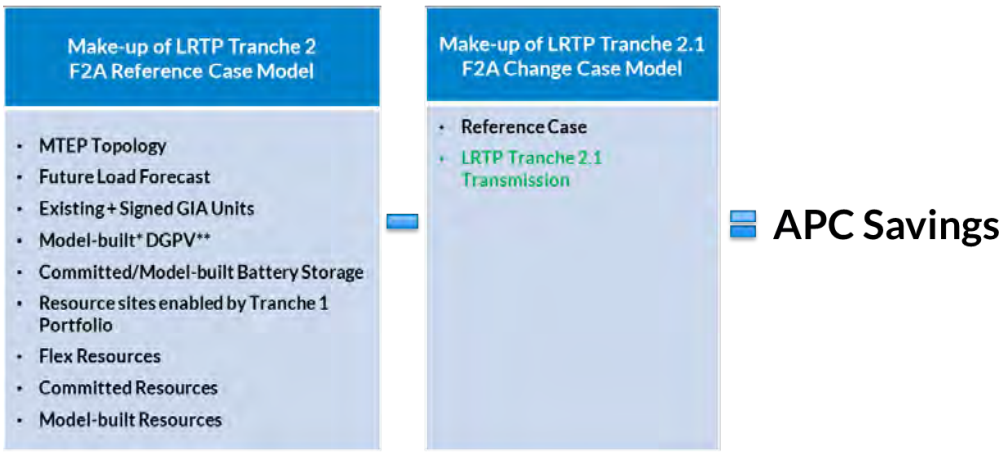


Figure 2.148: APC Savings

Results

The LRTP Tranche 2.1 Portfolio alleviates transmission constraint violations and reduces congestion to allow more efficient dispatch of lower cost resources which provides benefits of congestion and fuel savings benefits of $8.1B - $11.3B over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$1,366	$2,236	$2,856	$6,876
2	$2,546	$3,698	$3,888	$7,809
3	$1,689	$1,932	$1,000	-$326
4	-$341	-$407	-$255	-$121
5	$232	$433	$645	$1,727
6	$1,847	$2,612	$2,607	$4,922
7	$808	$940	$531	$31
Total	**$8,148**	**$11,443**	**$11,272**	**$20,916**

Table 2.31: Distribution of Congestion and Fuel Savings Benefits

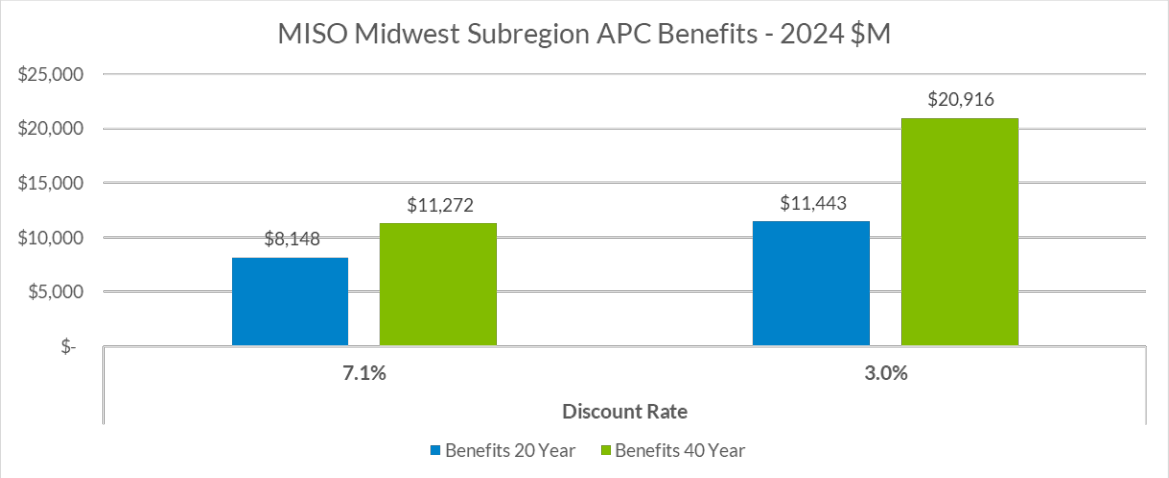


Figure 2.149: Congestion and Fuel Savings Benefit Value

Energy Savings from Reduced Losses

High-Level Methodology Overview

Energy Savings from Reduced Losses captures the lower production costs that result from the addition of transmission facilities that reduces the overall system losses. Transmission losses that are produced by flow of power across the transmission network contribute to the energy requirements and increase the overall costs of energy to customers. As the resource fleet transitions to utilize more dispersed generation in remote areas of the footprint, losses increase with the more extensive use of the transmission network and transport of power over longer distances further increasing energy costs.

The addition of new transmission facilities provides additional transmission capacity and lowers the effective system impedance which will result in a decrease in real system losses. These real losses are modeled as constant values within the load profiles used in the standard production cost simulations. Thus, production cost savings generally do not capture the incremental benefits of reduced losses provided by the addition of new transmission elements. The production cost model case can be modified to reflect the reduction in losses, estimated from the power flow cases and applied to the demand in the change case which includes the new transmission. The Adjusted Production Costs (APC) savings are calculated using a reference and change case model pair with base case losses in the reference case and the change case reflecting the estimated reduction in losses. The difference between those two APC values is the APC savings from reduced losses resulting from the transmission expansion.

The differences in losses are calculated with and without the LRTP Tranche 2.1 portfolio for the four 2032 and four 2042 core power flow models. Loss reduction values are averaged across all core models for each study year and compared to the average demand in the MISO Midwest subregion to determine an average percentage of load as a scaling factor. This scaling factor is used to adjust the load profiles in the change case economic models to reflect the reduced loss component.

Production cost simulations are run using the 2032, 2037 and 2042 reference case economic models and to produce annual values of Adjusted Production Costs (by zone) without LRTP transmission for the three study years. The production cost simulations are repeated using the 2032, 2037 and 2042 change case economic models to determine the annual values of Adjusted Production Costs (by Cost Allocation Zone)

with LRTP transmission for the three study years. The difference in APC between the change case containing the additional loss component and the reference case without the reduced losses provides the total APC savings when reduced loss energy is applied. The APC savings attributable to reduced loss energy is determined by netting out the value of the base Congestion and Fuel Savings metric.

$$APC\ Savings\ from\ Reduced\ Loss\ Energy = (Baseline\ Reference\ Case\ APC - Reduced\ Loss\ Energy\ Change\ Case\ APC) - (Baseline\ Reference\ Case\ APC - Baseline\ Change\ Case\ APC)$$

For the three study years (2032, 2037, and 2042), the annual production cost savings from reduced losses are used to interpolate or extrapolate annual values for the remaining years within the benefit period.

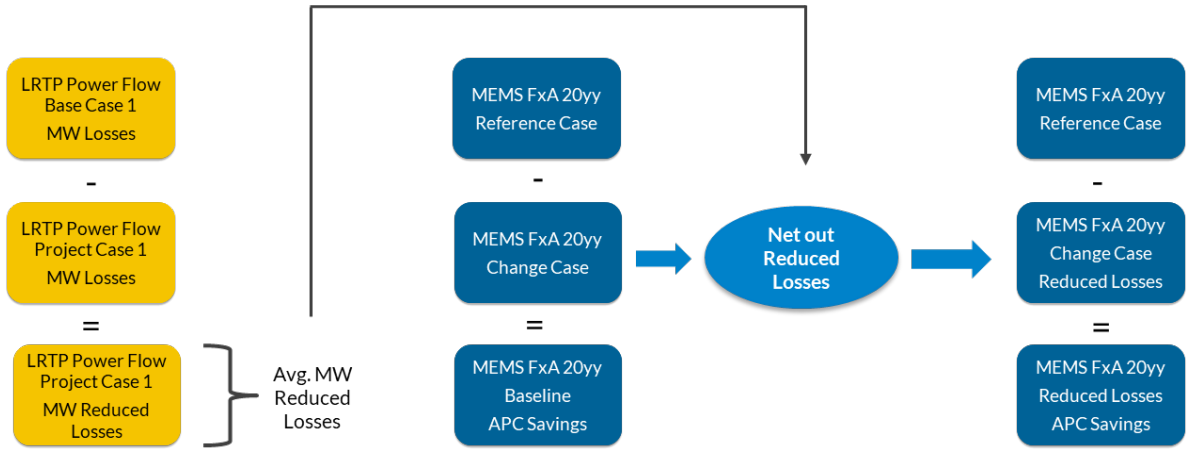


Figure 2.150: Energy Savings from Reduced Losses Calculation Process.

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity and redistributes flows to reduce system losses which delivers energy savings from reduced losses benefits of $1.6B - $2.4B over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$246	$361	$388	$799
2	$273	$376	$356	$626
3	$54	$102	$153	$413
4	$92	$143	$168	$379
5	$129	$180	$176	$323
6	$428	$598	$584	$1,069
7	$411	$571	$551	$993
Total	**$1,632**	**$2,332**	**$2,376**	**$4,602**

Table 2.32: Distribution of Energy Savings from Reduced Losses Benefits

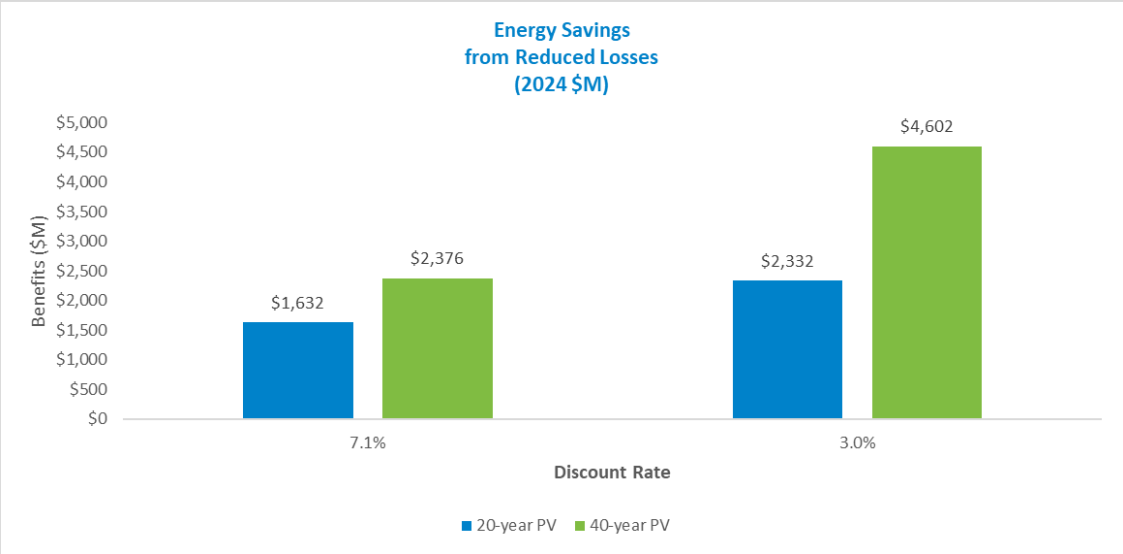


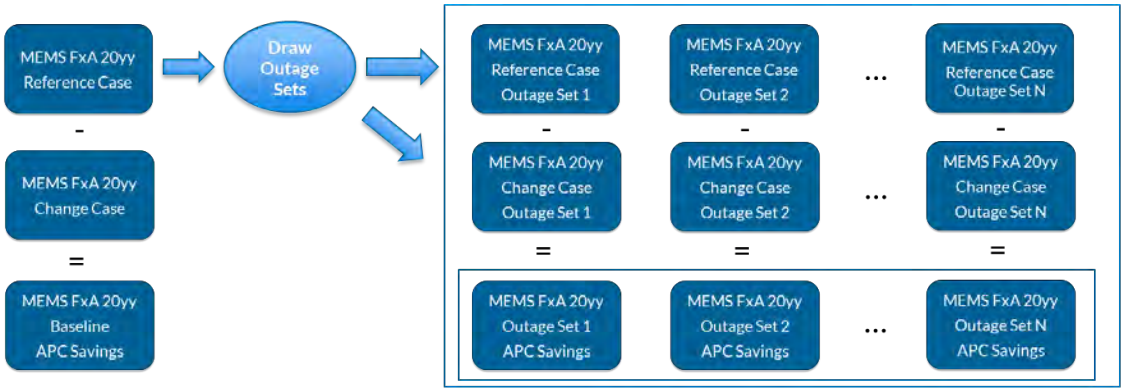
Figure 2.151: Energy Savings from Reduced Losses Benefit Value.

Reduced Transmission Outage Costs

High-Level Methodology Overview

Reduced Transmission Outage Costs captures incremental savings that more fully reflect the effects of congestion under actual operating conditions. Congestion and fuel savings benefits apply conservative modeling of system conditions that reflect an intact transmission network. Throughout the year there are typically numerous planned and forced transmission outages that occur with varying degrees of overlap. These facility outages remove available transmission capacity from the system, increase the loading on remaining in-service facilities, and contribute to congestion. The addition of LRTP transmission unlocks additional value by relieving the additional congestion attributed to typical planned and forced outage schedules.

Outage sets are created by applying outage probabilities established from historical transmission outage records to prepare annual profiles of random outage draws for modeled transmission elements on a daily basis for forced outages and on a monthly basis for planned outages. Ten outage sets are developed to reflect a range of different outage schedules. For each of the three study years (2032, 2037, and 2042), the difference in APC with and without LRTP is calculated to produce an annual savings that captures the effects of the randomized sets of planned and forced outages. For each of the three study years, the production cost savings are averaged across the 10 outage simulation runs to reflect annual savings for a typical year of outages. The APC savings attributed to the outage impact is determined by netting out the base Congestion and Fuel Savings, and the values for the three study years are used to interpolate or extrapolate the annual values for the remaining years within the benefit period.



$$Reduced\ Transmission\ Outage\ Costs = \frac{\sum_n Outage\ Set\ n\ APC\ Savings}{N} - Baseline\ APC\ Savings$$

Figure 2.152: Reduced Transmission Outage Costs Calculation Process

Results

The LRTP Tranche 2.1 Portfolio provides additional transmission capacity that helps to enhance operational flexibility and reduce congestion that occurs from typical outage schedules which provides Reduced Transmission Outage Costs benefits of $76M - $110M over a 20- to 40-year period.

	20 Year Present Value (2024$)		40 Year Present Value (2024$)	
Discount Rate	**7.1%**	**3.0%**	**7.1%**	**3.0%**
CAZ				
1	$31	$46	$49	$100
2	$14	$16	$8	-$2
3	-$34	-$40	-$26	-$15
4	-$3	-$9	-$18	-$56
5	$69	$90	$75	$106
6	$22	$34	$40	$91
7	-$22	-$27	-$18	-$12
Total	**$76**	**$108**	**$110**	**$211**

Table 2.33: Distribution of Benefits for Reduced Transmission Outage Costs

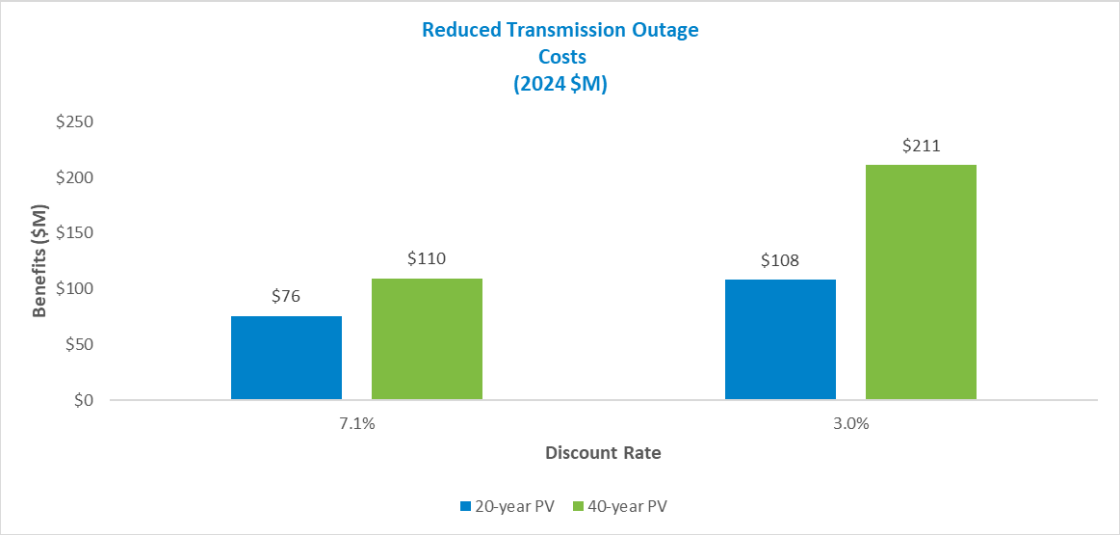


Figure 2.153: Reduced Transmission Outage Costs Benefit Value

Decarbonization

High-Level Methodology Overview

Decarbonization benefits are associated with avoided CO_2 emissions that result from the more efficient dispatch of lower-cost resources. Production cost simulations are used to economically dispatch resources with respect to availability and subject to transmission constraints and establish the hourly dispatch of resources over 8760 annual hours. The dispatch of lower-cost, non-emitting renewable resources avoids CO_2 emissions for the generation fleet. As transmission congestion occurs on the system, dispatchable carbon-emitting resources are needed to manage system flows and can displace carbon-free renewable energy, leading to higher levels of CO_2 emissions. The addition of LRTP transmission alleviates congestion, allowing dispatch of more renewable energy that provides benefits through avoided carbon emissions.

Analysis of Decarbonization benefits uses the emissions data from the Adjusted Production Cost (APC) analysis used for the base Congestion and Fuel Savings benefit metric and compares the change in CO_2 emissions between the reference case without LRTP and the change case with LRTP. Values are computed for years 2032, 2037 and 2042; and are interpolated for years in between and extrapolated for years beyond 2042. The reductions in annual CO_2 emissions are converted to metric tons and monetized by applying a range of carbon prices that reflect the value of decarbonization.

	Federal	MN PUC
2024$/metric ton	$85	$248.67

Table 2.34: Carbon Costs for Monetization of Benefits

Results

The LRTP Tranche 2.1 portfolio alleviates congestion, allowing for more efficient dispatch of non-emitting resources to reduce CO_2 emissions by 127-199M metric tons over 20 to 40 years. This provides Decarbonization benefits of $7.2B - $9.0B over a 20- to 40-year period.

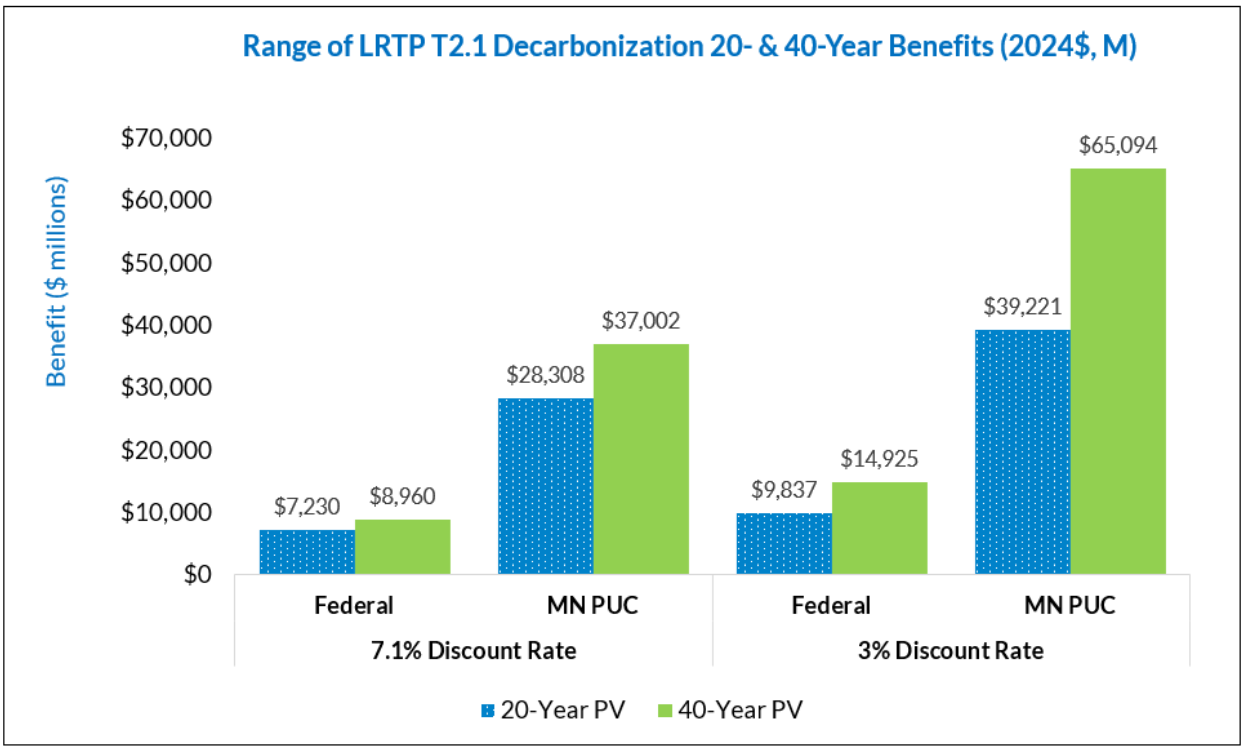


Figure 2.154: Decarbonization Benefit Value.

Future 1A Benefit Metric Analysis

The benefits metrics for the LRTP Tranche 2.1 portfolio were evaluated with Future 1A assumptions to assess value in a lower-bookend scenario applying the same methodologies used for Future F2A. The analysis demonstrates that under the Future 1A scenario, the LRTP Tranche 2.1 portfolio delivers benefits in excess of costs, totaling $34.2B - $61.9B over a 20-year period with an overall benefit-to-cost ratio ranging from 1.2 to 2.2.

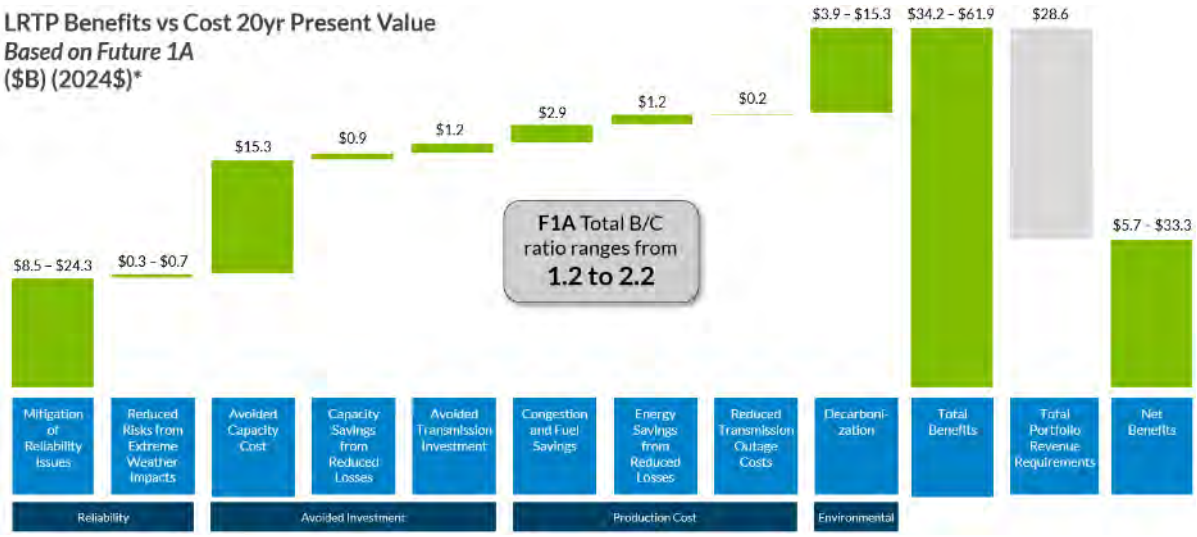


Figure 2.155: Tranche 2.1 Benefits based on Future 1A.

Step 6: Recommend Preferred Solutions

Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion estimated at $21.8 billion and targeted to go in service from 2032 to 2034.

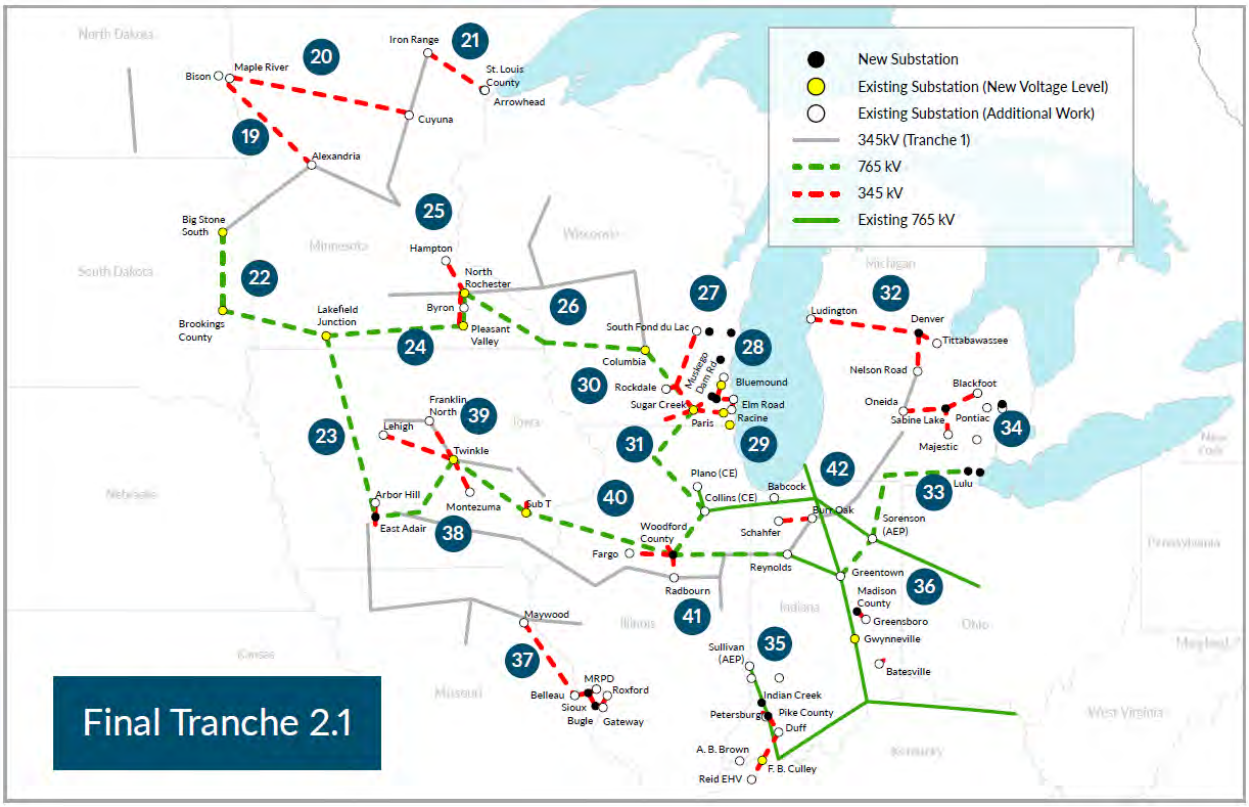


Figure 2.156: Tranche 2.1 Portfolio Map

ID	Project Name	Predominate kV	Targeted ISD	Est. Cost ($M, 2024)
19	Bison - Alexandria	345	2032	$216
20	Maple River- Cuyuna	345	2033	$908
21	Iron Range - Arrowhead	345	2032	$428
22	Big Stone South- Brookings County- Lakefield Junction	765	2034	$1,459
23	Lakefield Junction- East Adair	765	2034	$1,375
24	Lakefield Junction- Pleasant Valley- North Rochester	765	2034	$1,195
25	Pleasant Valley- North Rochester - Hampton Corner	345	2032	$222
26	North Rochester - Columbia	765	2034	$1,924
27	Rocky Run - Werner - North Appleton	345	2032	$212
28	South Fond du Lac- Rockdale- Big Bend- Sugar Creek - Kitty Hawk	345	2033	$1,102
29	Bluemond - Arcadian - Waukesha- Muskego- Elm Road - Racine	345	2032	$731
30	Columbia- Sugar Creek	765	2034	$743
31	Sugar Creek- Collins	765	2034	$733
32	Ludington- Denver - Tittabawassee & Nelson Road	345	2032	$1,553
33	Greentown - Sorenson - Lulu	765	2033	$1,310
34	Oneida - Sabine Lake- Blackfoot & Majestic	345	2032	$600
35	Southwest Indiana-Kentucky	345	2032	$743
36	Southeast Indiana	345	2032	$578
37	Maywood - Belleau- MRPD - Sioux - Bugle	345	2032	$881
38	East Adair - Marshalltown- Sub T	765	2034	$1,583
39	Lehigh- Marshalltown- Franklin North & Montezuma	345	2032	$588
40	Sub T - Woodford County - Collins & Reynolds	765	2034	$2,298
41	Woodford County - Fargo & Radbourn	345	2032	$422
42	Burr Oak - Schahfer	345	2032	$68
	Total Portfolio Cost		Total	**$21,868**

Table 2.35: Tranche 2.1 Portfolio Projects

Step 7: Apply Appropriate Cost Allocation

Distribution of Benefits and Portfolio Costs

Benefits are spread across the Midwest subregion. The LRTP Tranche 2.1 Portfolio of projects was developed for the MISO Midwest subregion to ensure transmission is reliable, economic, and compliant in the future, given state and utility policy and goals, projected conditions and industry trends. Analysis of the nine benefit metrics included identifying the distribution of each benefit across the Cost Allocation Zones in the Midwest subregion. The distribution of benefits of the LRTP Tranche 2.1 Portfolio is shown to provide benefits in excess of costs for each Cost Allocation Zone (CAZ) under Future 1A and 2A.

Benefit Metric	CAZ Allocation Method
Mitigation of Reliability Issues	Based on location of reliability issues
Reduced Risks from Extreme Weather Impacts	Based on load ratio share
Avoided Capacity Costs	Based on load ratio share
Capacity Savings from Reduced Losses	Based on load ratio share
Avoided Transmission Investment	Based on the zonal location of upgrade
Congestion and Fuel Savings	Derived directly from PROMOD results
Energy Savings from Reduced Losses	Derived directly from PROMOD results
Reduced Transmission Outage Costs	Derived directly from PROMOD results
Decarbonization	Based on load ratio share

Table 2.36: Benefit Metric Method to Distribute Benefits to Cost Allocation Zones

Future 2A

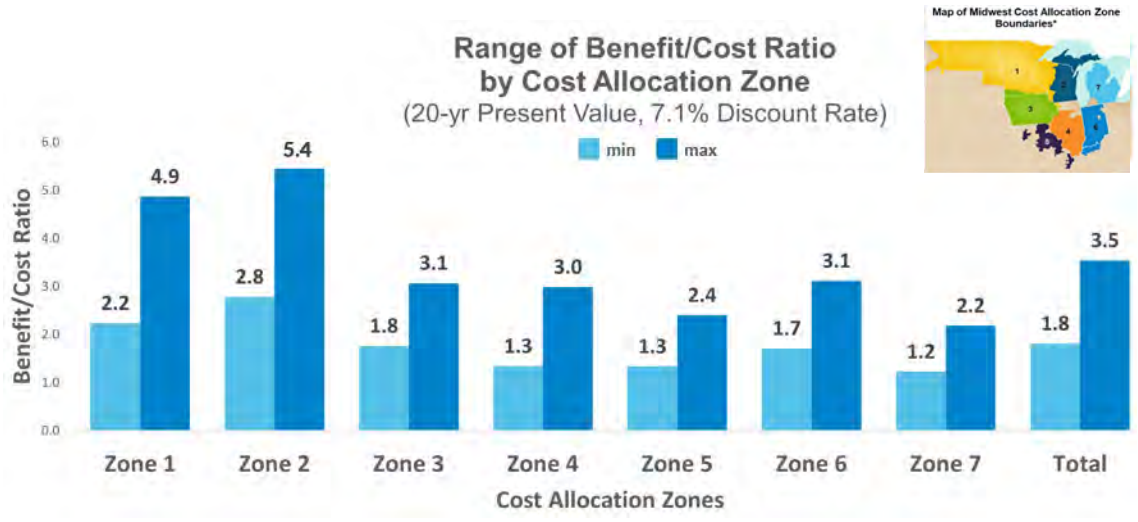


Figure 2.157: Tranche 2.1 Distribution of Benefits – Future 2A

Future 1A

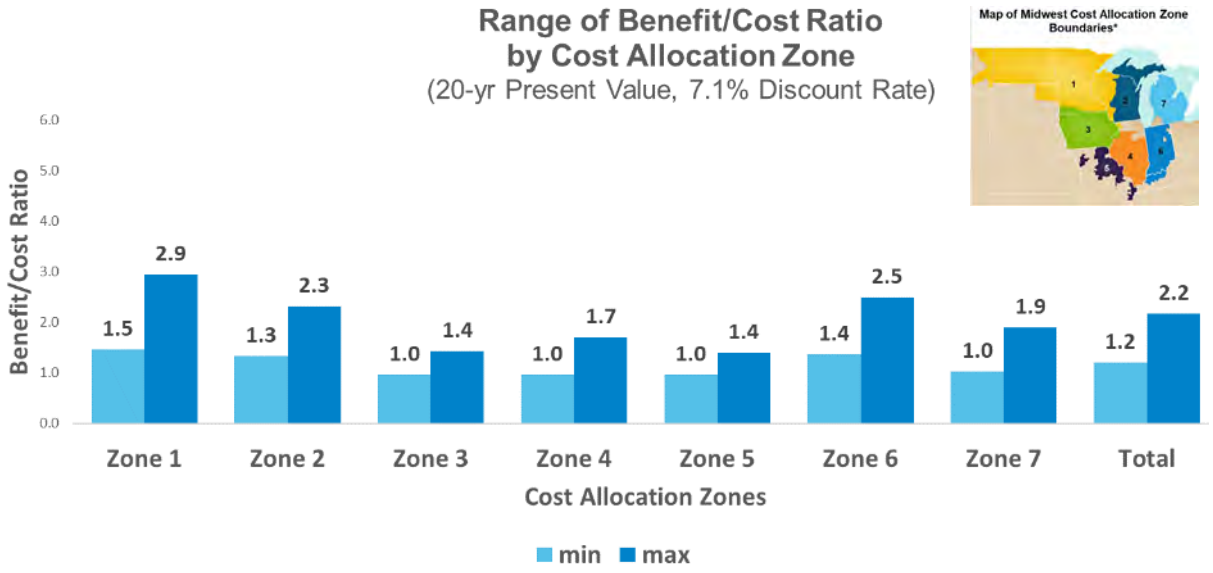


Figure 2.158: Tranche 2.1 Distribution of Benefits - Future 1A[4]

Estimates of MVP Usage Rates for Tranche 2.1 Portfolio

As Multi-Value-Projects, the costs of the LRTP Tranche 2.1 Portfolio will be recovered from MISO load and exports associated with the MISO Midwest subregion through the energy-based MVP Usage Rate ($/MWh). Additionally, indicative annual MVP usage rates for the LRTP Tranche 2.1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. The MVP Usage Rate for Tranche 2.1 is estimated to peak at $6.44 per MWh of energy usage and average $4.76 per MWh over a 40-year period. While the Tranche 2.1 portfolio is estimated to cost MISO members about $5 per 1 MWh or 1,000 kWh of energy used, that investment will provide $10 to $18 of value over that same amount of usage, based on Future 2A analysis.

[4] Min and Max range reflect changes in the assumptions for the value of lost load (Mitigation of Reliability Issues/Reduced Risks from Extreme Weather Impacts) and avoided CO_2 emissions values (Decarbonization).

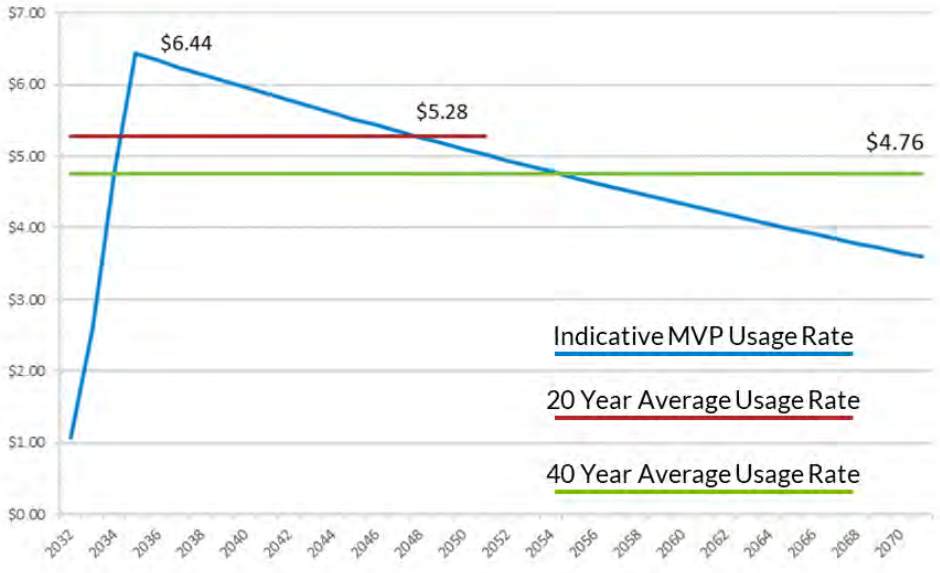


Figure 2.159: Tranche 2.1 Estimated MVP Usage Rate ($/MWh)[5]

Other Benefits

Natural Gas Price Sensitivity

MISO Futures used for the LRTP T2.1 study utilized a new natural gas price forecast methodology. Previous MISO methodologies had used a blend of fixed forecasts, anchored to Henry Hub (HH) price. In the new methodology Gas Pipeline Competition Model (GPCM) was used to develop forecasts that incorporate gas usage from the production cost model runs, to iteratively match both gas usage and price. In this way, gas prices can be calibrated to different Futures assumptions. Gas price base forecasts, used in the EGEAS Futures expansion, were fed into PROMOD, and the gas usage observed in those models was fed into GPCM to create updated price forecasts. This was repeated iteratively until prices between the two models converged, and those converged prices were used in the base PROMOD models. To gain further insight into the impact of gas prices on benefits, an analysis was performed where Future 2A natural gas prices were increased by 20 – 60% above those in the base model, testing both the LRTP reference and change case models. This range corresponds to a range of historical prices seen between 2012 and 2022.

[5] MISO's Schedule 26-A indicative MVP Usage Rate is reflective of rates applied to wholesale electricity transactions and not intended to be used for impacts to retail electricity rates.



Figure 2.160: Future 2A Natural Gas Price Sensitivity Results

The 20% gas price increase generates a $9.1B congestion and fuel savings, approximately $1B increase in savings, while a 60% gas price increase generates a $10.8B congestion and fuel savings increase, approximately $2.6B increase in savings.

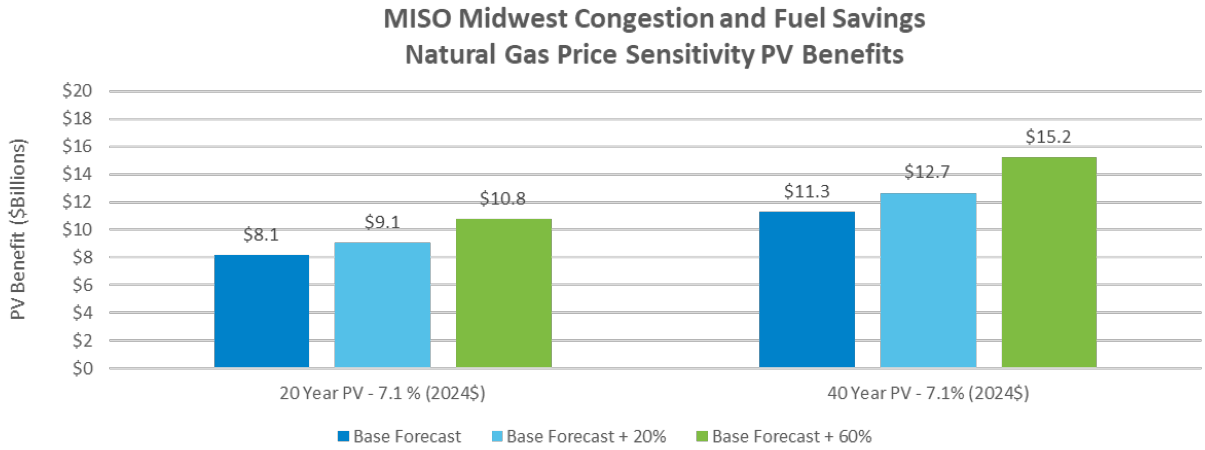


Figure 2.161: Natural Gas Price Sensitivity Congestion and Fuel Savings

Economic Development Benefits

In addition to the direct benefits calculated in the Business Case, Tranche 2.1 transmission investments will also deliver significant economic development benefits to local economies in the MISO region.

Some of these economic development benefits, such as the impact on long-run economic growth, are difficult to quantify. However, as electricity serves as a key input into business production processes, the access to lower and more efficient energy prices provided by transmission investments will support higher

productivity and long-run economic growth. Further, transmission has the potential to attract new businesses and support connections to burgeoning high-growth industries, such as data centers.

Other economic development benefits, such as the short-run impacts on employment and economic output in local economies can be quantified.

Local Investment and Job Creation

Economists typically place the impacts of investments on jobs and economic output into three groupings: direct, indirect, and induced economic activity.

Direct economic impacts refer to impacts in industries directly benefiting from transmission investment, such as construction companies and manufacturers of transmission materials. Indirect economic impacts refer to changes in industries further down the supply chain, such as the suppliers to transmission material manufacturers. Induced impacts refer to changes in the local economy from increased spending on housing, food, and other services by those directly or indirectly employed by the transmission investments.

To arrive at estimates for the potential economic development impacts of Tranche 2.1 investments, MISO surveyed the literature on the impacts of transmission investment on direct jobs, total jobs, and total economic output. MISOs literature survey found that $1 million in transmission investments powers between 1 and 3 direct local jobs, between 2 and 6 total local jobs (including direct, indirect, and induced effects), and between $0.2 and $1.1 million in total local economic output. Ranges were chosen to cover roughly 90% of study estimates found in the MISO literature review.

Using these multipliers, Tranche 2.1 investments are estimated to power roughly 22,000 to 65,000 direct jobs in the MISO region. Direct jobs stemming from Tranche 2.1 investments are also high-quality jobs, with wages estimated to be about 30% higher than a typical worker's wages. Adding in the effects of supply chains and further induced demand and Tranche 2.1 investments are estimated to power between 44,000 and 131,000 total jobs in the MISO region and between $4 and $24 billion in total economic output.

	Tranche 2.1 Investment ($Mns)	Direct Local Jobs		Total Local Jobs		Local Investment/Total Economic Output ($Mns)	
Central		*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*	*Low Estimate*	*High Estimate*
MO	$872	872	2,616	1,744	5,231	$ 174	$ 959
IL	$2,886	2,886	8,659	5,772	17,317	$ 577	$ 3,175
IN	$2,378	2,378	7,135	4,757	14,270	$ 476	$ 2,616
KY	$77	77	230	153	459	$ 15	$ 84
East							
MI	$2,672	2,672	8,015	5,344	16,031	$ 534	$ 2,939
West							
IA	$3,606	3,606	10,817	7,212	21,635	$ 721	$ 3,966
MN	$4,342	4,342	13,026	8,684	26,051	$ 868	$ 4,776
ND	$188	188	564	376	1,129	$ 38	$ 207
SD	$724	724	2,171	1,447	4,341	$ 145	$ 796
WI	$4,086	4,086	12,257	8,171	24,514	$ 817	$ 4,494
Total	$21,830	21,830	65,489	43,659	130,978	$ 4,366	$ 24,013

Table 2.37: Tranche 2.1 Investment by State and Jobs and Economic Impact.

2.3 Near Term Congestion Study Update

Introduction and Background

The first Near-Term Congestion Study was completed in 2023 in response to PAC-2021-1: Address Congestion at Existing Resources. The 2023 study focused on recreating and assessing historically congested flowgates in a near-term PROMOD model. In 2024 this issue was delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Information on stakeholder discussions and presentations on this issue can be found on the MISO website at *PAC-2021-1 Address Congestion At Existing Resources*.

The 2024 Near-Term Congestion Study provided stakeholders the opportunity to submit feedback on various near-term study approaches. The study options presented to stakeholders included:

- Year 5 Economic Model Refinement and Study
- LRTP Tranche 1 Construction Outages Assessment
- Year 2 Economic Model Development and Study

Based on stakeholder feedback and internal MISO interest, MISO moved forward with an LRTP Tranche 1 Construction Outages Assessment for the 2024 Near-Term Congestion Study. This study utilized the Year 5 PROMOD model from the 2023 Near-Term Congestion Study to test and analyze LRTP Tranche 1 construction outages. By partnering with Operations Planning and Competitive Transmission teams internally, and working with our Transmission Owners, outage sequence issues were identified, GETs solutions were requested, and general outage sequence recommendations were developed.

Study Objectives and Scope

The primary objective of this study was to provide insight into the impact of the LRTP Tranche 1 construction outages. Given the magnitude and siting of the LRTP Tranche 1 projects we anticipate temporary increases in congestion and the need for additional coordination with Transmission Owners to identify conflicting outages that could result in reliability issues. By collecting data on these construction outages early and studying them in PROMOD we can provide recommendations on outage sequences.

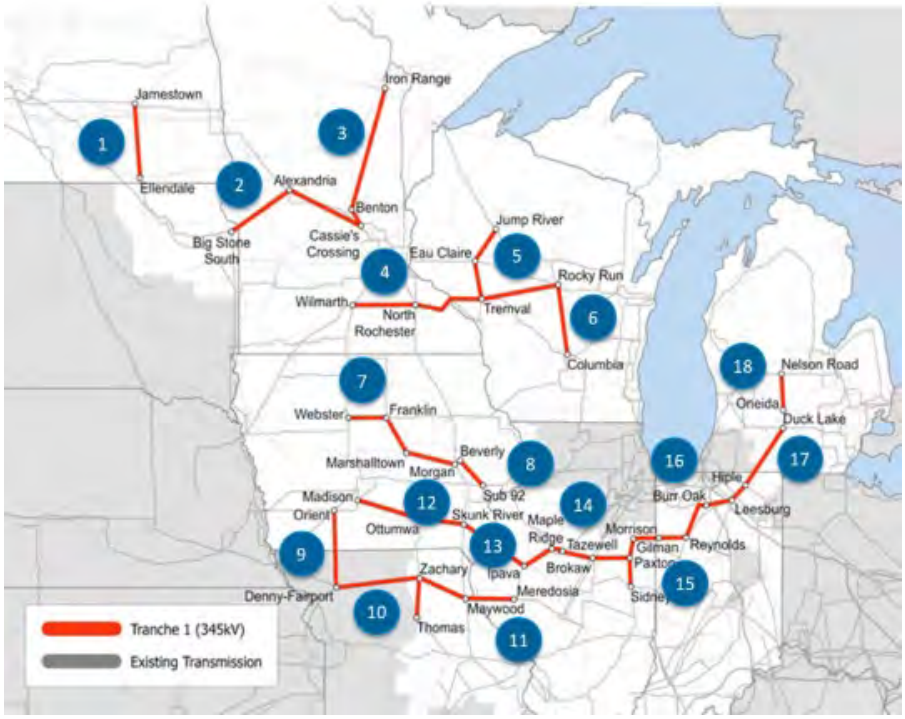


Figure 2.162: LRTP Tranche 1 Portfolio

The 2023 Near-Term Congestion Study model was utilized for this study with adjustments made to reflect random planned and forced, and construction outages.

Model assumptions include:

- Hitachi PROMOD[6] releases
  - Fall 2021 gen updates and economic data
  - Spring 2022 coal prices
  - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
  - Hartburg – Sabine was removed
  - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Operations Planning and Competitive Transmission teams supported the collection of outage information from Transmission Owners required for the study. Outage data was submitted directly to MISO teams through the MTEP Quarterly Update report and CROW. Operations Planning teams provided general guidelines and helped review potential reliability issues in outage information submitted.

General guidelines that have been used to develop and assess outage sequences include:

- Evaluate outages to minimize concurrent outages likely to strand or limit generation outlets.

[6] PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.

- Evaluate outages to ensure that multiple outages do not impact the same interface and interchange as it would create a significant challenge to the system's reliability.
- Review and compare against historical outages that have been challenging for our system.

PROMOD studies are typically conducted with transmission system intact assumptions, excluding the contingencies included in the event file. The Near-Term Congestion Study used a similar methodology to the LRTP Tranche 2.1 Transmission Outages business case metric to create a base random planned and forced outages scenario. This allows us to compare the impact of LRTP Tranche 1 construction outages against more simulated "real-world" conditions. Approximately 2,450 random planned and forced outages were included in all runs with about 250 planned and 2,200 forced outages.

The construction outage scenarios studied include LRTP Tranche 1 construction outage sequences combined with random planned and forced outages. The scenarios studied range from currently planned sequences to worst case scenarios that would present more severe impacts on the system.

Outage sequences from Transmission Owners were incorporated in the testing and study work as they were received. For LRTP Tranche 1 projects where outages were not submitted, Economic Planning estimated outages by utilizing powerflow models and input from Operations Planning and Competitive Transmission teams. Approximately 220 Tranche 1 construction outages were submitted and estimated based on in-service date expectations with about half of those outages occurring in 2027. Figure 2.163 outlines how outages were incorporated to build the scenarios studied.

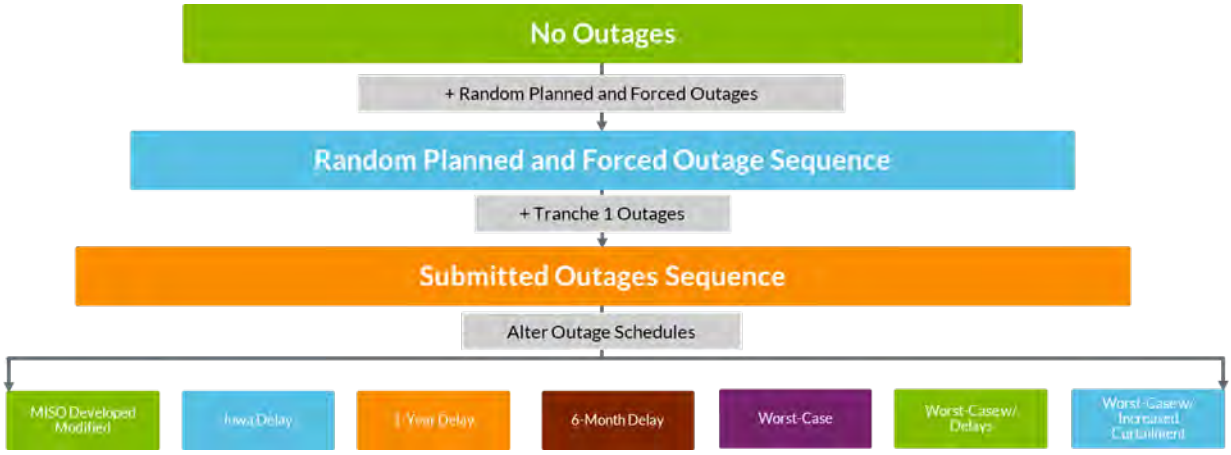


Figure 2.163: Process for Adding Outages and Building Scenarios

Study

Initial Testing

Testing for this study followed a path of simple to complex when it came to identifying outages and how they are included in the model. Initially, specific outages were entered into PROMOD. This worked for small amounts of outages but was not ideal for larger sequences of outages. By utilizing the PDTR (Power Dated Transmission Record) Tool in PAT (PROMOD Analysis Tool) and incorporating the LRTP Tranche 2.1 Transmission Outage business case outage methodology, we were able to come up with a more efficient process for incorporating outages.

Additional testing included comparing runs by Local Resource Zone (LRZ) versus region, and the impact of a larger number of outages within a year timeframe. Much of this testing was done to assess any impacts on runtime. Because PROMOD can only study one year at a time, we started by putting all outages in 2027 to test its capabilities. We then sequenced them between 2025-2030, with consistent lengths, followed by the same test with more realistic lengths. We also split the MISO footprint into multiple areas for these runs to analyze outages at a more localized level. Since we did not encounter any hurdles related to PROMOD run-times or processing, our study remained focused on the full MISO footprint.

Scenarios Studied

All sequences studied included random planned and forced outages and started with the Submitted Outages sequence. Adjustments or alterations were made to specific information in the Submitted Outages sequence relative to that scenario. Scenario descriptions and assumptions are listed below:

Submitted Outages (Base Outages)
Description

- Around 77% of all construction outage data was submitted by Transmission Owners and included in the sequence. The remaining 23% was estimated by the MISO Economic Planning Team with assistance from MISO Operations Planning and Competitive Transmission teams.
- All Iowa outages are estimated due to continued discussions around project ownership.

Assumptions

- Outages not submitted by Transmission Owners were estimated based off Tranche 1 line connection points. Start and end dates for outages were estimated by using in service dates and working with Competitive Transmission group to estimate outage durations.

6-Month Delay
Description

- Construction outages in the Submitted Outages sequence were pushed out by 6 months.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

1-Year Delay
Description

- Construction outages in the Submitted Outages sequence were pushed out by 1 year.

Assumptions

- Start dates were moved to the closest Monday and end dates were moved to the closest Sunday for PROMOD efficiency.

MISO Developed Modified
Description

- All submitted outage information and estimated outages that were not related to Iowa projects.
- Outages for estimated construction outages were adjusted due to various combinations of outages possible using engineering judgement.

Assumptions

- Adjustments were developed by taking the initial outage schedule and flipping it. The right pieces would still connect by making sure that certain outages followed one another while still ensuring that dates would be changed. Projects remained the same length of time.
    - For example: Outage A to B is from January to June and Outage C to D is from July to December. After making the adjustments, Project A to B is now from July to December and Project C to D is now from January to June. This ensures that outages are left in the same time frame but mixes up concurrent outages.

Iowa Delay

Description

- Outages related to Iowa projects were pushed out beyond the 2027 study year.

Assumptions

- Construction was assumed to be delayed due to ongoing discussions around Iowa project ownership. Outages were pushed out to 2028 and beyond.

Worst-Case

Description

- Outages are sourced from the Submitted Outages scenario but adjusted to all occur in 2027.

Assumptions

- Outages originally scheduled for 2027: These dates remain unchanged.
- Multi-year outages (e.g., Nov 2025–Feb 2026): These start on a comparable Monday in 2027 and conclude on the last Sunday of 2027.
- Outages originally scheduled outside of 2027: For outages scheduled in other years, we identified the same calendar date in 2027 and determined the corresponding day of the week. Based on this, we adjusted the start or end dates using the guidelines below:
    - Start date adjustments:
        - Outages that originally began on a Tuesday through Thursday were moved to the preceding Monday.
        - Outages that originally began on a Friday through Sunday were moved to the following Monday.
            - If the Monday is a national holiday, the outage is scheduled for the following Monday.
    - End date adjustments:
        - Outages that originally ended on a Monday through Wednesday are moved to the preceding Sunday.
        - Outages that originally ended on a Thursday through Saturday are moved to the following Sunday.
            - If the Sunday is a national holiday, the outage is scheduled for the following Sunday.

Worst-Case w/ Delays

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.

Assumptions

- Similar to the original Worst Case sequence, we assumed that all outages will occur in the year 2027, but with an additional 1 to 2 month delay to the original end dates. To complete this delayed scenario, the end dates for the outages were adjusted as follows:
    - Outages set to end between January and October: A 2-month delay was added to the original end date.

- Outages set to end in November: A 1-month delay was applied.
- Outages set to end in December: These were extended to the last Sunday of 2027.

- For the new end dates, we located the same day of the month in the adjusted period. If the corresponding day fell on a Monday through Wednesday, the outage was set to end on the preceding Sunday. If it fell on a Thursday through Saturday, the outage was set to end on the following Sunday.

Worst-Case w/ Increased Curtailment

Description

- Outages are pulled from the Submitted Outages scenario but adjusted to all occur in 2027 but with additional 1 to 2 month delays.
- Additional outages are added intended to stress the system and increase curtailment.

Assumptions

- Utilizes assumptions from the Worst Case scenario.
- Additional outages added include:
  - MN & ND:
    - Loss of HVDC lines between Square Butte - Arrowhead
    - Loss of HVDC lines between Coal Creek - Dickinson
    - Loss of MWEX Lines (King - Eau Claire 345 kV, Arrowhead - Stone Lake 345 kV are main two)
    - Loss of lines parallel to MWEX (North Rochester - Briggs Road 345 kV or Hazelton - Hickory Creek 345 kV)
  - AMEREN:
    - Sibley - Overton 345 kV, Zachary - Hughes 345 kV
    - Lutesville - Essex 345 kV
    - Sidney - Rising 345 kV
    - Sub T - Maywood 345 kV
    - McCredie - Burns 345 kV
  - NIPS:
    - Wilton Center – Dumont 765 kV
    - Reynolds – Olive 345 kV
    - Reynolds – Meadow Lake 345 kV ckt 1
  - Reynolds – Meadow Lake 345 kV ckt 2

2024 Near-Term Congestion Study Report

All information included in the Near-Term Congestion Study section of this chapter along with final study results and takeaways can be found in the 2024 Near-Term Congestion Study Report on the MISO MTEP website under the Related Documents section.

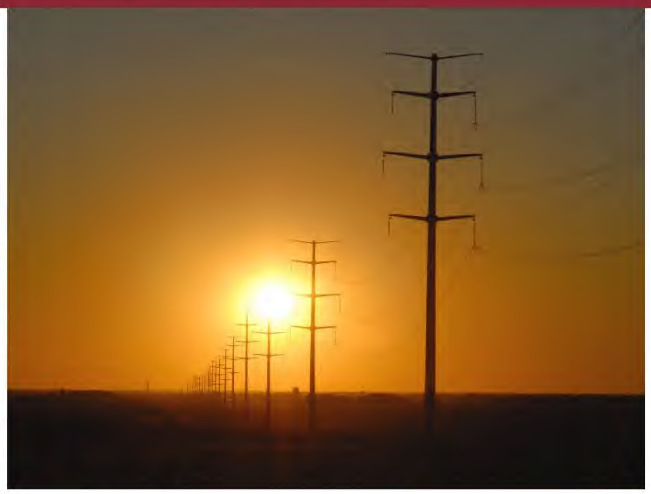
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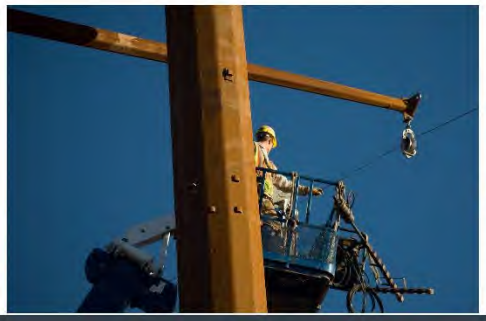
MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

UMD LOCAL ECONOMIC IMPACT STUDY

Maple River-Cuyuna Transmission Line Economic Impact Study

December 2025

BUREAU OF BUSINESS AND ECONOMIC RESEARCH

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DISLAIMER – The Bureau of Business and Economic Research (BBER) at the University of Minnesota Duluth's (UMD) Labovitz School was contracted to provide an unbiased economic impact study based primarily on data provided by the Maple River-Cuyuna project team. Publication and dissemination of this report, or any of its data, is not an endorsement by the BBER/UMD of Minnesota Power or their projects. The BBER was asked to supply an economic impact analysis only. This analysis does not consider the environmental impacts of the project and should not be viewed as a cost-benefit analysis or environmental impact assessment.

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Executive Summary

The Maple River–Cuyuna (MRC) project is an approximately 160 to 180-mile, double-circuit 345-kV transmission line[1] initiative being planned by Minnesota Power, Great River Energy, and Otter Tail Power. The proposed line will connect the Maple River Substation near Fargo, North Dakota, to the Cuyuna Substation in Minnesota. The project began in 2025 and is scheduled to be completed in 2033. The bulk of the construction activities will occur between 2027 and 2032.

Minnesota Power, Great River Energy, and Ottertail Power Company (the MRC project team) asked the Bureau of Business and Economic Research (BBER), an entity of the University of Minnesota Duluth's Labovitz School of Business and Economics, to assess the economic impact of the MRC project on four distinct study areas: the states of Minnesota and North Dakota combined, the state of Minnesota alone, the state of North Dakota alone, and the seven-county region where the project will be physically located.

Inputs required for modeling the MRC project included major construction expenditures, employment estimates, per diem compensation, and the percentage of local labor and equipment purchases. The research team worked in partnership with the MRC project team to account for economic leakage, where spending leaves the study area (e.g., through materials purchased from outside the region). The total estimated cost of the MRC project at the time of this evaluation was $907.8 million. Of the remaining $813 million in total spending (excluding land and right-of-way purchase costs), roughly $550 million will occur within Minnesota and North Dakota.

The research team used IMPLAN input-output data and software for modeling economic impacts. Project spending was modeled in the current year (2025) and presented in 2025 dollars. Given that the analysis includes multiple study areas, the research team used IMPLAN's multi-regional input-output (MRIO) approach, which examines economic impacts across multiple geographic regions and accounts for inter-regional trade flows.

Overall, the MRC project is expected to contribute $328.7 million in employee wages and benefits, roughly $541.5 million in value added, and more than $1.0 billion in new spending (output) to the combined states of Minnesota and North Dakota. The project is anticipated to support, on average, 272 jobs per year in the two states combined. The employment multiplier of 2.64—which indicates how much additional spending is added to the study area's economy for each dollar in direct spending—indicates that for every one job directly supported by the project, another 1.64 jobs may be added in other supporting industries. The results estimate that, at its peak in 2028, the project could support more than 500 jobs. Total effects for each of the four study areas are shown in Table 1, below.

Table 1. MRC Project Total Effects by Study Area, 2025-2033 (in Millions of 2025 Dollars)

Study Area	*Employment (Annual Average)*	*Labor Income*	*Value Added*	*Output*
Minnesota and North Dakota	272	$328.7	$541.5	$1,005.1
Minnesota Only	257	$312.9	$514.4	$952.3
North Dakota Only	15	$15.8	$27.2	$52.8
Seven-County Region	154	$206.2	$312.7	$609.3

SOURCE: IMPLAN

[1] The double circuit 345 kV transmission line will initially be operated as a single circuit transmission line but will be designed for future reconfiguration to operate as two separate transmission lines.

Bureau of Business and Economic Research
Labovitz School of Business and Economics
University of Minnesota Duluth

Maple River-Cuyuna Transmission Line Economic Impact Study

Introduction

Minnesota Power, in partnership with Great River Energy and Otter Tail Power Company, is planning the development of a new high-voltage transmission line known as the Maple River–Cuyuna (MRC) project. The proposed line will span approximately 160 to 180 miles and will operate at 345 kilovolts (kV), connecting the Maple River Substation near Fargo, North Dakota, to the Cuyuna area near Riverton, Minnesota.

The project involves the following:[2]

- Upgrades to Otter Tail Power's existing Maple River Substation, located near Fargo, North Dakota, and Minnesota Power's Cuyuna Substation, located near Riverton, Minnesota
- Construction of a new, approximately 160- to 180-mile-long, double-circuit 345 kilovolt (kV) transmission line that will be operated initially as a single transmission line from the Cuyuna Substation to the Maple River Substation

Minnesota Power, Great River Energy, and Otter Tail Power (the MRC project team) asked the Bureau of Business and Economic Research (BBER), an entity of the University of Minnesota Duluth's Labovitz School of Business and Economics, to assess the economic impact of the MRC construction project.

Overall, an economic impact analysis requires the analyst to select a study area—the boundary of what would be considered the local economy.[3] This economic impact analysis includes four study areas: the states of Minnesota and North Dakota (both individually and combined), as well as the seven-county region (Becker, Cass, Clay, Crow Wing, Hubbard, and Wadena counties in Minnesota and Cass County in North Dakota) through which transmission line will be built.[4]

This report is organized into the following chapters:

- Chapter I, Inputs and Assumptions, describes the key economic inputs and methodological assumptions used for modeling the full construction project and the primary study area of Minnesota and North Dakota combined.
- Chapter II, Economic Impacts, presents the results of the modeling. The chapter begins with the findings for the primary study area and an explanation of those results. The results for each of the additional study areas (Minnesota, North Dakota, and the seven-County region) are then presented individually, starting on page 9, along with a description of any specific modifications or adjustments made to the modeling inputs for those localized analyses.
- Chapter III, Conclusion, summarizes the key findings and their implications for the study areas.

[2] https://mrctransmissionproject.com/project-components/

[3] For a complete list of terms and definitions used in this report, see Appendix A.

[4] Because the project's final route has not yet been selected, the county-level study area encompasses all counties that may be included in the eventual alignment. All seven counties are contiguous.

I. Inputs and Assumptions

Inputs required for modeling the Maple River–Cuyuna (MRC) project were major construction expenditures, employment estimates, per diem compensation, and the percentage of local labor and equipment purchases. The research team worked in partnership with the MRC project team to determine the inputs and assumptions used in modeling. In instances where data was not provided by the project team, the research team relied on IMPLAN estimates and secondary data sources as inputs.[5]

The total estimate cost of the MRC project, as originally approved by the Midcontinent Independent System Operator, is $907.8 million (in 2024 dollars). Excluding the cost of land purchases for the purpose of this evaluation, as described in Appendix B, by the time the construction of the MRC project is completed in 2033, the companies will have spent $813 million over the nine-year project.[6] Table 2 shows a timeline for the project, along with the percentage of the overall budget that is scheduled to occur each year. It should be noted that the estimates in Table 2 reflect project projections and may change as the project develops.

Table 2. MRC Project Spending by Year, Primary Activity, and Share of Budget (in Millions of 2025 Dollars)

Year	Primary Activities	Spending	Percentage of Budget
2025	Stakeholder engagement and routing	$3.2	0.4%
2026	Permitting, engineering, environmental surveying	$35.9	4.4%
2027		$71.2	8.8%
2028	Construction	$176.3	21.7%
2029		$59.9	7.4%
2030		$155.5	19.1%
2031		$152.7	18.8%
2032		$154.6	19.0%
2033	In service	$3.8	0.5%
Total		$813.2	100.0%

*Totals may not sum due to rounding
SOURCE: MRC PROJECT TEAM

As shown in the table, the first year of the project focuses on stakeholder engagement and routing (e.g., public outreach, project setup, and preparation of permit applications). In years two and three of the project (2026-2027), project activities will focus on permitting, engineering, and environmental surveys, as well as right-of-way acquisition and public engagement. The construction of the line will occur from 2028 until 2032, and the line will be in service by 2033.

While the construction activity itself will happen within the study area, the MRC project team acknowledged that many of the contractors and large materials purchases (e.g., steel poles) will be sourced from outside of the study area. Spending that occurs outside the study area is considered a leakage—a payment that is not

[5] For a detailed description of the inputs and assumptions used in developing the economic impact models for this study, see Appendix B.
[6] Land purchases were excluded from the analysis as they are simply a transfer of funds and do not represent new spending in the study area.

recirculated within the study area region. To ensure that spending outside the study area would not be included, the research team adjusted the IMPLAN models to reflect only local spending for each of the project's major budget categories, based on estimates provided by the MRC project team. Table 3 below shows the share of project spending that is expected to occur within the primary study area (Minnesota and North Dakota combined).

Table 3. MRC Project Spending by Activity and Portion of Spending in Minnesota and North Dakota

Budget Category	***Local Spending Percentage (Minnesota and North Dakota)***
Construction (labor and professional services)	100%
Permitting and siting	100%
Project planning and management	70%
Engineering (services and engineered materials)	20%
Materials	5-15%

SOURCE: MRC PROJECT TEAM

As shown in Table 3, 100% of the construction spending will occur within the primary study area (Minnesota and North Dakota), as will all of the spending on permitting and siting. Also taking place within the two states are approximately 70% of the project planning and management spending, 20% of the spending for engineering and consulting services, and 5-15% of materials spending, depending on the purchase. Of the $813 million in total spending, roughly $550 million will occur within Minnesota and North Dakota.[7]

The research team used IMPLAN data in conjunction with data from the MRC project team to estimate employment and employee compensation for each budget category (Table 4). It should be noted that the "Employee Compensation" column in the table reflects all spending for the project, whereas employment estimates ("Average Annual Employment" column) are based on annual averages. This is because many of the jobs supported by the project will continue each year. By providing the average, the estimates represent the average number of workers employed by the project per year. As shown in the table, most of the workers employed by the project (annual average of 84) will be employed in the construction sector. Yet, because of the significant amount of spending on materials, engineering, and other tasks, the research team estimate that, on average, approximately 20 additional jobs will be supported annually in non-construction activities.

Table 4. MRC Project Employment and Employee Compensation, 2025-2033 (in Millions of 2025 Dollars)

Budget Category	***Average Annual Employment***	***Employee Compensation***
Construction (labor and professional services)	84	$140.9
Project planning and management	12	$20.6
Materials	4	$4.1
Permitting and siting	3	$4.2
Engineering (services and engineered materials)	1	$0.8
Total	104	$170.5

*Totals may not sum due to rounding
SOURCE: MRC PROJECT TEAM, BBER

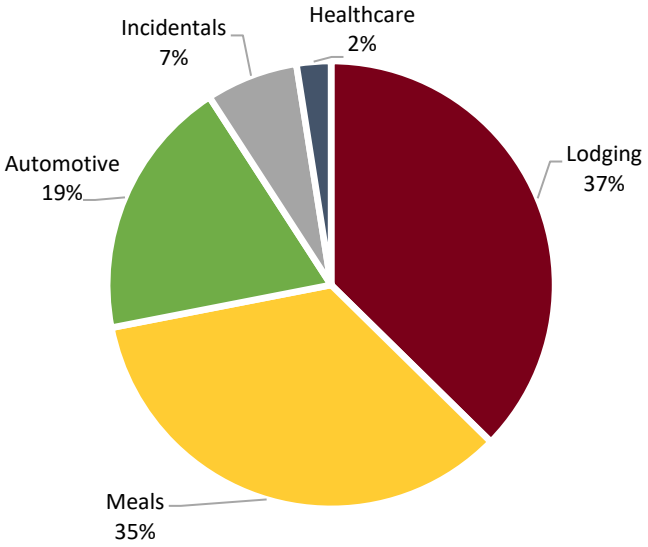
[7] Because this analysis includes four unique study areas, local spending varies depending on the individual study area. The research team adjusted inputs based on local spending estimates from the MRC project team. These spending estimates can be found in Appendix B.

For every industry in its database, the IMPLAN software estimates the proportion of spending the industry pays in employee compensation (i.e., wages and benefits) for a given amount of revenue (i.e., output). The research team relied on IMPLAN's estimates (shown in the final column of Table 4 above) to estimate employee compensation for each budget category.

IMPLAN also estimates employment in terms of jobs, not in terms of full-time equivalent employees. The software uses regional wage estimates to determine employee compensation per worker. But the MRC project team expects to employ primarily full-time workers and pay wages higher than IMPLAN's wage estimates. Therefore, the research team used compensation estimates for construction and engineering occupations—provided by the companies' representatives—to adjust the software's employment numbers for the study as shown in the column labeled "Average Annual Employment."[8]

For large construction efforts like the MRC project, construction firms typically establish project labor agreements with local unions that ensure a certain proportion of the labor force will be recruited from local union halls. However, with hundreds of construction laborers needed each year for several years, it is likely that a notable share of the construction workers necessary for the MRC project will need to be recruited from outside the local study area. Of the construction jobs, the MRC project team anticipates that 80% will be filled by union laborers from within the states.

Figure 1. Per Diem Spending Pattern for Nonlocal Construction Workers



SOURCE: BBER

To account for the nonlocal workforce that will be required to complete the project, the research team made two significant adjustments to the model. First, employee compensation for the construction activity was reduced to account for nonlocal workers' spending leaving the study area, using IMPLAN's commuting rate formula.[9] Then, 10% of the nonlocal workers' compensation was added back into the model to represent their per diem allowance. The research team estimated that roughly 70% of the projected per diem spending would go to lodging and food, with automotive costs, incidentals, and healthcare expenses rounding out the rest of the expected spending. Figure 1 shows a visual depiction of the

[8] The MRC project team estimates that construction laborers will earn roughly $63 per hour for a 40-hour workweek, assuming mostly union workers and prevailing wages. The team also estimated a 33% fringe rate and a 10% allowance for per diem expenses, equaling an average compensation per worker of $187,357 annually. For all other budget categories (project management, engineering, and permitting), the companies predicted that two-thirds of employees would be salaried, with an hourly base wage of about $78, while the other third would be hourly or technical workers, receiving a base wage of $46 per hour. These workers were also assumed to receive a 33% fringe rate but no per diem allowance, for an average annual compensation per worker of $185,681.

[9] Local Employee Compensation in Minnesota and North Dakota Combined = Total Employee Compensation * [(1-expected in-commuting rate)/(1- typical in-commuting rate)], where expected in-commuting rate = 20% and typical in-commuting rate = 3.03%. For more details on employee compensation adjustments, see Appendix B.

spending pattern.[10]

Once all the modeling inputs and assumptions were finalized and verified by the MRC project team, the research team used these inputs to model the total economic impacts of the project.

II. Economic Impacts

Between 2025 and 2033, the Maple River-Cuyuna project (MRC) will generate a significant but temporary economic impact throughout Minnesota and North Dakota while construction is underway.[11] During the project, increased demand for equipment, labor, and professional services will lead to increased economic activity. The following sections summarize the projected impacts of the full MRC project on the two-state region—Minnesota and North Dakota— in which the project will occur, as well as the impacts on each state individually and on the seven-county region where the line is being implemented.

Economic impact analysis tracks an initial economic activity (such as the MRC construction project) through several rounds of industry and consumer spending to show the ripple effects that occur through the local economy. The project spending estimates were used to model the economic effects—direct, indirect, and induced– of the project on other supporting local industries. The initial economic activity or shock is considered the direct effect, and the resulting increases in industry and consumer spending are the indirect and induced effects, respectively. Results of economic impact analysis are measured in employment, output, labor income, and value added.

The research team used IMPLAN input-output modeling data and software for modeling economic impacts. Project spending is shown in 2025 dollars and was modeled in the current year (2025). Results are presented in 2025 dollars. Given that the analysis includes multiple study areas, the research team used IMPLAN's multi-regional input-output (MRIO) modeling approach—linking the states of Minnesota and North Dakota for the analysis. The MRIO approach allows for economic impacts across multiple geographic regions and accounts for inter-regional trade flows.[12]

Minnesota and North Dakota

Modeling results are presented by type of effect, by year, and by industry. Tax impacts are also presented for the study area.

Impacts by Type of Effect

Table 5 on the next page provides the estimated economic impacts from the MRC project on the states of Minnesota and North Dakota, broken out by impact type: direct, indirect, or induced. The initial economic activity or shock is considered the direct effect, and the resulting increases in industry and consumer spending are the indirect and induced effects, respectively. Results of economic impact analysis are measured in terms of employment, output, labor income, and value added.

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[10] The research team used an average of the U.S. General Services Administration's (GSA) per diem rates, as well as the Minnesota Department of Employment and Economic Development and North Dakota State Government cost of living estimates to determine an appropriate per diem allocation.

[11] The economic impacts estimated in this report are solely related to the construction (including procurement and permitting) for the MRC project and do not include additional economic benefits that may be derived by reduced system congestion, additional renewable transmission, or other related changes to the grid.

[12] For more details on the data sources, assumptions, and methodology used in input-output modeling, see Appendix C.

Table 5. MRC Project Impacts by Type of Effect in Minnesota and North Dakota, 2025-2033 (Millions of 2025 $)

Impact Type	*Employment (Annual Average)*	*Labor Income*	*Value Added*	*Output*
Direct Effect	103	$206.9	$300.9	$549.5
Indirect Effect	49	$49.8	$108.3	$240.3
Induced Effect	120	$72.0	$132.4	$215.3
Total Effect	272	$328.7	$541.5	$1,005.1
Multiplier	2.64	1.59	1.80	1.83

*Totals may not sum due to rounding
SOURCE: IMPLAN

Direct effects represent the employment and spending coming from the project itself on wages, equipment, and supplies. These estimates are based on estimates provided by the MRC project team and the corresponding employment estimates described in the previous chapter, "Inputs and Assumptions."[13] In total, the project is projected to directly support $206.9 million in wages and benefits (labor income), $300.9 million in value-added spending, and $549.5 million in output. On average, it is estimated that 103 jobs will be directly supported by the project each year from 2025 to 2033.

Indirect effects measure the increase in spending from commercial, government, and service industries located within the study area, while induced effects reflect the impacts of an increase in household spending by MRC project workers and employees in related industries. According to the results of modeling, the indirect effects from the MRC project will add $240.3 million in industry spending over the nine years and add an average of 49 jobs annually. The induced effects from the project are predicted to bring $215.3 million in additional spending and add an average of 120 supported jobs annually to Minnesota and North Dakota.

Total effects are the sum of direct, indirect, and induced effects. Overall, the project is expected to contribute $328.7 million in employee wages and benefits, $541.5 million in value added spending, and roughly $1.0 billion in new spending. The project is anticipated to support, on average, 272 jobs per year in the two states combined.

The last row in the table shows the multipliers associated with each effect. A multiplier indicates how much additional spending is added to the study area's economy for each dollar in direct spending, represented as a ratio of total effects to direct effects. In the case of the MRC project, an employment multiplier of 2.64 indicates that for every one job directly supported by the project, another 1.64 jobs may be added in other supporting industries. The output multiplier suggests that, for every one dollar spent directly on the project, another $0.83 may be spent by households and supporting industries throughout the study area because of the project.

[13] Direct effects shown in Table 5 ($549.5 million) differ from the overall project spending ($813 million) for a few reasons. First, of the $813 million in total spending, roughly $550 million will occur within the study area. Second, retail industries have margins on their goods, which means that only a portion of each sale is introduced into the local economy.

Impacts by Year

Table 6 shows the total economic impact of the nine-year project, broken out by project year. The column labeled "Employment" indicates the number of jobs that the MRC project is expected to support, either directly or indirectly. IMPLAN estimates employment in terms of jobs, not in terms of full-time equivalent employees. For construction projects such as the MRC project, these jobs are temporary, meaning that this effect would only be felt during the duration of the project and will no longer be felt by the region once the project is completed. In total, the MRC project will support, on average, 272 jobs each year throughout the nine-year period. Employment estimates vary by year, however. The results of modeling estimate that, at its peak (2028), the project could support more than 500 jobs.

Table 6. MRC Project Impacts by Year in Minnesota and North Dakota, 2025-2033 (Millions of 2025 $)

Project Year	*Employment*	*Labor Income*	*Value Added*	*Output*
2025	10	$1.3	$2.2	$4.0
2026	108	$14.5	$23.9	$44.4
2027	215	$28.8	$47.4	$88.0
2028	531	$71.2	$117.4	$217.8
2029	180	$24.2	$39.9	$74.0
2030	468	$62.8	$103.5	$192.2
2031	460	$61.7	$101.7	$188.7
2032	466	$62.5	$103.0	$191.1
2033	12	$1.6	$2.6	$4.7
Total	272**	$328.7	$541.5	$1,005.1

*Totals may not sum due to rounding
**Employment is shown as the annual average for the nine-year project, rather than the sum.
SOURCE: IMPLAN

The column labeled "Labor Income" is the total of all employee compensation, including wages, benefits, proprietor income, and payroll taxes for both full and part-time workers. In total, the project will add an estimated $328.7 million in labor income to the states' economy over the nine-year period. The peak of economic activity is expected in 2028.

The third column, labeled "Value Added," shows the economic impacts of MRC project expenditures directed toward wages, rents, interest, and profits, as well as all non-payroll taxes associated with the project. Labor income is a component of value added, but value added specifically represents the contribution to gross regional product (GRP) made by an individual economic activity—in this case the MRC project. The nine-year project is estimated to add $541.5 million in value added spending to the combined states, with the bulk of the spending taking place between 2028 and 2032.

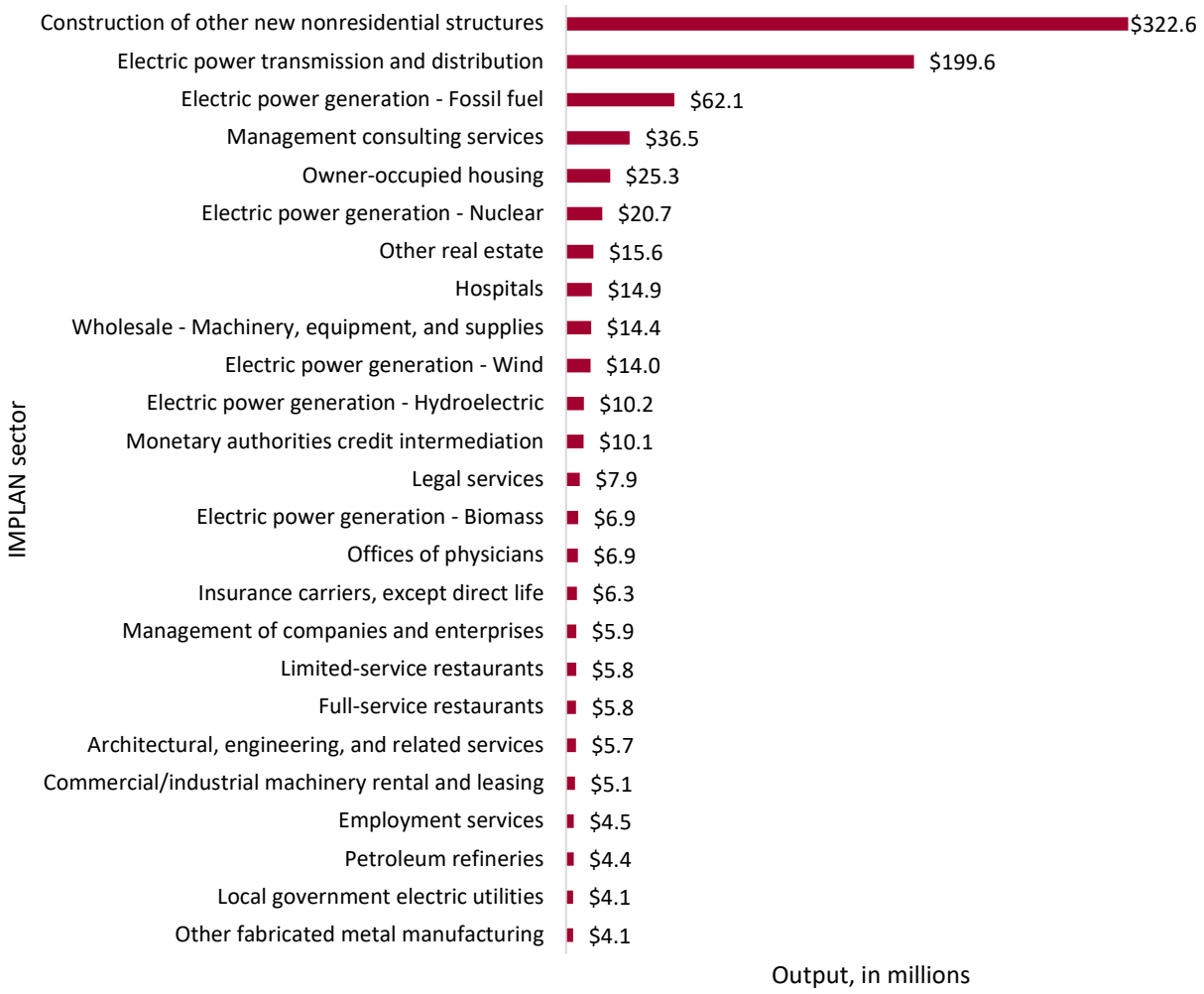
The last column, titled "Output," is the total value of all local production that is required to sustain activities. Output represents the sum of all spending caused by the project. In total, the MRC project is expected to contribute $1.0 billion in new spending to Minnesota and North Dakota over the life of the project.

Impacts by Industry

Figure 2 on the following page details the industries projected to receive the largest total impact in the study area (Minnesota and North Dakota) because of the MRC project. Construction of other new nonresidential structures is estimated to have the largest impact, at $322.6 million in total impacts, with electric power

transmission and electric power generation as the second and third largest impacted industries. Other industries most impacted by the project include management consulting services, owner-occupied dwellings (a sector representing the value of homeownership and home renting/leasing), and wholesale machinery sales.[14,15] While many of the industries are impacted directly by the project itself (e.g., construction, wholesale, electric power transmission), many of the top industries shown in the figure are the result of indirect effects or increased household spending (e.g., owner-occupied dwellings, hospitals).

Figure 2. MRC Project Impacts by Industry Output, Minnesota and North Dakota, 2025-2033 (Millions of 2025 $)



SOURCE: IMPLAN

[14] The "hospitals" industry in IMPLAN reflects spending paid to hospitals directly but also includes Medicare reimbursements and other transfer payments made to hospitals by insurance companies.
[15] For a more detailed breakdown of the direct, indirect, and induced effects that are projected for each of these top industries, see Appendix D.

Tax Impacts

Any substantial project, such as the MRC project, will have significant tax impacts at the local, county, state, and federal levels. The column titled "County and Local" includes taxes paid to county, city, and township governments, along with items such as school districts and fire departments. The columns labeled "State" and "Federal" are the taxes paid to these entities, such as income taxes and corporate profit taxes. Table 7 estimates the tax impacts from the MRC construction project on the states of Minnesota and North Dakota.[16]

Table 7. Tax Impacts from the MRC Project in Minnesota and North Dakota, 2025-2033 (Millions of 2025 $)

Impact Type	*County and Local*	*State*	*Federal*	*Total*
Direct Effect	$5.8	$16.1	$45.0	$66.9
Indirect Effect	$7.7	$13.0	$12.8	$33.5
Induced Effect	$4.5	$9.6	$17.4	$31.4
Total Effect	$18.0	$38.7	$75.2	$131.8

*Totals may not sum due to rounding
SOURCE: IMPLAN

As Table 7 outlines, MRC project spending is projected to lead to tax revenues of $18.0 million for local and county governments, $38.7 million for the states of Minnesota and North Dakota combined, and $75.2 million for the federal government. Direct spending from the MRC project is expected to provide $66.9 million in tax impacts, and the overall project is anticipated to provide $131.8 million in total tax impacts.[17] While not included in this study, the MRC project team will continue to pay annual property taxes after the construction of the transmission line is complete, based on either the transfer capacity or cost of the assets. These annual property tax payments, which are not included in this study, represent an additional and ongoing local revenue stream in the counties where the project is constructed.

Minnesota

This portion of the analysis uses the state of Minnesota as the study area, isolating the economic impacts within the state's borders. Extending from the Cuyuna area near Riverton, Minnesota, to the state's border, roughly 97% of the length of the MRC transmission line will be in the state of Minnesota. The construction of the Cuyuna Substation will also occur within the state.

To accurately reflect the spending allocated to the state of Minnesota alone, the research team adjusted the model to account for 97% of the total transmission line construction project and 100% of the Cuyuna Substation construction (planned for 2027-2029). The research team then adjusted the local spending inputs and local construction workforce estimates, in consultation with the MRC project team. Local employee compensation was calculated using IMPLAN's commuting rate formula.[18]

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[16] Throughout the report, total tax impacts include federal tax revenues. However, federal taxes do not accrue to state or county governments and are considered a leakage from the study area.
[17] The tax impacts estimated in this report are solely related to the construction (including procurement and permitting) for the MRC project and do not include additional tax benefits that might occur after the construction project is complete.
[18] Local Employee Compensation in Minnesota = Total Employee Compensation * [(1- expected in-commuting

Based on these adjustments, the research team estimates that of the project's total $813 million in spending, roughly $523.0 million will be spent within Minnesota (as shown in Table 8), primarily on construction activities, project management, and permitting. Results are broken out by type of effect, by year, and by industry below. Tax impacts for the study area are also shown.

As shown below, Minnesota will see, on average, almost 260 new jobs each year over the lifetime of the MRC project. The employment multiplier for the state is 2.65, meaning that for every one job directly created by the MRC project, another 1.65 are created in related industries throughout the state. In total, Minnesota will see $952.3 million in new economic activity (output) during the nine-year project.

Impacts by Type of Effect

Table 8. MRC Project Impacts by Type of Effect in Minnesota, 2025-2033 (Millions of 2025 $)

Impact Type	*Employment (Annual Average)*	*Labor Income*	*Value Added*	*Output*
Direct Effect	97	$197.1	$286.8	$523.0
Indirect Effect	45	$46.5	$100.1	$222.6
Induced Effect	115	$69.2	$127.4	$206.7
Total Effect	257	$312.9	$514.4	$952.3
Multiplier	2.65	1.59	1.79	1.82

*Totals may not sum due to rounding
SOURCE: IMPLAN

Impacts by Year

Table 9. MRC Project Impacts by Year in Minnesota, 2025-2033 (Millions of 2025 $)

Project Year	*Employment*	*Labor Income*	*Value Added*	*Output*
2025	9	$1.2	$2.0	$3.6
2026	101	$13.6	$22.3	$41.4
2027	202	$27.3	$44.9	$83.2
2028	505	$68.3	$112.3	$208.0
2029	172	$23.2	$38.2	$70.7
2030	447	$60.5	$99.4	$184.1
2031	440	$59.4	$97.7	$180.9
2032	429	$58.1	$95.5	$176.7
2033	9	$1.2	$2.0	$3.7
Total	257**	$312.9	$514.4	$952.3

*Totals may not sum due to rounding
**Employment is shown as the annual average for the nine-year project, rather than the sum.
SOURCE: IMPLAN

rate)/(1- typical in-commuting rate)], where expected in-commuting rate is 20% and typical in-commuting rate is 3.13%. For more details on employee compensation adjustments, see Appendix B.

Tax Impacts

Table 10. Tax Impacts from the MRC Project in Minnesota, 2025-2033 (Millions of 2025 $)

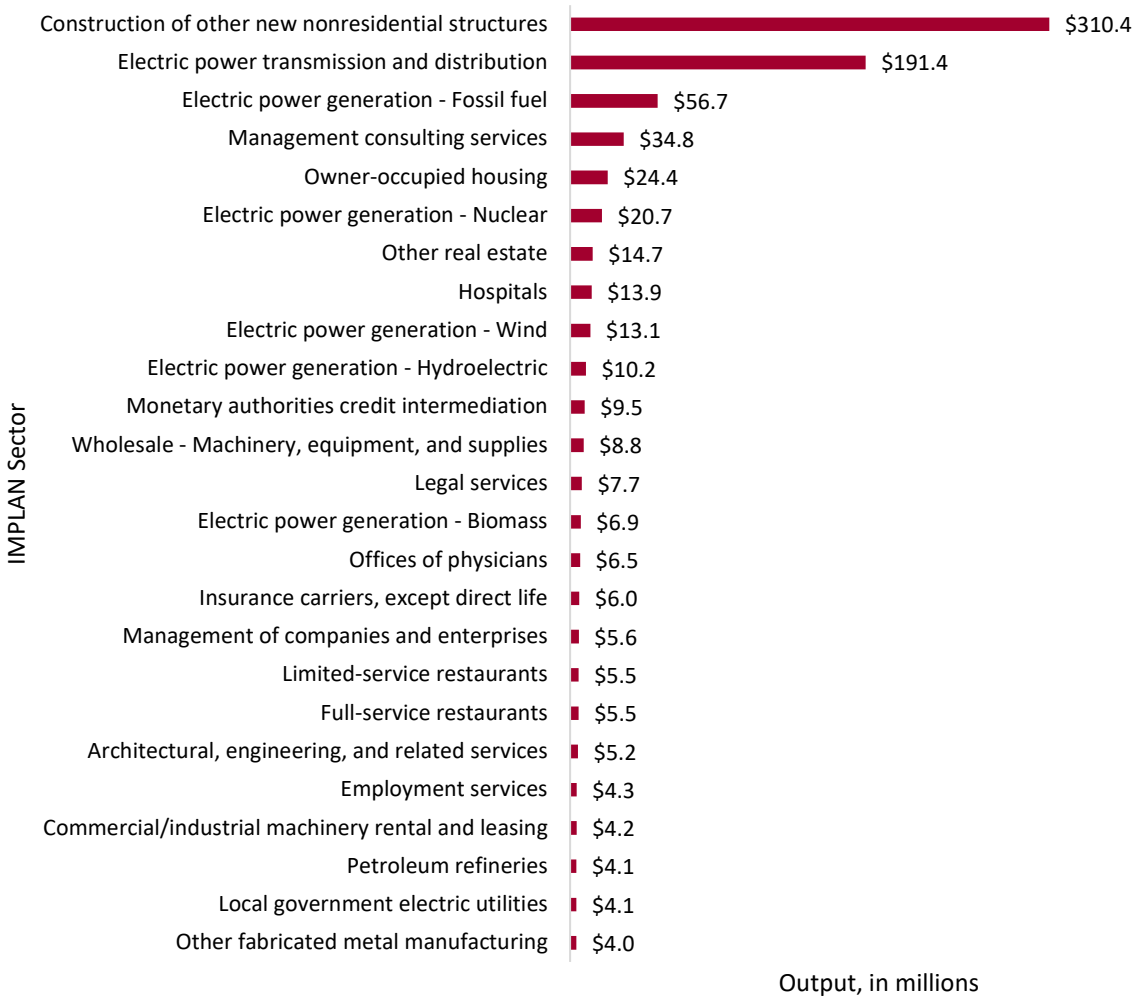
Impact Type	*County and Local*	*State*	*Federal*	*Total*
Direct Effect	$5.7	$15.8	$42.9	$64.4
Indirect Effect	$7.4	$12.1	$12.0	$31.6
Induced Effect	$4.4	$9.3	$16.7	$30.5
Total Effect	$17.5	$37.3	$71.7	$126.5

*Totals may not sum due to rounding

SOURCE: IMPLAN

Impacts by Industry

Figure 3. MRC Project Impacts by Industry Output in Minnesota, 2025-2033 (Millions of 2025 $)



SOURCE: IMPLAN

North Dakota

This portion of the analysis uses the state of North Dakota as the study area, isolating the economic impacts within the state's borders. Extending from Fargo, North Dakota, to the state's border, roughly 3% of the length of the MRC transmission line will be in the state of North Dakota. The construction of the Maple River Substation will also occur within the state.

To accurately reflect the spending allocated to the state of North Dakota alone, the research team adjusted the model to account for 3% of the total transmission line construction project and 100% of the Maple River Substation construction (planned for 2028-2033). The research team then adjusted the local spending inputs and local construction workforce estimates, in consultation with the MRC project team. Local employee compensation was calculated using IMPLAN's commuting rate formula.[19]

Based on these adjustments, the research team estimates that of the project's total $813 million in spending, $26.8 million will be spent within North Dakota, primarily on construction activities, project management, and machinery purchases. Results are broken out by type of effect, by year, and by industry below. Tax impacts for the study area are also shown.

Since only a small portion of the overall MRC project will occur within North Dakota, the economic impact on the state is more limited than that in Minnesota. The employment multipliers for the study area are also smaller, likely due to North Dakota's economy being smaller and less diversified than Minnesota's. However, the project will still have a significant economic impact on the state's economy, adding more than $50 million in output over the nine-year period (2025-2033) and an average of 15 new jobs per year during the life of the project.

Impacts by Type of Effect

Table 11. MRC Project Impacts by Type of Effect in North Dakota, 2025-2033 (Millions of 2025 $)

Impact Type	*Employment (Annual Average)*	*Labor Income*	*Value Added*	*Output*
Direct Effect	6	$9.8	$14.0	$26.5
Indirect Effect	4	$3.3	$8.2	$17.7
Induced Effect	5	$2.8	$4.9	$8.5
Total Effect	15	$15.8	$27.2	$52.8
Multiplier	2.56	1.62	1.94	1.99

*Totals may not sum due to rounding

SOURCE: IMPLAN

[19] Local Employee Compensation in North Dakota = Total Employee Compensation * [(1- expected in-commuting rate)/(1- typical in-commuting rate)], where expected in-commuting rate is 20% and typical in-commuting rate is 11.13%. For more details on employee compensation adjustments, see Appendix B.

Impacts by Year

Table 12. MRC Project Impacts by Year in North Dakota, 2025-2033 (Millions of 2025 $)

Project Year	*Employment*	*Labor Income*	*Value Added*	*Output*
2025	1	$0.1	$0.2	$0.4
2026	8	$1.0	$1.7	$3.3
2027	13	$1.5	$2.5	$4.9
2028	24	$2.8	$4.9	$9.5
2029	8	$0.9	$1.6	$3.1
2030	19	$2.3	$3.9	$7.6
2031	19	$2.2	$3.8	$7.3
2032	40	$4.6	$8.0	$15.5
2033	3	$0.4	$0.6	$1.3
Total	15**	$15.8	$27.2	$52.8

*Totals may not sum due to rounding

**Employment is shown as the annual average for the nine-year project, rather than the sum.

SOURCE: IMPLAN

Tax Impacts

Table 13. Tax Impacts from the MRC Project in North Dakota, 2025-2033 (Millions of 2025 $)

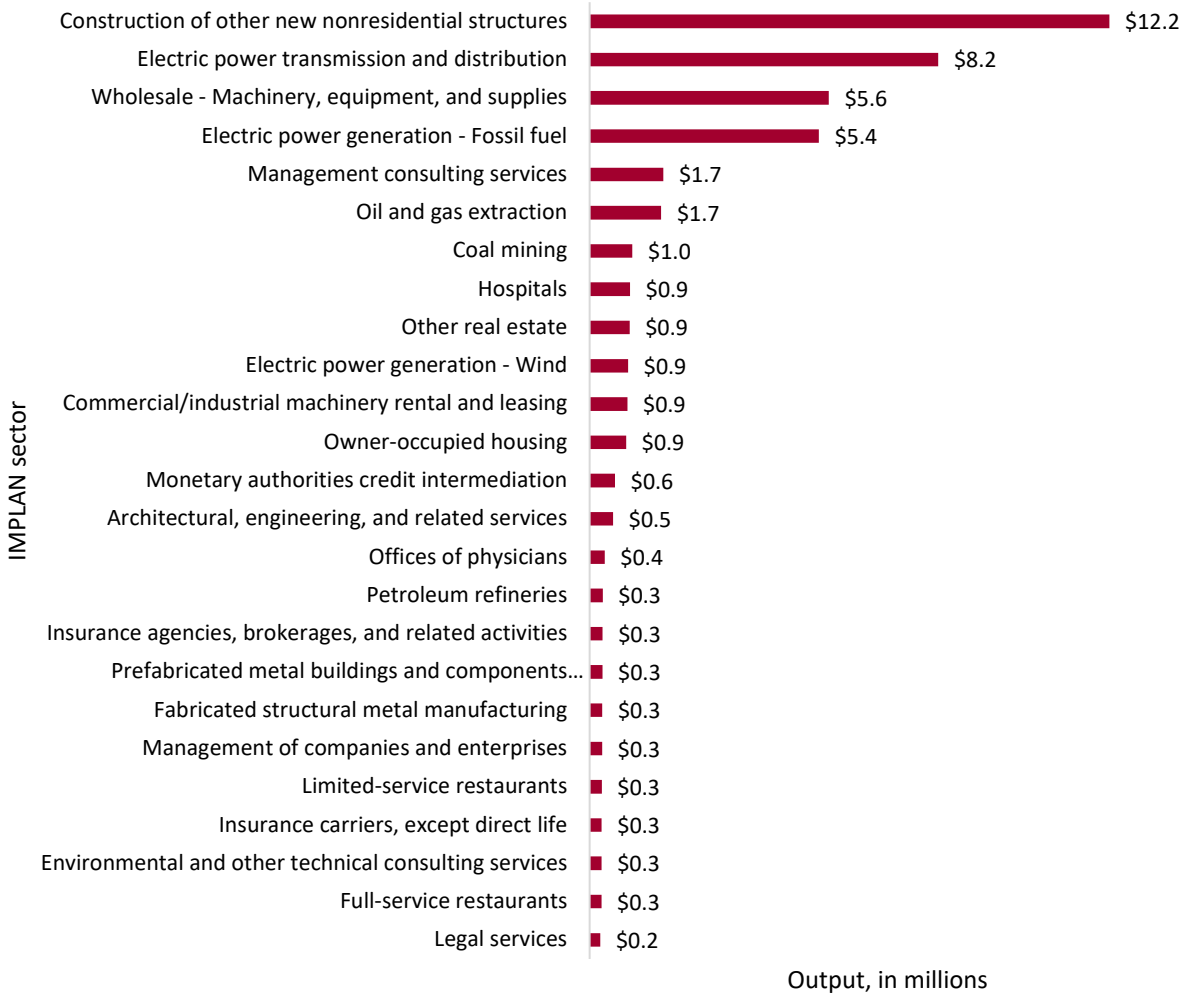
Impact Type	*County and Local*	*State*	*Federal*	*Total*
Direct Effect	$0.1	$0.4	$2.0	$2.5
Indirect Effect	$0.3	$0.8	$0.8	$2.0
Induced Effect	$0.1	$0.2	$0.6	$0.9
Total Effect	$0.5	$1.4	$3.5	$5.4

*Totals may not sum due to rounding

SOURCE: IMPLAN

Impacts by Industry

Figure 4. MRC Project Impacts by Industry Output in North Dakota, 2025-2033 (Millions of 2025 $)



SOURCE: IMPLAN

Seven-County Region

This analysis isolates the economic impacts strictly within the seven-county region where construction will be physically located. The proposed MRC transmission line will span approximately 160 to 180 miles, connecting the Maple River Substation near Fargo, North Dakota, to the Cuyuna Substation near Riverton, Minnesota. While the project's final route has not yet been selected, there are seven contiguous counties that may be included in the eventual alignment: Becker, Cass, Clay, Crow Wing, Hubbard, and Wadena counties in Minnesota and Cass County in North Dakota.

To accurately reflect the spending allocated to the seven-county region, the research team considered all construction activities to be local but assumed that all other professional services (i.e., engineering, permitting, project management) would occur outside of this seven-county study area. Furthermore, the research team estimated that just a small percentage of materials purchases (2-5%) would occur within the

seven-county region. The research team then adjusted the local employee compensation using IMPLAN's commuting rate formula.[20]

Based on these adjustments, the research team estimates that of the project's total $813 million in spending (excluding land rights), $476.9 million will be spent within the seven-county region, primarily on construction activities, project management, and permitting.

The impacts to the seven-county region are significant, given the amount of spending on construction and the extended length of the project. The study area is expected to see more than $609 million in new economic activity over the nine-year period because of the MRC construction project. Results are broken out by type of effect, by year, and by industry. Tax impacts for the region are also shown.

Impacts by Type of Effect

Table 14. MRC Project Impacts by Type of Effect in the Seven-County Region, 2025-2033 (Millions of 2025 $)

Impact Type	*Employment (Annual Average)*	*Labor Income*	*Value Added*	*Output*
Direct Effect	82	$166.5	$242.4	$476.5
Indirect Effect	13	$9.5	$15.4	$39.1
Induced Effect	60	$30.1	$54.9	$93.6
Total Effect	154	$206.2	$312.7	$609.3
Multiplier	1.88	1.24	1.29	1.28

*Totals may not sum due to rounding

SOURCE: IMPLAN

Impacts by Year

Table 15. MRC Project Impacts by Year in the Seven-County Region, 2025-2033 (Millions of 2025 $)

Project Year	*Employment*	*Labor Income*	*Value Added*	*Output*
2025	6	$0.8	$1.2	$2.4
2026	61	$9.1	$13.8	$26.9
2027	122	$18.1	$27.4	$53.4
2028	301	$44.7	$67.8	$132.1
2029	102	$15.2	$23.0	$44.9
2030	266	$39.4	$59.8	$116.5
2031	261	$38.7	$58.7	$114.4
2032	264	$39.2	$59.5	$115.8
2033	7	$1.0	$1.5	$2.9
Total	154**	$206.2	$312.7	$609.3

*Totals may not sum due to rounding

**Employment is shown as the annual average for the nine-year project, rather than the sum.

SOURCE: IMPLAN

[20] Local Employee Compensation in Seven-county Region = Total Employee Compensation * [(1- expected in-commuting rate)/(1- typical in-commuting rate)], where expected in-commuting rate is 50% and typical in-commuting rate is 7.61%. For more details on employee compensation adjustments, see Appendix B.

Tax Impacts

Table 16. Tax Impacts from the MRC Project in the Seven-county Region, 2025-2033 (Millions of 2025 $)

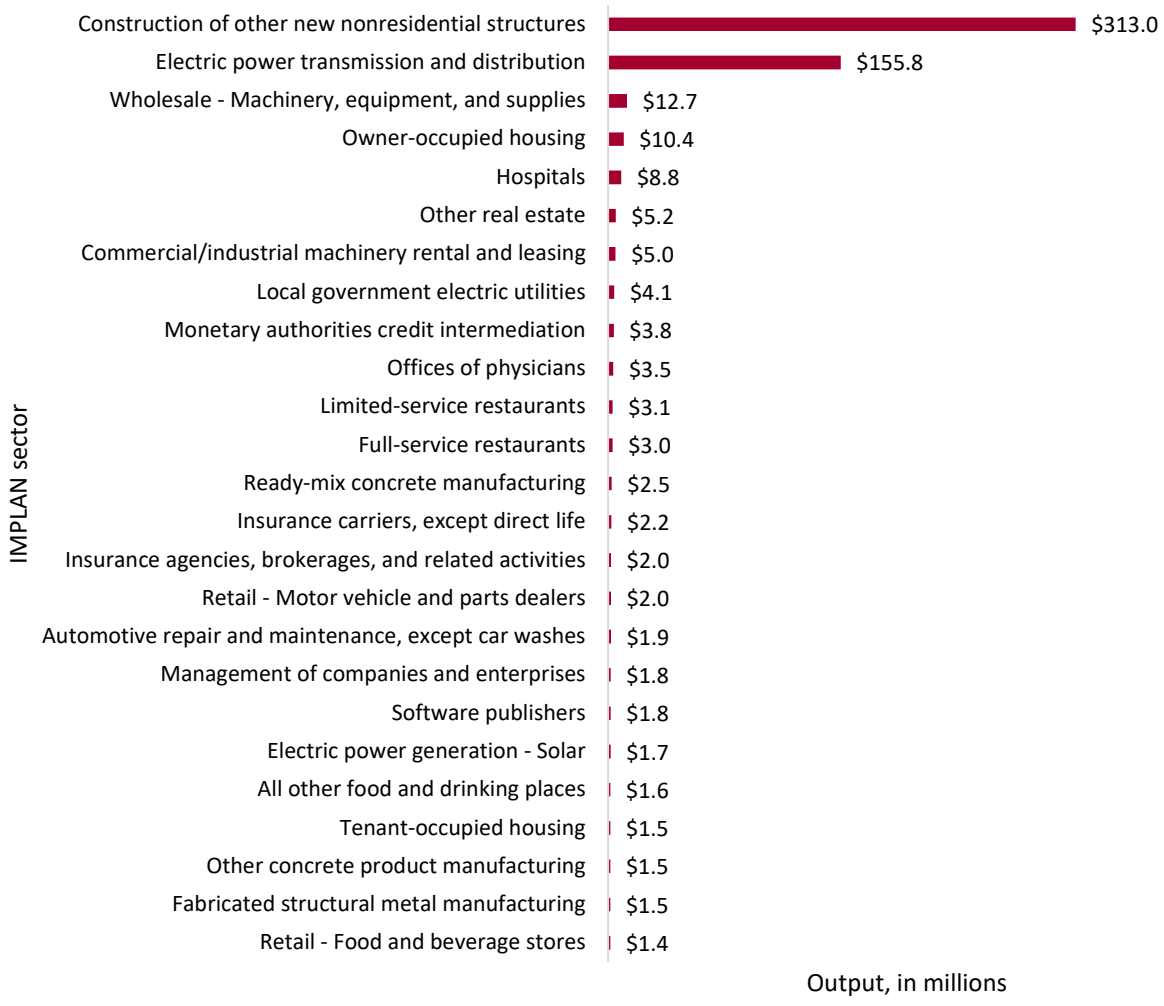
Impact Type	*County and Local*	*State*	*Federal*	*Total*
Direct Effect	$3.3	$9.9	$36.5	$49.7
Indirect Effect	$0.4	$0.9	$2.2	$3.5
Induced Effect	$1.6	$3.6	$7.2	$12.4
Total Effect	$5.3	$14.5	$45.9	$65.7

*Totals may not sum due to rounding

SOURCE: IMPLAN

Impacts by Industry

Figure 5. MRC Project Impacts by Industry Output in the Seven-county Region, 2025-2033 (Millions of 2025 $)



SOURCE: IMPLAN

III. Conclusion

The economic analysis of the Maple River–Cuyuna (MRC) construction project, conducted on behalf of the MRC project team, confirms that the nine-year project with an estimated $813 million in spending (excluding land rights) is anticipated to generate a significant economic impact throughout the primary study area of Minnesota and North Dakota. The analysis used a Multi-Regional Input-Output (MRIO) modeling approach, linking the states of Minnesota and North Dakota, and included several detailed adjustments to account for local spending and labor leakage. Overall, the MRC project is expected to contribute approximately $1.0 billion in new economic spending (output), $541.5 million in value added spending, and support an average of 272 jobs per year in the primary two-state region between 2025 and 2033. The peak of economic activity is projected to occur in 2028, coinciding with the most intensive construction period. The employment multiplier of 2.64 indicates that for every one job directly supported by the project, another 1.64 jobs are supported in other industries. Finally, the project is expected to generate $131.8 million in total tax revenues for federal, state, and local governments.

In addition to the economic impact on the two-state study area, the analysis estimated impacts for three smaller study areas: Minnesota, North Dakota, and the seven-county region in which construction will take place.

The Minnesota-only analysis captured the largest share of the economic impact, projecting $952.3 million in output and 257 average annual jobs. This result is due to the greater project scope within the state's borders ($523.0 million in direct spending) and its diversified economy, which supports higher multipliers. Comparatively, the economic impact on North Dakota is more limited, generating $52.8 million in output and 15 average annual jobs. Finally, according to the results of modeling for the seven-county region, it’s estimated that the MRC project will contribute over $609 million in total output and support an average of 154 jobs annually in the seven counties where the construction is occurring.

The results demonstrate that the MRC project will provide a substantial, though temporary, economic stimulus throughout the study regions during its nine-year construction period (2025-2033).

Appendix A. Definitions Used in This Report

Direct Effect: Initial new spending in the study area resulting from the project

Economic impacts: The effects of an event on the economy in a specified area, ranging from a single neighborhood to the entire globe. It usually measures changes in business revenue, business profits, personal wages, and/or jobs.

Employee compensation: In IMPLAN, employee compensation is the sum of all wages and salary income plus benefits.

Employment: Estimates (from U.S. Department of Commerce secondary data) are in terms of jobs, not in terms of full-time equivalent employees. Therefore, these jobs may be temporary, part-time, or short-term.

Indirect Effect: The additional inter-industry spending from the direct impact

Induced Effect: The impact of additional household expenditures resulting from the direct and indirect impact

Input-output modeling: A type of applied economic analysis that tracks the interdependence among various producing and consuming sectors of an economy. More particularly, it measures the relationship between a given set of demands for final goods and services and the inputs required to satisfy those demands.

Intermediate Inputs: Purchases of non-durable goods and services that are used to produce other goods and services rather than for final consumption.

Labor Income: All forms of employment income, including employee compensation (wages and benefits) and proprietor income.

Margins: The value of wholesale and retail trade services provided in delivering commodities from producers' establishments to purchasers. Margin is calculated as sales receipts less the cost of the goods sold. It consists of the trade margin plus sales taxes and excise taxes that are collected by the trade establishment. (BEA)

Multipliers: Total production requirements within the study area for every unit of production sold to final demand. Total production will vary depending on whether induced effects are included and the method of inclusion. Multipliers may be constructed for output, employment, and every component of value added.

Output: The value of local production required to sustain activities

Per Diem: Allowance for lodging (excluding taxes), meals and incidental expenses.

Proprietor Income: Income from sole proprietorships, partnerships, and tax-exempt cooperatives

Substation: A set of equipment reducing the high voltage of electrical power transmission to that suitable for supply to consumers

Value Added: A measure of the impacting industry's contribution to the local community, including wages, rents, interest, profits, and all non-payroll taxes.

Appendix B. Detailed Assumptions Used in Modeling

This section provides detailed inputs and assumptions used in modeling the MRC project for all four study areas.

The following IMPLAN industries were selected for sectoring these impact activities.

Table 17. IMPLAN Sectors Used in Modeling

IMPLAN Sector Description
All other food and drinking places
Architectural, engineering, and related services
Automotive repair and maintenance, except car washes
Construction of other new, nonresidential structures
Dry-cleaning and laundry services
Electric power transmission and distribution
Full-service restaurants
Hospitals
Hotels and motels, including casino hotels
Legal services
Limited-service restaurants
Management consulting services
Offices of physicians
Other accommodations
Other ambulatory health care services
Other real estate
Retail – Food and beverage stores
Retail – Gasoline stores
Retail – General merchandise stores
Wholesale services – Machinery, equipment, and supplies

SOURCE: IMPLAN

The cost of land purchases was not included in the model. Materials costs across all categories were modeled using a Commodity Output IMPLAN activity within the economic sector "Wholesale services – machinery, equipment, and supplies."

The range of years for the project is assumed to be 2025 to 2033. All project spending was modeled in 2025, using the most recent available data from 2024 and presented in 2025 dollars. Spending totals were distributed among the project years according to the timeline in the table on the following page.

Table 18. MRC Project Spending by Year, Primary Activity, and Share of Budget (in Millions of 2025 Dollars)

Year	Primary Activities	Spending (in millions of dollars)	Percentage of budget
2025	Stakeholder engagement and routing	$3.2	0.4%
2026	Permitting, engineering, environmental surveying	$35.9	4.4%
2027		$71.2	8.8%
2028	Construction	$176.3	21.7%

2029		$59.9	7.4%
2030		$155.5	19.1%
2031		$152.7	18.8%
2032		$154.6	19.0%
2033	In service	$3.8	0.5%
Total		$813.2	100.0%

*Totals may not sum due to rounding

SOURCE: MRC PROJECT TEAM

While the construction activity itself will happen within the study area, the MRC project team acknowledged that many of the contractors and large materials purchases (e.g., transformers, poles) will be sourced from outside of the study area. Of the $813 million in spending, the companies estimate that around $477 million will occur within the seven-county region, $523 within Minnesota, $27 million within North Dakota, and roughly $550 million within Minnesota and North Dakota. To ensure that spending outside the study area would not be included, the research team adjusted the IMPLAN models to reflect only local spending for each of the project's major budget categories, based on estimates provided by the MRC project team. Table 19 below shows the detailed share of project spending that is expected to occur within each study area.

Table 19. Share of Local MRC Project Spending by Segment and Activity

Segment	Spending Activity	Seven-county Region	Minnesota	North Dakota	Minnesota and North Dakota
Maple River Substation	Construction Labor	100%	0%	100%	100%
	Engineering & Consulting Services	2%	0%	20%	20%
	Permitting, Siting, and Land Services	0%	97%	3%	100%
	Project Planning and Management	2%	0%	70%	70%
	Materials	5%	0%	15%	15%
345kV Transmission Line	Construction Labor	97%	97%	3%	100%
	Engineering & Consulting Services	2%	20%	0%	20%
	Permitting, Siting, and Land Services	0%	97%	3%	100%
	Project Planning and Management	2%	68%	2%	70%
	Materials	5%	3%	2%	5%
Cuyuna Substation	Construction Labor	100%	100%	0%	0%
	Engineering & Consulting Services	2%	20%	0%	20%
	Permitting, Siting, and Land Services	0%	97%	3%	100%
	Project Planning and Management	2%	70%	0%	70%
	Materials	5%	15%	0%	15%

SOURCE: MRC PROJECT TEAM

IMPLAN provides an in-commuting rate for each region, representing the share of employee compensation earned by workers who commute into the area and return to residences elsewhere. Because employee compensation is recorded at the place of work, earnings attributed to in-commuters still appear as direct effects in the model. However, since these workers reside outside the study area, their earnings do not generate induced spending locally and are treated as leakages in the model. When a project's expected in-commuting rate differs from IMPLAN's default estimates, adjustments are required to reflect the amount of income leaving the region.

Of the construction jobs expected to be supported by the MRC project each year, the research team assumed that 50% would be filled by union laborers from within the seven-county region and 80% will be filled by union laborers from within the states of Minnesota and North Dakota. Table 19 presents the resulting adjustments to employee compensation across the study areas. To estimate these adjustments, employee compensation for the construction portion of the project was adjusted using the following formula:

> Local Employee Compensation in Seven-county Region = Total Employee Compensation * [(1- expected in-commuting rate)/(1- typical in-commuting rate)]

Table 19. Construction Employee Compensation Adjustments by Study Area (in Millions of 2025 Dollars)

Study Area	*Total Employee Compensation*	*Expected In-Commuting Rate*	*Typical In-Commuting rate*	*Local Employee Compensation*
Minnesota and North Dakota	$140.9	20%	3.03%	$116.2
Minnesota	$135.4	20%	3.13%	$111.8
North Dakota	$5.5	20%	11.13%	$4.9
Seven-county Region	$130.9	50%	7.61%	$70.8

SOURCE: IMPLAN

The research team used compensation estimates provided by the companies' representatives to adjust the software's employment numbers for the project. For construction laborers, the MRC project team estimates that workers will earn roughly $63 per hour for a 40-hour workweek, assuming a majority of union workers and prevailing wages. The team also estimated a 33% fringe rate and a 10% allowance for per diem expenses, equaling an average compensation per worker of $187,357 annually. For all other budget categories (project management, engineering, and permitting), the companies predicted that two-thirds of employees would be salaried, with an hourly base wage of about $78, while the other third would be hourly or technical workers, receiving a base wage of $46 per hour. These workers were also assumed to receive a 33% fringe rate but no per diem allowance, for an average annual compensation per worker of $185,681.

To account for construction workers' per diem allowance, 10% of nonlocal employee compensation was added to the model. That value was $6.0 million for the seven-county region, $2.4 million for the state of Minnesota, and $54.8 thousand for the state of North Dakota. Roughly 70% of the projected per diem spending is on lodging and food, with automotive costs, incidentals, and healthcare expenses rounding out the rest of the expected spending. [21]

[21] The research team used an average of the U.S. General Services Administration's (GSA) per diem rates for Minnesota and the Minnesota Department of Employment and Economic Development cost of living estimates to determine an appropriate per diem allocation.

Appendix C. Input-Output Modeling

Data Sources

This study uses IMPLAN's input-output modeling data and software. The IMPLAN database contains county, state, zip code, and federal economic statistics, which are specialized by region, not estimated from national averages. Using classic input-output analysis in combination with region-specific Social Accounting Matrices and Multiplier Models, IMPLAN provides a highly accurate and adaptable model for its users. IMPLAN data files use the following federal government data sources:

- U.S. Bureau of Economic Analysis Benchmark Input-Output Accounts of the U.S.
- U.S. Bureau of Economic Analysis Output Estimates
- U.S. Bureau of Economic Analysis Regional Economic Information Systems (REIS) Program
- U.S. Bureau of Labor Statistics Covered Employment and Wages (CEW) Program
- U.S. Bureau of Labor Statistics Consumer Expenditure Survey
- U.S. Census Bureau County Business Patterns
- U.S. Census Bureau Decennial Census and Population Surveys
- U.S. Census Bureau Economic Censuses and Surveys
- U.S. Department of Agriculture Census

IMPLAN data files consist of the following components: employment, industry output, value added, institutional demands, national structural matrices, and inter-institutional transfers. Economic impacts are made up of direct, indirect, and induced impacts. The data used was the most recent IMPLAN data available, which is for the year 2024.

Economic impacts are made up of direct, indirect, and induced impacts. The following are suggested assumptions for accepting the impact model: IMPLAN input/output is a production-based model, and employment numbers (from U.S. Department of Commerce secondary data) treat both full- and part-time individuals as being employed.

Regional data for the impact models for value added, employment, and output are supplied by IMPLAN for this impact. Employment assumptions were provided to the model to enable construction of the impact model. From these data, social accounts, production, absorption, and byproducts information were generated from the national level data and was incorporated into the model. All region study definitions and impact model assumptions were agreed on before work with the models began.

Suggested Assumptions

The following are suggested assumptions for accepting the impact model:[22]

Constant Returns to Scale: The same quantity of input is needed per unit of Output, regardless of the level of production. In other words, if Output increases by 10%, input requirements will also increase by 10%.

Employment: IMPLAN input-output is a production-based model, and employment numbers (from U.S.

[22] https://www.bea.gov/system/files/papers/WP2012-3.pdf

Department of Commerce secondary data) treat both full- and part-time individuals as being employed.

Fixed prices and no supply constraints: IMPLAN is a fixed-price model. This means that the modeling software assumes no price adjustment in response to supply constraints or other factors. In other words, the model assumes that firms can increase their production as needed and are not limited by availability of labor or inputs and that firms in the local economy are operating at full capacity.

Fixed production patterns: Input-output (I-O) models assume inputs are used in fixed proportion, without any substitution of inputs, across a wide range of production levels. This assumption assumes that an industry must double its inputs (including both purchases and employment) to double its output. In many instances, an industry will increase output by offering overtime, improving productivity, or improvements in technology.

Industry homogeneity: I-O models typically assume that all firms within an industry have similar production processes. Any industries that fall outside the typical spending pattern for an industry should be adjusted using IMPLAN's Analysis-by-Parts technique.

Leakages: A small area can have a high level of leakage. Leakages are any payments made to imports or value-added sectors, which do not in turn re-spend the dollars within the region. Additionally, a study area that is part of a larger functional economic region will likely miss some important linkages. For example, workers who live and spend outside the study area may hold local jobs.

Appendix D. Impacted Industries

The following tables (20-23) breakdown the direct, indirect, and induced impacts for the top 25 impacted industries in each of the four study areas.

Table 20. MRC Project Impacts by Industry Output, Minnesota and North Dakota, 2025-2033 (Millions of 2025 $)

Rank	*IMPLAN Industry*	*Direct*	*Indirect*	*Induced*	*Total*
1	Construction of other new nonresidential structures	$322.6	$0.0	$0.0	$322.6
2	Electric power transmission and distribution	$166.4	$30.1	$3.0	$199.6
3	Electric power generation - Fossil fuel	$0.0	$61.2	$0.9	$62.1
4	Management consulting services	$34.2	$1.2	$1.1	$36.5
5	Owner-occupied housing	$0.0	$0.0	$25.3	$25.3
6	Electric power generation - Nuclear	$0.0	$20.4	$0.3	$20.7
7	Other real estate	$4.8	$4.4	$6.5	$15.6
8	Hospitals	$0.0	$0.0	$14.9	$14.9
9	Wholesale - Machinery, equipment, and supplies	$13.0	$1.0	$0.4	$14.4
10	Electric power generation - Wind	$0.0	$13.8	$0.2	$14.0
11	Electric power generation - Hydroelectric	$0.0	$10.1	$0.2	$10.2
12	Monetary authorities and depository credit intermediation	$0.0	$3.0	$7.1	$10.1
13	Legal services	$4.0	$1.8	$2.2	$7.9
14	Electric power generation - Biomass	$0.0	$6.8	$0.1	$6.9
15	Offices of physicians	$0.0	$0.0	$6.8	$6.9
16	Insurance carriers, except direct life	$0.0	$1.3	$4.9	$6.3
17	Management of companies and enterprises	$0.0	$2.5	$3.5	$5.9
18	Limited-service restaurants	$0.2	$0.3	$5.3	$5.8
19	Full-service restaurants	$0.2	$0.9	$4.7	$5.8
20	Architectural, engineering, and related services	$4.5	$0.8	$0.4	$5.7
21	Commercial/industrial machinery rental and leasing	$0.0	$4.8	$0.3	$5.1
22	Employment services	$0.0	$2.8	$1.7	$4.5
23	Petroleum refineries	$0.0	$1.6	$2.8	$4.4
24	Local government electric utilities	$0.0	$3.9	$0.2	$4.1
25	Other fabricated metal manufacturing	$0.0	$4.0	$0.0	$4.1

SOURCE: IMPLAN

Table 21. MRC Project Impacts by Industry Output, Minnesota, 2025-2033 (Millions of 2025 $)

Rank	*IMPLAN Industry*	*Direct*	*Indirect*	*Induced*	*Total*
1	Construction of other new nonresidential structures	$310.4	$0.0	$0.0	$310.4
2	Electric power transmission and distribution	$160.0	$29.0	$2.9	$191.8
3	Electric power generation - Fossil fuel	$0.0	$57.2	$0.9	$58.1
4	Management consulting services	$32.6	$1.1	$1.1	$34.7
5	Owner-occupied housing	$0.0	$0.0	$24.4	$24.4
6	Electric power generation – Nuclear	$0.0	$20.4	$0.3	$20.7

7	Other real estate	$4.6	$3.9	$6.2	$14.8
8	Hospitals	$0.0	$0.0	$14.0	$14.0
9	Electric power generation - Wind	$0.0	$13.1	$0.2	$13.3
10	Electric power generation - Hydroelectric	$0.0	$10.1	$0.2	$10.2
11	Monetary authorities and depository credit intermediation	$0.0	$2.8	$6.8	$9.6
12	Wholesale - Machinery, equipment, and supplies	$7.6	$0.9	$0.4	$8.8
13	Legal services	$3.8	$1.7	$2.1	$7.7
14	Electric power generation - Biomass	$0.0	$6.8	$0.1	$6.9
15	Offices of physicians	$0.0	$0.0	$6.5	$6.5
16	Insurance carriers, except direct life	$0.0	$1.2	$4.8	$5.9
17	Management of companies and enterprises	$0.0	$2.2	$3.4	$5.6
18	Limited-service restaurants	$0.2	$0.2	$5.1	$5.5
19	Full-service restaurants	$0.2	$0.8	$4.5	$5.5
20	Architectural, engineering, and related services	$4.1	$0.7	$0.4	$5.2
21	Commercial/industrial machinery rental and leasing	$0.0	$4.5	$0.3	$4.8
22	Employment services	$0.0	$2.7	$1.6	$4.3
23	Petroleum refineries	$0.0	$1.5	$2.7	$4.2
24	Local government electric utilities	$0.0	$3.9	$0.2	$4.1
25	Other fabricated metal manufacturing	$0.0	$3.9	$0.0	$4.0

SOURCE: IMPLAN

Table 22. MRC Project Impacts by Industry Output, North Dakota, 2025-2033 (Millions of 2025 $)

Rank	*IMPLAN Industry*	*Direct*	*Indirect*	*Induced*	*Total*
1	Construction of other new nonresidential structures	$12.2	$0.0	$0.0	$12.2
2	Electric power transmission and distribution	$6.5	$1.2	$0.1	$7.8
3	Wholesale - Machinery, equipment, and supplies	$5.4	$0.2	$0.0	$5.6
4	Electric power generation - Fossil fuel	$0.0	$4.0	$0.1	$4.0
5	Management consulting services	$1.7	$0.1	$0.0	$1.8
6	Other real estate	$0.2	$0.4	$0.3	$0.9
7	Hospitals	$0.0	$0.0	$0.9	$0.9
8	Owner-occupied housing	$0.0	$0.0	$0.9	$0.9
9	Electric power generation - Wind	$0.0	$0.7	$0.0	$0.7
10	Oil and gas extraction	$0.0	$0.5	$0.1	$0.6
11	Architectural, engineering, and related services	$0.5	$0.1	$0.0	$0.5
12	Monetary authorities and depository credit intermediation	$0.0	$0.2	$0.3	$0.5
13	Insurance carriers, except direct life	$0.0	$0.2	$0.2	$0.3
14	Offices of physicians	$0.0	$0.0	$0.3	$0.3
15	Management of companies and enterprises	$0.0	$0.2	$0.1	$0.3
16	Commercial/industrial machinery rental and leasing	$0.0	$0.3	$0.0	$0.3
17	Insurance agencies, brokerages, and related activities	$0.0	$0.1	$0.1	$0.3

18	Limited-service restaurants	$0.0	$0.0	$0.2	$0.3
19	Full-service restaurants	$0.0	$0.1	$0.2	$0.3
20	Legal services	$0.1	$0.1	$0.1	$0.3
21	Coal mining	$0.0	$0.2	$0.0	$0.2
22	Truck transportation	$0.0	$0.1	$0.1	$0.2
23	Retail - Motor vehicle and parts dealers	$0.0	$0.0	$0.2	$0.2
24	Other local government enterprises	$0.0	$0.1	$0.1	$0.2
25	Environmental and other technical consulting services	$0.0	$0.2	$0.0	$0.2

SOURCE: IMPLAN

Table 23. MRC Project Impacts by Industry Output, Seven-county Region, 2025-2033 (Millions of 2025 $)

Rank	*IMPLAN Industry*	*Direct*	*Indirect*	*Induced*	*Total*
1	Construction of other new nonresidential structures	$313.0	$0.0	$0.0	$313.0
2	Electric power transmission and distribution	$150.1	$4.7	$1.0	$155.8
3	Wholesale - Machinery, equipment, and supplies	$12.3	$0.2	$0.2	$12.7
4	Owner-occupied housing	$0.0	$0.0	$10.4	$10.4
5	Hospitals	$0.0	$0.0	$8.8	$8.8
6	Other real estate	$0.1	$1.4	$3.6	$5.2
7	Commercial/industrial machinery rental and leasing	$0.0	$4.9	$0.1	$5.0
8	Local government electric utilities	$0.0	$4.0	$0.1	$4.1
9	Monetary authorities and depository credit intermediation	$0.0	$0.6	$3.2	$3.8
10	Offices of physicians	$0.0	$0.0	$3.4	$3.5
11	Limited-service restaurants	$0.5	$0.1	$2.5	$3.1
12	Full-service restaurants	$0.5	$0.2	$2.3	$3.0
13	Ready-mix concrete manufacturing	$0.0	$2.4	$0.0	$2.5
14	Insurance carriers, except direct life	$0.0	$0.3	$1.9	$2.2
15	Insurance agencies, brokerages, and related activities	$0.0	$0.4	$1.6	$2.0
16	Retail - Motor vehicle and parts dealers	$0.0	$0.0	$1.9	$2.0
17	Automotive repair and maintenance, except car washes	$0.6	$0.1	$1.3	$1.9
18	Management of companies and enterprises	$0.0	$0.7	$1.0	$1.8
19	Software publishers	$0.0	$0.2	$1.6	$1.8
20	Electric power generation - Solar	$0.0	$1.7	$0.0	$1.7
21	All other food and drinking places	$0.5	$0.2	$0.9	$1.6
22	Tenant-occupied housing	$0.0	$0.0	$1.5	$1.5
23	Other concrete product manufacturing	$0.0	$1.5	$0.0	$1.5
24	Fabricated structural metal manufacturing	$0.0	$1.5	$0.0	$1.5
25	Retail - Food and beverage stores	$0.1	$0.0	$1.3	$1.4

SOURCE: IMPLAN

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

APPENDIX H

MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

ANNUAL ELECTRIC UTILITY FORECAST REPORTS

Appendix H

Forecast Information from Minnesota Power, Great River Energy, and Otter Tail Power Company

Pursuant to Minn. R. 7849.0270, Subp. 1 and Minn. R. 7849.0270, Subp. 2(A)-2(D), a Certificate of Need application must provide information related to peak demand and annual consumption data for an applicant's entire service territory and system. Minnesota Power, Great River Energy, and Otter Tail Power Company (the "Applicants") requested and were granted an exemption from this rule requirement by the Minnesota Public Utilities Commission.[1] In lieu of the information required by Minn. R. 7849.0270, the Applicants agreed to provide substitute data in the form of forecast information from The Applicants' most recent Annual Electric Utility Forecast Report ("AFR"), and any forecast information used by the Applicants or MISO in analyzing the need for the Project.[2]

In Docket No. E999/PR-25-11, Great River Energy filed its 2025 AFR with the Commission on July 1, 2025, Otter Tail Power Company filed its 2025 AFR with the Commission on July 1, 2025, and Minnesota Power filed its 2025 AFR with the Commission on August 1, 2025. Copies of these AFR filings are provided in this appendix. Other forecast information used by the Applicants or MISO in analyzing the need for the Project is discussed in Chapter 3 of the Application.

[1] *In re Application for a Certificate of Need for the Maple River – Cuyuna 345 kV Transmission Line*, Docket No. E015, E017,ET2/CN-25-109, ORDER GRANTING EXEMPTIONS (Oct. 21, 2025).
[2] *In re Application for a Certificate of Need for the Maple River – Cuyuna 345 kV Transmission Line*, Docket No. E015/CN-25-109, REQUEST FOR EXEMPTION FROM CERTAIN CERTIFICATE OF NEED APPLICATION CONTENT REQUIREMENTS (Aug. 27, 2025).

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

August 1, 2025

VIA E-FILING
Ms. Anne Sell
Department of Commerce – Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN 55101-2198

Re: Minnesota Power's 2025 Annual Electric Utility Forecast Report
Docket No. E-999/PR-25-11
ANNUAL COMPLIANCE FILING

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2025 Annual Electric Utility Forecast Report pursuant to Minn. Stat. § 216C.17, subd. 2 and Minn. Rules Chapter 7610. As an electric utility with Minnesota service areas, Minnesota Power (or the "Company") is required to submit to the Minnesota Department of Commerce – Division of Energy Resources ("Department") by July 1 of each year an annual report specifying its short- and long-term energy demand forecasts and the facilities necessary to meet the demand. On June 3, 2025, the Company requested a one-month extension on its Annual Electric Utility Forecast Report which is now due August 1, 2025.

Information included in the "**ELEC_68_2024 Largest Customer List.xlsx**" and "**ELEC_68_2024 Forecast Report.xlsx**" Excel workbooks, as well as in the **Methodology** document, has been designated as **TRADE SECRET**.

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Department and Minnesota Public Utilities Commission eDockets/eFiling system using Docket Number 25-11:

- ELEC_68_2024 Annual Report.xlsx
- ELEC_68_2024 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2024 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2024 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2024 MN Service Area Map.pdf
- ELEC_68_2024 USDOE EIA-861.pdf
- ELEC_68_2024 Rate Schedules.pdf
- METHOD24.pdf (**TRADE SECRET** & Public versions)

Please don't hesitate to contact me if you need additional paper copies or have any questions.

Sincerely,



Debbie A. Mencel
Regulatory Compliance Specialist
Minnesota Power
218-355-3182
dmencel@mnpower.com

DAM:amh
Attach.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2025 Annual Electric Utility Forecast Report	Docket No. E-999/PR-25-11

INTRODUCTION

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption and seasonal peak demand requirements. Minnesota Power's forecast process combines a sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power (or "the Company") is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2025 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, completion of systematic and replicable processes, and thorough analysis of results.

The 2025 AFR forecasts a total of 9.2M MWh of energy sales in 2025, increasing by approximately 17.4% to 10.8M MWh of energy sales in 2039. The system peak forecast, by 2039, is 1,826 MW (winter), representing an increase of approximately 13.6% from Minnesota Power's actual system peak of 1,607 MW in 2024 with all current mining and metals customers operating.

Additionally, as national and regional trends continue to identify a new landscape for energy demand, along with Minnesota Power having ~7400 MW of industrial interconnection requests in the queue the Company included in this year's submittal, a Load Growth Forecast Planning Scenario (Section VI). This scenario is tied to the +1,100 growth case in Minnesota Power's 2025 Integrated Resource Plan ("IRP")[1] and is a conservative scenario given the potential. The Company also included a load down scenario (Section VII) to capture the complexities and volatility of industrial mining growth outlooks. These are important components to monitor for the utility as it continues to prepare for the electric needs of its service area.

[1] Docket No. 015-RP-25-127

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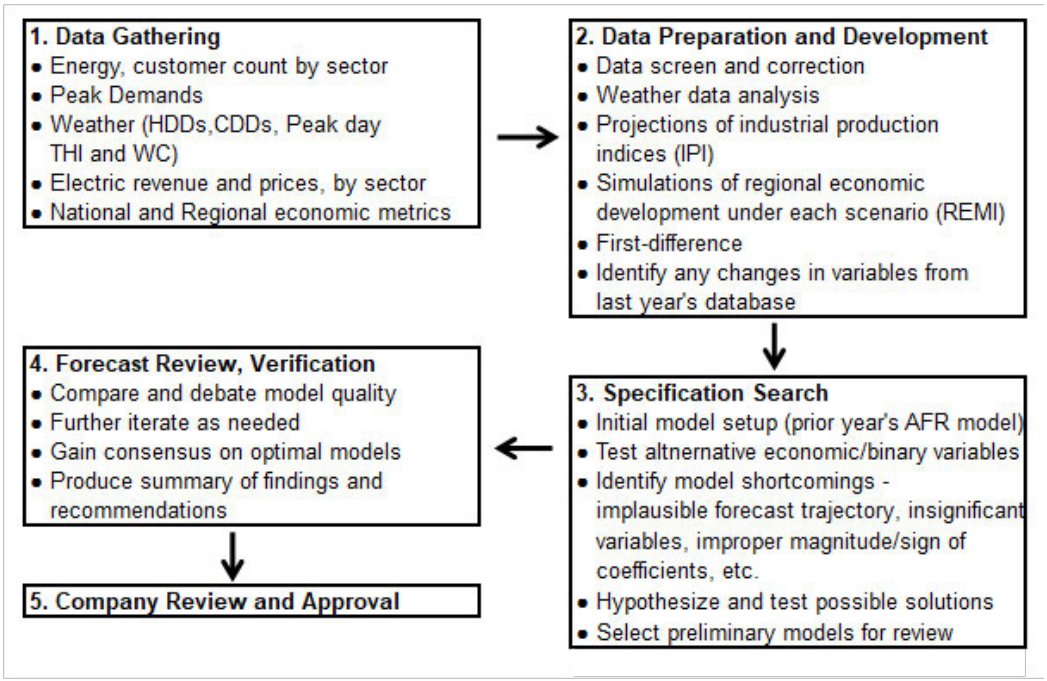
I. Forecast Methodology

A. Overall Framework (7610.0320, Subp. 1.A)

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50 percent probability that a realized actual will be less than forecast and a 50 percent probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) initial review and verification, and 5) internal company review and approval. The steps of the forecast process are sequential, and the process is diagrammed in Figure 1 below.

Figure 1: Minnesota Power's Forecast Process



B. Specific Analytical Techniques (7610.0320, Subp. 1.B) and Relation to Forecast (7610.0320, Subp. 1.C)

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency of definition in a variable series and identify different potential relationships between predictor variables and the dependent variable. Minnesota Power uses the following data transformations in data development:

- *Constant-dollar Deflating/Inflating* – is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2017 as its base year in AFR 2025. The 2017 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis ("BEA").
- *Per-day Conversion* – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.
- *De-trend and De-seasonalize* – is the process of removing the historical trend/seasonality from a data series. This reduces the potential for the spurious, or *false,* correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable (peak demand).
- *First Difference* – changes the definition of the series from *level* (e.g., the number of customers in a month) to *change* (e.g., the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no potential to mistake similarity of *trend* with similarity of *variation*.
- *Exponential* – is the application of an exponent to the series; either squaring or cubing the series. This transformation of raw data was only applied to the temperature variables in the Peak Demand model so the non-linear relationship of load to temperature could be more accurately quantified.

Interpolation Technique – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly frequency (e.g., U.S. Gross Domestic Product ("GDP") is only available in quarterly and annual frequencies).

Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

Modeling Techniques – Most of the dependent count and energy variables are modeled using a trend variable to explain general, underlying growth and one or two economic/demographic variables to explain any economically-driven divergence from this trend. This approach to regression modeling reduces the potential for an independent variable to be erroneously identified as significant due to spurious, or *false,* correlation.

- *Leveraging Binary Variables to Account for Recent Trends* – Several of Minnesota Power's largest industrial and resale customers are in a time of significant change, and an accurate load forecast depends on properly identifying and accounting for these changes. Minnesota Power adjusts historical sales series to "back-out" recent large customer load additions and reductions to avoid double-counting customer usage in the forecast timeframe; once (partially) embedded in the econometric projection, and again through a post-regression load adjustment. This approach is appropriate when the load addition/loss is quantifiable (e.g., a new customer, or a new customer-owned generator).
  This approach is supplemented with the use of binary and trend variables that account for large changes in load that cannot be precisely quantified (such as a customer expansion that is not metered separately). The variables denote and account for a structural shift in a dependent variable (historical sales) and are then terminated at the start of the forecast timeframe to effectively "back out" this recent change so it can be accurately quantified and explicitly applied through a post-regression adjustment to the econometric series.

- *Polynomial temperature specification for peak demand* – The AFR 2025 peak demand model uses a third-degree (cubed) temperature series alongside an un-adjusted temperature series to capture the non-linear relationship of load to temperature. The two variables (cubed and un-adjusted) create a polynomial temperature specification.

- *Modeled Peak Demand using hour-specific weather observations* – Minnesota Power has modeled peak demand as a function of the weather observations specific to the hour in

which the peak occurred. The Company identified the historical peak date/times and queried an hourly weather observation dataset to identify the hourly temperature, humidity, and wind-chill coincident with the system peak. In theory, the temperature at the time of the peak should be more closely related with the load than a daily high or low temperature. As a rule, all models are ordinary least squares ("OLS"), which are simple, transparent, explainable, and produce optimal estimates of the coefficients. Once input variables' coefficients are determined to be statistically significant and models are finalized, they form the basis of the "econometrically determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/losses and/or adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

C. Statistical Techniques, Typical Computations Specifying Variables and Data, and the Results of Appropriate Statistical Tests (7610.0320, Subp. 1.D)

This section presents the statistical detail of all models utilized in the development of the AFR 2025 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, P-value and Heteroscedasticity and Autocorrelation Consistent ("HAC") P-value. Minnesota Power includes the HAC P-value as it adjusts for biases resulting from autocorrelation and/or heteroscedasticity. These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment. Below, for each model, a graph displays the historical series, growth rates for timeframes of interest, and a comparison of this year's forecast to last year's forecast. There is a table that shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates, and key diagnostic statistics for the OLS model are shown in a table in the bottom left corner of each page. Minnesota Power also offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues. In addition, this portion of the documentation compares this year's model with last year's model and discusses findings or insights gained.

Figure 2: Residential Customer Count – Expected Scenario

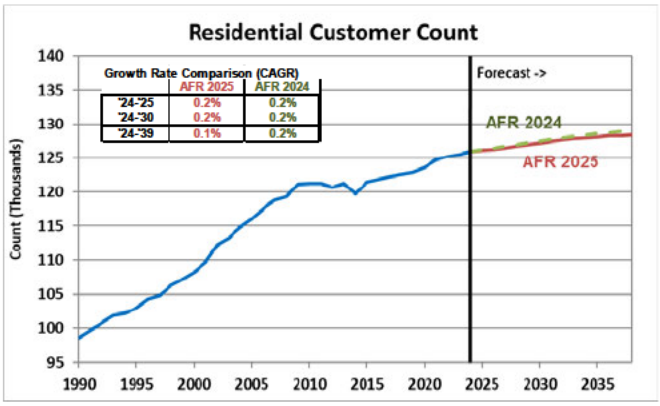
Residential Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	98,162.90	0.00%	0.00%
Bill_Res_1	(2,152.26)	0.00%	0.00%
Bill_Res_2	(2,789.99)	0.00%	0.00%
Dum_2009_2039	8,164.46	0.00%	0.00%
T_2009_2039	(33.14)	0.00%	0.00%
Res_C_2021_2039	1,572.33	0.00%	0.00%
MSA_HousStart_Cumulative	1.07	0.00%	0.00%

Residential Customer Count		
	Count	Y/Y Growth
2012	120,697	
2013	121,314	0.5%
2014	121,601	0.2%
2015	121,515	-0.1%
2016	121,836	0.3%
2017	122,295	0.4%
2018	122,557	0.2%
2019	122,926	0.3%
2020	123,617	0.6%
2021	124,691	0.9%
2022	125,243	0.4%
2023	125,573	0.3%
2024	125,896	0.3%
2025	126,168	0.2%
2026	126,283	0.1%
2027	126,497	0.2%
2028	126,733	0.2%
2029	126,989	0.2%
2030	127,197	0.2%
2031	127,420	0.2%
2032	127,632	0.2%
2033	127,822	0.1%
2034	127,983	0.1%
2035	128,117	0.1%
2036	128,227	0.1%
2037	128,311	0.1%
2038	128,373	0.0%
2039	128,412	0.0%

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	6250
Durban-Watson	0.7
MAPE	0.27
In-Sample RMSE	409



Model Discussion

AFR 2025 has a slightly more conservative growth rate compared to AFR 2024. On average, AFR 2025 has a 0.1% growthrate in residential cutomer count compared to AFR 2024's growthrate of 0.2%.

The key economic variable driving the residential customer count projection was Duluth MSA Cumulative Housing Starts, which is a rolling accumulation of annual housing starts beginning in 1990. This transformation converts a rate variable into a level variable, which better describes the underlying long-term trend of customer growth.

A combination of binary and trend variables ("Dum_2009_2039"" and "T_2009_2039") denote post-recession shifts in the relationship of MSA housing starts and residential customer count; housing starts continued, but customer counts stalled. This may be due in part to a shift towards suburban construction, where home construction continued but just outside Minnesota Power service territory. Without these corrective binary and a trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

The "Res_C_2021_2039" binary variable begins in mid-2021 and denotes a realignment of the MSA housing starts metric and customer counts; the mid-pandemic increase in demand for housing appears to be driving residential development in Minnesota Power's service territory, leading to customer growth. Two binary variables (Bill_Res) account for divergence from long-term trends due to "seasonal billing" between 1994 and 2001. This accounting practice recorded customer counts from November to May as 2,000-6,000 lower than from June to October.

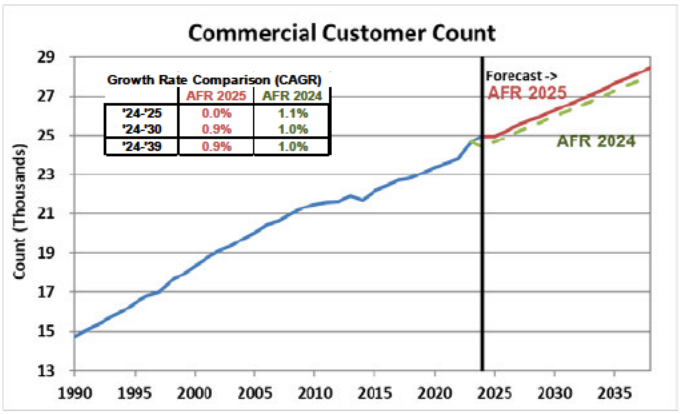
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model that's not over fit. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as the MAPE indicate model accuracy is comparable to AFR 2024 (0.27%).

Figure 3: Commercial Customer Count – Expected Scenario

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	12,385.00	0.00%	0.00%
T	24.78	0.00%	0.00%
Dum_2010_2039	846.27	0.00%	2.11%
T_2010_2039	(5.48)	0.00%	0.01%
MSA_Real_GMP	0.24	0.00%	0.00%



Commercial Customer Count		
	Count	Y/Y Growth
2012	21,614	
2013	21,915	1.4%
2014	22,096	0.8%
2015	22,170	0.3%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,059	1.0%
2020	23,346	1.2%
2021	23,580	1.0%
2022	23,816	1.0%
2023	24,650	3.5%
2024	24,962	1.3%
2025	24,963	0.0%
2026	25,255	1.2%
2027	25,531	1.1%
2028	25,775	1.0%
2029	26,012	0.9%
2030	26,270	1.0%
2031	26,543	1.0%
2032	26,788	0.9%
2033	27,060	1.0%
2034	27,336	1.0%
2035	27,615	1.0%
2036	27,892	1.0%
2037	28,163	1.0%
2038	28,442	1.0%
2039	28,723	1.0%

Model Statistics	Magnitude
Adjusted R^2	99.7%
AIC	5472
Durban-Watson	0.5
MAPE	0.57
In-Sample RMSE	162

Model Discussion

The AFR 2025 Commercial Count forecast has a similar long-term annual growth rate to AFR 2024, both averaging approximately 1.0%.

The key economic driver of customer growth was Duluth MSA Real Gross Metro Product (GMP). Local GMP has historically tracked well with commercial customer counts, but COVID-19 caused the two series (GMP and commercial counts) to diverge, likely due to government supports like the Paycheck Protection Program (PPP) and Minnesota Power suspending disconnections for small business (general service) customers. A Trend variable accounts for some of this underlying customer count growth that appears unrelated to immediate economic conditions.

A combination of binary and trend variables ("Bi_2010_2039" and "T_2010_2039") denote a post-Great Recession, abrupt shift in customer count growth – customer counts grew at an average rate of 2.0% prior to 2010, and only 0.8% since. Without these corrective binary and trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

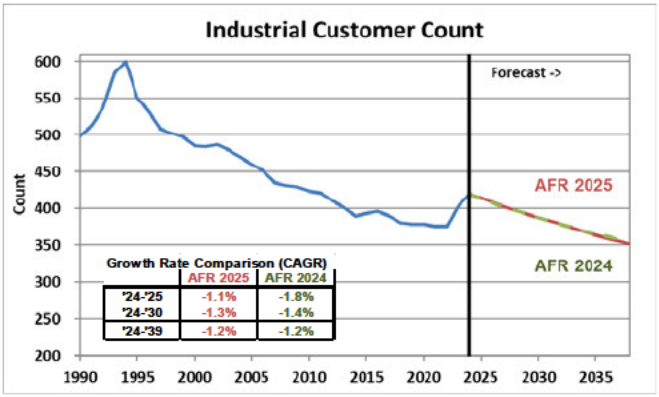
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are very similar: MAPE rose slightly compared to the 2024 model (0.49%), and RMSE is 162 vs. 158 in the 2024 model.

Figure 4: Industrial Customer Count – Expected Scenario

Industrial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	431.35	0.00%	0.00%
T	(0.35)	0.00%	0.00%
Ind_1991_1997	43.52	0.00%	0.00%
MFG_13	0.004	0.00%	0.00%
Ind_2023_2039	55.234	0.00%	0.00%



Industrial Customer Count		
	Count	Y/Y Growth
2012	411	
2013	402	-2.2%
2014	394	-2.0%
2015	394	-0.1%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	378	-0.2%
2021	375	-0.7%
2022	375	0.0%
2023	403	7.4%
2024	419	4.0%
2025	415	-1.1%
2026	408	-1.6%
2027	402	-1.4%
2028	397	-1.4%
2029	392	-1.2%
2030	388	-1.1%
2031	383	-1.1%
2032	379	-1.2%
2033	373	-1.3%
2034	368	-1.4%
2035	363	-1.3%
2036	359	-1.1%
2037	355	-1.1%
2038	351	-1.1%
2039	347	-1.2%

Model Statistics	Magnitude
Adjusted R^2	92.9%
AIC	3564
Durban-Watson	0.1
MAPE	2.18
In-Sample RMSE	17

Model Discussion

The AFR 2025 and AFR 2024 forecast annual growth rate for industrial customer both are approximately -1.2%, with the customer count projection declining to 347 by 2039 compared to AFR 2023's customer count of 354 by 2038.

The key economic driver of industrial customer count was Manufacturing sector employment (13-County). This sector was a good representation of Minnesota Power's industrial customers as it encompasses the range of business sectors in this class, including: wood products, pulp/paper/paperboard mills, food products, foundries, and petroleum refining.

"Ind_1991_1997" is a binary variable that denotes the January-1991 through December-1997 timeframe where Industrial customer counts increased and then decreased very rapidly: a 23.7% increase from January-1991 to June-1994, followed by a 36.2% decrease from June-1994 to December-1997. These dramatic swings in customer counts were most likely due to accounting classifications of customers at the time and this binary variable effectively "backs-out" these points from consideration to avoid biasing the model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. The MAPE has decreased from 2.21 in AFR 2024 to 2.18 in the AFR 2025 model, and RMSE is unchanged at 17 from last year's model.

Figure 5: Public Authorities Customer Count – Expected Scenario

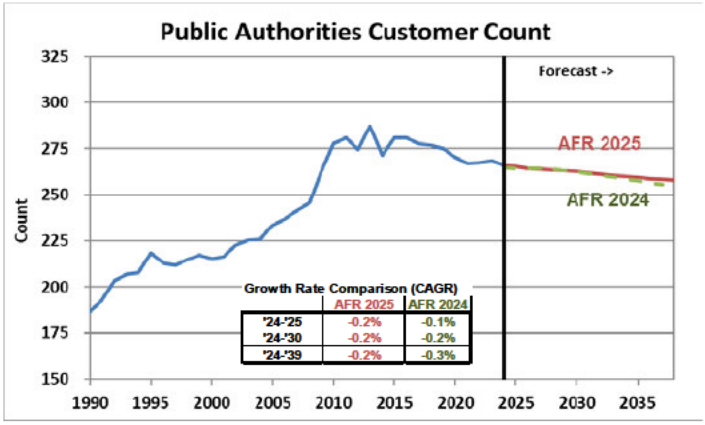
Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	126.59	0.00%	0.00%
Dum_Gov_Light_2009_2039	40.02	0.00%	0.00%
Dum_2015_2039	68.63	0.00%	0.00%
T_2015_2039	(0.21)	0.00%	0.00%
GRP_13	4.39	0.00%	0.00%

Public Auth. Customer Count		
	Count	Y/Y Growth
2012	275	
2013	287	4.6%
2014	282	-1.9%
2015	281	-0.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	271	-1.5%
2021	267	-1.4%
2022	268	0.1%
2023	269	0.5%
2024	266	-1.1%
2025	265	-0.2%
2026	264	-0.4%
2027	264	-0.2%
2028	263	-0.2%
2029	263	-0.1%
2030	263	-0.1%
2031	262	-0.3%
2032	261	-0.3%
2033	260	-0.3%
2034	260	-0.2%
2035	259	-0.2%
2036	259	-0.2%
2037	259	-0.2%
2038	258	-0.1%
2039	258	-0.1%

Model Statistics	Magnitude
Adjusted R^2	97.1%
AIC	2618
Durban-Watson	0.4
MAPE	1.68
In-Sample RMSE	5.4



Model Discussion

The AFR 2025 forecast annual growth rate for public authorities customer count has increased from AFR 2024's -0.4% to a -0.2% average decrease.

The key economic driver of customer growth was 13-County Gross Regional Product (GRP). GRP is a measure of general economic health that correlates with local government revenues, and presumably local government accounts with Minnesota Power. A binary variable starting in July-2009 accounts for a step-change or "systematic shift" in the historical accounting data. The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

The combination of a binary and a trend variable for the 2015-2039 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2025) to align with the last historical year (2024). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2024 forecast value confirms this. Without these binary and trend variables, the model would project an abrupt and unreasonably large increase in customers in 2024.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are comparable to the AFR 2024 model: MAPE decreased slightly to 1.68 compared to AFR 2024's 1.84, and RMSE also decreased to 5.4 in AFR 2025 compared to 2024's

Figure 6: Street Lighting Customer Count – Expected Scenario

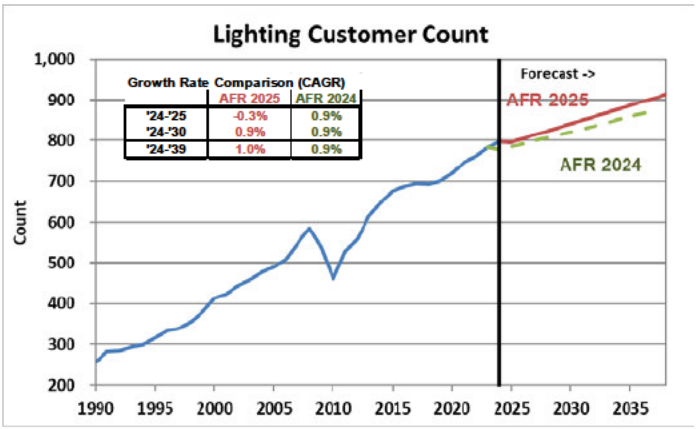
Street Lighting Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	227.20	0.00%	0.00%
T	1.47	0.00%	0.00%
Light_09_14	(723.40)	0.00%	0.00%
Light_T_09_14	2.46	0.00%	0.00%
Dum_Light_2015_2039	188.34	0.00%	0.00%
T_Light_2015_2039	(0.64)	0.00%	0.00%
Light_2020_2039	26.73	0.00%	0.19%
Light_2020_T	(2.14)	0.19%	1.55%

Lighting Customer Count		
	Count	Y/Y Growth
2012	559	
2013	615	10.0%
2014	648	5.4%
2015	673	2.0%
2016	689	2.4%
2017	695	0.9%
2018	693	-0.3%
2019	701	1.1%
2020	720	2.7%
2021	746	3.7%
2022	762	2.1%
2023	784	2.9%
2024	799	1.8%
2025	796	-0.3%
2026	805	1.1%
2027	814	1.1%
2028	823	1.1%
2029	833	1.1%
2030	842	1.1%
2031	851	1.1%
2032	860	1.1%
2033	869	1.1%
2034	878	1.0%
2035	887	1.0%
2036	896	1.0%
2037	905	1.0%
2038	915	1.0%
2039	924	1.0%

Model Statistics	Magnitude
Adjusted R^2	99.2%
AIC	3467
Durban-Watson	0.2
MAPE	2.68
In-Sample RMSE	15



Model Discussion

The AFR 2025 forecast annual growth rate for street lighting customer count is nearly identical to AFR 2024, increasing from 0.9% in AFR 2024 to 1.0% in AFR 2025.

A combination of a binary and trend variable starting in July-2009 account for a step-change or "systematic shift" in the historical accounting data and extends through December-2014.

A combination of a binary variable and trend variable denoting the 2015-2038 timeframe pick up where the 2009-2014 variable left off, shifting the level and trend of the estimate to align with the updated accounting data going forward.

The combination of a binary and a trend variable for the 2020-2039 timeframe (beginning early-2020) mark a shift in the level and trend of the estimate to align with recent customer growth (this was in addition to the 2015-2039 change in forecast trajectory captured by the variables above). These variables effectively shift the first forecast year (2025) to align with the last historical year (2024). Without these corrective variables, 2025 monthly forecasted values would be understated.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as MAPE and RMSE are nearly identical.

Figure 7: Residential Energy Use – Expected Scenario

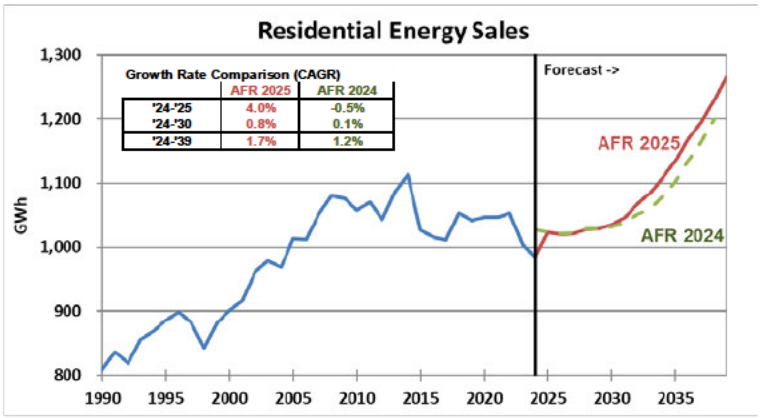
Residential Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	17.06	0.00%	0.00%
Feb	(1.4747947)	0.00%	0.26%
Mar	(2.0783349)	0.00%	0.00%
Apr	(1.6993026)	0.00%	0.00%
May	(1.6054394)	0.00%	0.00%
Jun	(1.1956499)	0.06%	0.00%
Oct	(2.6531024)	0.00%	0.00%
Nov	(2.2446113)	0.00%	0.00%
Dum_2008_2039	1.6895431	0.00%	0.00%
EE_Res	(0.0000146)	0.00%	0.00%
Dul_HDDpd	0.2502352	0.00%	0.00%
Dul_CDDpd	1.0469543	0.00%	0.00%

Residential Energy Sales		
	MWh	Y/Y Growth
2012	1,043,281	
2013	1,086,481	4.1%
2014	1,112,579	2.4%
2015	1,026,454	-7.7%
2016	1,015,465	-1.1%
2017	1,010,955	-0.4%
2018	1,052,800	4.1%
2019	1,042,353	-1.0%
2020	1,046,910	0.4%
2021	1,046,341	-0.1%
2022	1,053,657	0.7%
2023	1,004,064	-4.7%
2024	983,679	-2.0%
2025	1,022,765	4.0%
2026	1,019,977	-0.3%
2027	1,020,482	0.0%
2028	1,027,198	0.7%
2029	1,028,736	0.1%
2030	1,034,807	0.6%
2031	1,045,933	1.1%
2032	1,066,696	2.0%
2033	1,084,161	1.6%
2034	1,108,374	2.2%
2035	1,135,393	2.4%
2036	1,168,074	2.9%
2037	1,194,604	2.3%
2038	1,229,314	2.9%
2039	1,265,699	3.0%

Model Statistics	Magnitude
Adjusted R^2	85.9%
AIC	1659
Durban-Watson	2.0
MAPE	5.40
In-Sample RMSE	1.7



Model Discussion

The graph above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of light-weight electric vehicle and distributed solar adoption.

The AFR 2025 residential per-customer use model did not use an employment or demographic indicator variable as these variables rarely correlate well with per-customer usage and often are not intuitive or explainable. Instead, the Company uses weather and seasonal binary variables to indicate month-to-month variation in sales, a time-trend to indicate long-term underlying growth, and an Energy Efficiency variable to explain recent changes (since 2007) in the underlying trend of per-customer usage growth.

The "EE_Res" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year.

The AFR 2025 model uses simple monthly HDD and CDD (per-day) specifications. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month – this results in the "per-day" series HDDpd and CDDpd.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 5.4% vs 5.45% in the 2024 model, and RMSE in AFR 2025 is 1.7 compared to AFR 2024's 1.8.

Figure 8: Commercial Energy Use – Expected Scenario

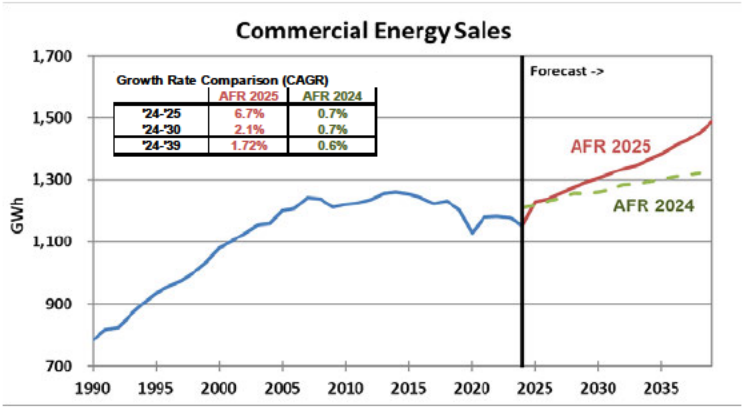
Commercial Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	53.83	0.00%	0.00%
Jan	(6.58)	0.04%	0.12%
Apr	(11.92)	0.00%	0.00%
May	(9.02)	0.00%	0.00%
Aug	10.71	0.00%	0.00%
Sep	7.15	0.02%	0.01%
Oct	(10.06)	0.00%	0.00%
Nov	(11.56)	0.00%	0.00%
Dum_2007_2039	3.88	0.59%	0.02%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.4681	0.00%	0.00%
Dul_CDDpd	4.16	0.00%	0.00%
EmpltoPop_13	227.01	0.00%	0.00%

Commercial Energy Sales		
	MWh	Y/Y Growth
2012	1,237,386	
2013	1,256,540	1.5%
2014	1,262,464	0.5%
2015	1,254,681	-0.6%
2016	1,243,045	-0.9%
2017	1,223,786	-1.5%
2018	1,233,117	0.8%
2019	1,202,403	-2.5%
2020	1,131,101	-5.9%
2021	1,181,246	4.4%
2022	1,181,683	0.0%
2023	1,178,825	-0.2%
2024	1,152,595	-2.2%
2025	1,229,281	6.7%
2026	1,239,950	0.9%
2027	1,256,533	1.3%
2028	1,275,654	1.5%
2029	1,291,103	1.2%
2030	1,304,840	1.1%
2031	1,319,861	1.2%
2032	1,336,171	1.2%
2033	1,347,900	0.9%
2034	1,366,025	1.3%
2035	1,385,166	1.4%
2036	1,409,117	1.7%
2037	1,426,992	1.3%
2038	1,451,394	1.7%
2039	1,488,083	2.5%

Model Statistics	Magnitude
Adjusted R^2	70.2%
AIC	3044
Durban-Watson	2.5
MAPE	4.61
In-Sample RMSE	9



Model Discussion

The AFR 2025 forecast of commercial energy use is higher than AFR 2024 due to forecasted higher use-per-customer. The commercial energy use forecast grows at a 1.7% per year (average) pace, compared to the AFR 2024 forecast of 0.6%.

The graph above shows the final commercial energy sales outlook, which combines the econometric forecasts of use-per-customer per day and customer count, along with arithmetic adjustments for: 1) Adoption of medium and heavy-duty electric vehicles used for commercial and fleet operations, 2) the planned installation of new generation at a specific customer's facility, and 3) the projected impacts of distributed solar adoption.

The key driver of this year's commercial energy use model was the 13-County Employment-to-Population ratio. COVID-19 resulted in a substantial loss of energy sales without any corresponding decrease in customer counts, which is unprecedented and difficult to model with the typical economic indicators. The Employment-to-Population ratio indicates the rate of employment utilization, and both correlates and explains commercial property/account energy utilization during the initial economic contraction and recovery from COVID-19.

"Dum_2007_2039" is a binary variable starting in 2007 that accounts for a step-change, or "systematic shift," in energy use for this class around the time of the 2007 Energy Act. Sales to this class have remained essentially flat since this time (aside from the COVID-19 recession of 2020).

The AFR 2025 model uses an Energy Efficiency variable as a predictor of commercial per-customer sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 70.2% indicates there's just a moderate traditional "goodness-of-fit", but this was the case in last year's model as well (Adjusted R-Squared was only 68%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power leverages other objective metrics for determining model selection such as Mean Absolute Percent Error and Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 4.61% vs. 4.57% in the 2024 model, and RMSE is unchanged at 9 in both the 2025 and 2024 models.

Figure 9: Mining and Metals Energy Use – Expected Scenario

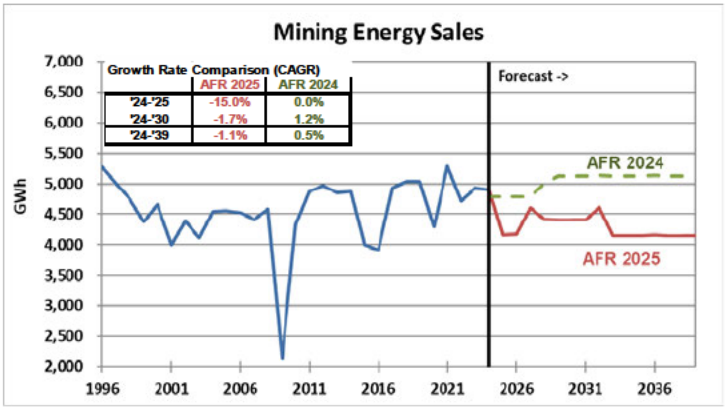
Mining and Metals Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	6,575.01	0.00%	0.00%
LTV_T	(24.73)	0.00%	0.01%
Mine_Maint	(313.65)	18.61%	5.16%
Mine_Downturn1	(3,294.14)	0.00%	0.00%
Mine_Downturn2	(1,783.56)	0.00%	0.00%
Mine_Downturn3	(1,496.32)	0.01%	0.00%
Metals	148.27	28.21%	23.60%
MN_Iron_IPI	58.94	0.00%	0.00%

Mining and Metals Energy Sales		
	MWh	Y/Y Growth
2012	4,968,517	
2013	4,851,094	1.9%
2014	4,879,520	-2.4%
2015	4,000,557	0.6%
2016	3,906,570	-18.0%
2017	4,930,188	-2.3%
2018	5,039,138	26.2%
2019	5,038,704	2.2%
2020	4,295,593	0.0%
2021	5,280,743	-14.7%
2022	4,712,773	22.9%
2023	4,935,265	-10.8%
2024	4,896,466	4.7%
2025	4,161,137	-15.0%
2026	4,165,169	0.1%
2027	4,603,455	10.5%
2028	4,417,259	-4.0%
2029	4,407,031	-0.2%
2030	4,408,133	0.0%
2031	4,407,060	0.0%
2032	4,617,835	4.8%
2033	4,149,141	-10.1%
2034	4,149,502	0.0%
2035	4,148,925	0.0%
2036	4,159,739	0.3%
2037	4,149,659	-0.2%
2038	4,150,970	0.0%
2039	4,150,401	0.0%

Model Statistics	Magnitude
Adjusted R^2	71.8%
AIC	5815
Durban-Watson	1.0
MAPE	5.41
In-Sample RMSE	993



Model Discussion

The AFR 2025 outlook for mining and metals energy use is lower than the AFR 2024 projection due to decreased customer operations (post-regression adjustments). The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load adjustments.

The key economic driver of this year's mining energy use model was the Minnesota (MN) Iron IPI, which measures the real production output nationwide in the industry and is scaled to MN-only.

This year's model incorporates several binary variables to control for known or suspected definitional changes in the historical mining energy sales series. These variables have been added with the goal of avoiding bias in the IPI's coefficient for these past definitional changes in the mining and metals sales series.

"LTV_T" is a trend variable that denotes the timeframe from 1996-2001, when a large mining customer ended operations. The variable accounts for a possible change in relationship between Minnesota Power mining customer energy and the MN IPI, and allows for a more exact estimation of the relationship during the current paradigm.

The "Mine_Maint" binary variable denotes and normalizes for some of the observable seasonality in mining operations.

The "Mine_Downturn1" binary variable denotes the recession period from early 2009 to early 2010, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn2" binary variable denotes a timeframe from May-2015 to February-2017, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Mine_Downturn3" binary variable denotes months between April-2020 and November-2020, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Metals" binary variable denotes operations of four smaller metals customers in the January-2010 to September-2016 timeframe. These customers' are backed out of the historical series prior to regression modeling, but their historical production contributed to national iron IPI. This binary variable ("Bi_Mine6") explains the temporary distortion in the energy-sales-to-National-IPI relationship.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant-with the exception of "Metals". It was determined this variable was needed because this variable was used in last year's model, i.e. for year-to-year consistency, and this is an important factor shaping consumption in the forecast timeframe. In-sample error metrics are similar: the MAPE is 5.4 compared to 2023 model at 5.7%, but the RMSE is lower at 993 vs. 1018 in the 2024 model.

Figure 10: Paper and Pulp Products Energy Use – Expected Scenario

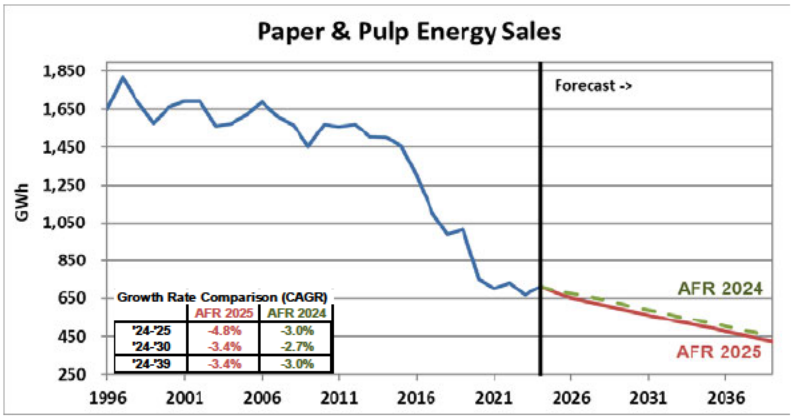
Paper and Pulp Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	4,696.26	0.00%	0.00%
T	(3.93)	0.00%	0.00%
Mar	132.30	15.11%	1.48%
Jun	162.13	7.88%	1.28%
Aug	275.51	0.29%	0.01%
Sep	305.79	0.11%	0.01%
Oct	262.58	0.49%	0.05%
Dec	(131.28)	15.43%	5.68%
Term_Paper_20_38	(1,503.94)	0.00%	0.00%
Paper_IPI_diff	27.16	13.04%	8.30%
Paper_22_Gen	961.23	0.45%	0.00%

Paper & Pulp Energy Sales		
	MWh	Y/Y Growth
2012	1,570,852	
2013	1,505,113	0.7%
2014	1,498,810	-4.2%
2015	1,456,091	-0.4%
2016	1,302,920	-2.9%
2017	1,104,160	-10.5%
2018	987,208	-15.3%
2019	1,013,971	-10.6%
2020	752,072	2.7%
2021	701,549	-25.8%
2022	735,506	-6.7%
2023	668,406	4.8%
2024	714,239	-9.1%
2025	679,876	-4.8%
2026	650,672	-4.3%
2027	632,557	-2.8%
2028	617,031	-2.5%
2029	597,978	-3.1%
2030	580,630	-2.9%
2031	563,325	-3.0%
2032	547,506	-2.8%
2033	528,671	-3.4%
2034	511,456	-3.3%
2035	494,241	-3.4%
2036	478,266	-3.2%
2037	459,810	-3.9%
2038	442,594	-3.7%
2039	425,378	-3.9%

Model Statistics	Magnitude
Adjusted R^2	78.2%
AIC	5278
Durban-Watson	0.5
MAPE	9.27
In-Sample RMSE	458



Model Discussion

The AFR 2025 outlook for paper and wood products energy requirements is slightly lower than the AFR 2024 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The AFR 2025 model was driven by the Industrial Production Index (IPI) for Paper, which measures the real production output nationwide in the industry, and indicates an underlying secular decline of the North American Paper industry (and demand for paper products).

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's reasonable goodness-of-fit, and In-sample error metrics are a bit different: MAPE is slightly lower in AFR 2025 at 9.3 compared to 9.4 in AFR 2024, and RMSE decreased to 458 vs. 466 in the 2024 model.

The AIC indicates a highly parsimonious model. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

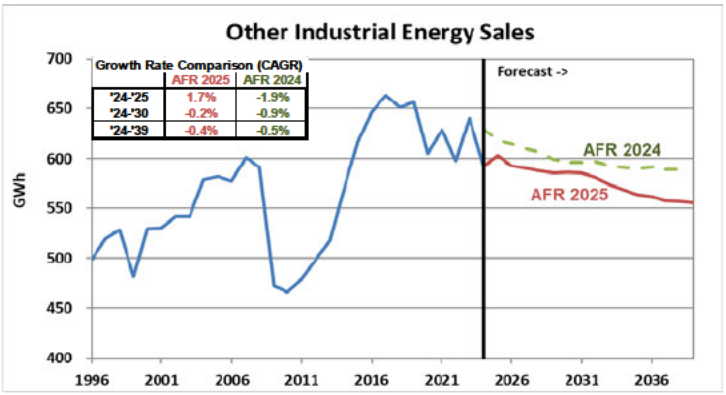
Figure 11: Other Industrial Energy Use – Expected Scenario

Other Industrial Energy Use - Expected Scenario

Estimation Start/End:
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value

Other Industrial Energy Sales		
	MWh	Y/Y Growth
2012	498,474	
2013	517,786	3.9%
2014	568,206	9.7%
2015	616,625	8.5%
2016	646,339	4.8%
2017	663,444	2.6%
2018	651,546	-1.8%
2019	656,590	0.8%
2020	605,277	-7.8%
2021	629,017	3.9%
2022	597,430	-5.0%
2023	640,688	11.3%
2024	592,586	-5.3%
2025	602,801	1.7%
2026	593,039	-1.6%
2027	590,510	-0.4%
2028	587,261	-0.6%
2029	585,797	-0.2%
2030	586,415	0.1%
2031	585,437	-0.2%
2032	580,754	-0.8%
2033	573,771	-1.2%
2034	568,624	-0.9%
2035	563,769	-0.9%
2036	562,026	-0.3%
2037	557,985	-0.7%
2038	556,899	-0.2%
2039	555,523	-0.2%



Model Discussion

Minnesota Power has broken out Other Industrial into four sectors: 1) Pipelines, 2) Foundries, 3) Food Products, and 4) Remaining.

Due to several Other Industrial sub-sectors containing just two or three customers, these sector-level forecasts could imply trade secret information. Minnesota Power will only show the aggregate of all sectors ("Other Industrial") in the graph above and table to the left. The sector-specific models of projected energy and the model discussions are discussed on the following pages, and are marked "TRADE SECRET" due to the limited number of customers in each sector.

Figure 12: Pipelines Energy Use – Expected Scenario

Pipelines Energy Use - Expected Scenario

Estimation Start/End: 1/1996 - 12/2024
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	(725.78)	0.09%	3.06%
Term_13_23	(5,208.81)	0.00%	0.00%
Term_13_23_T	18.06	0.00%	0.00%
TTU_13	0.03	0.00%	0.01%

Model Statistics	Magnitude
Adjusted R^2	68.8%
AIC	4320
Durban-Watson	0.5
MAPE	13.49
In-Sample RMSE	117

Model Discussion

Minnesota Power modeled and projected energy sales to pipeline customers individually, independent of total Other Industrial sales.

The AFR 2025 econometric driver for the pipelines model was 13-County Trade, Transportation, & Utilities (TTU) Employment. The TTU employment variable was selected as it directly encompasses the pipeline sector being modeled and highlights a major advantage of more granular forecasting for Other Industrial sub-sectors – economic variable specificity (last year's total Other Industrial model had 13-County Total Non-Farm Employment as the economic variable).

A binary ("Term_13_23") and a trend variable ("Term_13_23_T") denote the period in which a large pipeline customer began adding substantial load, and drove the majority of the energy use increase in the customer class. The binary and trend variables effectively "back-out" this recent load addition, so this customer's expected energy use can be addressed in isolation through a post-regression load addition to avoid double-counting.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are notably comparable to last year's model: MAPE increased to 13.49% compared to 2024 models MAPE of 12.18%. RMSE is higher than the AFR 2024 model at 117. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 13: Foundries Energy Use – Expected Scenario

Foundries Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(416.42)	0.00%	0.01%
Foundry_1999_2000	(64.47)	0.00%	0.00%
Foundry_2011_2014	55.89	0.00%	0.00%
TotNonF_StLou	0.01	0.00%	0.00%
Foundry_IPI	1.18	0.00%	0.00%
Foundry_2024_2039	(70.24)	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	56.2%
AIC	3390
Durban-Watson	0.9
MAPE	8.69
In-Sample RMSE	31

Model Discussion

Minnesota Power modeled and projected energy sales to foundry customers individually, independent of total Other Industrial sales.

The Foundries energy use model leveraged two economic variables: Total St. Louis County Non-Farm Employment, and IPI for Primary Metals. The IPI for Primary Metals measures the national level real output in the industry, and is the model's indicator of national demand of primary metals products. St. Louis County non-farm employment is a more granular indicator of local business operations, and explains local foundry operations that may deviate from the national trend. All of Minnesota Power's foundry customers are located in St. Louis County.

"Foundry_1999_2000" is a binary variable denoting the 1999-2000 timeframe when energy sales began decreasing ahead of the national-level Primary Metals IPI-recognized-downturn due to a local mining customer winding down operations. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

"Foundry_2011_2014" is a binary variable denoting the 2011-2014 timeframe and represents a customer that expanded operations temporarily, diverging from the national-level Primary Petals IPI. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are comparable to last year's model: MAPE is 8.69% vs 8.77% in the AFR 2024 model, and RMSE is 31, unchanged from 2024's model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 14: Food Products Energy Use – Expected Scenario

Food Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(297.88)	0.00%	0.13%
LPP_2015_2039	24.63	0.00%	0.02%
Food_IPI	4.84	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	72.1%
AIC	2984
Durban-Watson	1.2
MAPE	7.52
In-Sample RMSE	17

Model Discussion

Minnesota Power modeled and projected energy sales to food product customers individually, independent of total Other Industrial sales.

Energy sales to the food products sector was modeled using the IPI for Food Products (Food, Beverage, and Tobacco). The IPI for Food Products measures the real production output nationwide in the industry, and indicates an underlying growth trend in this class.

"LLP_2015_2039" is a binary variable denoting the 2015-2039 timeframe. This variable represents a new level of sales following period of expansion for one of the customers in this class (beginning in 2015) and continues throughout the forecast timeframe. A binary variable approach is utilized as Minnesota Power is not adjusting the econometric model in the forecast timeframe to account for increased sales.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also comparable to last year's model: MAPE is 7.52 vs. 7.60% in AFR 2024, and RMSE is consistant at 17 vs. 17 in AFR 2024 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 15: Other Industrial Remaining Energy Use – Expected Scenario

Other Industrial Remaining Energy Use - Expected Scenario

Estimation Start/End:	1/2001 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	0.36	0.00%	0.00%
Misc_Ind_2001_2002	0.42	0.00%	0.00%
Rem_2023_2039	0.15	0.00%	0.00%
MFG_StLou	0.00	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	53.4%
AIC	-484
Durban-Watson	2.0
MAPE	9.47
In-Sample RMSE	0.1

Model Discussion

Minnesota Power modeled and projected energy sales to other industrial: remaining customers individually, independent of total Other Industrial sales. The other industrial: remaining sub-sector includes all industrial customer usage not accounted for in: Mining, Paper, Pipelines, Foundries, and Food Product Manufacturing.

The sole econometric variable used in the other industrial remaining model was St. Louis County Manufacturing Employment. Many of the customers in this class are either directly involved in manufacturing, or supply manufacturers with the goods/inputs they need to create a finished product to sell. Several of the larger customers in this class are located in St. Louis County; because of this, Minnesota Power selected the more granular variable to inform the model, instead of a more general/broader Manufacturing employment series.

"Misc_Ind_2021_2002" is a binary that indicates months in the 2001-2002 timeframe where energy sales have erroneous values. This binary essentially removes the erroneous data points from consideration in the model as they would have a negative influence on the model's integrity.

The Adjusted R-Squared indicates there's a moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also reasonable and comparable to AFR 2024 models: MAPE is less that AFR 2024 at 9.87 vs. 12.71, and RMSE is similar to AFR 2024 models at just 0.1 vs. 0.1. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 16: Public Authorities Energy Use – Expected Scenario

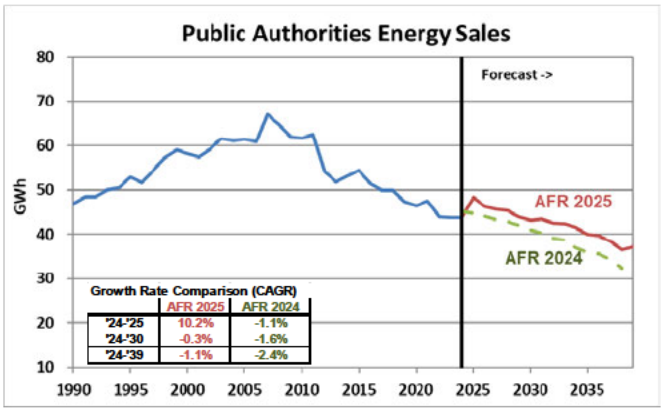
Public Authorities Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(1,200.17)	0.00%	0.00%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.18	0.66%	0.63%
Dul_CDDpd	4.32	0.00%	0.00%
MSA_Pop	4.90	0.00%	0.00%

Public Auth. Energy Sales		
	MWh	Y/Y Growth
2012	54,074	
2013	51,736	-4.3%
2014	53,237	2.9%
2015	54,471	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	46,375	-2.0%
2021	47,497	2.4%
2022	43,943	-7.5%
2023	43,671	-0.6%
2024	43,792	0.3%
2025	48,264	10.2%
2026	46,234	-4.2%
2027	45,622	-1.3%
2028	45,289	-0.7%
2029	43,877	-3.1%
2030	43,076	-1.8%
2031	43,454	0.9%
2032	42,475	-2.3%
2033	42,344	-0.3%
2034	41,618	-1.7%
2035	39,902	-4.1%
2036	39,588	-0.8%
2037	38,344	-3.1%
2038	36,491	-4.8%
2039	37,134	1.8%

Model Statistics	Magnitude
Adjusted R^2	42.1%
AIC	3697
Durban-Watson	2.0
MAPE	10.43
In-Sample RMSE	20



Model Discussion

The key economic driver of this year's Public Authorities energy use model was Duluth MSA Population. This variable indicates the underlying growth trend, which impacts government entities' operations (affecting energy use).

The AFR 2025 model uses an Energy Efficiency variable as a predictor of public authorities' energy sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The commercial-sector energy efficiency variable was used for the public authorities model since: 1) both customer groups are served by the same CIP program, and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.

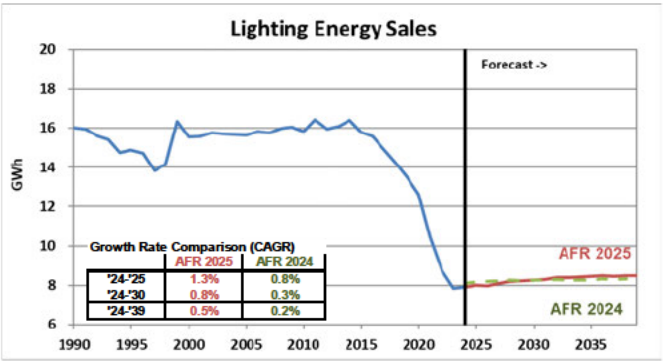
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 10.43% vs. 10.35% in the 2024 model, and RMSE is unchanged at 20 in the 2025 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 17: Street Lighting Energy Use – Expected Scenario

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2024
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	50.17	0.00%	0.00%
T	(0.01)	4.42%	5.18%
Jan	2.67	0.57%	0.10%
Feb	(2.01)	3.65%	0.42%
Mar	(9.06)	0.00%	0.00%
Apr	(13.69)	0.00%	0.00%
May	(19.45)	0.00%	0.00%
Jun	(22.50)	0.00%	0.00%
Jul	(22.13)	0.00%	0.00%
Aug	(18.75)	0.00%	0.00%
Sep	(11.49)	0.00%	0.00%
Oct	(8.28)	0.00%	0.00%
Nov	(2.94)	0.23%	0.00%
Dum_Light_1990_1999	(2.58)	0.23%	1.49%
LED_Lighting	106.46	0.00%	0.00%
LED_Lighting_T	(0.32)	0.00%	0.00%
NonWPI_StLou	0.002	2.25%	1.84%



Lighting Energy Sales		
	MWh	Y/Y Growth
2012	15,954	
2013	16,066	0.7%
2014	16,400	2.1%
2015	15,801	-3.7%
2016	15,588	-1.4%
2017	14,873	-4.6%
2018	14,206	-4.5%
2019	13,482	-5.1%
2020	12,617	-6.4%
2021	10,445	-17.2%
2022	8,744	-16.3%
2023	7,864	-10.1%
2024	7,907	0.6%
2025	8,010	**1.3%**
2026	7,983	**-0.3%**
2027	8,102	**1.5%**
2028	8,206	**1.3%**
2029	8,232	**0.3%**
2030	8,274	**0.5%**
2031	8,307	**0.4%**
2032	8,372	**0.8%**
2033	8,372	**0.0%**
2034	8,409	**0.4%**
2035	8,441	**0.4%**
2036	8,486	**0.5%**
2037	8,463	**-0.3%**
2038	8,475	**0.1%**
2039	8,473	**0.0%**

Model Statistics	Magnitude
Adjusted R^2	87.7%
AIC	2375
Durban-Watson	1.5
MAPE	6.37
In-Sample RMSE	4

Model Discussion

The AFR 2025 lighting per-day use model utilized St. Louis County Non-Wage Personal Income as a key economic/demographic indicator.

"Dum_Light_1990_1999" is a binary variable denoting the 1990-1999 timeframe and effectively shifts the level of the estimate to account for changes to the Company's accounting practices, which affected historical energy use data. The corrective binary shifts the forecast to avoid improbably changes in energy use, but does not impact the forecast trajectory; this is determined by the economic variables.

"LED_Lighting" and "LED_Lighting_T" are binary and trend variables denoting the 2017-2039 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2017 (this level is then held constant in the forecast timeframe after January-2025). This binary and trend combination shifts the forecast to account for Minnesota Power's LED lighting program's impact on energy use, and unlike "Dum_Light_1990_1999," it does impact the forecast trajectory; in addition to the economic variables.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 6.37% vs. 5.97% in the 2024 model, and RMSE is 4.0, the same as AFR 2024. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

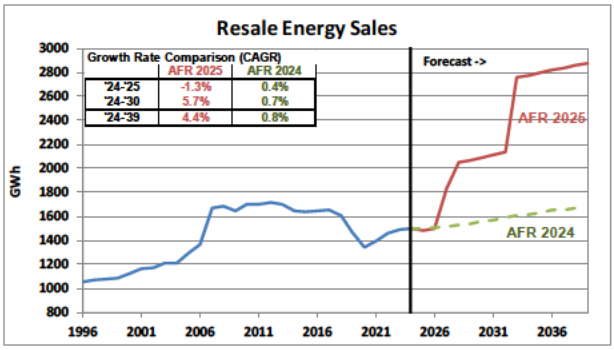
Figure 18: Resale Energy Use – Expected Scenario

Resale Energy Use - Expected Scenario

Estimation Start/End:
Unit Modeled/Forecast: Monthly Per-Day Use (MWh)

Variable	Model Specifications			
	Coefficient	P-Value	HAC-P-Value	VIF

Resale Energy Sales		
	MWh	Y/Y Growth
2012	1,718,819	
2013	1,700,993	7.2%
2014	1,585,993	3.3%
2015	1,634,786	3.1%
2016	1,649,405	0.9%
2017	1,656,865	0.5%
2018	1,610,792	-2.8%
2019	1,468,108	-8.9%
2020	1,340,290	-8.7%
2021	1,393,315	4.0%
2022	1,456,237	4.5%
2023	1,487,350	2.0%
2024	1,499,240	0.7%
2025	1,479,765	-1.3%
2026	1,500,518	1.4%
2027	1,830,163	22.0%
2028	2,053,756	12.2%
2029	2,069,135	0.7%
2030	2,090,526	1.0%
2031	2,111,371	1.0%
2032	2,138,113	1.3%
2033	2,754,040	28.8%
2034	2,774,605	0.7%
2035	2,794,668	0.7%
2036	2,822,702	1.0%
2037	2,834,727	0.4%
2038	2,855,195	0.7%
2039	2,875,914	0.7%



Model Discussion

AFR 2025 is continuing the practice of forecasting each resale customer separately. Minnesota Power will not be providing graphs or tables that include forecast values for individual resale customers (similar to the approach mentioned above for Other Industrial).

Due to the trade secret nature of individual resale customers' forecasts, Minnesota Power will only be showing the aggregate forecast summary for total Resale energy sales in the graph above and table to the left.

Figure 19: System Peak Demand – Expected Scenario

System Peak Demand - Expected Scenario

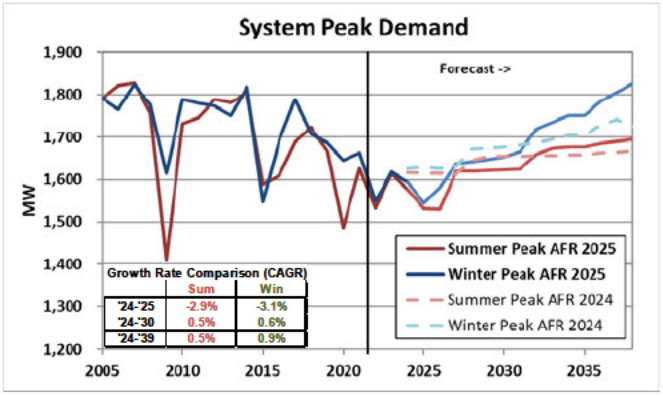
Estimation Start/End:	6/1999 - 12/2024
Unit Modeled/Forecast:	Monthly Peak Demand

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	499.98	0.00%	0.00%
WN_MWhpd	0.03	0.00%	0.00%
S	39.50	0.00%	0.01%
W	19.78	6.20%	1.02%
Dum_1999_2001	(35.22)	0.01%	0.00%
Dum_2008	105.34	0.04%	0.00%
WC_THI	(1.54)	0.00%	0.00%
WC_THI_3	0.0003	0.00%	0.00%
Jan_WN_MWhpd	(0.001)	4.29%	0.57%
Feb_WN_MWhpd	(0.001)	1.47%	0.37%
Mar_WN_MWhpd	(0.001)	0.58%	0.10%

System Peak Demand

	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2012	1,789		2012	1,773	
2013	1,781	0%	2013	1,751	-1%
2014	1,805	1%	2014	1,818	4%
2015	1,589	-12%	2015	1,547	-15%
2016	1,610	1%	2016	1,683	9%
2017	1,688	5%	2017	1,789	6%
2018	1,724	2%	2018	1,707	-5%
2019	1,668	-3%	2019	1,687	-1%
2020	1,487	-11%	2020	1,646	-2%
2021	1,625	9%	2021	1,663	1%
2022	1,533	-6%	2022	1,550	-7%
2023	1,614	5%	2023	1,618	4%
2024	1,577	-2%	2024	1,594	-1%
2025	1,531	-3%	2025	1,544	-3%
2026	1,530	0%	2026	1,581	2%
2027	1,619	6%	2027	1,637	4%
2028	1,620	0%	2028	1,641	0%
2029	1,621	0%	2029	1,646	0%
2030	1,623	0%	2030	1,653	0%
2031	1,624	0%	2031	1,665	1%
2032	1,660	2%	2032	1,719	3%
2033	1,674	1%	2033	1,734	1%
2034	1,677	0%	2034	1,750	1%
2035	1,677	0%	2035	1,750	0%
2036	1,685	0%	2036	1,785	2%
2037	1,690	0%	2037	1,805	1%
2038	1,695	0%	2038	1,826	1%
2039	1,702	0%	2039	1,826	0%

Model Statistics	Magnitude
Adjusted R^2	83.6%
AIC	3161
Durban-Watson	1.0
MAPE	2.25
In-Sample RMSE	41



Model Discussion

The long-run outlook for Minnesota Power's system peak is higher than the 2024 outlook primarily due to higher econometric outputs compared to AFR 2024.

Temperature variables play a critical role in peak demand modeling, and both the definition and structure of these variables are important for interpreting the results. 2025 AFR used a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index. Peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

The 2025 AFR peak demand model utilized two binaries to indicate the month of the system's historical summer and winter peaks, and assumed this peak in July/January (respectively) throughout the forecast timeframe. Summer peaks typically occur in either July or August, historical winter peaks have occurred in November, December, February, but are most likely in January. This broad distribution of peak occurrence dilutes the model's measured seasonality, and as a result, the peak forecast will understate both the summer and winter peak demand figures. The utilization of these peak binaries focuses the seasonal peaks – which may have occurred in August or July, or December or January - into the months of July and January. This ensures seasonal peaks are not under forecast as a result of historical diversity in the timing of those seasonal peaks.

The model also includes two binaries ("Dum_1999_2001" and "Dum_2008") denoting periods of economic downturn for Minnesota Power's large industrial customers, resulting in abnormally low usage. During (or immediately following) these periods the normal relationship of Peak-to-Energy was affected by the idling of large, high load factor customers. These binaries effectively remove these downturn periods from consideration in the regression model and allow for more accurate estimation of model coefficients under more normal economic conditions.

There is no energy efficiency variable in the peak demand model and no explicit assumption for peak demand savings. Conservation impacts are accounted for by leveraging the energy sales forecast, which includes the effects of conservations, as the key input to the peak demand regression model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are very similar to the 2024 model: MAPE is 2.2% vs. 1.8% in the 2024 model, and RMSE is 41 vs. 33 in the 2024 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

D. Forecast Confidence and Historical Accuracy (7610.0320, Subp. 1.E and Subp. 1.F)

Minnesota Power has a strong record of both accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), as well as the 2020 COVID-19 recession (including 2021), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.006 percent over the prior year.

Figures 20 through 22 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, in Figure 20 the bottom value of -15.7 percent in the 2020 column is the difference between the forecast produced in 2020 (AFR 2020) and the 2020 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2015 (formulated in 2015) forecast of 2016 was 5.9 percent (581 GWh) above the actual (due to effects of the Mining downturn).

Figure 20: AFR Forecast Accuracy – Aggregate System Energy

Total Energy Sales Forecast Error

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AFR 2000	**-3.9%**	***1.5%***	0.5%	1.9%	-0.6%	***-2.2%***	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%										
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	***-4.1%***	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%									
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	***-3.8%***	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%								
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	***-2.7%***	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.8%	12.5%								
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%						
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%					
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%	38.1%				
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%	31.6%	18.6%			
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%	32.1%	19.5%	26.9%		
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	8.5%	10.2%	13.4%	30.2%	17.5%	24.3%	22.8%	
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	1.1%	**11.6%**	15.2%	6.9%	7.7%	10.1%	26.1%	13.8%	20.5%	19.2%	21.3%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	7.5%	8.4%	10.8%	26.9%	14.4%	21.0%	19.7%	21.7%
AFR 2012													**-1.4%**	***0.5%***	0.7%	11.5%	15.4%	**6.9%**	7.8%	10.2%	26.4%	13.9%	20.5%	19.2%	21.4%
AFR 2013														**-0.2%**	***2.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	40.2%	26.2%	33.4%	31.7%	33.8%
AFR 2014															**-0.3%**	***13.9%***	24.2%	13.9%	14.9%	**17.2%**	34.0%	20.3%	27.0%	25.3%	27.0%
AFR 2015																**2.4%**	***5.9%***	9.9%	11.0%	13.1%	**29.4%**	16.3%	22.6%	20.9%	22.5%
AFR 2016																	**-1.4%**	***-4.3%***	-2.9%	-2.2%	20.4%	**10.1%**	19.3%	17.9%	19.6%
AFR 2017																		**1.8%**	***2.5%***	3.6%	24.2%	13.1%	**19.3%**	**17.8%**	19.7%
AFR 2018																			**1.4%**	***1.7%***	20.4%	9.7%	16.7%	**15.1%**	**16.8%**
AFR 2019																				**-1.8%**	***14.7%***	4.2%	12.1%	12.0%	**13.7%**
AFR 2020																					**-15.7%**	***-7.8%***	-2.2%	-4.0%	-2.9%
AFR 2021																						**-8.7%**	***-2.7%***	***-2.9%***	-1.3%
AFR 2022																							**-1.2%**	***-0.9%***	***0.5%***
AFR 2023																								**-4.4%**	***-4.5%***
AFR 2024																									**0.3%**

N.n% = *Year-Ahead Foreast* **N.n%** = Current Year Forecast **N.n%** = 5 Year-Ahead Forecast

Figure 21: AFR Forecast Accuracy – Summer Peak

Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.1%										
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.6%	17.4%									
AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	2.3%	16.7%	16.9%								
AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-2.0%	12.4%	12.0%	7.5%							
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%	6.3%	22.5%	22.7%	18.4%	17.5%						
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%	5.2%	21.3%	22.8%	19.2%	19.1%	25.6%					
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%	7.0%	22.0%	22.0%	17.1%	15.2%	20.0%	35.2%				
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.4%	18.1%	33.4%	23.0%			
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.6%	16.3%	31.6%	21.6%	30.2%		
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	2.0%	1.1%	6.1%	20.9%	12.2%	20.5%	16.0%	
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.7%	5.1%	9.3%	23.4%	13.6%	21.2%	15.8%	20.4%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.9%	9.2%	23.3%	13.6%	21.2%	15.8%	19.3%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	3.1%	7.3%	21.2%	11.7%	19.3%	14.1%	19.4%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.5%	18.0%	32.9%	22.2%	30.2%	24.2%	17.6%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.3%	17.6%	32.5%	21.6%	29.3%	23.2%	27.7%
AFR 2015																1.0%	5.4%	10.6%	10.6%	14.9%	29.4%	18.9%	26.4%	20.6%	26.6%
AFR 2016																	-1.4%	1.0%	0.0%	1.6%	24.0%	16.2%	23.9%	18.3%	23.9%
AFR 2017																		4.5%	2.2%	4.0%	20.0%	11.1%	18.1%	12.8%	21.5%
AFR 2018																			-0.6%	0.9%	15.4%	7.6%	14.8%	9.7%	16.1%
AFR 2019																				-1.1%	11.4%	3.2%	12.1%	7.6%	12.7%
AFR 2020																					-17.7%	-4.9%	1.3%	-3.9%	10.7%
AFR 2021																						-6.3%	0.8%	-3.5%	-1.8%
AFR 2022																							3.9%	1.2%	-1.4%
AFR 2023																								-2.2%	4.1%
AFR 2024																									-1.3%

N.n% = *Year-Ahead Foreast* | N.n% = Current Year Forecast | N.n% = 5 Year-Ahead Forecast

Figure 22: AFR Forecast Accuracy – Winter Peak

Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AFR 2000	0.4%	-1.0%	-2.6%	-4.1%	-6.2%	-5.7%	-3.6%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	1.8%	-1.1%										
AFR 2001		5.8%	3.1%	1.1%	-1.6%	-1.6%	0.2%	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	5.5%	2.5%	21.4%									
AFR 2002			1.1%	0.2%	-1.6%	-0.9%	1.3%	-1.3%	2.0%	15.1%	0.2%	1.8%	2.8%	4.9%	1.7%	20.1%	11.2%								
AFR 2003				-5.2%	-7.4%	-6.7%	-4.4%	-6.6%	-3.1%	9.0%	-4.1%	-2.1%	-0.3%	2.4%	-0.2%	18.4%	10.2%	5.7%							
AFR 2004					-5.0%	-4.3%	-0.9%	-3.6%	4.2%	16.6%	1.9%	5.1%	7.6%	11.2%	8.9%	29.9%	21.4%	16.9%	24.5%						
AFR 2005						-3.8%	-1.5%	-3.9%	3.2%	15.8%	1.2%	2.9%	4.4%	7.5%	5.1%	25.2%	17.0%	12.5%	19.9%	23.3%					
AFR 2006							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.9%	17.9%	20.1%	23.7%				
AFR 2007								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.5%	12.8%	15.5%	19.8%	19.8%			
AFR 2008									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.8%	15.4%	18.3%	22.8%	23.1%	35.4%		
AFR 2009										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.5%	7.8%	10.8%	15.1%	15.3%	26.6%	21.8%	
AFR 2010											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	3.2%	8.7%	10.6%	14.0%	13.4%	23.7%	18.2%	22.9%
AFR 2011												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.5%	9.2%	11.2%	14.7%	14.3%	24.7%	19.3%	21.3%
AFR 2012													0.1%	1.3%	-1.9%	15.8%	7.1%	2.0%	7.6%	9.6%	13.1%	12.6%	23.0%	17.6%	30.4%
AFR 2013														0.4%	1.5%	20.5%	16.5%	11.0%	16.9%	19.0%	22.5%	21.8%	32.8%	26.8%	28.6%
AFR 2014															-2.7%	24.2%	15.7%	10.3%	15.9%	17.9%	21.3%	20.4%	31.1%	25.1%	26.6%
AFR 2015																10.3%	10.5%	8.1%	13.8%	15.8%	19.3%	18.6%	29.1%	23.1%	23.2%
AFR 2016																	1.8%	-2.8%	2.1%	4.8%	11.4%	15.1%	25.7%	19.8%	17.8%
AFR 2017																		0.1%	4.8%	5.3%	11.1%	10.4%	20.4%	14.5%	14.8%
AFR 2018																			1.7%	3.2%	6.4%	7.8%	17.3%	11.7%	12.2%
AFR 2019																				-1.0%	2.8%	2.3%	14.3%	9.0%	-0.7%
AFR 2020																					-7.2%	-6.0%	1.8%	-3.3%	-1.1%
AFR 2021																						-7.0%	0.9%	-3.3%	4.6%
AFR 2022																							7.1%	1.7%	-0.7%
AFR 2023																								0.9%	3.1%
AFR 2024																									1.4%

N.n% = *Year-Ahead Foreast* | N.n% = Current Year Forecast | N.n% = 5 Year-Ahead Forecast

E. Methodology Strengths and Weaknesses and Suitability to the System (7610.0320, Subp. 1.F)

The Company's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads or new technology adoption. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook and capturing the historical and projected effects of energy efficiency. However, a fully econometric process would not reflect any of the substantial industrial expansions that are likely in the Minnesota Power service territory. A

combined “econometric/large customer load addition” approach produces the most reasonable forecast.

The Company’s econometric modeling process has two key strengths: it is both highly replicable, and adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

That said, there are some weaknesses to a combined “econometric/large customer load addition” approach. For instance, there is some subjectivity in the perceived likelihood of individual large customer load additions/losses since their magnitude or timing is difficult to estimate in a probabilistic way. To minimize subjectivity on the part of Minnesota Power, the Company utilizes information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power’s system demand and energy sales at any given point in time. The Company addresses this potential for error by maintaining close contact with existing and potential customers to keep current on their plans.

F. Data Requirements (7610.0320, Subp. 1.F)

Data used in Minnesota Power’s forecast can be broadly categorized as follows:

- *Historical quantities of the variables to be forecast,* which consists of energy sales and customer counts for Minnesota Power’s defined customer classes, energy sales, and peak demand.
- *Regional Demographic and Economic data:*
    - *Duluth Metropolitan Statistical Area (“MSA”)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
    - *Aggregate 13-County Minnesota Power service territory (“13-Co”)* consists of population, Gross Regional Product (a Regional GDP metric), sector-specific employment, and income metrics.
    - *Individual 13-County Minnesota Power service territory (“13-Co”)* consists of sector-specific employment and income metrics for each individual County.

- *Indicators of National economic activity* such as the Industrial Production Indexes ("IPI") or Macroeconomic indicators such as U.S. GDP or Unemployment.
- *Weather and related data* including heating degree days ("HDD"), cooling degree days ("CDD"), temperature, humidity, dew point, and wind speed.
- *Electricity and Alternative Fuel prices*, which includes the price of electricity, natural gas, and heating oil by sector for the Minnesota Power service territory.

II. Forecast Data Inputs & Adjustments

A. Forecast Database Inputs (7610.0320, Subp. 2.A)

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration ("NOAA") and from Weather Underground ("WU").[2] Minnesota Power utilizes Monthly HDDs and CDDs in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This results in the "per-day" series HDDpd and CDDpd.

Normalizing the series by transforming to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales. The forecast assumes more than a twenty-year historical average for each month (Jan 2001 – Dec 2024).

Temperature, humidity, and wind-chill data used to model peak demand are derived from Schneider Electric. In previous forecasts, the Company has leveraged either NOAA or WU for daily or monthly-frequency values. The AFR 2025 forecast database features weather observations that are specific to the historical peak hour (i.e., the temperature, humidity, and wind-chill at the time of the peak). This closer alignment between the peak demands and the weather that induced them should produce a more accurate estimate of weather-sensitivity and a more accurate forecast of future peak demand.

[2] http://www.wunderground.com/.

Development of the historical weather series begins by establishing the date and time of historical monthly peaks. Weather observations for these date/times are then gathered and organized into a monthly-frequency weather series.

A Temperature-Humidity Index ("THI")[3] is utilized to consider the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 75 degrees. A Wind-Chill ("WC") index[4] was also utilized to capture the cold temperatures and, when applicable, the cooling effects of wind speed. The WC index is only applicable when temperatures drop below 40 degrees and wind speeds are greater than 3 miles per hour.

IHS Global Insight

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[5] A single source for National, Metropolitan Statistical Area ("MSA"), and County-level outlooks ensures internal consistency of forecast assumptions.

IHS Global Insights data development process begins with producing a national-level forecast. County-level and MSA data for Northeast Minnesota is then calculated through a "Top-down/Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels.

IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect the historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Regional Economic Models, Inc. ("REMI")

Minnesota Power subscribes to the latest REMI Policy Insight version ("PI+") for northeastern Minnesota. This input/output econometric simulation software combines a national economic

[3] http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
[4] http://www.nws.noaa.gov/os/windchill/index.shtml.
[5] With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.

outlook[6] with specified regional economic conditions to produce a forecast for a 13-County Planning Area such as employment by sector, population, economic output by sector, and Gross Regional Product ("GRP").

For AFR 2025, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e., expansions and layoffs/closures) to produce an expected economic outlook for the region.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and GRP are not provided by IHS Global Insight for the 13-County Planning area. These series are derived directly from REMI outputs and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Like IHS Global Insight, REMI relies on data from public sources that are subject to revision. These revised data inputs result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

Indexes of Industrial Production ("IPI" series)

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2017 in this case (that is, 2017 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are, therefore, ideal for forecasting future energy sales to the class.

The historical national-level IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are explained on the Federal Reserve's website.[7]

[6] Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook.
[7] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.

Forecasts for each national-level IPI were developed from the projections of national-level economic indicators from IHS Global Insight, and are, therefore, consistent with all other AFR 2024 forecast assumptions. These macroeconomic drivers are used to model and forecast the national-level IPI series.

The historical Minnesota iron IPI was developed using actual iron ore production data from the U.S. Geological Survey website ("USGS").[8] The projected Minnesota iron IPI was developed by scaling the national-level Iron IPI forecast using an assumption of the industry's composition going forward. Minnesota now comprises about 83 percent of U.S. product, so the Minnesota iron IPI equals the national-level IPI x 0.83. The entire historical and forecast Minnesota iron IPI was then indexed to 2017 for consistency with past AFRs, the other IPI series used in AFR 2025, and the U.S. Federal Reserve's current standard index year.

Energy Prices

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in the Company's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy ("DOE") and Energy Information Administration ("EIA"). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook ("AEO") is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central ("WNC") region, and the national total. Minnesota Power's historical average electric price data are from the Company's FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2017 base year GDP implicit price deflator ("IPD").

B. Forecast Adjustments (7610.0320, Subp. 2.B)

1. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2025, which fall into three general categories:

[8] https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/.

a. **Adjustments to raw customer count data for billing anomalies:** Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts. Where there is a systemic shift (e.g., seasonal billing in residential customers count), Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are fewer than three consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

b. **Adjustments to raw sales and peak demand data for large load additions and losses**: All adjustments to the historical database are described below in detail and organized by sector:

[TRADE SECRET DATA BEGINS



[redacted]

[redacted] TRADE SECRET DATA ENDS]

2. Adjustments to Econometric Forecast

Minnesota Power's forecast scenario is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These adjustments fall into the following categories:

a. **Net Load/Energy Added**: Exogenous adjustments for load added due to Distributed Solar Generation, Electric Vehicle impacts, new customers or expansion by existing customers, and lost load due to closure, loss of contract, or reduced industry operating levels. This variability and average operating levels are expected over the forecast period and are taken into account as a normalized adjustment to a representative level in the forecast. This adjustment includes all load added or lost on the system, regardless of how that load is met; "Net Load/Energy Added" accounts for any change

in load at the system level. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values.

b. Customer Generation: The demand on Minnesota Power system that is met by customer owned generation. Customer generation can fluctuate without clear economic causes, so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in three steps:

- Remove Customer Generation from the historical peak series.
- Econometrically project a less volatile "FERC load coincident w/Monthly Minnesota Power System peak (MW)" monthly peak series.
- Arithmetically account for Customer Generation after forecasting.

c. Dual Fuel: Minnesota Power has a demand response program for residential and commercial customers. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruptions as a resource and not as an adjustment to the load forecast.

d. Electric Vehicles: There are two components of the Electric Vehicle (EV) energy forecast: 1) The EV saturation rate of the total light-weight vehicles in Minnesota Power service territory and 2) the energy requirements per vehicle.

First, Minnesota Power estimated its current EV saturation rate of all light, medium, and heavy-duty vehicles in its service territory. Currently, there are 770 known light-weight, 19 medium-duty, and 7 heavy-duty electric vehicles in Minnesota Power's service territory,[9]. This equates to a 0.37 percent saturation rate of the total light-weight vehicles, 0.25% of total medium-duty vehicles, and 0.33% to total heavy-duty vehicles in Minnesota. To date, this saturation rate trails the national average electric vehicle adoption rate by about seven years for light and heavy-weight and eight years for

9 https://mn.gov/puc/activities/economic-analysis/electric-vehicles/

medium-weight vehicles. The Company then identified an updated publicly available forecast that considers recent industry trends and legislative action that incentivizes EVs. The EV adoption rate forecast for the Minnesota Power service territory follows Goldman Sachs's projected national adoption rate,[10] but lagged by about seven years. The Company attributes this lag in adoption to issues of income, population density/cost-efficiency of commercial charging station locations, and reduced efficiency in cold-weather. The annual saturation rate outlook is then multiplied by the estimated number of light, medium and heavy-duty vehicles in Minnesota Power's service territory [11] to estimate the total number of EVs.

The annual EV energy requirements forecast was calculated by multiplying the EV count and an estimate of per-unit energy requirements, which the Company assumes is about 2,800 kWh per year, 6.0 kWh per year, and 96.6 kWh per year for light, medium, and heavy-duty EVs respectively. This kWh per year estimate is based off a weighted average of the top three electric vehicles, in their respective weight class, in MP service territory and their respective energy usage. The Company also leveraged regional temperature information to impart a seasonal (i.e., monthly) distribution to the overall annual EV energy requirements estimates.

Identifying the impact of EV charging on monthly peak demand requires information on charging patterns/characteristics – i.e., how/when customers will tend to charge their vehicles. A National Renewable Energy Laboratory ("NREL") value assessment study of electric vehicles[12] contained modeled EV charging patterns for several customer types. For the purposes of determining EV charging load coincident with the system peak demand, Minnesota Power assumed the charging profile representative of level 1 charging, at a -single-family dwelling, with *no* Time of Use ("TOU") restriction or rate.

Under the AFR 2025 expected scenario, Minnesota Power customers own about 90,500 light-weight, 2,950 medium-duty, and 940 heavy-duty EVs (approximately 42.5%, 37.1%, and 42.5% saturation rate of light, medium, and heavy-duty vehicles

10 https://www.goldmansachs.com/intelligence/pages/electric-vehicles-are-forecast-to-be-half-of-global-car-sales-by-2035.html#:~:

11 Count of Standard Residential and All Electric accounts – excludes Dual Fuel and Controlled Access to avoid double counting and inflating the estimate of households served.

respectively in Minnesota Power service territory) by 2039, and the added energy requirements from post-2023 EV adoption increases to about 350,000 MWh total. This level of EV ownership would increase summer peak coincident demand by about 45 MW and winter peak demand by 131 MW.

e. **Distributed Generation** ("DG"): The process of forecasting DG solar generation involves two separate assumptions: 1) the rate of adoption (i.e., number of new installations each year), and 2) the average size of those new installations. Minnesota Power continued to use the following methodology for the rate of adoption to use the publicly available US Energy Information Administrations distributed residential solar generation forecast for AFR 2025. The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class. Minnesota Power then calculated the estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11 percent capacity factor assumption for new distributed installations.

   Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that is likely during a specific month's likely peak time (i.e., historical median peak hour) using a simulated hourly solar production curve. Minnesota Power typically peaks at 6:00 or 7:00 PM (well after sunset) in winter months, so DG solar at the time of the peak is zero percent and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3:00 or 4:00 PM when DG solar is on average 55 percent of installed capacity (the effective load carrying capacity or ELCC is 0.55).

III. Overview of Key Assumptions (7610.0320, Subp. 3)

A. National Economic Assumptions

The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales.

B. Regional Economic Assumptions

The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the "13-County Planning Area." Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas County in Wisconsin).

The 13-County Planning Area's Gross Regional Product is forecasted to average 1.5 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages 2.0 percent per-year in the forecast timeframe. Population for the 13-County Planning Area grows at about 0.3 percent in the forecast timeframe and the Duluth MSA area population remains consistent with current levels.

IV. Subject of Assumption (7610.0320, Subp. 4)

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
    - *Minnesota Power makes no assumptions regarding the availability of alternative sources of energy*.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
    - *Minnesota Power makes no assumptions regarding the expected conversion from one fuel source to another*.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
    - *See Section II.A.*
- Assumptions made in arriving at the data requested (historical reporting).
    - *Minnesota Power makes no such assumptions*.

- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand and assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Federal or State legislation.

  Minnesota Power uses energy efficiency as an input variable to the regression models, referred to as "EE as RHS var" or "Energy Efficiency as a Right-Hand Side Variable." The "EE as RHS var" methodology has several advantages over other common energy efficiency forecasting methodologies:

  - *Avoids double-counting energy efficiency impacts in the forecast timeframe.*
  - *Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.*
  - *Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.*
  - *Doesn't require after-the-fact adjustments to econometric outputs: the energy sales forecasts already contain the effects of energy efficiency.*

  An "Energy Efficiency" variable explains recent trends in customer consumption that cannot be explained by economic, demographic, or weather effects. Further, this method allows the Company to quantify the volume of energy efficiency embedded in the load forecast.

  Development of the "Energy Efficiency" variable began by gathering savings data for each retail customer class, Superior Water Light and Power, and the Company's 14 Minnesota municipal customers. Incremental (i.e., first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Historical incremental savings data for Minnesota Power was obtained from the Company's past annual energy efficiency compliance filings, Minnesota Municipal customers' historical savings information was obtained from CIP results filed with the Department of Commerce.[13] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

  Forecast assumptions for Minnesota Power's residential and commercial savings were derived from the Company's most recent preliminary estimates of achieved and

[13] Historical achievements filed in Docket No. E-999/PR-22-24

energy savings assumptions beyond 2024, were based on the Company's 2024-2026 Triennial ECO Plan Filing.

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings to produce a "cumulative energy savings" series.[14] This cumulative series is the optimal variable format/definition for modeling energy sales. A cumulative savings metric represents the lasting impacts of conservation programs by aggregating or cumulating the savings from all past conservation measures. Minnesota Power used an annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authority classes, as well as three of the Company's 14 resale customers modeled in AFR 2025.

- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
    - *Minnesota Power makes no assumptions regarding current and future saturation levels of appliances and electric space heating*.

V. Coordination of Forecasts with Other Systems (7610.0320, Subp.5)

Minnesota Power is a member of the Midwest Reliability Organization ("MRO"), Midcontinent Independent System Operator ("MISO"), Edison Electric Institute ("EEI"), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

VI. Load Growth Forecast Planning Scenario

U.S. electric demand is expected to grow over the next decade due to policy focused on sustainability through electrification, onshoring of industrial manufacturing, and expansion in data processing capabilities. Minnesota Power is currently seeing interest in electrification and data centers and is including a scenario in this AFR for substantial load growth aligned with its most

[14] Using internal estimates of Minnesota Power's past programs' life of measures. A Life of Measure (LoM) is the approximate time a conservation measure will reduce energy consumption. Most conservation measures have a 10- to 20-year life. A portfolio from any particular program year will contain measures that end earlier than others, so the overall impact of measures implemented in a program year will fade over time.

recent Integrated Resource Plan representative of the possible opportunities for expansion of these technologies and customers in the region. Minnesota Power will continue to work with our current and new customers and update the forecast and associated planning processes as needed.

Electrification

In 2021, the Energy Conservation and Optimization Act was signed into law. ECO allows for streamlining of efficient fuel switching, which includes technologies such as air source heat pumps to replace fossil fueled heating technologies, supporting the probability of increased electricity consumption while homes and businesses reduce overall fossil fuel usage and carbon dioxide emissions.

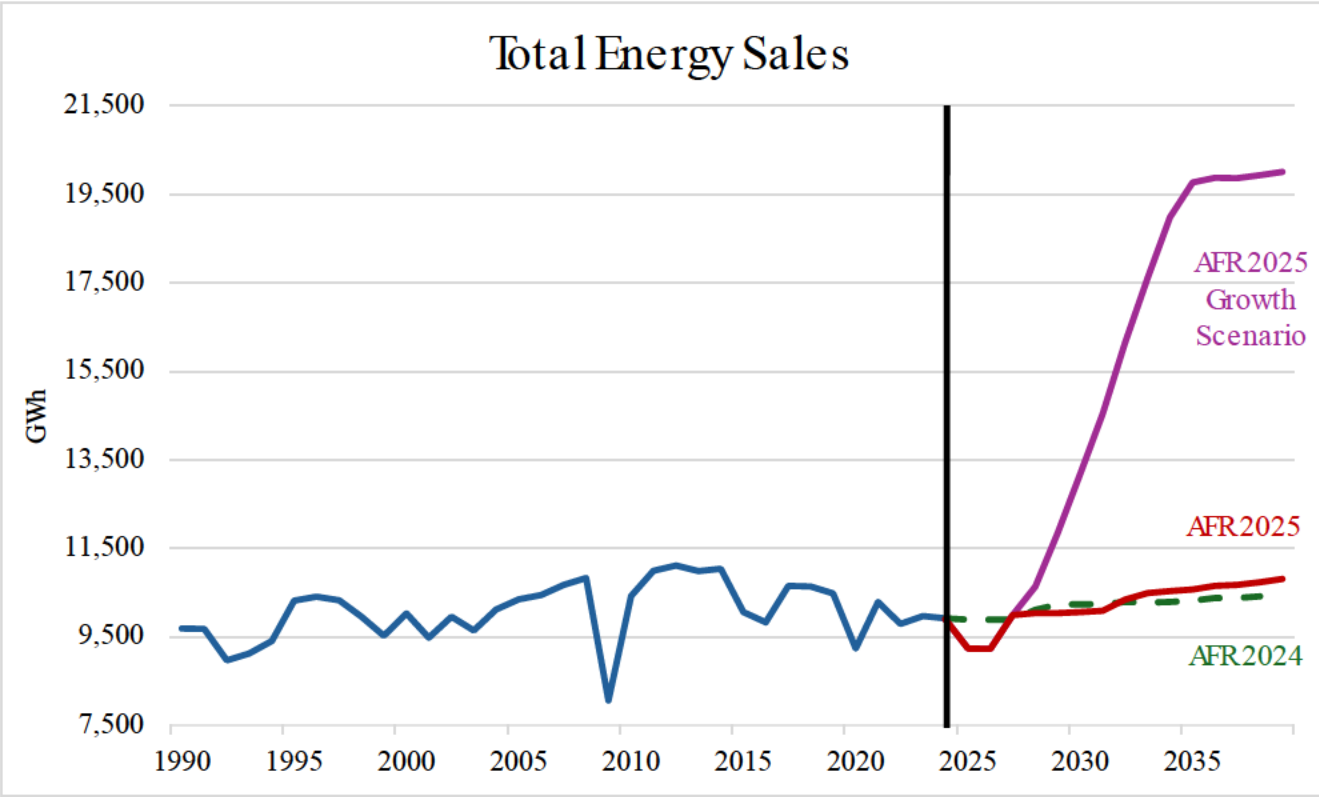
Data Centers

Energy consumption by data centers in the United States is expected to double by 2030 according to a recent study by the Electric Power Research Institute ("EPRI").[15] Trends in computing are shifting towards Artificial Intelligence ("AI") and machine learning, as well as the increasing reliance on digital services that require data processing and storage, driving the expansion of new data centers being built with capacities ranging from 100 MW to over 1,000 MW in locations with interconnection capabilities for large loads. These loads are typically very high load factor facilities requiring high energy density to support their operation.

15 https://www.epri.com/research/products/3002028905.

Below, for the Load Growth Forecast Planning scenario, the total energy sales graph displays the base AFR 2025 results, along with the AFR 2025 load growth scenario.

Figure 23 Total Energy Sales for Load Growth Forecast Planning Scenario



The table below shows the peak forecast results based on the load growth forecast planning scenario included in the AFR 2025 filing.

Figure 24 Peak Forecast (MW) for the Load Growth Forecast Planning Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak		
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*
2000					1,469	1,503	242	281	1,711	1,784	*1,784*
2001					1,383	1,421	150	175	1,533	1,595	*1,595*
2002					1,464	1,455	165	287	1,629	1,742	*1,742*
2003					1,342	1,496	310	250	1,651	1,746	*1,746*
2004					1,449	1,533	218	250	1,667	1,783	*1,783*
2005					1,535	1,555	255	238	1,789	1,793	*1,793*
2006					1,584	1,534	237	232	1,821	1,766	*1,821*
2007					1,582	1,584	246	241	1,828	1,825	*1,828*
2008					1,529	1,575	228	203	1,757	1,777	*1,777*
2009					1,200	1,369	211	246	1,411	1,615	*1,615*
2010					1,591	1,599	140	190	1,732	1,789	*1,789*
2011					1,573	1,630	173	150	1,746	1,780	*1,780*
2012					1,603	1,605	186	168	1,789	1,773	*1,789*
2013					1,645	1,589	135	162	1,781	1,751	*1,781*
2014					1,620	1,637	184	180	1,805	1,818	*1,818*
2015					1,442	1,461	148	87	1,589	1,547	*1,589*
2016					1,453	1,520	157	173	1,610	1,693	*1,693*
2017					1,538	1,594	150	195	1,688	1,789	*1,789*
2018					1,585	1,557	139	150	1,724	1,707	*1,724*
2019					1,560	1,588	108	99	1,668	1,687	*1,687*
2020					1,410	1,548	78	97	1,487	1,646	*1,646*
2021					1,553	1,556	73	108	1,625	1,663	*1,663*
2022					1,484	1,456	49	94	1,533	1,550	*1,550*
2023					1,551	1,529	63	89	1,614	1,618	*1,618*
2024	1,372	1,420	0	57	**1,372**	**1,477**	54	122	**1,426**	**1,599**	**1,599**
2025	1,414	1,422	53	58	**1,467**	**1,480**	122	122	**1,589**	**1,602**	**1,602**
2026	1,414	1,423	52	93	**1,466**	**1,516**	122	122	**1,588**	**1,638**	**1,638**
2027	1,416	1,424	139	220	**1,555**	**1,645**	122	122	**1,677**	**1,766**	**1,766**
2028	1,417	1,426	210	369	**1,628**	**1,795**	122	122	**1,749**	**1,917**	**1,917**
2029	1,419	1,428	356	530	**1,775**	**1,958**	122	122	**1,897**	**2,080**	**2,080**
2030	1,421	1,430	514	694	**1,935**	**2,124**	122	122	**2,057**	**2,246**	**2,246**
2031	1,422	1,430	673	866	**2,095**	**2,296**	122	122	**2,217**	**2,418**	**2,418**
2032	1,423	1,431	867	1,080	**2,290**	**2,511**	122	122	**2,412**	**2,633**	**2,633**
2033	1,424	1,432	1,042	1,254	**2,466**	**2,686**	122	122	**2,587**	**2,808**	**2,808**
2034	1,424	1,433	1,205	1,358	**2,629**	**2,791**	122	122	**2,751**	**2,913**	**2,913**
2035	1,425	1,434	1,297	1,374	**2,722**	**2,808**	122	122	**2,844**	**2,930**	**2,930**
2036	1,426	1,435	1,301	1,391	**2,726**	**2,826**	122	122	**2,848**	**2,948**	**2,948**
2037	1,426	1,437	1,304	1,409	**2,731**	**2,846**	122	122	**2,852**	**2,967**	**2,967**
2038	1,428	1,440	1,308	1,428	**2,736**	**2,868**	122	122	**2,858**	**2,989**	**2,989**
2039	1,431	1,407	1,319	1,436	**2,750**	**2,843**	122	122	**2,872**	**2,965**	**2,965**

VII. Load Reduction Forecast Planning Scenario

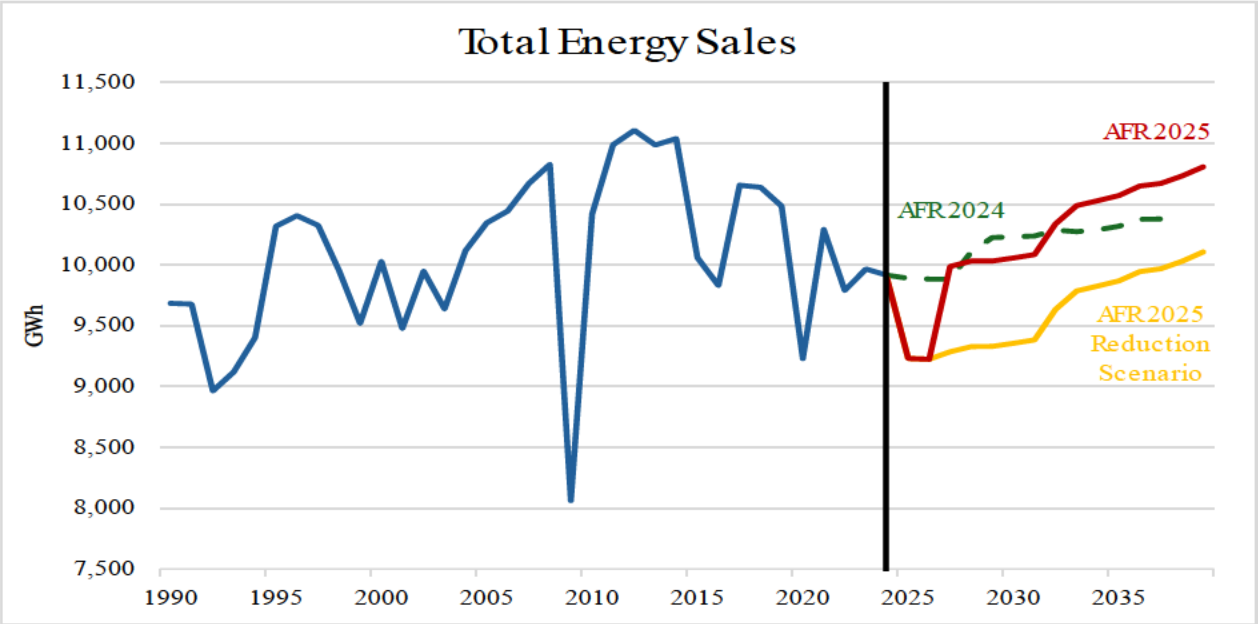
The mining industry in Northern Minnesota, particularly on the Iron Range, is known for its volatility, influenced by various factors. Due to the uncertainty of future mining load, Minnesota Power is including a load reduction scenario in this AFR tied to uncertainty at Cleveland-Cliffs, Mesabi Metallics, and New Range. At Cleveland-Cliffs there have been recent announcements to lay off over 600 employees at both their Hibbing Taconite and Minorca mining facilities, along with citing that Hibbing Taconite's mine will have an ore shortage[16]. Additionally, Mesabi Metallics is currently constructing a mining facility that is 80 percent complete and included in the Minnesota Power expected forecast plan through its wholesale service agreement with Nashwauk Public Utilities[17]. It is important to plan for a range of customers' load since economic, financial, and construction challenges may occur. Finally, load growth tied to customers face unpredictable hurdles such as environmental, permits, and falling copper prices. Minnesota Power will continue to work with our current and new large power customers and update the forecast and associated planning processes as needed.

16 https://minnesotareformer.com/2025/03/20/cleveland-cliffs-set-to-layoff-630-steelworkers-at-minorca-hibbing-taconite/#:~:text=The%20bigger%20concern%20around%20HibTac,long%2Dterm%20picture%20is%20unclear.

17 https://www.northernnewsnow.com/2025/06/20/mesabi-metallics-expects-open-taconite-mine-early-2026/

Below, for the Load Reduction Forecast Planning scenario, the total energy sales graph displays the base AFR 2025 results, along with the AFR 2025 load reduction scenario.

Figure 25 Total Energy Sales for Load Reduction Forecast Planning Scenario



The table below shows the peak forecast results based on the load reduction forecast planning scenario included in the AFR 2025 filing.

Figure 26 Peak Forecast (MW) for the Load Reduction Forecast Planning Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak		
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*
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2010					1,591	1,599	140	190	1,732	1,789	*1,789*
2011					1,573	1,630	173	150	1,746	1,780	*1,780*
2012					1,603	1,605	186	168	1,789	1,773	*1,789*
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2015					1,442	1,461	148	87	1,589	1,547	*1,589*
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2017					1,538	1,594	150	195	1,688	1,789	*1,789*
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2019					1,560	1,588	108	99	1,668	1,687	*1,687*
2020					1,410	1,548	78	97	1,487	1,646	*1,646*
2021					1,553	1,556	73	108	1,625	1,663	*1,663*
2022					1,484	1,456	49	94	1,533	1,550	*1,550*
2023					1,551	1,529	63	89	1,614	1,618	*1,618*
2024	1,372	1,420	0	57	**1,372**	**1,477**	54	122	**1,426**	**1,599**	**1,599**
2025	1,414	1,422	53	58	**1,467**	**1,480**	122	122	**1,589**	**1,602**	**1,602**
2026	1,414	1,423	52	31	**1,466**	**1,454**	122	122	**1,588**	**1,576**	**1,588**
2027	1,416	1,424	58	67	**1,474**	**1,491**	122	122	**1,596**	**1,613**	**1,613**
2028	1,417	1,426	57	69	**1,474**	**1,496**	122	122	**1,596**	**1,617**	**1,617**
2029	1,419	1,428	56	73	**1,476**	**1,501**	122	122	**1,597**	**1,622**	**1,622**
2030	1,421	1,430	56	78	**1,477**	**1,508**	122	122	**1,599**	**1,629**	**1,629**
2031	1,422	1,430	56	89	**1,479**	**1,520**	122	122	**1,601**	**1,641**	**1,641**
2032	1,423	1,431	91	143	**1,514**	**1,574**	122	122	**1,636**	**1,696**	**1,696**
2033	1,424	1,432	104	156	**1,528**	**1,588**	122	122	**1,650**	**1,710**	**1,710**
2034	1,424	1,433	107	171	**1,532**	**1,605**	122	122	**1,653**	**1,726**	**1,726**
2035	1,425	1,434	111	188	**1,535**	**1,622**	122	122	**1,657**	**1,743**	**1,743**
2036	1,426	1,435	114	204	**1,540**	**1,640**	122	122	**1,661**	**1,761**	**1,761**
2037	1,426	1,437	118	223	**1,544**	**1,659**	122	122	**1,666**	**1,781**	**1,781**
2038	1,428	1,440	122	240	**1,550**	**1,680**	122	122	**1,671**	**1,802**	**1,802**
2039	1,431	1,415	126	265	**1,556**	**1,680**	122	122	**1,678**	**1,802**	**1,802**

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING
	)ss	
COUNTY OF ST. LOUIS	)	

I, Amy M. Honkala of the City of Duluth, County of St. Louis, State of Minnesota, hereby certify that on the 1st day of August, 2025, I electronically filed a true and correct copy of Minnesota Power's **Annual Compliance Filing Docket number E999/PR-25-11** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on eDocket's Official Service List for this Docket were served as requested.



Amy M. Honkala

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - LARGEST CUSTOMER LIST
CY 2024

WHEN E-FILING THIS FORM, IT SHOULD BE UPLOADED AS TRADE SECRET

ENTITY ID#	68
REPORT YEAR	2024

UTILITY DETAILS	
UTILITY NAME	Minnesota Power Co
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642 x3865

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

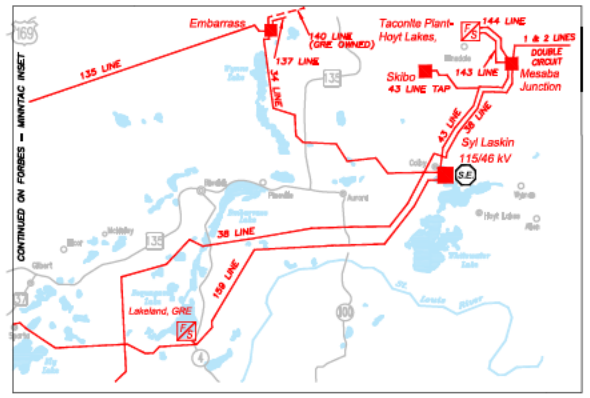
ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2024 MWH
[redacted]						

THIS LARGEST CUSTOMER LIST SHOULD BE SUBMITTED TO COMMERCE AS AN EXCEL WORKBOOK.
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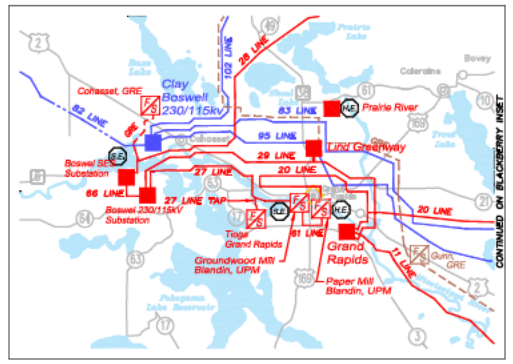
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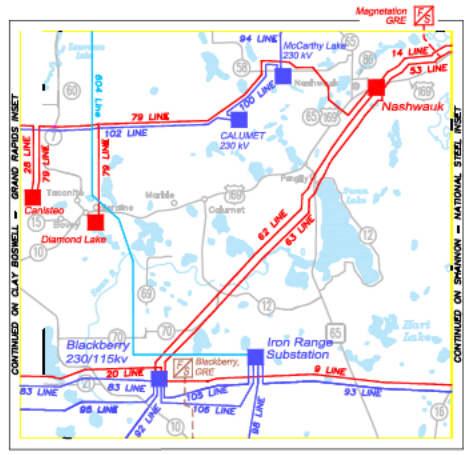
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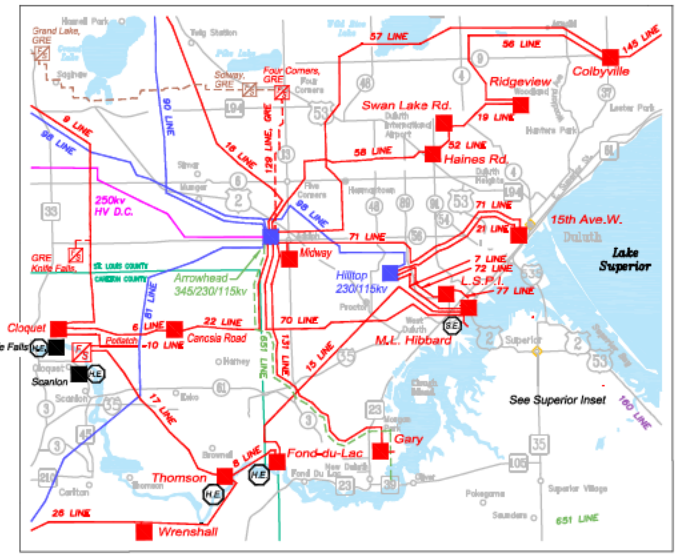
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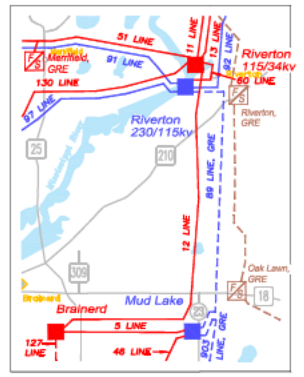
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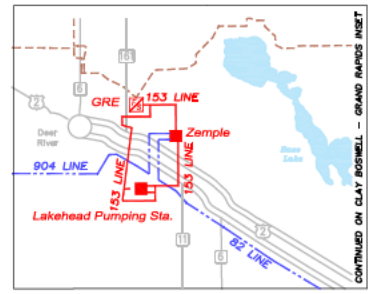
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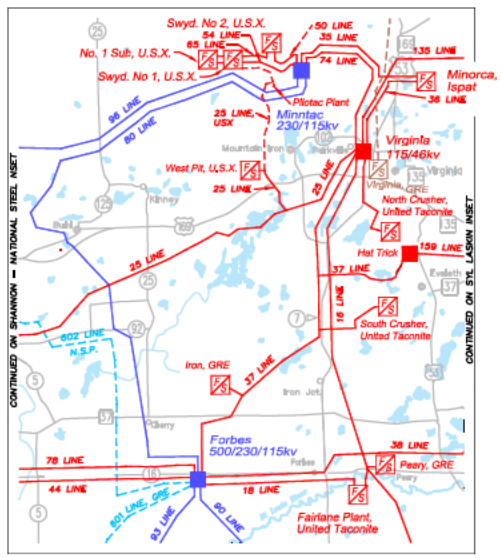
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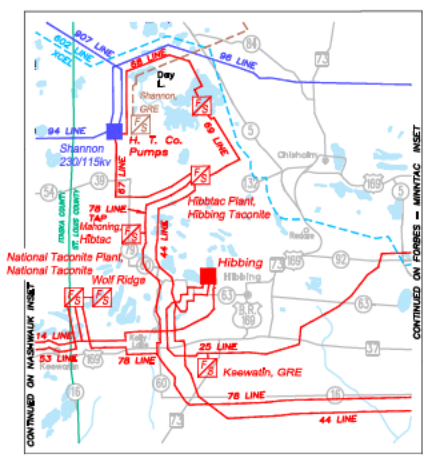
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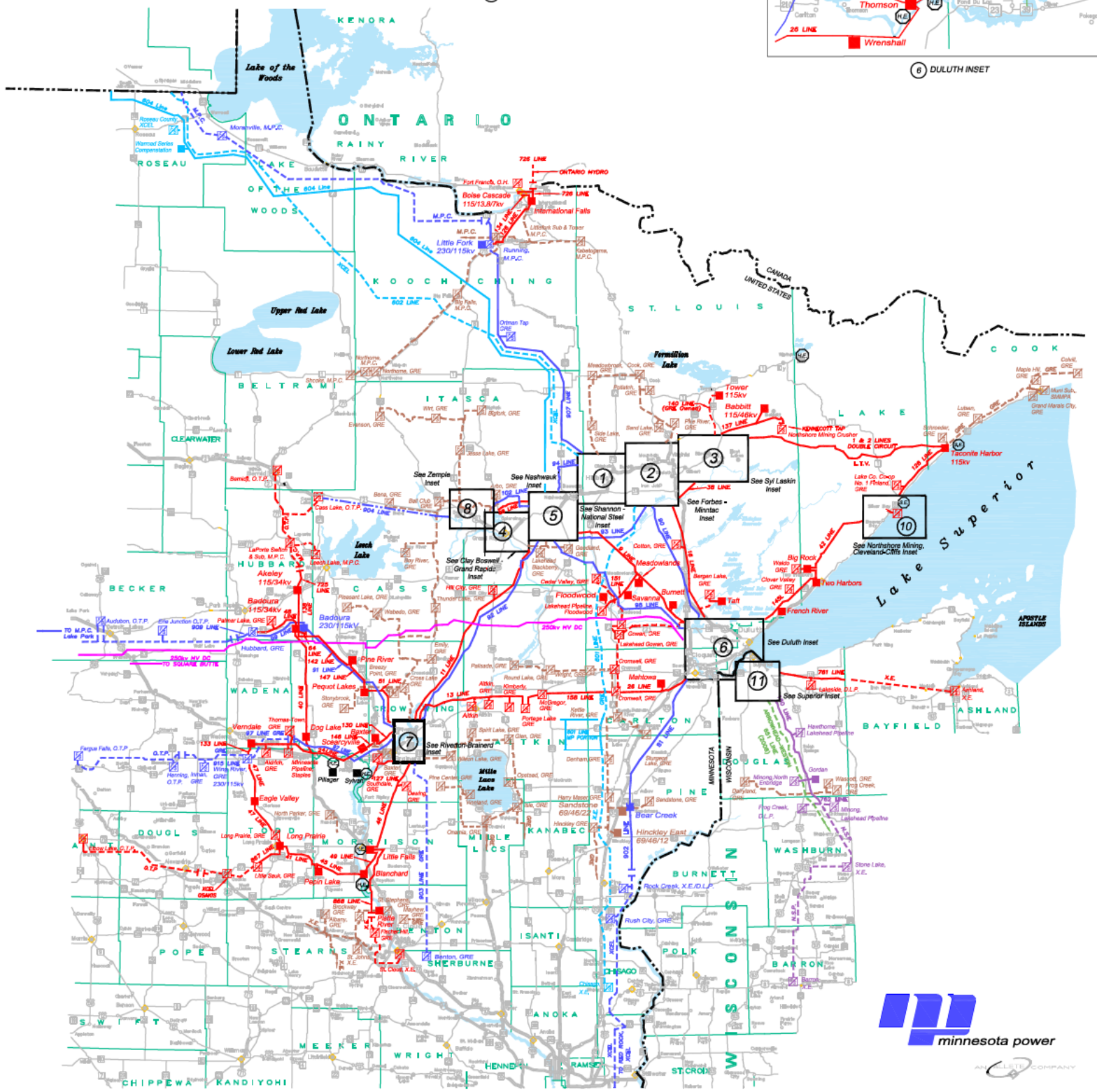
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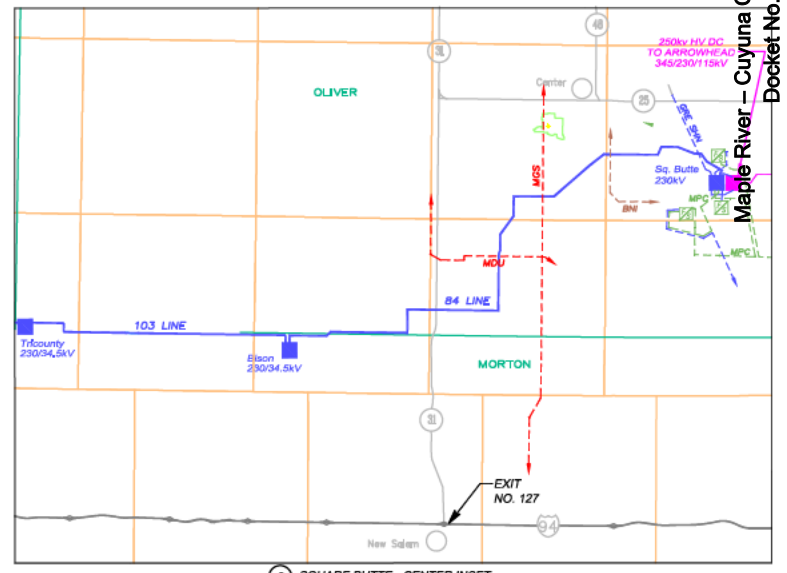


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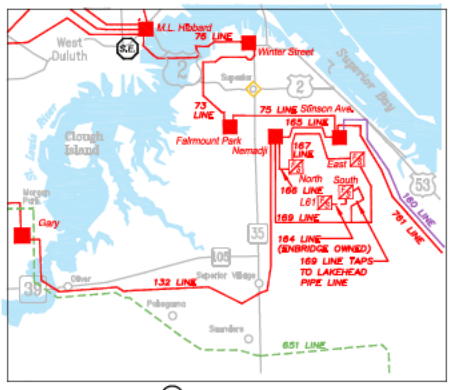




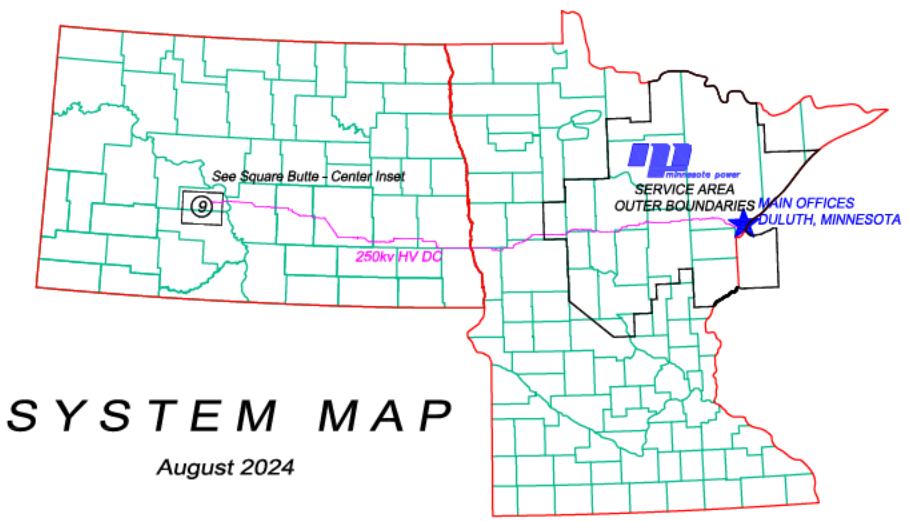
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11 SUPERIOR INSET



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- 115KV TRANSMISSION
- 161KV TRANSMISSION
- 230KV –AC TRANSMISSION
- 250KV HV DC TRANSMISSION
- 345KV TRANSMISSION
- 500KV TRANSMISSION
- FOREIGN TRANSMISSION*
- CapX TRANSMISSION*

- 69KV SUBSTATION
- 115KV SUBSTATION
- 161KV SUBSTATION
- 230KV SUBSTATION
- 345KV SUBSTATION
- 500KV SUBSTATION
- < 69KV SUBSTATION
- FOREIGN SUBSTATION*
- (S.E.) STEAM ELECTRIC STATION
- (H.E.) HYDRO ELECTRIC STATION
- * COLOR INDICATES VOLTAGE

minnesota power
AN ALLETE COMPANY

SYSTEM MAP

August 2024

TITLE PAGE

MINNESOTA POWER

ELECTRIC RATE BOOK

This book contains Minnesota Power's retail rates and related information per the Minnesota Department of Public Service Initial Filing Instructions issued November 18, 1974 and is the Company's official Electric Rate Book on file with the Minnesota Department of Commerce.

The Minnesota Power official responsible for this rate book is:

Leah N. Peterson
Manager - Customer Analytics

Authorizing Signature:

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RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESIDENTIAL SERVICE

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APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations, and any applicable Riders. There is a maximum of one Residential – General or Residential – Space Heating service per customer.

A customer will be billed on the seasonal rate if the dwelling is typically occupied for 182 days or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$9.00	$15.00
All kWh (¢/kWh)	10.818¢	11.324¢

0 kWh to 600 kWh discount for eligible customers -4.329¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

RESIDENTIAL SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh, along with being a low-income customer. A low-income customer is defined as eligible for the Low Income Home Energy Assistance Program ("LIHEAP") in Minnesota Power's billing system or a customer who has completed a self-declaration process. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

11. Eligible customers will receive the discount for a one year time period, at which point average monthly usage will be re-calculated to determine the continued eligibility for the following year.

12. Self-declaration for the low-income eligibility will require a renewal every two years in general and every four years for those on a fixed income.

13. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

14. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)
Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus
Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20 hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge – Dual Fuel (standard)	
Small Service	7.989¢ per kWh
Large Service	7.989¢ per kWh

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

Energy Charge - Dual Fuel Plus	
Small Service	5.584¢ per kWh
Large Service	5.584¢ per kWh

Plus any applicable Adjustments.

Customers who have a qualified Air Source Heat Pump as approved by the company, may elect to be exempt from dual fuel interruptions from June through September and would pay the energy charge below.

Energy Charge	
All kWh (per kWh)	10.818¢

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. Interruption will normally occur at such times:

   (a) when the Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when the Company expects to incur a new system peak,
   (c) at such other times when, in the Company's opinion, system reliability is endangered,
   (d) when the Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL FIXED OFF-PEAK SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time (CPT) each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

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RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00

Energy Charge	
Small Service (per kWh)	5.584¢
Large Service (per kWh)	5.584¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

RESIDENTIAL FIXED OFF-PEAK SERVICE

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer's load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

To electric service for residential customers for the sole purpose of recharging electric vehicle(s) or battery powered equipment. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$6.00
Off-Peak Energy Charge	
All kWh (per kWh)	3.231¢
On-Peak Energy Charge	
All kWh (per kWh)	11.540¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The Residential Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

2. The total connected off-peak load shall not exceed 100 kW.

3. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

5. On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$15.00
Energy Charge for all kWh	9.919¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$15.00
Demand Charge for all kW	$6.50
Transmission Demand for all kW	$4.03
Energy Charge for all kWh	6.931¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2,500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Customers whose monthly demand has been less than 10 kW during the past 12-month period and whose monthly consumption has not exceeded 2,500 kWh in three or more consecutive months during the same 12-month period will be identified and the 12-month history of such customer's kW and kWh requirements are reviewed. After review, where appropriate, a rate change will be made to a non-demand general service rate.

GENERAL SERVICE

All customers exceeding the demand threshold criteria are required to be moved to the demand rates. Those not reaching the criteria are eligible to be removed from the demand rates.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

RATE CODES

29

APPLICATION

Available to Commercial and Industrial customer's electric service requirements for electric vehicle loads that serves public charging including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE PUBLIC CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the

price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the total demand charges, including Transmission Demand Charge, exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Transmission Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the demand charges, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

RATE CODES

30

APPLICATION

Available to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge for On-Peak ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge ($/kW) On-Peak Transmission Demand	$4.03

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

COMMERCIAL ELECTRIC VEHICLE FLEET CHARGING SERVICE

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

RATE CODES

31

APPLICATION

Available to Company-owned Electric Vehicle Service Equipment which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$15.00
Demand Charge ($/kW)	$6.50
Energy Charge for all kWh	6.931¢
Transmission Demand Charge All kW of Billing Demand ($/kW)	$4.03

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.800¢ per kWh of Energy. Where service is delivered and metered at (or compensated to) the available distribution bulk delivery voltage of 23,000 volts to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

COMPANY-OWNED ELECTRIC VEHICLE SERVICE EQUIPMENT

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the total demand charges, including Transmission Demand Charge, exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Transmission Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the demand charges, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to the Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kilowatts (kW) or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers, or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

DUAL FUEL PROGRAM OPTIONS

Dual Fuel (standard)

Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.

Dual Fuel Plus

Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 1,000 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted for 20-hours per calendar day. In the event of a 20-hour interruption period, there will be a period of at least two hours before the next interruption period.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge – Dual Fuel (standard)	
Small Service	7.949¢ per kWh
Large Service-Low Voltage	7.949¢ per kWh
Large Service-High Voltage	7.812¢ per kWh
Energy Charge – Dual Fuel Plus	
Small Service	5.551¢ per kWh
Large Service-Low Voltage	5.551¢ per kWh
Large Service-High Voltage	5.435¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

Customers who have a qualified Air Source Heat Pump as approved by the company, may elect to be exempt from dual fuel interruptions from June through September and would pay the energy charge below.

Energy Charge	
All kWh (per kWh)	9.919¢ per kWh

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) when, in the Company's opinion, the reliability of the system is endangered, or
   (d) when the Company performs necessary testing of interruptibility of customer's loads.

   Interruptions shall normally occur for reliability-related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. If Company is unable to disconnect with integrated disconnects in the meters, Company will provide and customer will install as directed by the Company, equipment to provide signals to control load. Customer must provide a continuous 120 volt AC power source at the Company's control point for operation of the Company's remote control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

7. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, as specified in Dual Fuel program options above.

8. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

   (a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer's service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 10 p.m. and 6 a.m. Central Prevailing Time (CPT) each day. Service is subject to the Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

The small service rates are applicable where connected load is 75 kW or less single phase and served at 120 volt, 120/240 volt or 120/208 network voltage and supplied through one meter at one point of delivery.

The large service rates are for any three phase customers or any current transformer rated single phase services. The connected load on these services is larger than 75 kW and is supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	
Small Service	$6.00
Large Service	$16.00
Energy Charge	
Small Service - Low Voltage	5.551¢ per kWh
Large Service - Low Voltage	5.551¢ per kWh
Large Service - High Voltage	5.435¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL FIXED OFF-PEAK SERVICE

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Where direct load control by meter is not available, customer's load shall be controlled by a switching device approved or supplied by the Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,050.00
All additional kW of Billing Demand ($/kW)	$9.25
Transmission Demand Charge	
All kW of Billing Demand ($/kW)	$6.07
Energy Charge	
All kWh (¢/kWh)	5.165¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $2.45 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will be subject to a discount of 0.800¢ per kWh of Energy. Where service is delivered and metered

LARGE LIGHT AND POWER SERVICE

at (or compensated to) the available distribution bulk delivery voltage of 23,000 to 46,000 volts, the Energy Charge will also be subject to a discount of 0.153¢ per kWh of Energy.

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

LARGE LIGHT AND POWER SERVICE

10. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the lower of:

a) 75% of the greatest adjusted demand during the preceding eleven months, or
b) The greatest adjusted demand during the preceding eleven months minus 100 kW.

However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

RATE CODES

73

APPLICATION

To the electric service requirements of a customer requiring service for no less than 2,000 kW and no more than 50,000 kW of connected load, where such electric service requirements are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at the voltage level specified in customer's contract.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Light and Power Service Rate Schedules 75 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Light and Power Service Rate Schedules 75 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

LARGE POWER SERVICE

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

LARGE POWER SERVICE

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$244,764
All additional kW of Firm Demand ($/kW)	$24.00

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$8.49

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.187¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under "ENERGY."

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

2. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Charge.

3. Capacity Revenue and Expense Adjustment. A capacity revenue and expense adjustment will be determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

4. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

5. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

LARGE POWER SERVICE

6. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

7. CARE Low-Income Affordability Program Surcharge. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

8. Solar Energy Adjustment. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

9. Minnesota Policy Adjustment. The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

10. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

11. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

LARGE POWER SERVICE

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be based on amount specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this a mount shall be deemed to be the Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases. For all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or

participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

LARGE POWER SERVICE

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$293,717
All additional kW of Non-Contract Billing Demand ($/kW)	$28.80

Transmission Demand Charge

All kW of Firm Demand ($/kW)	$10.19

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.187¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY."

Plus any applicable Adjustments.

NON-CONTRACT LARGE POWER SERVICE

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge. Such Fuel Charge shall be applicable to Customer's Non-Contract Firm Energy only.

2. There shall be added to or deducted from the monthly billing, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

6. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Minnesota Policy Adjustment: The combination of Conservation, Transmission, Renewable Resource, and Solar Energy Adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

NON-CONTRACT LARGE POWER SERVICE

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are

usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

Capacity Portion
For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

Energy Portion
For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

NON-CONTRACT LARGE POWER SERVICE

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

RATE CODES

79

APPLICATION

To the electric service requirements of a customer requiring 10,000 kW or more, where the electric service requirements of 10,000 kW or more are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Three phase, 60 hertz at high voltage of 13,000 through 69,000 volts or at transmission voltage of 115,000 volts.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Power Service Rate Schedules 74 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Power Service Rate Schedules 74 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

2. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$12.92			
20,000 Lumens (400 watts)	MV400W	$20.57			
55,000 Lumens (1,000 watts)	MV1000W	$38.33			
Sodium Vapor Fixtures					
8,500 Lumens (100 watts)	SV100W	$11.34		$6.54	
14,000 Lumens (150 watts)	SV150W	$13.07			
23,000 Lumens (250 watts)	SV250W2	$18.54		$11.19	
45,000 Lumens (400 watts)	SV400W	$24.83		$11.87	
Metal Halide Fixtures					
17,000 Lumens (250 watts)	MH250W	$18.34			
28,800 Lumens (400 watts)	MH400W	$22.34		$13.24	
88,000 Lumens (1,000 watts)	MH1000W	$37.22		$24.18	
Light Emitting Diodes (LED)					
4,000 Lumens (48 watts or less)	LED48W	$11.45			
10,000 Lumens (71 watts or less)	LED71W	$11.99			
24,000 Lumens (184 watts or less)	LED184W	$20.76			
46,800 Lumens (320 watts or less)	LED320W	$31.52			
Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$13.00		$13.00	

OUTDOOR AND AREA LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	11.010¢

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

   The monthly capacity revenue and expense adjustment per lamp shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

OUTDOOR AND AREA LIGHTING SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Fixture CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
	Daily Estimates	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours		4200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH250W	3	1,260	139	114	110	91	79	70	76	88	101	120	130	142
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MH1000W	12	4,410	485	398	385	317	277	245	264	309	353	421	457	499
LED48W	1	207	23	19	18	15	13	11	12	14	17	20	21	24
LED71W	1	299	33	27	26	21	19	17	18	21	24	28	31	34
LED184W	2	774	85	70	68	56	49	43	46	54	62	74	80	87
LED320W	4	1,344	148	121	117	97	84	75	81	94	108	128	139	152

Company shall furnish all electric energy required for service under this schedule.

OUTDOOR AND AREA LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, photo-electric control and wiring.

Option 2

Reserved for Future Use

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include, but not be limited to, the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

OUTDOOR AND AREA LIGHTING SERVICE

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Fixture Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2 (Reserved for Future Use)	Option 3 (Closed to New Installation)	Option 4
Mercury Vapor Fixtures (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$17.85		$13.34	
10,000 Lumens (250 watts)	MV250W			$16.95	
20,000 Lumens (400 watts)	MV400W	$24.28		$22.91	
55,000 Lumens (1,000 watts)	MV1000W2			$27.46	
Sodium Vapor Fixtures (Closed to New Installations)					
8,500 Lumens (100 watts)	SV100W	$15.77		$10.71	
14,000 Lumens (150 watts)	SV150W	$17.45		$15.08	
14,000 Lumens (150 watts)	SV150W-P			$9.11	
20,500 Lumens (200 watts)	SV200W	$21.58		$16.47	
23,000 Lumens (250 watts)	SV250W	$21.73		$17.79	
45,000 Lumens (400 watts)	SV400W	$26.69		$21.42	
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$15.90			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$19.98			
23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$26.74			

STREET AND HIGHWAY LIGHTING SERVICE

Monthly Service Charge	Included	Included	$5.00
Energy Charge - Per kWh	Included	Included	11.010¢

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Charge.

   The monthly fuel and purchased energy adjustment per fixture shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

2. There shall be added to or deducted from the monthly bill, as computed above, a capacity revenue and expense adjustment determined in accordance with the Rider for Capacity Revenue and Expense Adjustment.

   The monthly capacity revenue and expense adjustment per fixture shall be determined as the above capacity revenue and expense adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

STREET AND HIGHWAY LIGHTING SERVICE

9. The combination of conservation program, transmission cost, renewable resources, and solar energy adjustments may be shown on Customer's bills as the Minnesota Policy Adjustment.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Fixture CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
	Daily Estimates	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours		4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W2	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV150W-P	1	468	51	42	41	34	29	26	28	33	37	45	48	54
SV200W	3	1,140	125	103	100	82	72	63	68	80	91	109	118	129
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

Company shall furnish all electric energy required for service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, fixture, ballast, photo-electric control, driver, and wiring.

Option 2

Reserved for Future Use

Option 3

The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, fixture, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out fixtures and photo-electric controls and will clean or replace glassware at the time of fixture replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to

STREET AND HIGHWAY LIGHTING SERVICE

deliver power to Customer's system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, fixture, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a lever bypass meter socket. Company's point of delivery shall be on the bus work on the load side of the meter socket breaker.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of fixtures of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the

STREET AND HIGHWAY LIGHTING SERVICE

Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For fixtures which satisfy the conditions as set forth in Options 1 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

7. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1, Company will repair equipment (not covered above) damaged by vandalism and will bill Customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79.

FUEL AND PURCHASED ENERGY CHARGE

The Forecasted System Average Fuel and Purchased Energy (FPE) Charge for each month shall be the forecasted FPE Charge for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted FPE Charge shall be added to customers' monthly bill according to each customer's rate class and Fuel and Purchased Energy Adjustment (FPEA) Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve month recovery period the true-up rate will be in effect and then multiplied by the applicable FPEA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly FPE Charge.

FORECASTED SYSTEM AVERAGE FUEL AND PURCHASED ENERGY CHARGE

The monthly Forecasted Average Fuel and Purchased Energy Charge shall be the **sum** of the following:

(a) The fossil and nuclear fuel forecasted to be consumed in Company's generating stations,

(b) The forecasted net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

energy is to be purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,

(c) The forecasted identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,

(d) The forecasted cost of steam from other sources to be used in the generation of electricity at the Company's generating stations,

(e) The forecasted cost of the Released Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

(f) The forecasted cost of the Buyback Energy Credit to be paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

(g) Forecasted fuel and purchased energy expenses to be incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691 excluding the cost of fuel and purchased energy related to meeting the Solar Energy Standard,

(h) All forecasted RTO (Regional Transmission Organization) energy market costs net of revenues, excluding administrative costs,

(i) The forecasted cost of the purchase of SO_2 and NOx allowances,

(j) The forecasted Time of Generation Adjustment as calculated in the Rider for Solar Energy Adjustment

(k) Reagent and chemical costs for environmental compliance

and **less**

(l) Forecasted revenues from the sale of SO_2 and NOx allowances,

(m) The forecasted cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis,

(n) Forecasted net revenues from the sale of environmental attributes from any Commission approved contract, and

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

(o) Forecasted net revenues (margins) from asset-based wholesale energy sales and capacity sales greater than three years.

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (l) above and solar energy production and purchases referred to in (g) above.

FUEL AND PURCHASED ENERGY ADJUSTMENT (FPEA) FACTORS

A separate FPEA Factor shall be applied to calculate the Forecasted FPE Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) and Large Light & Power Time-Of-Use (TOU) customers a TOD or TOU Factor shall also be calculated for each TOD or TOU period. The FPEA Factor is the Class Cost Factor multiplied by the corresponding TOD or TOU Factor.

Rate Class	Class Cost Factor	TOD / TOU Factor	FPEA Factor
Residential	1.05841	1.00000	1.05841
Residential On-Peak	1.05841	1.17042	1.23878
Residential Off-Peak	1.05841	1.03330	1.09366
Residential Super Off-Peak	1.05841	0.75930	0.80365
General Service	1.02995	1.00000	1.02995
Large Light & Power	0.99451	1.00000	0.99451
Large Light & Power On-Peak	0.99451	1.17042	1.16399
Large Light & Power Off-Peak	0.99451	1.03330	1.02763
Large Light & Power Super Off-Peak	0.99451	0.75930	0.75513
Large Power	0.98328	1.00000	0.98328
Lighting	0.89264	1.00000	0.89264

2025 FORECASTED FPE RATE and 2023 TRUE-UP FPE RATE

The monthly forecasted 2025 FPE Rate was approved by the Minnesota Public Utilities Commission ("Commission") Order issued on November 12, 2024, in Docket No. E015/AA-24-64.

RIDER FOR FUEL AND PURCHASED ENERGY CHARGE

The 2023 FPE True-up Rate was approved in the Commission Order issued on July 1, 2024, in Docket No. E015/AA-22-216.

Applicable Month	FPE 2025 Forecasted Rate (¢/kWh)	FPE 2023 True-up Rate (¢/kWh)
January 2025	3.262	(0.133)
February 2025	3.105	(0.148)
March 2025	2.893	(0.140)
April 2025	2.883	(0.153)
May 2025	2.874	(0.149)
June 2025	2.784	(0.153)
July 2025	3.087	(0.144)
August 2025	3.267	(0.145)
September 2025	3.015	
October 2025	2.881	
November 2025	2.844	
December 2025	3.267	

A breakdown by month and Rate Class can be found on Minnesota Power's website at https://www.mnpower.com/CustomerService/YourBill

TEMPORARY SERVICE RIDER TO GENERAL SERVICE SCHEDULES

Any customer whose use of service may be temporary (less than one year duration) shall receive service under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Customer will pay in advance the estimated cost of installation and removal, less salvage, of facilities required to render service. Where the actual cost of providing such facilities is different from the advance payment, as determined upon completion of temporary service, Company will refund any excess payment made by Customer or render a bill for any additional costs.

2. Customer may at any time terminate service under this Rider and contract to receive future service under any applicable Schedule.

3. If Customer requests that service be discontinued and subsequently requests restoration of service at the same premises within 12 months of discontinuance, the charge for restoring service will be the sum of the minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service. The minimum bills during the elapsed period shall also include any billings which would have been applicable as a result of the minimum under the below Modification.

MODIFICATION

The second paragraph under DETERMINATION OF THE BILLING DEMAND in the applicable General Service rate schedule shall be changed to read as follows:

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the greatest adjusted demand during the preceding eleven months, nor less than the minimum demand specified in customer's contract.

SPORTS FIELD LIGHTING RIDER TO GENERAL SERVICE SCHEDULES

Any customer may elect to receive service for sports field lighting under the Conditions of this Rider in conjunction with a General Service Schedule modified as follows:

CONDITIONS

1. Service is available hereunder only to the extent that Company has unused capacity in facilities at the location. Customer shall pay any cost of extending or increasing the capacity of facilities.

2. Customer will own, install and maintain any transformers or other facilities required to utilize the available line voltage.

MODIFICATIONS

1. Service will be at the available line voltage (and phase).

2. The HIGH VOLTAGE SERVICE provision will not be applicable.

3. Demand will not be measured.

RIDER FOR MULTIPLE METER SERVICE

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through more than one meter. There may be conditions under which it will be desirable and/or necessary to provide service to customers at more than one point of delivery (Multiple Meter Service). Therefore, at Company's discretion, a customer not receiving multiple meter service or receiving multiple meter service but desiring an additional point of delivery may receive such service upon completion and proper approval of "Request for Multiple Meter Service".

CONDITIONS

1. When service is being taken through more than one meter, the metered quantities of demand (kW) and energy (kWh) at each metered point of service shall be billed under a separate application of a standard rate schedule.

2. The conditions under which a "Request for Multiple Meter Service" may be approved include but are not limited to:

   a. Customer's premises are divided by a public road or alley preventing the customer from performing its own distribution of service.

   b. Customer's buildings or operations are geographically separated to the extent that it is not electrically feasible for the customer to perform its own distribution of service.

   c. The location and/or adequacy of existing Company facilities make it economically more advantageous for Company to provide an additional point of delivery.

   d. Customers having two or more separate businesses on one premises for which the electric service costs must be accounted for separately.

RIDER FOR EXPEDITED BILLING PROCEDURES

APPLICATION

Applicable to taconite producing customers taking Large Power Service under Schedule 74 under Non-Contract Large Power Service Schedule 78, and under any other Large Power rate schedules in effect from time to time.

Service received under Large Light and Power Schedule 75 by a taconite producing Large Power customer may also be billed in accordance with this Rider, at the option of Minnesota Power.

Non-taconite customers taking service under a Large Power Service rate schedule may, at their option, be billed in accordance with the terms of this Rider.

The monthly billing requirement of Minnesota Rule 7820.3300 is modified to permit expedited weekly billing of a customer's electric service in accordance with the terms of this Rider.

TERMS

1. After instituting weekly billing, the bill payment is due in "same day funds" seven (7) days following issuance of the bill, the "Due Date" for payment. "Same day funds" means funds that are available for the Company's use on the same day as the Due Date. Bills not paid in "same day funds" on or before such Due Date as printed on the bill are "past due", or "delinquent." The weekly billing is based on estimated weekly electric service usage, including the minimum demand charge, not on an actual meter reading. Weekly billing payments received and charges for actual electric service usage will be reconciled each month ("actual billing true-up"). The monthly actual billing true-up shall be reflected on the first weekly billing rendered after such true-up amount has been determined. See Exhibit 1 to this Rider.

2. Customers subject to this Rider will receive credit for expedited billing payments reflecting the time value of funds made available to Minnesota Power earlier than such funds otherwise would have been available under the Company's standard monthly billing cycle. When the customer makes its first payment under the expedited cycle, the time value of money associated with that payment will be determined from the due date of that payment to the customer's due date under the standard monthly billing cycle, using prime plus two and one-half percent (2.5%) as the interest rate.

3. This time value of money credit ("TVMC") will be determined for each of the succeeding expedited payments. If the customer has not made timely payment of the estimated bills in full in "same day funds" as they become due on the expedited due dates, no time value of money associated with such late payment will be included in the TVMC. The total TVMC determined in a month shall be given by Minnesota Power

RIDER FOR EXPEDITED BILLING PROCEDURES

to the customer as a credit on the weekly bill that falls on the same week as the due date under the standard monthly billing cycle. If the credit exceeds $100,000, the customer has the option to have Minnesota Power wire the credit to the customer's bank account. The mechanics of this credit are shown on Exhibit 1 of this Rider. The prime rate is defined as the average of the daily prime lending rates offered to preferred customers at the largest bank in the Ninth Federal Reserve District in effect during the month preceding the bill.

RIDER FOR EXPEDITED BILLING PROCEDURES

Exhibit 1
Page 1 of 3

MINNESOTA POWER
Sample Weekly Billing Procedure
Assuming Procedure Commences January 1

Jan	Tue	1	
	Wed	2	
	Thu	3	
	Fri	4	Bill #1 Issued = 4/31 x Estimated Monthly Billing (EMB) for January
	Fri	11	Bill #2 Issued = 7/31 x EMB for January Bill #1 Due
	Fri	18	Bill #3 Issued = 7/31 x EMB for January Bill #2 Due
	Fri	25	Bill #4 Issued = 7/31 x EMB for January Bill #3 Due
Jan	Thu	31	Meter Read
Feb	Fri	1	Bill #5 Issued = 6/31 x EMB for January + 1/28 x EMB for February Bill #4 Due
	Mon	4	Charges for actual January usage determined January TVMC calculated to February 19th
	Fri	8	Bill #6 Issued = 7/28 x EMB for February Bill #5 Due January Actual Billing True-Up amount determined
	Fri	15	Bill #7 Issued = 7/28 x EMB for February + Actual Billing True-Up amount for January Bill #6 Due
	Tue	19	January TVMC is applied to bill or wire transferred
	Fri	22	Bill #8 Issued = 7/28 x EMB for February Bill #7 Due
Feb	Thu	28	Meter Read
Mar	Fri	1	Bill #9 Issued = 6/28 x EMB for February + 1/31 x EMB for March Bill #8 Due
	Mon	4	Charges for actual February usage determined February TVMC calculated to March 19th
	Fri	8	Bill #10 Issued = 7/31 x EMB for March Bill #9 Due February Actual Billing True-Up amount determined
	Fri	15	Bill #11 Issued = 7/31 x EMB for March + Actual Billing True-Up amount for February Bill #10 Due
	Tue	19	February TVMC is applied to bill or wire transferred

RIDER FOR EXPEDITED BILLING PROCEDURES

MINNESOTA POWER
Sample Monthly Adjustments

January Time Value of Money Credit (TVMC from page 1) assuming Bill #'s 1 thru 5 are paid in full and when due:

January TVMC =
Bill #1 x [(# days from Jan 11 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #2 x [(# days from Jan 18 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #3 x [(# days from Jan 25 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Bill #4 x [(# days from Feb 1 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%) +

Jan portion of Bill #5 x [(# days from Feb 8 to Feb 19)/365] x (Avg. Daily Prime Rate in December + 2.5%)

January Actual Billing True-Up Adjustment =
Sum of Payments for January service received on or before Feb 19 - Actual Charges for January usage

February Time Value of Money Credit (TVMC from page 1) assuming only Bill #'s 5 and 6 are paid in full and when due:

February TVMC =
Feb portion of Bill #5 x [(# days from Feb 8 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%) +

Bill #6 x [(# days from Feb 15 to Mar 19)/365] x (Avg. Daily Prime Rate in January + 2.5%)

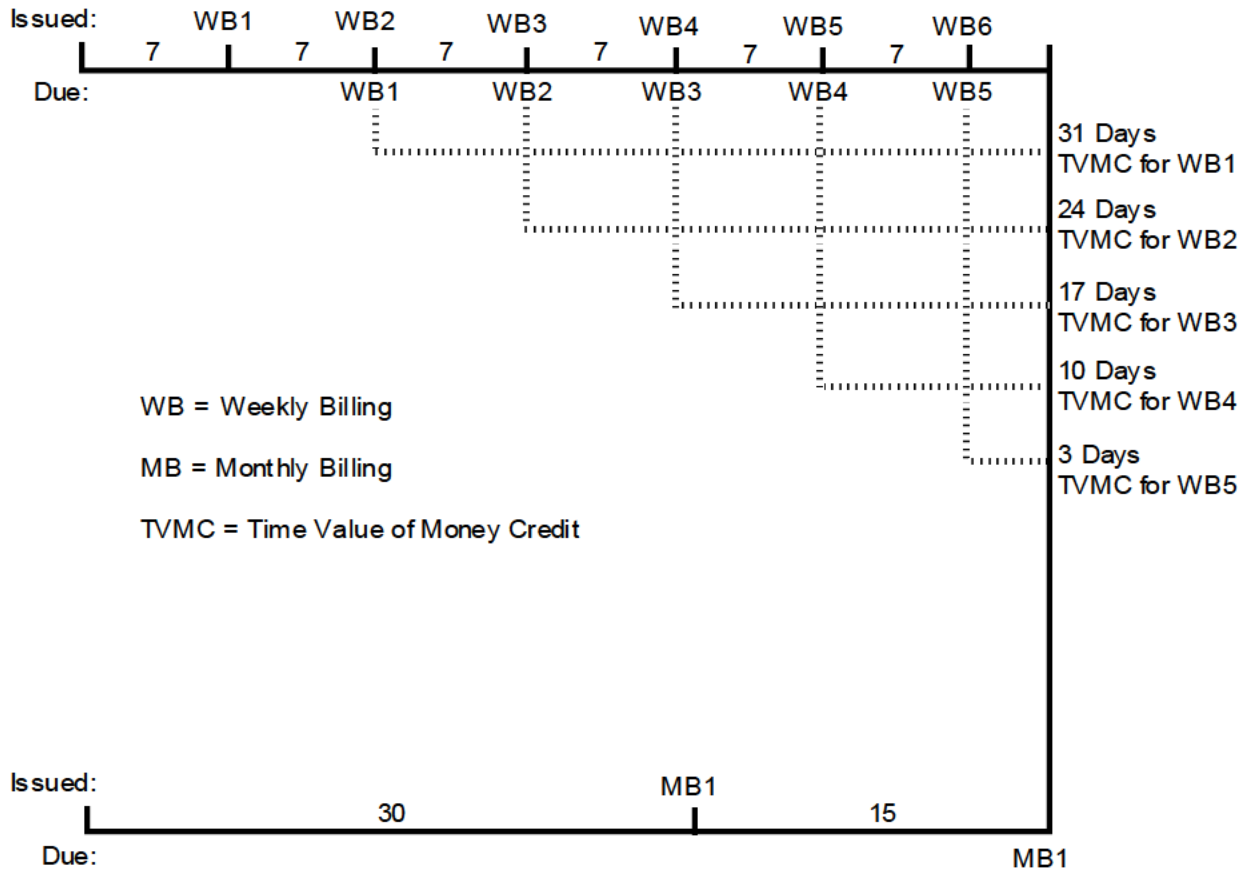
February Actual Billing True-Up Adjustment =
Sum of Payments for February service received on or before Mar 19 - Actual Charges for February usage

Note: 1) Time Value of Money Credit will not be reflected for any Weekly Billing which has not been received in same day funds, in full and on or before the Due Date.
2) The TVMC is calculated to (and applied to bill or wire transferred on) the standard monthly billing cycle due date which is 15 days from the date customer is notified of the charges for actual monthly usage.

RIDER FOR EXPEDITED BILLING PROCEDURES

Exhibit 1
Page 3 of 3

MINNESOTA POWER
METHOD FOR DETERMINING
TIME VALUE OF MONEY CREDIT



Note: This example assumes a 30 day month and the due date under the standard monthly billing cycle to be the 15th of the following month.

RIDER FOR SCHOOLS

APPLICATION

To Large Light and Power Service Schedule 75 for schools which are part of the elementary and secondary school system.

MODIFICATIONS

The RATE (Monthly) and other provisions of the applicable schedule shall apply except that:

1. The first block under Demand Charge shall be changed to read, "$10.50 per kW for the first 100 kW of Demand" or less as determined below.

2. Determination of the Billing Demand shall be replaced by the following:

   "Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month as adjusted for power factor, but not less than the minimum demand specified in customer's contract and in no case will the billing demand be less than 50 kW. For all Billing Demand between 51 kW and 100 kW the demand will be billed at the $10.50 per kW rate. All Billing Demand above 100 kW shall be billed at the third block demand rate of $9.25 per kW.

   Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%."

RIDER FOR REVENUE CREDIT FROM NON-CONTRACT LARGE POWER SERVICE

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Non-Contract Large Power Service Schedule 78.

REVENUE CREDIT

There shall be deducted from each Customer's monthly bill, as computed under the applicable rate schedule, a Revenue Credit. Such Revenue Credit for each Customer, other than Large Power Service Schedule 74 Customers, shall be a monthly Revenue Credit Rate (¢/kWh) multiplied by the kWh billed in the current month. Such Revenue Credit for Large Power Service Schedule 74 Customers shall be a monthly Revenue Credit Rate ($/kW) multiplied by the Firm Power Billing Demand (kW) billed.

DETERMINATION OF REVENUE CREDIT AMOUNT

The Revenue Credit Amount in month shall be one-sixth (1/6) of the total of all Non-Contract Large Power Service Demand Charges billed in the second preceding month.

REVENUE CREDIT RATES

(a) Applicable to Non-Large Power Service (in ¢/kWh)

The Revenue Credit Amount in month multiplied by .3606; divided by Company's total kilowatt-hour Sales of Electricity, excluding Non-Contract Large Power Service, non-firm service, Resale Service and Large Power Service sales, in the second preceding month.

(b) Applicable to Large Power Service (in $/kW)

The Revenue Credit Amount in month multiplied by .5207; divided by the sum of all Firm Power Billing Demand (kW) billed to Customers under Company's Large Power Service Schedule 74 in the current month.

RIDER FOR CITY OF DULUTH FRANCHISE FEE

APPLICATION

Applicable to bills for electric service within the corporate limits of the City of Duluth, except bills for service to the City of Duluth.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Duluth Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Duluth, which is currently 3% of the total bill excluding sales taxes and is billed per electric service agreement. The fee is listed on the bill as "Duluth Franchise Fee (3%)" and is effective as January 1, 2017.

The total amount assessed to any Minnesota Power customer shall not exceed $420,000 per year.

100% of the City of Duluth Franchise Fee assessment collected will be passed along to the City of Duluth.

RIDER FOR PARALLEL GENERATION

APPLICATION

Applicable to cogenerator or small power producers less than 1,000 kW AC capacity. To any customer taking single or three phase service under one of the Company's standard electric rate schedules and who has entered into a contract with the Company for the sale of electricity as a cogenerator or small power producer (Seller) as defined under State or Federal Law.

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Sellers with Distributed Energy Resources less than 40 kW AC capacity shall have the option of selling to Company under either the Average Retail Energy Rate, the Simultaneous Purchase and Sale Rate or the Time-of-Day Purchase Rate. The Rate selected shall be as specified in the Cogeneration and/or Small Power Production Facilities Agreement between Seller and Minnesota Power.

A. Average Retail Energy Rate
The Seller shall be billed according to the Company's applicable standard rate schedule for the energy (kWh) supplied by the Company that exceeds the amount of energy supplied by the Seller to the Company's distribution system during each billing period. The Seller will be subject to the following Meter Aggregation Charge. When energy supplied by the Seller exceeds the amount of energy supplied by the Company, the Seller shall be subject to the following Average Retail Energy Rate Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Average Retail Energy Rate Credit
13.16¢ per kWh of Net Energy - Residential Customers
13.98¢ per kWh of Net Energy - General Service Customers
10.71¢ per kWh of Net Energy - Large Light & Power Customers

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by

RIDER FOR PARALLEL GENERATION

the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

II. Distributed Energy Resources at 40 kW AC capacity or greater and less than 500 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate. Customers who do not elect to be compensated for net input in the form of a kilowatt-hour credit under the Kilowatt-Hour Energy Credit rate will be compensated for the net input at the Company's Simultaneous Purchase and Sale Rate or Time-of-Day Purchase Rate.

RIDER FOR PARALLEL GENERATION

A. Kilowatt-Hour Energy Credit Rate

The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company

B. Simultaneous Purchase and Sale Rate

The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate

The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and Energy and applicable Credit:

RIDER FOR PARALLEL GENERATION

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

III. Distributed Energy Resources at 500 kW AC capacity or greater and less than 1,000 kW AC capacity shall have the option of selling to Company under either the Kilowatt-Hour Energy Credit, the Simultaneous Purchase and Sale Rate, or the Time-of-Day Purchase Rate.

A. Kilowatt-Hour Energy Credit Rate
The Seller shall be compensated for net input in the form of a kilowatt-hour credit shown on the customer's bill, which will be carried forward on subsequent energy bills. The Seller will be subject to the following Meter Aggregation Charge. Any remaining net input at the end of the calendar year shall be compensated at the applicable Credit as shown below:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

B. Simultaneous Purchase and Sale Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and applicable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

RIDER FOR PARALLEL GENERATION

Energy Credit
2.92¢ per kWh delivered to Company.

Energy and Firm Power Capacity Credit
4.02¢ per kWh delivered to Company.

C. Time-of-Day Purchase Rate
The Seller shall be billed for all energy and capacity it consumes during each billing period according to the Company's applicable retail rate schedule. The Company may require those Distributed Energy Resources that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis. The Company shall purchase all energy and capacity which is made available to it by the Seller. The Seller will be subject to the following Meter Aggregation Charge and appliable Credit:

Meter Aggregation Charge (Monthly, if option selected by Customer)
$0.00

Energy Credit
3.05¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

Energy and Firm Power Capacity Credit
5.35¢ per kWh delivered to Company during On-Peak periods.
2.81¢ per kWh delivered to Company during Off-Peak periods.

DETERMINATION OF FIRM POWER

Energy delivered by the QF to the Company must have a 65 percent on-peak capacity factor in the month to be considered "firm power". The capacity factor is based upon the QF's maximum on-peak metered capacity delivered to the Company during the month. If the QF does not meet the firm power requirements, compensation will be for the energy portion only.

INDIVIDUAL SYSTEM CAPACITY LIMITS

1) Customers with a facility of 40-kilowatt AC capacity or more and participating in net metering and net billing may be required to limit the total generation capacity of an individual Distributed Energy Resource by either:

RIDER FOR PARALLEL GENERATION

a. for wind generation systems, limiting the total generation system capacity kilowatt alternating current to 120 percent of the customer's on-site maximum electric demand; or
b. for solar photovoltaic and other distributed generation, limiting the total generation system annual energy production kilowatt hours alternating current to 120 percent of the customer's on-site annual electric energy consumption.

2) Limits under paragraph (a) applicable to measuring on-site maximum electric demand must be based on standard 15-minute intervals, measured during the previous 12 calendar months, or on a reasonable estimate of the average monthly maximum demand or average annual consumption if the customer has either:
   a. less than 12 calendar months of actual electric usage; or
   b. no demand metering available.
3) The total generation capacity of an individual Distributed Energy Resource is determined by the total capacity of all of the customer's systems which are on the same set of aggregated meters. On-site maximum electric demand and on-site annual electric energy consumption are determined by total demand or electric energy consumption associated with the same set of aggregated meters.
4) For wind generation systems, the Company will estimate customer demand use for purposes of calculating the 120 percent rule by determining a demand-billed customer's highest billed on-site kW demand in all bills issued during the most recent calendar year. For non-demand customers, the Company shall impute the equivalent peak demand level by first determining the customer's most recent on-site annual (12-month) billed kWh sales. Those kWh sales shall be divided by the product of the annual load factor for the applicable customer class and the number of actual hours in that year (either 8,760 hours in a standard year or 8,784 hours in a leap year). The resulting quotient will serve as the customer's estimated on site maximum electric demand. The load factor is 19.3 percent for the residential customer class and 24.2 percent for the non-demand general service customer class as calculated in the Company's 2013 Load Research study.
5) For solar photovoltaic and other Distributed Energy Resources, where 12 months of usage data is not available, the Company will estimate customer energy use for purposes of calculating the 120 percent rule by averaging four months of usage. If four months of usage is not available, the Company will estimate usage based on home size for residential customers and other substantiating documentation for commercial and demand billed customers.

METER AGGREGATION

The Company will aggregate for billing purposes a Customer's designated distributed generation bidirectional meter with one or more aggregated retail meters if a Customer requests that it do so and the following conditions are satisfied:

RIDER FOR PARALLEL GENERATION

1) the meters must be located on contiguous property owned by the customer requesting the aggregation;
2) the account(s) associated with the meters must be in the name of the customer;
3) the retail services associate with the aggregated meters of a customer must be either all time-of-day or all non-time-of-day;
4) the total of all aggregated meters must be subject in the aggregate to the size limitation under the single rate chosen by the Customer applicable to all of the aggregated meters; and
5) the total of all aggregated meters is subject in the aggregate to the Individual System Capacity Limits.

As the term is used here, “contiguous property” means property owned or leased by the Customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or Company rights-of-way. The Company must comply with a request by a customer-generator to aggregate additional meters within 90 days. The specific meters must be identified at the time of the request. In the event that more than one meter is identified, the Customer must designate the rank order for the aggregated meters to which the net metered credits are to be applied. At least 60 days prior to the beginning of the next annual billing period, a Customer may amend the rank order of the aggregated meters.

The aggregation of meters applies only to charges that use kilowatt-hours as the billing determinant. All other charges applicable to each meter account shall be billed to the customer. The Company will first apply the kilowatt-hour credit to the charges for the designated meter and then to the charges for the aggregated meters in the rank order specified by the customer. If the Net Metered Facility supplies more electricity to the Company than the energy usage recorded by the customer-generator's designated and aggregated meters during a monthly billing period, the Company will apply, at the election of the Customer, any excess production based on a monthly credit or the Annual Net Metering (kWh) Banking Option. Where a monthly credit is selected, the Company shall apply monetary credits to the customer's next monthly bill for the excess kilowatt-hours.

DISTRIBUTED ENERGY RESOURCES OF 1,000 KILOWATT CAPACITY OR MORE

A Seller with 1,000 kW AC capacity or more must negotiate a contract with the Company to set the applicable rates for payments to the customer of avoided capacity and energy costs. Sellers fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10,000 kW AC capacity of interconnected capacity at a point of common coupling to Company’s distribution system may also apply for service under the Company’s Rider for Distributed Generation Service.

RIDER FOR PARALLEL GENERATION

DEFINITIONS

"Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available before each filing required by parts 7835.0300 to 7835.1200 must be used in the computation.

“Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and a utility's electric system.

"Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum on-peak metered capacity delivered to the utility during the month.

"Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical Distributed Energy Resources necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated from its own Distributed Energy Resources or purchased from other sources an equivalent amount of electric energy or capacity. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

"Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

“Off-Peak periods” shall include all hours not included in On-Peak periods.

“On-Peak periods” shall include all hours between 7 a.m. and 10 p.m. Central Prevailing Time, Monday through Friday excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

"Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial

RIDER FOR PARALLEL GENERATION

operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions.

"Standby charge" means the rate or fee a utility charges for the recovery of costs for the provision of standby service or standby power.

"Standby service" means:
A. for public utilities, service or power that includes backup or maintenance services, as described in the public utility's commission-approved standby tariff, necessary to make electricity service available to the distributed generation facility; and
B. for a utility not subject to the commission's rate authority, the service associated with the applicable tariff in effect under Minnesota Statutes, section 216B.1611, subdivision 3, clause (2).

TERMS AND CONDITIONS

1. The interconnection between the QF and the Company must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers.
2. The QF is responsible for complying with all applicable local, state, and federal codes, including building codes, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The Company requires proof that the QF is in compliance with the NEC before the interconnection is made. The QF must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.
3. The QF's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.
4. Any existing Interconnection Agreement executed between the Company and a QF with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract.
5. In accordance with Minnesota Rules 7835.5950, generators own all renewable energy credits unless other ownership is expressly provided for by a contract between the generator and the Company, state law specifies a different outcome, or specific commission orders or rules specify a different outcome.
6. Customers with a Distributed Energy Resource under 40 kW AC capacity shall execute a Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910. Additionally, customers with a Distributed Energy Resource of 40 kW AC capacity or greater and less than 1,000 kW AC capacity may execute the Uniform Statewide Contract with the Company in the form prescribed by Minn. Rules 7835.9910

RIDER FOR PARALLEL GENERATION

to elect an eligible rate. Customers with a Distributed Energy Resource less than 40 kW AC capacity and less than 10,000 kW AC capacity shall execute the Minnesota Distributed Energy Resource Interconnection Agreement with the Company. Before the Customer signs the Uniform Statewide Contract or the Minnesota Distributed Energy Resource Interconnection Agreement, the Company shall provide the Customer a copy of, or link to current interconnection standards in accordance with Minnesota Rules 7835.4750.

7. In accordance with Minnesota Rules 7835.4500, in case of a dispute between the Company and a QF or an impasse in the negotiations between them, either party may request the Minnesota Public Utilities Commission (MPUC) to determine the issue. When the MPUC makes the determination, the burden of proof must be on the utility. Fees and costs for dispute resolution shall be in accordance with Minnesota Rules 7835.4550.
8. QFs with Distributed Energy Resources more than 100 kW AC capacity may be required to take service under the Company's Rider for Standby Service, as described in the tariff.
9. Customers with a Distributed Energy Resource sized between 40 kW AC capacity and 1,000 kW AC capacity taking service under the Rider for Parallel Generation will be required to install a separate production meter to record generation.

RIDER FOR STANDBY SERVICE

APPLICATION

Applicable to any Customer with on-site generation of 10 MW or less and taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75) and Large Power Service (Schedule 74) who has a distributed generation system which is able to generate on a continuous basis and who has entered into the "Minnesota Power's standard interconnection agreement" with the Company.

Service under this Rider shall be required for a Customer who has a distributed generation system that is run on a continuous basis and for non-emergency purposes which normally serves all or a portion of that Customer's electric load requirements, and who desires use of the Company's electric service for temporary backup. Exceptions to this Application include: (i) For any Customers with distributed generation systems rated at 100 kW or less, standby service will be available through their standard rate schedules; or (ii) any Customer, in lieu of service under this Rider, who provides physical assurance that standby service is not taken. A Customer requesting physical assurance shall agree to furnish and install an approved load limiting device which shall be set and sealed by the Company to prevent the Customer from utilizing standby service. The cost of the load limiting device shall be paid by the Customer.

The Customer shall execute a Standby Service Agreement with the Company for service under this Rider. The initial minimum term of service taken under this Rider shall be one (1) year. At the end of the initial term the contract will be automatically renewed on an annual basis, unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the initial term or any subsequent renewal thereof.

Energy provided to the Customer under this rider is limited to energy for Scheduled and Unscheduled Outages as defined below. The Customer shall not generate and allow energy flow onto the Company's system unless it is separately metered and permitted in accordance with the Company's Electric Service Regulations.

All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Service shall be taken at 60 hertz and at the voltage and phase relationship specified under the Company's applicable standard rate schedule for service to the Customer.

RIDER FOR STANDBY SERVICE

DEFINITIONS

Nominated Standard Service
Billed demand up to the level specified in the Standby Service Agreement under the Customer's standard rate schedule.

Reserved Standby Service
Maximum Scheduled Outage or Unscheduled Outage service allowed under this Rider for Standby Service as stated in the Standby Service Agreement. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

Excess Standard Service
Demand utilized in excess of the aggregation of the Customer's Nominated Standby Service and Reserved Standby Service billed on the Customer's standard rate schedule.

Scheduled Standby Service Demand
Measured demand during Scheduled Outages greater than the Nominated Standard Service that is not Excess Standard Service.

Unscheduled On-Peak Standby Service Demand
Measured demand during Unscheduled Outages and on-peak periods greater than the Nominated Standard Service that is not Excess Standard Service. On-peak periods shall include all hours between 6 a.m. and 10 p.m. Central Prevailing Time Monday through Friday excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Unscheduled Off-Peak Standby Service Demand
Measured demand during Unscheduled Outages and off-peak periods in excess of Unscheduled On-Peak Standby Service Demand and greater than the Nominated Standard Service that is not Excess Standard Service. Off-peak periods shall include all hours not included in on-peak periods.

Generator Outage Rate
The unplanned generator outage expressed as a percentage. For the first twelve (12) months the Customer takes service under this Rider, such rate shall be the Equivalent demand Forced Outage Rate (EFORd) class average published on the Midcontinent Independent System Operator (MISO) website most similar to the Customer's generation. The EFORd measures the probability that a generating unit will not be available. For subsequent 12-month periods, the Generator Outage Rate will be calculated based on generator availability for the Customer's generating facilities within the previous 12-month period. The Generator Outage Rate for the Customer's generating facilities shall be

calculated as the number of hours the generator was not available in the prior 12-month period excluding Scheduled Outages divided by the number of hours in a year.

Scheduled Outage
Planned outage periods that shall be prearranged by the Customer with the Company. Scheduled outages are available in April, May, October, November during any hours, and in all other months during off-peak hours between 10:00 p.m. and 06:00 a.m. Central Prevailing Time Monday through Friday, and all hours on weekends and holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. The Customer must provide at least a 45-day notice of its proposed timeline for a Scheduled Outage. The Customer may modify the outage schedule with 45 days' notice to the Company.

Scheduled Outages may not exceed 60 days in any continuous 12-month period unless otherwise agreed to by the Company in writing. Any extension of the outage period may be requested by the Customer in writing and shall be responded to by the Company in writing.

Customers that do not comply with the terms and conditions for qualifying Scheduled Outage periods will be subject to Unscheduled Outage charges as defined below.

Unscheduled Outage
Any outage that occurs outside of the allowed months listed above or which occurs without a 45-day notice to the Company. Any usage above the Nominated Standard Service that does not occur during the Scheduled Outage periods as defined above or that exceeds the allowed number of Scheduled Outage days will be treated as an Unscheduled Outage.

RATE (Monthly)

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Standby Reservation Fee ($/kW)
For purposes of applying the Standby Reservation Fee, the contracted Reserved Standby Service shall be the quantity specified by the Customer in the Standby Service Agreement with the Company. The contracted Reserved Standby Service shall not exceed the nameplate capacity of the Customer's distributed generation system.

The Customer shall pay a Standby Reservation Fee equal to the rate specified below times the contracted Reserved Standby Service and multiplied by the Generator Outage Rate as stated in the Customer's Standby Service Agreement.

RIDER FOR STANDBY SERVICE

Standby Reservation Fee Rate

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	25.32	37.15
Primary	21.20	29.95	NA
Secondary	23.22	30.63	NA

During months in which Scheduled or Unscheduled Outages occur, the Standby Reservation Fee shall apply only if the Standby Demand Charge as defined below is less than the Standby Reservation Fee.

Standby Demand Charge ($/kW)

The Standby Demand Charge shall be sum of Scheduled and Unscheduled Standby Demand Charges as defined below. During months in which Scheduled or Unscheduled Outages occur, the Standby Demand Charge shall only apply if the Standby Reservation Fee as defined above is less than the Standby Demand Charge.

Scheduled Outage

For purposes of applying the Standby Demand Charge during Scheduled Outages, the measured demand shall be determined during the 15-minute period of the Customer's greatest Scheduled Standby Service Demand during the billing month. To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the billing month and divided by the number of days in the billing month.

During Scheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate established in the standard rate schedule times the standby billing demand.

Unscheduled Outage

For purposes of applying the Standby Demand Charge during Unscheduled Outages, the demand shall be determined during the 15-minute periods of the Customer's greatest Unscheduled On- and Off-Peak Standby Service Demands during the billing month.

During Unscheduled Outages, the Customer shall pay a Standby Demand Charge equal to the rate defined below times the corresponding Unscheduled On- and Off-Peak Standby Service Demand.

RIDER FOR STANDBY SERVICE

On-Peak Standby Demand Charge

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	26.31	38.61
Primary	22.03	31.12	NA
Secondary	24.13	31.83	NA

Off-Peak Standby Demand Charge

Rate Schedule / Service Voltage Level	General Service	Large Light and Power	Large Power
Transmission	NA	24.37	35.75
Primary	20.40	28.82	NA
Secondary	22.35	29.48	NA

Energy Charge

Scheduled Outage

The Customer shall pay for all energy usage during a Scheduled Outage according to their standard rate schedule, plus any applicable adjustments.

Unscheduled Outage

For all energy usage during an Unscheduled Outage, the Customer shall pay the Company's hourly incremental energy costs during the time of the sale, including third-party transmission costs incurred by the Company, plus an energy surcharge of $0.02 per kWh. Incremental energy costs are determined after assigning lower-cost energy to all firm retail and firm wholesale Customers including all inter-system pool sales which involve capacity on a firm or participation basis and to all interruptible sales to Large Power, Large Light and Power, and General Service Customers.

RIDER FOR STANDBY SERVICE

SERVICE CONDITIONS

1. All electricity delivered to the Customer by the Company shall be measured by one or more meters installed at a single point of common coupling or as determined by the Company. The Company's meter for standby service shall measure the flow of capacity and energy from the Company to the Customer only. Any flow of capacity and energy from the Customer to the Company shall be separately metered.

2. The Customer shall be required to pay the installation, operation, and maintenance costs incurred by the Company for the metering equipment installed on the Customer's generation equipment. Access shall be provided by the Customer to the Company for maintaining and operating such equipment.

3. The Company shall not be obligated to supply standby service to back up the Customer's distributed generation system at a level in excess of Reserved Standby Service. This restriction in no way limits the electric load requirements for which the Customer may require service from the Company under the standard rate schedule to which this Rider is attached.

4. Service shall be provided under this Rider if the Company has sufficient capacity available in existing production, transmission and distribution facilities to provide such service at the location where service is requested.

5. The Customer shall pay the Company the installed cost of any additional required facilities which are not supported by this Rider.

6. The Company may be reimbursed by the Customer for costs which are incurred, or which have been incurred, in providing facilities which were utilized principally or exclusively in providing service for any portion of the Customer's electric load requirements which are to be normally provided from the distributed generation system.

7. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

RIDER FOR STANDBY SERVICE

Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule:

Unscheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge	Greater of Reservation Fee or Demand Charge + Energy Charge
General Service			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
On-Peak Demand Charge	N/A	$22.03 ($/kW)	$24.13 ($/kW)
Off-Peak Demand Charge	N/A	$20.40 ($/kW)	$22.35 ($/kW)
Energy Charge	N/A	incremental	incremental
Large Light & Power			
Reservation Fee	$25.32 ($/kW)	$29.95 ($/kW)	$30.63 ($/kW)
On-Peak Demand Charge	$26.31 ($/kW)	$31.12 ($/kW)	$31.83 ($/kW)
Off-Peak Demand Charge	$24.37 ($/kW)	$28.82 ($/kW)	$29.48 ($/kW)
Energy Charge	incremental	incremental	incremental
Large Power			
Reservation Fee	$37.15 ($/kW)	N/A	N/A
On-Peak Demand Charge	$38.61 ($/kW)	N/A	N/A
Off-Peak Demand Charge	$35.75 ($/kW)	N/A	N/A
Energy Charge	incremental	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.

RIDER FOR STANDBY SERVICE

Minnesota Power
Standby Rate Options

The following charges are applicable in addition to all charges for service being taken under the Customer's standard rate schedule, plus any applicable adjustments:

Scheduled Outage			
	Transmission	**Distribution Primary**	**Distribution Secondary**
Minimum Monthly Bill	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments	Greater of Reservation Fee or Demand Charge + Energy Charge + Applicable Adjustments
General Service without a Demand Meter			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
Demand Charge[1]	N/A	N/A	N/A
Energy Charge	N/A	9.919 (¢/kWh)	9.919 (¢/kWh)
General Service with a Demand Meter			
Reservation Fee	N/A	$21.20 ($/kW)	$23.22 ($/kW)
Demand Charge[1]	N/A	$10.53 ($/kW)	$10.53 ($/kW)
Energy Charge	N/A	6.931(¢/kWh)	6.931(¢/kWh)
Large Light & Power			
Reservation Fee	$25.32 ($/kW)	$29.95 ($/kW)	$30.63 ($/kW)
Demand Charge[1]	$15.32 ($/kW)	$15.32 ($/kW)	$15.32 ($/kW)
Energy Charge	5.165 (¢/kWh)	5.165 (¢/kWh)	5.165 (¢/kWh)
Large Power			
Reservation Fee	$37.15 ($/kW)	N/A	N/A
Demand Charge[1]	$32.49 ($/kW)	N/A	N/A
Energy Charge	1.187 (¢/kWh)	N/A	N/A

Note: The reservation fee only applies in months when no standby service was taken or when the calculated demand charge is less than the reservation fee. The Reservation Fee is multiplied by the generator outage rate for billing purposes.

[1] The demand charge is calculated based on a daily proration.

RIDER FOR STANDBY SERVICE

STANDBY BILLING EXAMPLES

Scheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Scheduled Standby Service Demand	2,000	kW
Outage Days	5	
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		**Rate**	**Billing**
Reservation Fee	200	kW	$ 25.32	$ 5,064.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
	2,000	kW	$ 15.32	$ -
	2,000	kW	$ (2.45)	$ -
*Scheduled Standby Service Demand * Standard Service Rate * (# of Outage Days/Days in Month)*				
Energy Charge	156,000	kWh	$ 0.05165	$ 8,057.40
	TOTAL STANDBY SERVICE BILLING			**$13,121.40**
Also subject to other applicable adjustments				

RIDER FOR STANDBY SERVICE

Unscheduled Outage:

Customer Example:		
Peak Load	5,000	kW
Nominated Standard Service	3,000	kW
Reserved Standby Service	2,000	kW
Generator Outage Rate	10%	
Unscheduled Off-Peak Standby Service Demand	500	kW
Note: Customer standby demand peaked at 2,000 kW in off-peak hour		
Unscheduled On-Peak Standby Service Demand	1,500	kW
Standby Energy Used	156,000	kWh
Standard Service Schedule	Large Light & Power	
Service Voltage	115,000 volts	

	Billing Units		**Rate**	**Billing**
Reservation Fee	200	kW	$25.32	$0.00
*Reserved Standby Service * Generator Outage Rate * Reservation Fee*				
Note: Not charged if Standby Demand charge is greater				
Demand Charge				
Unscheduled Off-Peak Standby Service Demand	500	kW	$24.37	$12.185.00
*Unscheduled Off-peak Standby Service Demand * Off-peak Standby Demand Charge*				
Unscheduled On-Peak Standby Service Demand	1,500	kW	$26.31	$39,465.00
*Unscheduled On-peak Standby Service Demand * On-peak Standby Demand Charge*				
Energy Charge	156,000	kWh	$0.0550	$8,580.00
Company's hourly incremental energy costs during the time of sale				
Rate of $0.055 per kWh is for example purposes				
	TOTAL STANDBY SERVICE BILLING			**$60,230.00**
Also subject to other applicable adjustments				

RIDER FOR FOND DU LAC RESERVATION BUSINESS LICENSE FEE

APPLICATION

Applicable to billings for electric service provided within the Fond du Lac Reservation located in the southern portion of St. Louis County and the northern portion of Carlton County, Minnesota.

ADJUSTMENT

In accordance with the Corporate Code, Business License System and Employment Rights Law contained in the Fond du Lac Reservation Ordinance 5/84, businesses operating within the Reservation shall pay an assessment of 0.5 percent on revenues from sales within the Reservation. Therefore, there shall be added to each customer's monthly electric service bill a Fond du Lac Reservation Business License Fee assessment. The amount of the fee to be assessed shall be the applicable Assessment Rate multiplied by the Customer's bill for electric service. Compliance by Minnesota Power with the Business License System is governed by the terms of an agreement dated September 25, 1985, as amended by letter dated January 6, 1986, made with the Reservation Business Committee. Since the License Fee assessable by Minnesota Power applies retroactively to October 2, 1985, the initial Assessment Rate shall be 1.0 percent until such time as all retroactive amounts have been collected. Thereafter, the Assessment Rate shall be 0.5 percent.

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

APPLICATION

Applicable to bills for electric service under all Retail Rate Schedules except for Company's Competitive Rate Schedules 73 and 79. This Rider shall not be applicable to Economy or Standby service to retail customers.

Except as provided below in the CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section, there shall be added to each non-CIP exempt customer's monthly bill a Conservation Program Adjustment (CPA) charge which shall be the applicable CPA factor multiplied by the customer's monthly kWh of energy usage. The applicable CPA factor per kWh shall be determined annually as described below.

DETERMINATION OF THE CONSERVATION PROGRAM ADJUSTMENT FACTOR

The Conservation Program Adjustment factor shall be the quotient of the Recoverable Tracker balance, divided by projected retail energy sales (exclusive of those energy sales from customers who have been granted an exemption from CIP costs (see CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS section). The CPA factor will remain in effect until subsequent MPUC approval of an updated factor. The Recoverable Tracker balance shall be determined by adjusting the prior year-end Conservation Improvement Program (CIP) Tracker balance by:

1) Subtracting the unamortized beginning CIP Tracker account balance;
2) Adding financial incentives awarded by the MPUC not reflected in the prior year-end balance;
3) Adding actual and anticipated CIP program expenditures at their approved and/or budgeted level for the applicable time period; and
4) Subtracting actual and anticipated CIP cost recovery through base rates, determined by multiplying the CCRC (shown below) by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the applicable time period; and
5) Subtracting actual and anticipated CIP cost recovery from the applicable CPA factor not accounted for in the prior year-end balance, as determined by multiplying the applicable CPA by the Company’s budgeted retail sales in kWh to non-CIP exempt customers for the remaining applicable time period. The remaining applicable time period for the applicable CPA is dependent upon subsequent MPUC approval which, for the purposes of this calculation, Minnesota Power assumes to align with the end of the current fiscal year (June 30, 2024).

RIDER FOR CONSERVATION PROGRAM ADJUSTMENT

All costs appropriately charged to the CIP Tracker account shall be eligible for recovery through this adjustment and all revenues received from the application of the CPA factor shall be credited to the CIP Tracker account.

In order to normalize the effect of significant changes in the CPA factor, the Company may request approval of an upper limit or cap on the calculated CPA factor.

The CPA factor effective December 1, 2024 for all non-CIP exempt customers shall be 0.1444¢ per kWh.

DETERMINATION OF CONSERVATION COST RECOVERY CHARGE (CCRC)

The CCRC is the amount included in base rates dedicated to the recovery of CIP costs as approved by the Minnesota Public Utilities Commission in the Company's last general rate case. The CCRC is approved and applied on a per kWh basis by dividing the test-year CIP expenses by the test-year sales volumes (net of CIP-exempt volumes). All revenues received from the CCRC shall be credited to the CIP Tracker Account.

The CCRC effective March 1, 2025 for all non-CIP exempt customers is 0.458916¢ per kWh.

CUSTOMER EXEMPTIONS AND RATE ADJUSTMENTS

For customers granted an exemption from CIP costs by the Commissioner of the Minnesota Department of Commerce, pursuant to Minn. Stat. § 216B.241, the CPA factor shall not be applicable. No CCRC is included in base rates for Large Power customers. For Large Power customers who have not been granted an exemption, the CCRC of 0.458916¢ per kWh shall apply to the total billing energy. In addition, non-Large Power customers who have been granted an exemption shall receive a billing credit of 0.458916¢ per kWh to offset the CCRC that is included in base rates under the applicable rate schedule. For those customer accounts granted exemption by a decision of the Commissioner after the beginning of a calendar year, any CIP collections billed after January 1 of the year following the Commissioner's decision shall be credited back to customers.

RIDER FOR NON-METERED SERVICE

APPLICATION

To General Service Schedules 25

DISCUSSION

Minnesota Power provides service for several types of operations that would normally be a part of the General Service class of customers. However, due to the unique nature of the customer's operations it is not always practical to meter the service points. Therefore, at Company's discretion, a customer may receive service under the General Service - Non-Demand Schedule without the metering requirements of that schedule and be billed for energy usage based on the table below. Additional end-use types and associated energy usages per unit may be added from time to time to address new situations. For purposes of applying the appropriate service charge, one service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required for service under the applicable General Service Schedule. In the case of Holiday decorative lighting, the customer shall be billed with a single service charge and energy usage per the table below one time per the holiday season, estimated at 45 operating days for 12 lighting hours per day.

Item Type	Description	Units	Estimated Monthly Energy Usage/Unit
SEC-CAM	Security Cameras	kWh	43 kWh
CBL2WY90	90v 2-Way Comm Cable PS	Volts	617 kWh
AMP-CBL	Amplifier Cable	Amplifiers	377 kWh
XFLSHR60	Crossing Flashers-60kWh	kWh	60 kWh
HS160W	Strip Heaters-160Watts	kWh	65 kWh
HSGREHRT	Strip Heaters-GRE Hartford 99	kWh	58 kWh
SIGN-LTG	Sign Lighting	Signs	25 kWh
SIRENS	Civil Defense Sirens	Sirens	1 kWh
RR-XING	Railroad Crossings	Crossings	39 kWh
NOWIRE15	Wireless Metering-15kWh	kWh	15 kWh

RIDER FOR NON-METERED SERVICE

HL-LED	Holiday Lighting – LED	Bulbs	22.5 Watt-hours
HL-INCT	Holiday Lighting – Incandescent	Bulbs	315 Watt-hours

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

APPLICATION

Applicable to any Customer taking service under General Service (Schedule 25) or Large Light and Power Service (Schedule 75) and which has at least 200 kW of Interruptible Load that qualifies for interruptible service. All provisions of the applicable standard Service Schedule shall apply to interruptible service under this Rider except as noted below.

RATE MODIFICATION

The Rates (Monthly) of the applicable General Service or Large Light and Power Service Schedules shall apply. Additionally, the Customer shall receive a billing credit which will be 11 percent of the Customer's interruptible billing before any other applicable Adjustments.

INTERRUPTIBLE ENERGY CONDITIONS

Interruptible energy must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur. During a Midcontinent Independent System Operator (MISO) emergency event the Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events. Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that is required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

PRICE RECALL CONDITIONS

The Company shall have the right to re-price the Customer's Interruptible Load energy at 110% of the Company's incremental supply cost for up to 100 hours per year. During a price recall period the Customer will be given the option to continue service without interruption under the terms of this Rider. The Company will provide day-ahead email notice by 4:00 p.m. Central Prevailing time on the day prior to the price recall period(s), which will include the estimated prices during the price recall period(s). The Customer will have the option to curtail during the re-pricing periods or continue normal operation and pay 110% of the incremental supply cost for all Interruptible Load during the re-pricing period. Re-pricing periods will occur between the hours of 6:00 a.m. to 10:00 p.m. with the exception of time periods when MISO has declared an alert or emergency for the Minnesota Power service area.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED PHYSICAL INTERRUPTION

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the targeted demand reduction

threshold specified in the Customer's annual contract. In the event that the Customer fails to follow an Interruption request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Interruption conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

SERVICE CONDITIONS

1. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:

   (a) when the Company is required to purchase or generate power at a cost higher than the Customer's energy charge,
   (b) when the Company expects to incur a system peak,
   (c) at such other times when in the Company's opinion the reliability of the system is endangered,
   (d) when MISO declares an emergency event, or
   (e) when the Company performs necessary testing for certification of interruptibility of Customer's loads.

2. The Company shall not be liable for any loss or damage including consequential damages, caused by or resulting from any interruption of service.

3. The Customer must be able to physically interrupt its Interruptible Load when notified by the Company.

4. The Company may accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with the Module E Tariff and Business Practices Manual for Resource Adequacy. The Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the parties shall in good faith determine the most appropriate substitute and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either parties rights or obligations

RIDER FOR GENERAL SERVICE/LARGE LIGHT AND POWER INTERRUPTIBLE SERVICE

under the Electric Service Agreement. Any changes would be subject to regulatory approval.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. The Customer shall pay the Company the installed cost of any additional facilities required which are not supported by this rate.

7. The term of service under this Rider shall be no less than one year and must be consistent with the MISO or successor Planning Year or other planning criteria as determined by the Company. However, the Company, at its sole discretion, reserves the right to provide the Customer with a three-month notice to discontinue providing service under this Rider.

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

APPLICATION

Applicable to any Customer taking service under Large Power Service Schedule 74, whose Electric Service Agreement has a minimum term of at least four (4) years beyond the initiation of Incremental Production Service hereunder and which provides for the sale by the Company and the purchase by the Customer of Incremental Production Service, subject to the conditions set forth in the Customer's Electric Service Agreement and this Rider. Application of this Rider and establishment of an Incremental Production Service Threshold ("IPST") for those Customers with self-generation and whose Electric Service Agreement allows for purchase of Economy Energy shall be at the sole discretion of the Company.

DEFINITIONS

Real-time Buy-through Period: Period called by the Company where Company will re-price Incremental Production Service ("IPS") energy and where Customer will respond through curtailing IPS load or buying-through at the real-time locational marginal price ("LMP").

Curtailment Period: Period called by the Company where Customer is required to curtail load.

Renewable Surplus Period: Period called by the Company during times of high renewable generation, low system load or low LMPs where Customer may exceed 110% of the IPST.

RATE MODIFICATIONS

Demand Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST but not greater than 110% of the IPST or has Measured Demand in excess of the IPST during a Renewable Surplus Period, the Customer's Measured Demand above the IPST shall not be subject to any demand charges or ratchet provisions associated with Contract Demand and Incremental Service Requirements under the Large Power Service Schedule and the Customer's Electric Service Agreement unless otherwise provided in this Rider or the Customer's Electric Service Agreement. If Customer has Measured Demand in excess of the IPST during a Curtailment Period, the Customer's Billed Demand will be increased by the amount the Measured Demand exceeded the IPST, and the Customer will be subject to any penalties imposed upon Company by the Midcontinent Independent System Operator ("MISO") or a successor entity relating specifically to Customer's failure to curtail IPS service.

Energy Charge
During any Billing Month in which the Customer has Measured Demand in excess of the IPST, the energy associated with the Customer's Measured Demand above the IPST shall

be subject to an energy charge equal to the Incremental Production Rate, the Real-time Buy-through Period Rate or the Curtailment Period Rate.

Incremental Production Rate
The Incremental Production Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly day-ahead LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Real-time Buy-through Period Rate
The Real-time Buy-through Period Rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company .

Curtailment Period Rate
The Curtailment Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Renewable Surplus Period Rate
The Renewable Surplus Period rate shall consist of an energy surcharge of $0.01 per kWh plus the greater of the hourly real-time LMP at the Company's load node, MP.MP, during the time of the sale plus MISO costs incurred by the Company or the current year average Large Power forecasted fuel and purchased energy rate, unless the adjusted forecasted rate is reduced at the sole discretion of the Company.

Excess Reactive Demand
Whenever a Customer's metered demand exceeds the IPST, the Company shall not bill the Customer for any excess reactive demand adjustments below the level specified in the Customer's Electric Service Agreement. However, the Company may, at its sole discretion, bill the Customer for any excess reactive demand adjustments above the specified level at the Excess Power Demand Charge, with excess reactive demand calculated as indicated in the Large Power Service Schedule.

SERVICE CONDITIONS

1. All curtailments, buy-throughs, or Company declarations of Curtailment Periods or Renewable Surplus Periods can be superseded by Company requests of Customer to

curtail load as soon as reasonably possible for purposes of grid stability, in accordance with Company's Service Regulations.

2. The Customer shall be permitted to purchase Incremental Production Service from the Company, for service above the IPST established in the Electric Service Agreement, whenever the Customer's Measured Demand during any Billing Month exceeds the IPST, with the exception of during Curtailment Periods.

The Customer's Measured Demand shall not exceed 110% of the IPST without the Company declaration of a Renewable Surplus Period or Company's prior written consent, which consent shall not be unreasonably withheld. In the event that the Customer exceeds this level without Company consent or outside of Renewable Surplus Periods, the Company may increase the Customer's contractual requirements, including Contract Demand, IPST, or other related terms, by that amount for the duration of the Customer's Electric Service Agreement.

Additional Service Conditions for Real-time Buy-through Periods

3. Upon notification from the Company of a Real-time Buy-through Period, the Customer has the option of reducing its metered demand to the IPST by the time given by the Company or have the Incremental Production Service energy repriced at the Real-time Buy-through Rate. The Customer shall be given 30 minutes or greater notice of a Curtailment Period.

4. Real-time Buy-through Periods will not be called for greater than 170 hours per calendar year, excluding MISO capacity event curtailments.

5. The duration and frequency of Real-time Buy-through Periods shall be at the sole discretion of the Company. Real-time Buy-through Periods shall normally occur during times of high or volatile real-time LMPs or low generation.

Additional Service Conditions for Curtailment Periods

6. Upon notification from the Company of a Curtailment Period, the Customer shall reduce its metered demand to the IPST by the time given by the Company, and for a duration as required by the Company. The curtailment shall be for the entire amount of Incremental Production Service unless otherwise notified by the Company. The Company shall give Customer 30 minutes or greater notice of a Curtailment Period. Thirty (30) minute notification under this Rider shall be via automatic control unless otherwise provided in the Customer's Electric Service Agreement.

7. Curtailment Periods will not be called for more than 170 hours per calendar year, excluding MISO capacity event curtailments.

8. Curtailment Periods will not be called for more than eight hours per day and no more than four hours per Curtailment Period.

RIDER FOR LARGE POWER INCREMENTAL PRODUCTION SERVICE

9. The duration and frequency of Curtailment Periods shall be at the sole discretion of the Company. Curtailments shall normally occur for reasonable testing requirements, at such times when the Company expects to incur a system peak in excess of its MISO (or successor organization) accredited generating capability (less the required planning reserve) and at such other times when, in the Company's opinion, the reliability of the Company or MISO systems are endangered. Curtailments shall normally not occur due to high energy costs. Curtailments shall normally occur for capacity related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service Customers (those loads that meet the requirements as specified in the MISO (or successor organization) procedure for the certification of interruptible demand). Unless agreed to in advance by the Customer, the Company shall not make additional non-firm off-system energy sales that would, if made, require curtailment of Incremental Production Service.

10. The Customer shall pay any and all penalties or other costs incurred by the Company if the Customer fails to reduce its metered demand to the IPST or the requested reduction level (but not less than the IPST) within 30 minutes of receiving such notice from the Company. The penalties or other costs shall be divided pro rata between those Customers that did not curtail service as requested by the Company.

11. The Company shall reserve the right to discontinue service under this Rider to Customers who fail to curtail service as requested by the Company.

12. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

Additional Service Conditions for Renewable Surplus Periods

13. Upon notification from the Company, Customer may exceed 110% of the IPST for a duration determined at the sole discretion of the Company. The Customer shall be given, whenever possible, information regarding the probable time and duration of Renewable Surplus Periods the calendar day prior to any such period. Notice may also be given with at least a 30 minute notice.

14. The duration and frequency of Renewable Surplus Periods shall be at the sole discretion of the Company. Renewable Surplus Periods may occur during times of high renewable generation or low MP system load.

15. The Company may cancel Renewable Surplus Periods with 30 minutes notice if MISO or MP system conditions change.

RIDER FOR RELEASED ENERGY

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74. Application of this Rider and establishment of Released Energy Credit shall be at the sole discretion of Company and participation by Customer is voluntary.

RATE MODIFICATIONS

Energy Credit for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Large Power Service requirement, the Released Energy Credit shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

Energy Credit for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a Released Energy Credit for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The Released Energy Credit shall equal a fair market value for the hours of the release.

The Released Energy Credit shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

CONDITIONS

1. Customer may not purchase Large Power Incremental Production Service ("IPS") as established under the Rider for Large Power Incremental Production Service while participating in Released Energy Credit opportunities.

2. If Customer makes energy available for sale and the identified released energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the Released Energy Credit shall be zero. In the event that a scheduled released energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

3. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is released for sale or an avoided energy purchase is completed.

RIDER FOR RELEASED ENERGY

4. When Released Energy Credit opportunities are anticipated, Company shall provide advance notice, if possible, of the approximate margins or available energy purchase costs and hours of sale or purchase opportunity available to Customers who have indicated interest. Opportunities for voluntary load reductions will be communicated to customers primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. If two or more notified customers make energy available for sale for the same time period, Company will prorate the Released Energy Credit among those customers. Released Energy Credits shall be determined for each Customer according to the amount of capacity made available for sale by each in proportion to the total amount of capacity made available by all Customers for a given time period.

5. In the event that additional released energy sales or avoided energy purchase opportunities arise during a day, Company shall provide Customers with as much advance notice as possible (via email and phone calls) to enable their participation. Credits associated with such opportunities shall be allocated to Customers on a first-come, first-served basis.

6. Customer may notify Company when Customer desires to reduce energy requirements for released energy sales or avoided energy purchase opportunities. Customer may have a "standing agreement" with Company regarding the conditions for Released Energy Credit opportunities, allowable duration, required margins, margin sharing, etc. These agreements, may be made on a customer by customer basis and shall be considered by Company without notice to other customers.

7. Energy shall be made available for sale in increments of 5 MW with a 10 MW minimum and shall be associated with actual reduced power requirements.

PENALTY FOR INSUFFICIENT LOAD CONTROL

In the event that Company has entered into a sale or purchase agreement for energy made available by a Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the released energy sale or avoided energy purchase, Customer shall receive no credit for the time that load exceeded the specified level and shall be responsible for any and all costs incurred by Company due to such failure to control load.

RIDER FOR VOLUNTARY ENERGY BUYBACK

APPLICATION

Applicable to any Customer eligible for service under General Service Schedule 25; Large Light and Power Service Schedule 75 (and including all applicable Riders thereto); or Competitive Rate Schedules 73 or 79, and customers receiving service under contracts authorized by Minn. Stat. §216B.162 (the competitive and discretionary rate statute). Customer must be able to provide a minimum of 200 kW of curtailable demand for energy buyback transactions. Energy buyback transactions facilitate short-term off-system energy sales or assist in avoiding higher-cost energy purchases to meet Company's firm energy requirements. Application of this Rider and establishment of Buyback Energy Credit ("BEC") shall be at the sole discretion of Company. Participation by Customer is voluntary. All provisions of the applicable standard Service Schedule shall apply to service under this Rider except as noted below.

RATE MODIFICATION

Customer shall receive a BEC for any calendar month in which Customer and Company have agreed to participate in energy buyback transactions. The BEC shall occur as an adjustment on Customer's bill and shall consist of a payment per kWh for each hour subject to an energy buyback transaction.

BEC for Off-System Sales
Customer shall receive a credit during any Billing Month in which Customer and Company have cooperated to make an off-system energy sale. If the energy made available for sale is associated with Customer's Firm Service requirement, the BEC shall equal a negotiated amount based on the off-system energy sale price, less (i) Company's highest firm energy costs, (ii) and all Midcontinent Independent System Operator (MISO) costs for each hour that such sales opportunity occurs.

BEC for Avoided Energy Purchases
Company may request, and Customer may voluntarily reduce, Customer's energy requirement during times when Company anticipates purchasing energy to serve Firm Energy requirements, thereby enabling Company and its customers to avoid higher-cost energy purchases. Company shall provide Customer a BEC for the reduced energy usage, such credit to not exceed the avoided cost for the hours of the release. The BEC shall equal a fair market value for the hours of the release.

The BEC shall be allowed as a recoverable cost for Fuel and Purchased Energy Rider purposes.

RIDER FOR VOLUNTARY ENERGY BUYBACK

SERVICE CONDITIONS

1. Company and Customer shall enter into an Energy Buyback Agreement specifying the rates, and the terms and conditions, for participation in energy buyback transactions, including, but not limited to: (i) BEC calculation; (ii) period of possible energy buyback; (iii) minimum/maximum duration of each energy buyback; and (iv) commencement/ termination notice requirements.

2. Company and Customer shall agree to a typical peak kW level of operation ("Reference Operating Level"). Customer shall determine an acceptable reduced operating level for each energy buyback transaction time period ("Reduced Operating Level"). The amount of energy associated with each energy buyback transaction shall be equal to the difference between Customer's Reference Operating Level and the Reduced Operating Level multiplied by the hours of curtailment at a load factor mutually agreed to by Company and Customer.

3. Company shall notify Customer of energy buyback opportunities primarily via email, and when possible, notice shall also be made via phone calls to individuals designated by Customer. Alternatively, Customer may notify Company when Customer desires to reduce energy requirements for energy buyback transactions.

4. Under the terms of the Energy Buyback Agreement, at Company's request, Customer shall curtail down to the Reduced Operating Level for a duration as required by Company, such duration not to exceed the maximum number of curtailment hours agreed to by Company and Customer. Company shall establish and administer procedures to ensure actual and verifiable Customer load reductions occur when energy is made available for sale or an avoided energy purchase is completed.

5. Customer shall pay Company the installed cost of any additional facilities (e.g., metering, protective devices for interconnection with Company's system, etc.) required to participate in energy buyback transactions under this Rider.

6. If Customer makes energy available for sale and the identified off-system energy sale or avoided energy purchase is not actually completed (for example, due to transmission constraints), the BEC shall be zero. In the event that a scheduled off-system energy sale or avoided energy purchase is not completed or the terms and conditions change, Company shall notify Customer of such change as soon as possible.

7. In the event that Company has entered into a sale or purchase agreement for energy made available by Customer, and Customer subsequently fails to maintain sufficient load control during the time(s) of the buyback energy sale or avoided energy purchase, (i) Customer shall receive no credit for that calendar month in which the curtailment failure occurred, and (ii) Customer shall be responsible for any and all costs incurred by Company

RIDER FOR VOLUNTARY ENERGY BUYBACK

due to such failure, including but not limited to: (a) penalties imposed upon Company by the Midcontinent Independent System Operator (MISO) or any other entity, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases.

8. Company shall not be liable for any loss or damage caused by or resulting from any curtailment of service at Customer's facility undertaken in response to BEC.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

APPLICATION

Application to customers taking service under all retail rate schedules. All provisions of the applicable standard Service Schedule shall apply to renewable energy service under this Rider except as noted below. The renewable energy service provided under this schedule is subject to the availability of renewable energy designated to it, as determined by the Company, and is made available on a first-come, first-served basis. “Renewable energy” means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary.

RATE MODIFICATIONS

The Rates (Monthly) and all adjustments included in the applicable service Schedule shall apply. Additionally, the Customer shall pay a monthly renewable energy surcharge for each kWh of renewable energy nominated, and shall receive a credit for the rate-class-specific monthly Fuel and Purchased Energy Charge.

DETERMINATION OF THE RENEWABLE ENERGY SURCHARGE

The renewable energy surcharge shall be based on the total program costs including the sum of:

[b] The cost of renewable energy that will supply the program,

[c] The delivery costs,

Divided by

[a] The expected annual energy output.

The renewable energy surcharge will be recalculated annually to reflect power supply costs. An example of the calculation is shown below in Appendix 1.

Renewable Energy Surcharge

$0.03900 per kWh – All Customer Classes

The charge per kWh is in addition to the applicable Service Schedule currently serving the customer. All charges under existing tariffs remain in effect.

RIDER FOR VOLUNTARY RENEWABLE ENERGY

SERVICE CONDITIONS

1. The Customer may nominate between 25% and 100% of their monthly kWh use.

2. The Customer shall take service under this Rider for no less than one year. Service shall continue thereafter until and unless the Customer notifies the Company that service under the Rider is to be terminated.

Appendix 1

MINNESOTA POWER
Sample of
Renewable Rate Pricing Calculation

Power Supply Cost:	
[a] Expected annual energy output (PPA)	xx kWh
[b] Cost of Renewable energy to supply program (per PPA guidelines)	$xx
[c] Delivery Cost of renewable energy	$xx
[d] Renewable Energy Surcharge ([b] + [c]) / [a]	$xx per kWh

RIDER FOR CITY OF LONG PRAIRIE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Long Prairie, except bills for electric service to property owned by the City of Long Prairie.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Long Prairie Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Long Prairie Franchise Fee assessment collected will be passed along to the City of Long Prairie.

RIDER FOR CITY OF LITTLE FALLS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Little Falls, except bills for electric service to property owned by the City of Little Falls.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Little Falls Franchise Fee assessment in the amount of:

$1.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Little Falls Franchise Fee assessment collected will be passed along to the City of Little Falls.

RIDER FOR CITY OF HERMANTOWN FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hermantown, except bills for electric service to property owned by the City of Hermantown and property owned or leased by Company.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hermantown Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Hermantown Franchise Fee assessment collected will be passed along to the City of Hermantown.

RIDER FOR CITY OF PARK RAPIDS FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Park Rapids, except bills for electric service to property owned by the City of Park Rapids.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Park Rapids Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Park Rapids Franchise Fee assessment collected will be passed along to the City of Park Rapids.

RIDER FOR CITY OF AURORA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Aurora, except bills for electric service to property owned by the City of Aurora.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Aurora Franchise Fee assessment in the amount of:

$2.00 per month for each residential electric service agreement; and
$2.00 per month for each commercial, industrial or other electric service agreement.

Dual fuel meters shall constitute one meter for purposes of this franchise fee assessment.

100% of the City of Aurora Franchise Fee assessment collected will be passed along to the City of Aurora.

RIDER FOR DISTRIBUTED GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: Residential Service (Schedule 20), Residential Dual Fuel Interruptible (Schedule 21), Commercial/Industrial Dual Fuel Interruptible (Schedule 26), General Service (Schedule 25), Large Light and Power Service (Schedule 55, 75), Municipal Pumping Service (Schedule 87) and Large Power Service (Schedule 54, 74) and who has entered into Minnesota Power's standard interconnection agreement with the Company for the operation of the on-site interconnection of a Distributed Energy Resource operating in parallel with the Company's distribution system. The Distributed Energy Resource must be:

a. an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site; and

b. fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than 10 MW of interconnected capacity at a point of common coupling to Company's distribution system. The interconnection and operation of Distributed Energy Resources at each point of common coupling shall be considered as a separate application of the Rider.

Service under this Rider shall be required for any Customer who meets the Application criteria in the previous paragraph, subject to the following exceptions: (i) any Customer who takes service, as applicable, under Company's Rider for Parallel Generation as established under Minnesota Rules Chapter 7835 – Cogeneration and Small Power Production; or (ii) any Customer, in lieu of service under this Rider, who pursues reasonable transactions outside this Rider as agreed to by Company and Customer.

Customer shall execute an electric service agreement and a power purchase agreement with Company for service under this Rider. The minimum term of service taken under this Rider shall be one (1) year or such longer period as may be required under the electric service agreement. Service under this Rider is subject to Company's Electric Service Regulations and any other rules as applicable. All provisions of the applicable standard rate schedule shall apply to service under this Rider except as noted below.

TYPE OF SERVICE

Output of the Distributed Energy Resource shall be provided at 60 hertz and at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer or as agreed to by Company and Customer.

RIDER FOR DISTRIBUTED GENERATION SERVICE

RATE (Monthly)

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard rate schedule:

Service Charge: $15.83

Capacity/Energy Credits:

Customer may sell all the energy produced by the Distributed Energy Resource to Company, use all the Distributed Energy Resource energy to meet its own electric load requirements or use a portion of the energy from the Distributed Energy Resource and sell the remaining to Company.

Company shall purchase all capacity and energy made available by Customer from the Distributed Energy Resource. Such capacity and energy shall be purchased by Company under the rates, terms and conditions for such purchases as established by Company in a power purchase agreement with Customer.

Capacity Credits shall only be provided on that capacity available to Company which meets the accreditation requirements of the Midcontinent Independent System Operator (MISO) or successor organization.

Capacity and Energy Credits shall be based on Company's calculation of avoided capacity and energy costs. The Capacity Credits in effect at the time Customer enters into a power purchase agreement with Company shall remain in effect for the length of the agreement. Energy Credits for use under the power purchase agreement shall vary by month and time period (on-peak and off-peak) and shall be updated annually for the upcoming calendar year. Upon written request by Customer and after Customer signs a confidentiality agreement, Company shall provide Customer the current schedule of Capacity and Energy Credits.

Delivery Charge ($/kw):

Company may require any Customer with a Distributed Energy Resource of 1 MW or greater nameplate capacity rating to pay a Delivery Charge for all capacity and energy made available by Customer from the Distributed Energy Resource. Such Delivery Charge shall compensate Company for any additional distribution, transmission and ancillary services not included under this Rider provided by Company to Customer through Company's participation in the MISO or successor organization. For applying the Delivery Charge, the capacity shall be determined during the 15-minute period of Customer's greatest capacity delivered to Company during the billing month.

RIDER FOR DISTRIBUTED GENERATION SERVICE

Distribution Credits:

If the installation of the Distributed Energy Resource results in Company delaying or avoiding distribution investment, Company shall provide Distribution Credits to Customer that reflect the avoided distribution cost.

Company shall provide, upon Customer's written request, a list of substation areas or feeders that could be likely candidates for Distribution Credits as determined through Company's normal distribution planning process. Upon receiving an application from Customer for the interconnection and operation of a Distributed Energy Resource, Company shall perform an initial screening study to determine if the project has the potential to receive Distribution Credits. Customer shall be responsible for the cost of such screening study. If Company's initial study shows that there exists potential for Distribution Credits, Company shall, at its own expense, pursue further study to determine the Distribution Credits, as part of its annual distribution capacity study.

Line Loss Credits:

If the installation of the Distributed Energy Resource results in Company avoiding additional line losses, Company shall provide Line Loss Credits to Customer that reflect the additional line loss savings.

Company shall perform, upon Customer's written request, a specific line loss study to determine if the project has the potential to receive Line Loss Credits. Customer shall be responsible for the cost of such line loss study.

Renewable Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company meeting a requirement to obtain renewable capacity and energy, Company shall provide Renewable Credits to Customer that equal the additional avoided cost of the renewable addition or purchase. The purchase price of such Renewable Credits shall be net of payment for capacity and energy identified above.

In the event that Customer producing the power receives renewable credits, (that is, the Customer is paid by the Company the avoided cost of renewable energy purchases), then the transaction represented by the power purchase agreement will constitute a transfer from the Customer to the Company of the property rights, for those renewable attributes specific to the renewable energy generated by the Customer and for which the Company paid renewable credits.

Customer may receive either renewable credits or tradable emission credits but not both.

RIDER FOR DISTRIBUTED GENERATION SERVICE

Tradable Emission Credits:

If Company's purchase of capacity and energy from the Distributed Energy Resource results in Company receiving an economic value associated with tradable emissions, Company shall provide Tradable Emission Credits to Customer that equal the credit revenues associated with the Distributed Energy Resource of such Tradable Emission Credits received by Company. Customer may receive either renewable credits or tradable emission credits but not both.

In the event that Customer producing the power receives tradable emission credits, then the transaction represented by the power purchase agreement will constitute a transfer from the Customer to Company of the property rights, if any, for those tradable emission credits received by Customer and for which Company paid tradable emission credits.

SERVICE CONDITIONS

1. All electricity delivered to Company by Customer shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. Company's meter for distributed generation service shall measure the flow of capacity and energy from Customer to Company only. Any flow of capacity and energy from Company to Customer shall be separately metered.

2. Service shall be provided under this Rider if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

3. Customer shall pay Company the installed cost of any additional required facilities which are not supported by this Rider.

4. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Company Distributed Energy Resource process and technical documents are available at www.mnpower.com or by contacting Company at 1-800-228-4966 or 30 West Superior Street, Duluth, MN 55802.

RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$0.74 per kW-month for all Billing Demand kW and 0.097¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.250¢ per kWh for all kWh

RIDER FOR TRANSMISSION COST RECOVERY

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	$0.36 per kW-month for all Billing Demand kW and 0.047¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.195¢ per kWh for all kWh

RIDER FOR CITY OF NASHWAUK FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Nashwauk.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Nashwauk Franchise Fee assessment. The amount of the fee to be assessed shall be the assessment rate equal to that imposed on Minnesota Power by the City of Nashwauk, which is currently 1.5% of the total bill excluding sales taxes. The fee is listed on the bill as "Nashwauk Franchise Fee (1.5%)" and is effective as of February 10, 2011.

100% of the City of Nashwauk Franchise Fee assessment collected will be passed along to the City of Nashwauk.

RIDER FOR FOUNDRY, FORGING AND MELTING CUSTOMERS

APPLICATION

Applicable to any customer in the Foundry, Forging, and Melting Industry, as determined by Company, taking service under Large Light and Power Service (Schedule 75).

Customers taking service under this Rider may not also take service under the Rider for General Service/Large Light and Power Interruptible Service.

The term of service under this Rider shall be no less than one year. Customers must provide 30 days advance notice to Company prior to taking service under this Rider or discontinuing service under this Rider after at least one year of service.

This Rider shall apply to the entire electric service requirements on Customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

RATE MODIFICATION

Demand Charge Credit: For each month that service is taken under this Rider, the Customer shall receive a billing credit of $3.00 per kW of Billing Demand.

Price Recall Energy: 200 Hours of Price Recall Energy per calendar year will be billed at Company's sole discretion subject to the following conditions.

- Minimum of three hours duration per price recall period.
- Price Recall hours will be limited to 6 a.m. to 10 p.m. Central Prevailing Time with the exception of time periods when Midcontinent Independent System Operator (MISO) (or successor) has declared an alert or emergency for the Minnesota Power area.
- Minnesota Power will provide day-ahead email notice by 4 p.m. Central Prevailing Time on the day prior to the price recall period(s). The notice will indicate the start and stop times for the price recall period(s) and estimated prices during these price recall period(s).
- Customer has the option to curtail load or to continue normal operations during the price recall period.
- Price Recall energy usage will be billed at 110% of the Company's hourly incremental energy costs during the time of the price recall period. Incremental energy costs are determined after assigning lower cost energy to all firm retail and firm wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis.

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

APPLICATION

Applicable to any customer taking service under Large Light and Power Service Schedule 75 with total power requirements of at least 3,000 kW. Application of this Rider shall be at the sole discretion of Company. All provisions of the Large Light and Power Service Schedule shall apply to the Time-of-Use service under this Rider except as noted below. Participation by customer is voluntary.

Customers taking service under this Rider may not also take service under the Rider for Parallel Generation or the Rider for General Service/Large Light and Power Interruptible Service.

RATE MODIFICATION

The monthly rate will be modified as follows:

Demand Charge	
For the first 100 kW or less of On-Peak Billing Demand	$1,050.00
All additional On-Peak Billing Demand ($/kW)	$9.75
Off-Peak Demand in excess of On-Peak Billing Demand ($/kW)	$4.50
Super Off-Peak Demand in excess of Off-Peak Billing Demand ($/kW)	$0.00
Transmission Demand Charge ($/kW)	
On-Peak Transmission Demand	$6.07
Energy Charge	
On-Peak kWh (¢/kWh)	7.071¢
Off-Peak kWh (¢/kWh)	4.715¢
Super Off-Peak kWh (¢/kWh)	3.538¢

Modified Determination of Billing Demand

On-Peak Billing Demand shall be the kW measured during the 15-minute period of the customer's greatest On-Peak use during the month, as adjusted for power factor, except that On-Peak Billing Demand will not be less than 75% of the greatest adjusted On-Peak demand during the preceding eleven months, nor shall it be less than any Minimum Contract Demand that may be specified in customer's Electric Service Agreement.

The Off-Peak Billing Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak or Off-Peak) during the current month, as adjusted for power factor, and the On-Peak Billing Demand.

The Super Off-Peak Demand is defined as the difference between the maximum kW measured during the 15-minute period of the customer's greatest use (On-Peak, Off-Peak,

PILOT RIDER FOR LARGE LIGHT AND POWER TIME-OF-USE SERVICE

or Super Off-Peak) during the current month, as adjusted for power factor, and the On-Peak and Off-Peak Billing Demand.

SERVICE CONDITIONS

1. On-Peak, Off-Peak, and Super Off-Peak Periods Defined: The On-Peak time period shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super-Off Peak period shall be defined as 11:00 p.m. to 5:00 a.m. CPT. The Off-Peak time period shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

2. At the end of the first year following the initial date when any customer takes service under this Rider, the applicability, rate modification, and service conditions will be evaluated for potential modification. The Rider will continue in effect after the initial year until it has been modified or cancelled based on the evaluation of the pilot.

3. The term of service under this Rider shall be no less than one year unless the pilot offering is terminated prior to the conclusion of customer's first year of service.

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

APPLICATION

Applicable to any Residential Service Customer taking service under Rate Code 20 (General) or Rate Code 22 (Space Heating) who is approved as qualified for the Low Income Home Energy Assistance Program (LIHEAP) by a designated social service agency (Agency) within Company's service territory during the program year (October 1 to September 30). Customers must receive certification annually through authorized Agency to be eligible for this Rider. A qualification exception applies for customers who initially self-declare as low income. Continued eligibility for the CARE program, beyond the initial exception, would be subject to customers requesting and being approved for LIHEAP within one year of their low income self-declaration.

DEFINITIONS

SENIOR Customers:
Seniors are those age 62 or older, as determined through the LIHEAP qualification and/or Low Income Self-Declaration process.

DISABLED Customers:
Disabled are those determined as disabled through the LIHEAP qualification and/or Low Income Self-Declaration process.

LEGACY CARE Customers:
Customers enrolled in the CARE Program as of September 30, 2019 or prior to the initial offering of the flat and affordability discounts under this Rider, whichever is later.

RATE MODIFICATION

All provisions of the Residential Service Schedule shall apply except as modified below:

FLAT DISCOUNT

Eligible Senior, Disabled, and / or Legacy CARE customers receive a $20 flat discount in each monthly billing period.

AFFORDABILITY DISCOUNT

Eligible Senior and / or Disabled Customers Under 62 Years of Age with no Disability, and Customers with certified medical circumstances:

A customer using more than 3% of their annual household income for electric bill payments may be eligible for the Company's affordability discount. The Company will offer customers with the lowest income, and a history of high electric consumption, an affordability discount

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

with the goal of keeping a household's annual energy burden within 3% of its income, on average. The affordability discount will be applied as a monthly percentage discount on bill.

LOW-INCOME AFFORDABILITY PROGRAM SURCHARGE

For Customers taking service under: Residential Service (Rate Code 20, 22, and 23) except those residential customers who are qualified for LIHEAP, General Service (Rate Code 25), Large Light & Power (Rate Code 75), Large Power (Rate Code 74), and Non-Contract Large Power (Rate Code 78) there shall be added to each service agreement, as designated above, on their monthly bill, a Low-Income Affordability Program Surcharge as specified below:

Residential (Except LIHEAP-qualified)	$2.41
General Service	$4.01
Large Light & Power	$26.74
Large Power	$1,826.31

SERVICE CONDITIONS

1. In order to determine customer eligibility for this Rider, the Company will review customer's LIHEAP approval and/or Low Income Self-Declaration status, Customer billing information, approved LIHEAP benefits, household income, and / or arrears.

2. For Legacy CARE and Affordability Discount Customers, any past due bills for electric service will be spread over a maximum of 24 months and shall be put in a 24-month payment arrangement under the Arrearage Forgiveness program.

3. Customers taking service under this Rider will be encouraged to participate in Minnesota Power's energy conservation programs.

4. Customers must be LIHEAP eligible by May 1 of each program year to continue receiving service under this Rider. The program year starts October 1 and ends September 30 of the following year.

5. Customers who become eligible through the Low Income Self-Declaration process must request and be determined eligible for LIHEAP within one year of their initial low income self-declaration in order to remain eligible for this Rider.

6. Customer must maintain an active account registered under Customer's name with the Company to be eligible for this Rider.

7. Qualified Customers are eligible to receive a discount under this Rider at only one residential location at any one time, and the Rider applies only to a qualified

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

Customer's primary residence. This Rider will not be available when, in the opinion of the Company, the Customer's residency or occupancy is of temporary nature.

8. It is the Customer's responsibility to notify the Company if there is a change of address or eligibility status.

9. Application of this Rider shall be prospective, and the Rider discount shall not be applicable to past due bills.

10. If the participating Customer misses two consecutive payments, the Customer will be removed from this Rider and ineligible until the next program year, at the Company's discretion. The Customer will become subject to standard collection activities for any past due amounts.

11. Refusal or failure of a Customer or Agency to provide documentation of eligibility acceptable to the Company may result in Customer removal from this Rider.

12. Customer may be re-billed for periods of ineligibility under the applicable standard rate schedule.

13. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 15 on low income affordability programs.

ARREARAGE FORGIVENESS CONDITIONS

1. Current Legacy CARE and Affordability Discount participants with past-due arrears balances that satisfy Service Condition 1 are eligible for Arrearage Forgiveness.

2. Potential Arrearage Forgiveness applies to outstanding arrears at the time of CARE enrollment or as of the effective date of the Arrearage Forgiveness component, whichever is later.

3. The Arrearage Forgiveness shall in no event exceed the outstanding arrears balance.

4. The Company shall total the amount of arrears payments made by all CARE customers each month, and based on available funds in the CARE Rider Tracker, shall determine the percentage matching rate and shall match each Customer's monthly paid arrears amount by applying the determined percentage to reduce arrears in the same month. The initial matching rate will be 100 percent.

5. In the event a Customer applies, qualifies and receives fuel assistance, the fuel assistance amount may be used to pay the arrears amount. The Company shall not match amounts paid by a third party; however, any amount of arrears paid by the Customer any

RIDER FOR CUSTOMER AFFORDABILITY OF RESIDENTIAL ELECTRICITY (CARE)

month shall be matched by the Company by applying the percentage of reduction in place as stated in Arrearage Forgiveness Condition 4 above.

6. If a Customer has new arrears, it means the Customer has missed at least two consecutive payments, therefore, Service Condition 10 applies, and the Customer shall no longer be eligible for the CARE Program or the Arrearage Forgiveness component.

RIDER FOR CITY OF SILVER BAY FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Silver Bay, except bills for electric service to property owned by the City of Silver Bay, for the period from January 1, 2014 to December 31, 2024.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Silver Bay Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Silver Bay Franchise Fee assessment collected will be passed along to the City of Silver Bay.

RIDER FOR CITY OF HOYT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Hoyt Lakes, except bills for electric service to property owned by the City of Hoyt Lakes, for the period from October 2015 to October 2035.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Hoyt Lakes Franchise Fee assessment in the amount of:

$3.00 per month for each residential electric service agreement; and
$3.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Hoyt Lakes Franchise Fee assessment collected will be passed along to the City of Hoyt Lakes.

RIDER FOR SOLAR ENERGY ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f), hereby defined as Solar-Paying Customers.

SOLAR ENERGY ADJUSTMENT

The Solar Energy Adjustment (SEA) shall be added to or deducted from each Solar-Paying Customer's monthly bill in an amount per kilowatt-hour determined as described below.

The SEA shall be calculated each month using data for the first two of the preceding three months as follows:

(a) Cost of solar energy purchased,
(b) Plus a credit for fuel and purchased energy costs included in the Rider for Fuel and Purchased Energy Adjustment (FPE Rider). The credit is an adjustment for cost already collected through the FPE Rider, including the Time of Generation Adjustment (TOGA). This credit is determined by multiplying the solar energy generation by the TOGA-adjusted FPE Adjustment (e) and adding the TOGA (d) as defined below.

Total of (a) and (b) shall be divided by the total kilowatt-hour sales for Solar-Paying Customers for the first two of the preceding three months.

TIME OF GENERATION ADJUSTMENT

The TOGA shall quantify the value of the time of generation for solar energy in order to compensate Solar-Paying Customers based on the time the solar energy is produced. The TOGA shall be added to the FPE cost and the resulting TOGA-adjusted FPE Adjustment shall be calculated in the FPE Rider as follows and applied to all customer energy usage:

(c) Calculate the FPE Adjustment without solar ($/MWh) by dividing the FPE costs excluding solar costs ($) by the non-solar energy generation (MWh);
(d) Calculate the TOGA by multiplying the TOGA Factor as determined below by the solar energy generation and by the FPE Adjustment without solar;
(e) Calculate the TOGA-adjusted FPE Adjustment by adding the TOGA to the FPE costs excluding solar costs and dividing this sum by non-solar energy generation.

RIDER FOR SOLAR ENERGY ADJUSTMENT

TIME OF GENERATION ADJUSTMENT FACTOR

The TOGA Factor shall be determined as follows:

(f) Calculate the simple average of actual non-solar energy cost ($/MWh) for the first two of the preceding three months by dividing total monthly costs of non-solar generation by total monthly non-solar MWh sales;
(g) Calculate the total hourly solar energy generation (MWh) for the first two of the preceding three months;
(h) Calculate the weighted average solar generation cost by multiplying each hourly projected avoided energy cost ($/MWh) by the associated solar energy generation amount (MWh) and then summing the total for the month ($);
(i) Calculate the weighted average solar energy generation cost ($/MWh) by dividing (h) by (g);
(j) Calculate the TOGA Factor by dividing (i) by (f) and subtracting 1.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

APPLICATION

This Rider shall be applicable on an optional basis to any retail customers who are not exempt from Solar Energy Standard obligations under Minnesota Statute § 216B.1691, subd. 2(d).

RATE (Monthly)

The Customer may choose one of the following options for charges and credits which shall be applicable in addition to all charges for service being taken under Company's standard rate schedule.

Option 1. Upfront Payment per kW

Customer shall pay a one-time subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy kilowatt-hours (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$2,132.15 per subscribed block.
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 2. Monthly Subscription per kW

Customer shall pay a monthly subscription charge for each contracted kW solar block. A solar block under this rider represents 1 kW of capacity. Customer will receive a monthly energy (kWh) credit for the solar energy produced by each solar block. The charge and credit shall be as follows:

kW Block Charge	$15.62 per subscribed block per month
Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Option 3. Fixed Charge per kWh

Customer shall pay a charge for the energy the customer's subscribed portion of the solar garden generates. The charge shall be as follows:

Fixed kWh Charge	$0.1115 per kWh

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

Monthly kWh Credit	Customer will receive a bill credit in kWh for the solar energy produced per subscribed kW block of capacity as an offset to the customer's standard energy use during the monthly billing period.

Monthly kWh Credit
The monthly energy credit (kWh) shall also be applied to the Company's following volumetric riders on the customer's monthly bill; Rider for Fuel and Purchased Energy Adjustment, Rider for Conservation Program Adjustment, Rider for Renewable Resources, Rider for Transmission Cost Recovery, Rider for Boswell Unit 4 Emission Reduction, and other Commission-approved volumetric riders on the customer's monthly bill.

Subscription Prices Calculation
The subscription prices above are calculated incorporating a $0.002 Solar Renewable Energy Credit (S-REC).

SERVICE CONDITIONS

1. To participate in the Community Solar Garden Pilot Program, a customer must submit an application to Minnesota Power's Renewable Programs Department. Each customer's subscription will be capped at 120 percent of the customer's average annual energy usage in the twelve months prior to the date of the customer's application to this program, but not to exceed 20 kW per Service Agreement.

2. Total participation of non-residential customers will be limited to no more than 50 percent of the total solar garden capacity during the initial offering.

3. Each customer participating in the Community Solar Garden Pilot Program will sign a 25-year contract which specifies the price the customer will pay for solar energy, aligned with the timeframe of the Company's power supply resource acquisition.
   a. Customers who choose Option 2 or Option 3 will have the ability to leave the program at any time. These customers may either have their subscriptions reassigned to another qualifying participant or relinquish their subscription to Minnesota Power.
   b. Customers who choose Option 1 will also have the opportunity to reassign or relinquish their subscription. Because customers on this option have made a significant upfront investment, if they cannot sell or transfer the subscription to another qualifying participant in a private transaction, Minnesota Power will purchase the subscription back from them at a predetermined amount that will decline by 4 percent per year from the original upfront payment amount.
   c. For cancelled subscriptions, Minnesota Power shall pay subscribers for the remaining kWh credits at the monthly average amount for the previous twelve months, plus any payment for S-RECs associated with the unused kWh credits.

PILOT RIDER FOR COMMUNITY SOLAR GARDEN SUBSCRIPTION

4. Customers will not receive any cash payments or monetary credits in this program, with the exception of any payments resulting from subscription cancellation. Any excess energy shall be carried forward in the form of a kWh credit to the customer's subsequent bills for a period of five years. During this five-year period, the Company will evaluate what limits, if any, should be placed on the rolling over of energy credits. Banked credits are not transferable to other customers through subscription transfers.

RIDER FOR BACKUP GENERATION SERVICE

APPLICATION

To any Customer taking service under one of Company's following standard rate schedules: General Service (Schedule 25), Large Light and Power Service (Schedule 75), and Municipal Pumping Service (Schedule 87) who contract for backup generation service of at least 50 kW for an initial period of ten years or more. Program participation will be limited to 10 MW total customer load.

RATE (Monthly)

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedule:

I. Customers taking firm service under this Rider will have an additional charge for backup generation applied to the customer maximum 15-minute demand as shown below:

   a. The firm demand charge will be applied each month to the demand specified in customer's Backup Generation Service Agreement.

   b. Redundant on-site backup generation capacity is available from Company if the added capacity is available to the Company under the existing terms of the tariff. Redundant backup generation service will be subject to an additional demand charges shown below applied to the capacity of the redundant generator. Any generator(s) installed in addition to generator(s) deemed appropriate by the Company to serve the customer's maximum 15-minute demand will be considered redundant under this tariff.

II. Customers taking interruptible service under this Rider will have an additional charge for backup generation applied to the agreed upon minimum contract firm demand level.

III. Firm demand charges are as follows:

   A monthly per kW Firm Demand Charge shall be applied to the Customer maximum 15-minute demand, as defined in customer's Backup Generation Service Agreement.

SERVICE CONDITIONS

1. A customer receiving service under this Rider must enter into a contract that identifies the size of the generator specified and installed by the Company, the customer's expected annual maximum load, and the monthly firm demand charge. The company will have discretion as to the size and number of generators required to meet customer needs under this Rider.

2. If after five years the maximum customer 15-minute demand level falls below 75% of the contracted demand agreed upon in the customer's Backup Generation Service Agreement, the Company will determine whether to remove the generator and

discontinue Backup Generation Service at that site or retain service and charge for this Rider based on the minimum contracted demand level as specified in the customer's Backup Generation Service Agreement. Generator size, use of the generator elsewhere, future customer demand, and special usage circumstances will be considered in making this decision.

3. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this Rider for all or only selected service feeds at that location. The Company may require the customer to pay in advance of installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise.

    a. For firm service customers, backup generation service must be taken at a minimum of the entire load at each distribution service chosen. For purposes of this Rider, the customer demand will be the greatest rate at which electrical energy has been used for the distribution service feeds during any 15 minute period, for a minimum, of the preceding 24 billing months. For purposes of this Rider, the minimum demand determined by Company will consider anticipated load changes and/or unusual operation circumstances.

    b. For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer's firm load. For purposes of this Rider, the contract firm load will be the customer's contract firm load in effect at the time the customer enters into the Backup Generation Service Agreement with the Company.

4. The contract will have an initial minimum term of ten years. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

5. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Minnesota Public Utilities Commission. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

6. The Company will work with the customer to determine where to install the generator(s) and associated equipment. The facilities will comply with National Electric Code, National Electric Safety Code, Minnesota electric code and all applicable, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

RIDER FOR BACKUP GENERATION SERVICE

7. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

8. The customer will supply the space for the generator(s) and a concrete pad as specified by the Company. The customer is responsible for clearing and grading the property and building the pad to specifications required by the Company.

9. The Company is responsible for installation of the generator and associated electrical interconnect. The customer is responsible for the cost of restoration of the property after the Company has completed installation where applicable.

10. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the customer will be required to make payment arrangements satisfactory to the Company for the cost of the facilities in excess of standard design.

11. The customer will be required to make the Company equipment available and permit entry upon the property by Company or contracted personnel at all times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

12. The Company reserves the right to operate the generator to meet system load requirements. The Company will coordinate these operations to accommodate customer business requirements if possible.

13. The availability of service under this Rider may be limited at the discretion of the Company. Service under this Rider may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

14. Energy furnished under this Rider will not be resold by the Customer.

15. The customer may request that Company’s on-site generation be operated during specific times. The Company will comply with Customer’s request provided the additional hours of operation do not adversely impact any permits or other regulatory requirements. The customer shall pay the replacement cost of all fuel consumed during the test. The Company will pay all associated fuel costs of the generator for standard operation.

16. Company shall not be held liable for loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Rider.

RIDER FOR BACKUP GENERATION SERVICE

17. If the customer chooses to end service under this Rider prior to the end of the current contract, the customer must pay 50% of the demand specified in customer's Backup Generation Service Agreement for the remaining term of the Backup Generation service obligation.

RIDER FOR BUSINESS EXPANSION INCENTIVE

APPLICATION

Applicable to any new or expanding commercial or industrial Customer taking service under General Service (Schedule 25), Large Light and Power Service (Schedule 75), or Large Power Service (Schedule 74) and which has at least 250 kW of new or expanding load. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

Customer must complete an application for service under the Rider for Business Expansion Incentive, and service is limited to customers whose application is approved by the Company. For existing customers, at least three months of Qualified Billing Demand must occur before service under this Rider may commence.

TYPE OF SERVICE

Service shall be taken at the voltage and phase relationship specified under Company's applicable standard rate schedule for service to Customer.

RATE

The provisions of the General Service, Large Light and Power, or Large Power Service Schedule shall apply, except monthly Demand Charges (excluding the Transmission Demand Charge) for customer's Qualified Billing Demand before the application of voltage discounts, shall be reduced as follows:

Large Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	30%	15%	5%	0%

General Service and Large Light and Power Service Schedule Demand Reduction Percent:

Years:	1-3	4	5	6
Percent Reduction:	50%	25%	15%	0%

For new or existing customers, Qualified Billing Demand is the new load of 250 kW or greater at a single delivery point. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. The demand charge reduction shall not apply during any month in which the Qualified Billing Demand is below 250 kW, unless as a consequence of documented new conservation or load control by the customer.

RIDER FOR BUSINESS EXPANSION INCENTIVE

NEW CUSTOMER QUALIFICATIONS

This Rider is available for new load that is associated with initial permanent service. To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:

1. Business has not been conducted at the premises for at least three monthly billing periods prior to application; or

2. The predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale; or

3. Customer's activities are largely or entirely different in nature from that of the previous customer.

EXISTING CUSTOMER QUALIFICATIONS

Existing customers, at an existing delivery point or new delivery point, who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company shall review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 250 kW at one delivery point, the customer will be eligible thereafter to receive service under this Rider. A customer may receive the rate at multiple delivery points so long as each delivery point independently qualifies. If a customer's activities are very similar to the customer's previous activities, then the customer is considered to be an existing customer whether or not the owner(s), operator(s), or manager(s) are substantially different.

ENERGY EFFICIENCY

The Company is required to conduct an energy audit for all customers taking service under this Rider, and inform the customer of the conservation programs available.

TERMS AND CONDITIONS

1. This Rider contemplates that this service shall utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required, which are not supported by this Rider.

RIDER FOR BUSINESS EXPANSION INCENTIVE

2. The minimum discount under this Rider shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the Rider is in effect.

3. The Company shall execute an Electric Service Agreement (ESA), having a minimum term of six (6) years with a minimum cancellation provision of one (1) year. The ESA shall state the increased or new load level of the customer, and the effective date of service under this Rider shall be set forth in the ESA.

ELECTRIC SERVICE AGREEMENTS

1. Every ESA and every amendment or modification of an ESA shall be approved by the Minnesota Public Utilities Commission ("Commission").

2. Every new or amended ESA shall be filed with the Commission within 30 days after signing the agreement with the Customer.

3. Every ESA filing shall include the incremental revenue and the incremental costs associated with the new ESA.

4. If no party objects to the ESA within 30 days of the filing date, the ESA is deemed approved.

RIDER FOR CITY OF UPSALA FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Upsala, except bills for electric service to property owned by the City of Upsala.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Upsala Franchise Fee assessment in the amount of:

$5.00 per month for each electric residential service agreement; and
$5.00 per month for each commercial, industrial or other electric service agreement.

Customers with both standard electric service meters and dual fuel meters shall not be assessed an additional application of the franchise fee for the dual fuel meter.

100% of the City of Upsala Franchise Fee assessment collected will be passed along to the City of Upsala.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74, having a minimum contract term of at least the duration of the respective demand response product, and subject to the Conditions below.

DEFINITIONS

Demand Response Billing Demand: Capacity volume associated with the Rider for Large Power Demand Response Products A and C that will receive Demand Charge Credits on a monthly basis, as specified herein.

Demand Response Contract Demand: The aggregate of Customer's accredited capacity of Products A and C under this Rider.

Firm Service Level or Targeted Demand Reduction Level: Customer's targeted demand reduction threshold that is specified when customer registers for Products A and C.

Emergency Curtailment: Requirement for participating Customers to physically reduce load to their Firm Service Level or Targeted Demand Reduction Level.

LARGE POWER DEMAND RESPONSE PRODUCTS AND CONDITIONS

There are two optional Demand Response products available to Customers. The characteristics and conditions for each product are as follows:

Large Power Demand Response Product A - Short-Term Emergency Capacity
Product A is a one-year emergency-only capacity product. A minimum one-year Demand Response commitment and one-year term remaining on Customer's Electric Service Agreement at time of selection is required for this product. Product A includes a Demand Charge Credit as detailed in the Rate section below. The Company will call on this capacity as allowed under the requirements to accredit capacity for satisfying resource adequacy requirements or to mitigate local system emergency events.

Short-Term Emergency Capacity must meet applicable requirements to accredit capacity for satisfying resource adequacy requirements, including, but not limited to, maximum number of annual emergency curtailments, maximum duration of emergency curtailments, and seasons in which emergency curtailments can occur.

Before an Emergency Curtailment, the Company will provide the lesser of (1) at least two hours advance notice or (2) the notice that as required in connection with requirements to accredit capacity for satisfying resource adequacy requirements.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

Large Power Demand Response Product C – Market Surplus Service
Contract periods of between three and six years are available, provided that Customer's Electric Service Agreement duration at time of bidding is at least as long as the Market Surplus Service contract, and provided that neither the Customer nor the Company has served an Electric Service Agreement cancelation notice. Product C includes a Demand Charge Credit as detailed in the Rate section below. The Company will facilitate identification of options for a customer's excess demand response capacity that doesn't fit into Large Power Demand Response Product A.

RATE MODIFICATIONS

The following charges and credits are applicable in addition to all charges for service being taken under Company's standard Large Power rate schedule:

Demand Response Product A - Short-Term Emergency Capacity
Demand Charge Credit:
For each month that Short-Term Emergency Capacity is provided, the Customer shall receive a per kW Demand Charge Credit based on an annual market price representative of market conditions as determined by the Company. Such credit shall be applied to the demand charges billed under Schedule 74. Customer will be notified of the annual credit amount by the preceding November for the following Midcontinent Independent System Operator (MISO) planning year.

Demand Response Product C- Market Surplus Service
Demand Charge Credit:
For each month that Market Surplus Service is provided and Minnesota Power has identified an option for customer's excess demand response capacity that results in revenue for the Company, the Customer shall receive a per kW Demand Charge Credit. Such credit shall be determined by the company and applied to Customer's demand charges billed under Schedule 74.

DETERMINATION OF DEMAND RESPONSE BILLING DEMAND (Monthly)

Demand Response Billing Demand shall be calculated as follows:

The lesser of: (1) the Demand Response Contract Demand or (2) Customer's nominated demand under Schedule 74 plus, if applicable, Maximum Replacement Amount less Firm Service Level.

Any reduction in the Demand Response Billing Demand from the Demand Response Contract Demand will first reduce Product A and then Product C.

The Customer's monthly Schedule 74 Billing Demand shall be calculated in accordance with Schedule 74.

RIDER FOR LARGE POWER DEMAND RESPONSE SERVICE

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED CURTAILMENT

A Customer is deemed to have failed to comply with the emergency capacity requirements when Minnesota Power calls on the emergency capacity and the Customer's actual firm load, as measured by the meters installed by the Company (netted across aggregated Customer facilities, if applicable), has not decreased to the Firm Service Level or Targeted Demand Reduction Level.

In the event that the Customer fails to follow an Emergency Curtailment request by Minnesota Power and such failure results in (a) any financial penalties being imposed upon the Company, and/or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases, the Customer shall reimburse the Company for that portion of the penalty and/or financial damages caused by their failure, within 15 days of notification by Minnesota Power. In the event that the Customer follows Emergency Curtailment conditions as specified herein, the Customer shall not be liable for any (a) penalties imposed on the Company, or (b) financial damages resulting from non-completed or replacement wholesale sales or purchases. Penalties and charges may include, but are not limited to, penalties associated with disqualification of the emergency capacity as accredited capacity.

ADDITIONAL SERVICE CONDITIONS

1. The duration and frequency of curtailments shall be at the sole discretion of the Company and follow the product conditions as stated above.

2. The Customer must provide, at its expense, a means of curtailing its demand response load upon receiving a command or signal from the Company. The Company reserves the right to inspect and approve the installation.

3. The Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any curtailment of service.

4. Company intends to accredit and register the demand response MW as a capacity resource with MISO (or successor entity), in accordance with Module E Tariff and Business Practices Manual for Resource Adequacy. Customer agrees to participate fully in the registration procedure.

5. In the event of a material change in MISO's (or any successor organization) capacity accreditation authority, the party's shall in good faith determine the most appropriate substitute accrediting and rate or cost determination authority within six months of the date such a change was made. Except as mutually agreed by the party's, no changes in MISO responsibilities shall materially and adversely affect either party's rights or obligations under the Electric Service Agreement. Any changes would be subject to regulatory approval.

PILOT RIDER FOR REMOTE SERVICE RECONNECTION

APPLICATION

Applicable on a voluntary basis to customers taking service under the Residential Service Schedule 20 or 22, Dual Fuel Interruptible Electric Service Schedule 21, Controlled Access Electric Service Schedule 24, or Residential Electric Vehicle Service Schedule 28.

In order to be eligible for this Pilot Rider, Customer must have Advanced Metering Infrastructure (AMI) with remote reconnect capability, and shall have been disconnected following procedures specified in Company's Service Regulations, Section VI, page 3.4, Regulation 19.

RATE MODIFICATION

Remote Service Reconnection is available any time of the day, all year and the Fee shall be as follows:

Remote Service Reconnection Fee: Waive

SERVICE CONDITIONS

1. Customers may choose to be reconnected using remote AMI capability and shall be reconnected for the Remote Service Reconnection Fee specified above after they have met the payment requirement as stipulated in the Company's Service Regulations, Section VI, page 3.5, Regulation 20. This Remote Service Reconnection Fee replaces the Service Reconnection Fee specified in regulation 20.A.

2. Customers who are remotely reconnected will be walked through the process on the phone by a Company representative during the reconnection process to ensure that the connection has taken place and is completed safely.

3. Customers without existing AMI equipment may request participation in this Pilot Rider. The Company will install and commission the equipment at the Customer's residence prior to making the Pilot Rider available.

RIDER FOR CITY OF PEQUOT LAKES FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Pequot Lakes, except bills for electric service to property owned by the City of Pequot Lakes.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Pequot Lakes Franchise Fee assessment in the amount of:

$1.00 per month for each electric residential account; and
$1.00 per month for each commercial, industrial or other electric service account.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Pequot Lakes Franchise Fee assessment collected will be passed along to the City of Pequot Lakes.

RIDER FOR RENEWABLE RESOURCES – SOLAR FACTOR ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79. This Rider shall be applicable to customers who are not exempt from Solar Energy Standard (SES) obligations under Minnesota Statutes, Section 216B.1691, subd. 2(f). During the 2013 Minnesota legislative session, Minnesota Statutes Section 216B.1691, the statute establishing Minnesota's Renewable Standard, was amended to include an additional SES under Minnesota Statutes Section 216B.1691, Subd. 2f. Included in Minnesota Statutes, Section 216B.1691, subd. 2f is a provision exempting retail electric sales to certain customers, namely large iron mining and paper production businesses, from the total retail electric sales calculation of a public utility. Per subdivision 2f(f), exempted customers are:

1. an iron mining extraction and processing facility, including a scram mining facility as defined in Minnesota Rules, part 6130.0100, subpart 16; or
2. a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer.

Exempted customers cannot be charged for any costs specific to satisfying the Solar Energy Standard.

The solar capacity benefit charge associated with the Camp Ripley Solar Project is applied to exempt customers as they share in these benefits.

ADJUSTMENT

Customers' monthly bills will be adjusted in accordance with each customer's status per Minnesota Statutes, Section 216B.1691, Subd. 2f. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules.

	SES-Paying Customers	SES-Exempt Customers
Residential Customers	0.045¢ per kWh for all kWh	----
General Service Customers	0.051¢ per kWh for all kWh	0.031¢ per kWh for all kWh
Large Light & Power Customers	0.026¢ per kWh for all kWh	0.018¢ per kWh for all kWh
Large Power Customers	----	0.010¢ per kWh for all kWh
Lighting Customers	0.131¢ per kWh for all kWh	----

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

APPLICATION

Applicable to Customers taking service under: Residential Service Schedule 20 (General), Schedule 22 (Space Heating), and Schedule 23 (Seasonal) who do not want advanced metering infrastructure ("AMI") at their residence ("Opt-Out Customers"). All provisions of the Residential Service Schedule and the Company's Electric Service Regulations shall apply to the service under this Rider except as noted below.

DESCRIPTION

There shall be applied to an Opt-Out Customer's monthly bill a recurring monthly fee after enrollment. The applicable fee for participating in the AMI Opt-Out will be shown as a separate line item on the monthly bill as follows:

AMI Opt-Out Charge $20.00 per month

The monthly charge will be applied following the meter exchange. Where a meter exchange is not required, the charge will be applied following the AMI Opt-Out election or action by the Opt-Out Customer, as described in the Service Conditions.

SERVICE CONDITIONS

1. The Company shall have the right to refuse to provide AMI Opt-Out service in any of the following circumstances:
   a) If such a service creates a safety hazard to the Customer or their premises, the public, or the Company's personnel or facilities.
   b) If a Customer does not allow the Company's employees access to the meter at the Customer's premises.
   c) If the Customer has a history of meter tampering.

2. Opt-Out Provisions:
   a) Opt-Out Election: A Customer must affirmatively elect to opt-out of having electric consumption metered through AMI to obtain service under this Rider. Customers shall default to AMI absent such an election. Customers who do not provide reasonable access to their meter or affirmatively prevent the installation of AMI shall be deemed to have elected this Opt-Out Rider.
   b) Frequency of Election: A Customer may only enroll in this AMI Opt-Out Rider once per twelve-month period at the same residence.
   c) Opt-In Election: At any time, Opt-Out Customers may opt back into electric service with AMI.
   d) Local governments and entities such as condominiums and other multi-unit dwellings are not allowed to exercise the Opt-Out option on behalf of individually metered residents.

RIDER FOR ADVANCED METERING INFRASTRUCTURE (AMI) OPT-OUT

3. Metering Equipment: A non-communicating meter will be used to provide electric service for Customers who elect this option.

4. Customers enrolled in interruptible electric service, controlled access, time-of-day, or other service requiring AMI will be notified that the Customer must discontinue participation in the service offering in order to participate in this Opt-Out option.

5. Estimated Meter Reading: Opt-Out Customers may receive bills based on estimated meter reads if circumstances prevent reading a meter in a given month.

6. Billing: Customers will be billed for charges incurred for electric consumption under the applicable Residential Service Schedule, plus the Monthly Charge described in this AMI Opt-Out Rider.

RIDER FOR RESIDENTIAL TIME-OF-DAY SERVICE

APPLICATION

Applicable to customers taking service under Residential Service Schedule 20 (General) or Schedule 22 (Space Heating), for single-family dwellings. All provisions of the Residential Service Schedule shall apply to the Residential Time-Of-Day service under this Rider except as noted below.

Customers taking service under this Rider may not also take service under the Pilot Rider for Community Solar Garden Subscription, nor under the Rider for Parallel Generation.

RATE MODIFICATION

Customers will be billed at the Residential Service rate, plus the following Energy Charge Adjustments shall apply:

	Energy Charge Adjustment
All On-Peak kWh	4.800¢/kWh
All Off-Peak kWh	-0.293¢/kWh
All Super Off-Peak kWh	-3.416¢/kWh

SERVICE CONDITIONS

On-Peak, Off-Peak, and Super Off-Peak Period Defined: The On-Peak Periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super Off-Peak Period shall be defined as 11:00 p.m. to 5 a.m. Central Prevailing Time (CPT), inclusive. The Off-Peak Periods shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

SPECIAL RULES

1. Any Customer choosing to be served on this rate tariff thereby waives all rights to any billing adjustment arising from any claim that the bill for the Customer's services would be cheaper on any alternative rate schedule for any period of time.

PRIVACY PROVISION

The Company follows its standard operational privacy guidelines and practices for all customers, including those participating under this Service Schedule. The Company complies with the State and Federal laws and regulations governing utility customer data

use such as the Federal Power Act, the Minnesota Public Utilities Act, and the Minnesota State Statutes including Chapters 47 and 248B.

The Company routinely collects data about and from its Customers through various sources as part of the normal course of providing services. Customer personal information, account and usage details, billing information, and program participation details are secured and retained in internal and online databases in accordance with the Company's standard operational guidelines which maintain administrative, technical, and physical safeguards to protect the privacy and security of the information. These safeguards include but are not limited to encryption, password protection, and secured files and buildings.

Energy Consumption Data:

Energy consumption and tariff data will be collected during the participation period. This data includes:

a. Date and hour of each day, with time zone;
b. Hourly interval meter usage data for 0-12 months prior to commencement of the Tariff (depending upon the date of meter installation relative to start of Tariff) and during the participation period;
c. Hourly weather data from the nearest weather station for 12 months prior to commencement of the Tariff and during the participation period;
d. Tariff sheet reference (i.e., which tariff sheet(s) each customer was on and the date range that the customer was on that tariff sheet for the 12 months prior to the commencement of the Tariff);
e. Start date of billing cycle;
f. Monthly electricity bill (i.e., $ amount) for 12 months prior to commencement of the Tariff; and
g. Electricity usage from the monthly bill for 12 months prior to commencement of the Tariff and during the participation period.

RIDER FOR CITY OF SANDSTONE FRANCHISE FEE

APPLICATION

Applicable to bills for retail electric service within the corporate limits of the City of Sandstone, except bills for electric service to property owned by the City of Sandstone.

ADJUSTMENT

There shall be added to each customer's monthly electric service bill a City of Sandstone Franchise Fee assessment in the amount of:

$2.59 per month for each electric residential service agreement; and
$2.59 per month for each commercial, industrial or other electric service agreement.
Dual fuel meters shall constitute one meter for purposes of this franchise fee Ord.

100% of the City of Sandstone Franchise Fee assessment collected will be passed along to the City of Sandstone.

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

APPLICATION

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79.

CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The Forecasted System Average Capacity Revenue and Expense Adjustment (CREA), that includes bilateral or customer capacity contracts and Planning Reserve Auction results for a period that is equal to or less than three years, for each month shall be the forecasted CREA for the current month divided by the forecasted Kilowatt-Hour Sales. The applicable Forecasted CREA shall be added to customers' monthly bill according to each customer's rate class and CREA Factor.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of revenue and expense for the twelve months ending May 31 of each year as reported in an annual compliance filing with the Minnesota Public Utilities Commission report to be filed by July 31 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs to the forecasted costs, and shall be applied to the subsequent months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under- recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each rate class shall be calculated as follows. The over- or under- recovery amount as shown in the current year annual compliance filing will be divided by the forecasted Kilowatt-Hours subject to the Capacity Revenue and Expense Adjustment for the proposed twelve-month recovery period the true-up rate will be in effect and then multiplied by the applicable CREA Factor. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each rate class that will be applied to Customers' bills in the same manner as the forecasted monthly CRE Charge.

FORECASTED SYSTEM AVERAGE CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The monthly Forecasted Average Capacity Revenue and Expense Adjustment shall be the **sum** of the following:

(a) MISO Planning Reserve Auction charges net of revenues for the applicable MISO planning year ending May 31 of each year.

(b) Bilateral and customer capacity contract charges net of revenues with terms of three years or less for the applicable MISO planning year ending May 31 of each year.

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

The Forecasted Kilowatt-Hour Sales shall be Company's total forecasted kilowatt-hour Sales of Electricity, excluding inter-system sales related to economy energy sales and other energy sold on an economic dispatch basis, sales related to the renewable source and community solar garden programs, and solar energy production and purchases to meet the Solar Energy Standard.

CAPACITY REVENUE AND EXPENSE ADJUSTMENT (CREA) FACTORS

A separate CREA Factor shall be applied to calculate the Forecasted CREA Charge for each Rate Class. A Class Cost Factor shall be calculated for each Rate Class. For Residential Time-Of-Day (TOD) and Large Light & Power Time-Of-Use (TOU) customers a TOD or TOU Factor shall also be calculated for each TOD or TOU period. The CREA Factor is the Class Cost Factor multiplied by the corresponding TOD or TOU Factor.

Rate Class	Class Cost Factor	TOD / TOU Factor	CREA Factor
Residential	1.05841	1.00000	1.05841
Residential On-Peak	1.05841	1.17042	1.23878
Residential Off-Peak	1.05841	1.03330	1.09366
Residential Super Off-Peak	1.05841	0.75930	0.80365
General Service	1.02995	1.00000	1.02995
Large Light & Power	0.99451	1.00000	0.99451
Large Light & Power On-Peak	0.99451	1.17042	1.16399
Large Light & Power Off-Peak	0.99451	1.03330	1.02763
Large Light & Power Super Off-Peak	0.99451	0.75930	0.75513
Large Power	0.98328	1.00000	0.98328
Lighting	0.89264	1.00000	0.89264

RIDER FOR CAPACITY REVENUE AND EXPENSE ADJUSTMENT

2025 FORECASTED and TRUE-UP CREA RATE

Applicable Month	CREA Forecasted Rate (¢/kWh)	CREA True-up Rate (¢/kWh)
January 2025	-	
February 2025	-	
March 2025	0.0030	
April 2025	0.0030	
May 2025	(0.0060)	
June 2025		
July 2025		
August 2025		
September 2025		
October 2025		
November 2025		
December 2025		

A breakdown by month and Rate Class can be found on Minnesota Power's website at https://www.mnpower.com/CustomerService/YourBill

RIDER FOR VOLUNTARY RENEWABLE ENERGY LARGE CUSTOMERS

APPLICATION

Applicable to any customer taking service under Large Power Service Schedule 74 or Large Light and Power Service Schedule 75; and having an approved Electric Service Agreement in which neither the Customer nor Minnesota Power has served a notice of contract cancelation; and subject to the Conditions below.

The total availability of service under this Rider is limited to 300 MW_{ac}, for qualifying customers who choose to offset a portion of their Firm Energy requirements in an existing Electric Service Agreement with dedicated renewable energy.

DEFINITIONS

Dedicated Renewable Resource: A new renewable generating resource(s) as defined under Minnesota Statues Section 216B.1691 that the Company will use to produce energy for sale to customer(s) under terms and condition of this Rider.

RATE MODIFICATIONS

The Rates (Monthly) and all adjustments included in the applicable service Schedule shall apply. Additionally, the Customer shall pay a monthly renewable energy surcharge for each kWh of renewable energy as defined in an Electric Service Agreement, and the Customer shall receive a credit for the rate-class-specific monthly Fuel and Purchased Energy Charge.

SERVICE CONDITIONS

1. A customer must execute an Electric Service Agreement which provides for dedication of renewable resource owned or procured by the Company and dedicated to a specific customer. The Electric Service Agreement must demonstrate benefits to the customer without harming the Company and non-participating customers and must include details of the Dedicated Renewable Resource to provide energy to the customer at the Renewable Resource Rate.

2. If applicable, multiple customers purchasing power from the same Dedicated Renewable Resource may not, in total, exceed 100% of the average annual output of the Dedicated Renewable Resource, as determined by the Company.

3. Energy purchased under this Rider will be considered as ‘first through the meter’ in deliveries to the customer.

RIDER FOR VOLUNTARY RENEWABLE ENERGY LARGE CUSTOMERS

4. When applicable, multiple customers purchasing power from the same Dedicated Renewable Resource will purchase and receive energy based on a pro-rata share of the energy produced:

   (Contracted kWac ÷ Total Resource kWac) x Resource kWh produced

5. A customer's pro-rata share of the energy purchased from a Dedicated Renewable Resource may not exceed 100% of the average annual usage of the customer's aggregated accounts subject to the contract as determined by the Company. Terms and conditions shall be reflected in the Electric Service Agreement and approved by the Commission.

6. The Company may require the credit of a customer to be established to the Company's satisfaction in sole judgment of the Company.

7. After the term or termination of the Electric Service Agreement the Company will be assigned and assume all responsibilities associated with the Dedicated Renewable Resource.

8. All Renewable Energy Credits ("RECs") associated with energy generated by Dedicated Renewable Resources shall be assigned to the Company on behalf of the Customer, and the Company shall retire any RECs associated with Dedicated Renewable Resource generation that are tracked in the Midwest Renewable Energy Tracking System program or any similar program established by the Commission under Minnesota Statutes Section 216B.1691, subdivision 4 on behalf of the Customer, unless the Electric Service Agreement describes an alternative treatment of RECs, and shall also be used for compliance with MN Renewable Energy Standard, Solar Energy Standard, and/or the Carbon Free standard under Minnesota Statutes Section 216B.1691, as applicable, and any other eligible state or federal requirements and standards.

9. Service may be limited at the sole discretion of the Company. The Company reserves the right to terminate this program at its sole discretion upon a requisite filing with the MPUC. The Electric Service Agreement will define the terms and conditions under which the Company may terminate the program and will include an assignment provision which allows customers who choose to terminate their participation in the program early to reassign their subscription to another customer. In addition, the Customer's Electric Service Agreement associated with this Rider will include language that protects the Company and the non-participating customers from paying for the renewable asset in the event the contract is terminated early.

DEFINITIONS OF CLASSES OF CUSTOMERS

RESIDENTIAL

A customer using electric energy supplied for residential (household) purposes.

RESIDENTIAL WITH TOTAL ELECTRIC SPACE HEATING

A subdivision of the Residential classification that includes those customers who use electricity as the source of space heating throughout the entire premises from permanently installed electric heating equipment.

COMMERCIAL

A customer using service at a location where the purchaser is engaged in selling, warehousing, or distributing a commodity, in some business activity, in rendering professional service, or in some form of social activity. In borderline cases where the nature of the customers' activities does not differentiate clearly between Commercial and Industrial, the service is classified as Commercial.

INDUSTRIAL

A customer using service at a location where the purchaser is engaged in an industrial activity, such as the operation of factories, mills, machine shops, mines, oil wells, refineries, pumping plants, cleaning and dyeing works, creameries, canning establishments, stockyards, etc., that is, in extractive, fabricating or processing activities.

GOVERNMENTAL

Municipalities and all divisions or agencies of state or federal governments.

RESIDENTIAL SERVICE RULES

1. Equipment which is capable of disturbing service to neighboring customers and/or motors operating with phase converters totaling more than 20 horsepower shall be separately metered on the applicable General Service schedule. Equipment capable of disturbing service to neighboring customers may include, but is not limited to, the following: welders, motors not conforming to Company's starting current limits, cooking and heating equipment of a design not approved by the Company.

2. In buildings having two or more apartments (as defined below), each apartment shall be considered a single-family dwelling. For each apartment building or portion of a building used for apartments that is arranged to permit the consumption of electricity by each apartment to be individually metered, Company will install meters to measure the consumption of electricity and will separately bill each individual apartment on the applicable rate schedule. However, where a landlord advises the Company that service applies to a single-metered residential apartment building, the billing shall be to the landlord and in accordance with Minn. Stat. 504B.215. The billing shall be computed as though each apartment used an equal portion of the total service and were independently billed. Service shall not be submetered or resold.

3. An apartment is defined as a portion of a building consisting of two or more rooms completely equipped for living purposes. Janitor's quarters shall be classified as an apartment.

4. A customer occupying a building or apartment for residential and commercial purposes jointly may combine his residential and commercial use on the applicable General Service schedule but not under the Residential Service schedule.

5. The public portion of apartment buildings, such as lobbies, halls, laundry rooms, boiler rooms, etc., and the power equipment, such as coal stokers, oil burners, air conditioners, elevators, etc., shall be served on the applicable General Service schedule.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

PURPOSE AND CONTENTS

These Service Regulations govern the supplying and taking of electric service. The regulations are designed to provide each Customer the greatest practicable latitude in the use of safe, reliable, and affordable service .

These Service Regulations, together with Extension Rules and Rate Schedules, are on file in the Company's various offices, and copies are obtainable by any Customer upon request by telephone, by mail, or www.mnpower.com.

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ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

SECTION I - DEFINITIONS

The following terms when used in these Service Regulations, in Rate Schedules and in Service Agreements, shall, unless otherwise indicated, have the meanings given below:

1. **Customer:** Any individual(s), partnership, association, firm, public or private corporation or governmental agency having Company's electric service at any specified location.

2. **Company:** Minnesota Power.

3. **Electric Service:** The supplying of electric power and energy, or its availability, irrespective of whether any electric power and energy is actually used. Supplying of service by Company consists of the maintaining by it, at the point of delivery, of approximately the agreed voltage and frequency by means of facilities adequate for carrying Customer's contracted load.

4. **Point of Delivery:** The end of Company's service drop, or the point where Company's wires are joined to Customer's service entrance conductors or apparatus, unless otherwise specified in Customer's Service Agreement.

5. **Customer's Installation:** In general, all wiring, appliances and apparatus of any kind or nature on Customer's side of the point of delivery (except Company's meter installation), useful in connection with Customer's ability to take electric service.

6. **Service Drop:** The wires, owned by Company, connecting Company's distribution mains to Customer's service entrance conductors.

7. **Service Entrance Conductors:** The wires provided by the Customer extending from Customer's main line switch or center at which circuits originate, to the terminal of the Company's service drop.

8. **Month:** An interval of approximately thirty days between successive meter reading dates, except when the calendar month is specified.

9. **Service Agreement:** The agreement or contract between Company and Customer pursuant to which service is supplied and taken.

10. **Notice:** Unless otherwise specified, a written notification delivered personally or mailed by one party to the other at such other party's last known address, the period of notice being computed from the date of such personal delivery or mailing.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

11. **Meter:** The meter or meters, together with auxiliary devices, if any, constituting the complete installation needed to measure and report the power and energy supplied to any Customer at a single point of delivery.

12. **Customer Extension:** Any branch from, or continuation of, an existing line to the point of delivery to Customer, including increases in capacity of any of Company's existing facilities, or the changing of any line to meet the Customer's requirements, and including all transformers, service drops and meters.

SECTION II - SERVICE AGREEMENTS

13. **Form and Execution of Service Agreements:** Each application for service normally is made on Company's standard form of application, which, when properly executed by Customer and Company, becomes binding and along with the applicable Rate Schedules, Rules and Regulations, is termed a Service Agreement. Any Service Agreement referred to herein is subject to amendment or change by Company. Any such amendment or change to a Service Agreement may be subject to acceptance or approval by any regulatory body having jurisdiction thereof and upon acceptance or approval will automatically apply to any executed Service Agreement.

    If for any reason an application is not signed by the Customer, the giving of service by the Company and the accepting of such service by all Customers receiving service shall impose the same obligation on each as if a Service Agreement had been executed.

14. **Contract Period of Service Agreements:** The contract period shall be as indicated in the applicable Rate Schedule, unless otherwise provided for in the Service Agreement.

15. **Renewal and Termination of Service Agreements:** Renewals shall be as provided for in the Service Agreement. Unless otherwise provided in the Service Agreement or Rate Schedule, Customers requesting termination of service through a physical disconnect and removal of Company owned equipment must fill out Form 6032 and give Company at least 7 days notice prior to the date termination is desired. Customer will be held responsible for all service supplied to vacated premises until such notice has been received by Company. Notification may be made by writing, e-mail through the MyAccount tool, or by visiting the Company's website at www.mnpower.com.

    When the contract period of a Service Agreement is extended, the demand previously established by Customer is considered as having been established under the extended contract period.

When a new Service Agreement is entered into, the demand previously established by Customer is considered as having been established under the contract period of the new Service Agreement except that, when the contract demand under the new Service Agreement is less than 60% of the highest actual demand established in the previous contract year, the Company will waive the above requirement.

16. **Company's Right to Cancel Service Agreement or to Suspend Service:** Company, in addition to all other legal remedies, may terminate the Service Agreement, or suspend delivery of service, for any default or breach of the Service Agreement by the Customer, but no such termination or suspension will be made by Company without five (5) days written notice, excluding Sundays and legal holidays, to Customer, stating in what particular the Service Agreement has been violated, except in cases of unlawful or unauthorized use of service by Customer, or dangerous leakage or short circuit on Customer's side of the point of delivery, or in case of utilization by Customer of service in such manner as to cause danger to persons or property. Failure of Company at any time to either suspend delivery of service or to terminate the Service Agreement, or to resort to any other legal remedy, or its adoption of either one or the other of such alternatives, shall not affect Company's right to resort to any of such remedies for the same or any future default or breach by Customer.

17. **Successors and Assigns:** Service Agreements inure to the benefit of and are binding upon the respective heirs, legal representatives, successors and assigns of the parties thereto; but no assignment by Customer shall be binding upon Company until accepted in writing by the latter.

SECTION III - SUPPLY AND TAKING OF SERVICE

18. **Supplying of Service:** Service is supplied only under and pursuant to these Service Regulations and the applicable Rate Schedule, Riders, and Regulatory Rules. Service is supplied under a given Rate Schedule only at such points of delivery as are adjacent to facilities of Company adequate and suitable, as to capacity and voltage, for the service desired.

Service will be subject to disconnection and deposit requirements as provided by rules of the Minnesota Public Utilities Commission and other applicable law, if, at the time of application for service, the Customer is indebted to the Company for service previously supplied at the same or another address.

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19. **Disconnection of Service:**

A. With Notice - Service may be disconnected with notice for any reason under Minn. Rules Part 7820.1000 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

B. Without Notice - Service may be disconnected without notice for any reason under Minn. Rules Part 7820.1100 or as may otherwise be provided in Company's Service Regulations, Service Schedules or Service Agreements.

20. **Reconnection of Service:** Company shall reconnect service following disconnection for non-payment:

- After all past due accounts, deposits and reconnection fees, where applicable, shall have been paid or

- Under a payment agreement for all past due accounts, deposits and reconnection fees, where applicable. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected.

A. The Service Reconnection Fee shall be as follows:

i. $20.00 between the hours of 8:00 AM and 4:30 PM Monday through Friday.

ii. $100.00 after 4:30 PM, before 8:00 AM and on Saturdays, Sundays and legal holidays.

B. Where service has been disconnected under Minn. Rules Part 7820.1100.B., a reconnection fee will not be required.

C. Following disconnection under Minn. Rules 7820.1100.A., reconnection will occur only after Company has received payment from Customer of the following:

i. Power and energy not recorded on the meter at the appropriate rate, the amount of which may be estimated by Company based on the best available data.
ii. All expenses incurred by Company due to any such unauthorized act or acts.

21. **Service Relock Penalty:**

A. Company shall assess a Service Relock Penalty of $100.00 where the Company has previously disconnected service and is required to subsequently return to relock or disconnect the service after it was connected by a Customer without Company authorization.

B. Company shall assess a penalty for all expenses incurred if additional disconnection of service is required at Customer premises.

C. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

22. **Continuity of Service:** Company will endeavor to provide continuous service but does not guarantee a constant supply of electric energy and shall not be liable to Customer for damages occasioned by interruption, except as provided by law. The Company shall not be liable for any loss of profits, special, or consequential damages resulting from the use of service or any interruption or disturbance of service.

In the event of power shortage any curtailment among Customers shall be made as nearly as practical pro rata without liability on the part of Company to any Customer affected.

If any part of service furnished by Company is employed for purpose of pumping water, Company assumes no obligation to maintain an adequate supply for fire protection, or any other purpose, whatsoever, and such use shall not subject Company to any liability to any party for damages to person or property due to failure of water supply resulting from an interruption or deficiency of electric service from whatsoever cause the same may arise.

23. **Suspension of Service for Repairs and Changes:** When necessary to make repairs to or changes in its lines or system, Company may, without incurring any liability therefore, suspend service for such periods as may be necessary, and in such manner as to minimize inconvenience to Customer.

24. **Use of Service:** Service is for Customer's use only. Company permits redistribution and submetering only where allowed by law. The electric service equipment and associated building wiring of buildings shall be arranged by the owner to permit individual metering of the electrical consumption of each building and occupancy unit

to comply with Minn. Stat. 504B.161 and any law amendatory thereto. If desired by the owner, the Company will install and maintain necessary individual Company meters to measure consumption and render bills on the applicable Rate Schedules to each Customer and separately occupied building and occupancy unit.

In no case may Customer, except with the written consent of Company, extend or connect an installation to lines across or under a street, alley, lane, court or avenue or other public or private space in order to obtain service for adjacent property through one meter even though such adjacent property be owned by Customer. Such consent may be given when such adjacent properties are operated as one integral unit under the same name and for carrying on parts of the same business. In case of unauthorized remetering, sale or extension of service to another person, Company, after five (5) days written notice excluding Sundays and legal holidays, may discontinue the supplying of service to Customer until such unauthorized act is discontinued and full payment is made for all service supplied or used, billed on proper classification and Rate Schedule, and reimbursement in full made to Company for all extra expenses incurred, including expenses for clerical work, testing and inspections.

25. **Customer's Responsibility:** Customer assumes all responsibility on Customer's side of the point of delivery for the service supplied or taken, as well as for the electrical installation, appliances and apparatus used in connection therewith, and shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from such service or the use thereof on Customer's side of the point of delivery.

26. **Right-of-Way:** Customer shall, without compensation, make or procure satisfactory conveyance to Company of right-of-way for Company's lines necessary and incidental to the furnishing of service to Customer and for continuing or extending said lines over, under, across or through the property owned or controlled by Customer in a manner deemed appropriate by the Company (including facility maintenance and vegetation management rights).

27. **Access to Premises:** Company personnel may enter Customer's premises only as authorized by applicable law and regulations. Failure of Customer to provide Company reasonable access may result in disconnection of service under Minn. Rules Part 7820.1000(E).

28. **Location of Point of Attachment:** Customer's Point of Attachment is to be located at a point readily accessible to Company's distribution mains. Customer shall install and maintain a point of attachment for Company's service drop. Said point of attachment shall be of sufficient mechanical strength to support the wind and ice

loaded weight of the service drop and shall be located as determined by the Company.

SECTION IV - CUSTOMER'S INSTALLATION

29. **Nature and Use of Installation:** All of Customer's wires, apparatus and equipment shall be selected with the view to obtaining safety, good efficiency, good voltage regulation and the highest practicable power factor and shall be installed in accordance with standard practices. Customer shall install and maintain, on Customer's side of point of delivery, suitable protective equipment as may be required by the Company for the protection of its service to other customers and may not employ or utilize any equipment, appliance or device so as to affect adversely Company's service to Customer or to others. The Company's failure to require such equipment shall not operate to relieve Customer from the obligation to utilize and comply with standard practices. Company may require auto starters or other suitable starting devices for motors above 5 horsepower. When polyphase service is supplied by Company, Customer shall control the use thereof so that the load at the point of delivery will be maintained in reasonable electrical balance between the phases.

    Installations of neon, fluorescent, mercury vapor lamps or tubes, or other types of gaseous tube lamps, or other devices having low power factor characteristics, should be equipped with corrective apparatus to increase the power factor of each unit or separately controlled group of units to not less than approximately 90% lagging.

30. **Inspection by Company:** Company retains the right, but does not assume the duty, to inspect Customer's installation at any time and will refuse to commence or to continue service whenever it does not consider such installation to be in good operating condition, but Company does not in any event assume any responsibility whatever in connection with such matters.

31. **Changes in Installations:** As Company's service drops, transformers, meters, and other facilities used in supplying service to Customer have a definite limited capacity, Customer shall give notice to Company, and obtain Company's consent, before making any material changes or increases in Customer's installation. Company as promptly as possible after receipt of such notice will give its approval to the proposed change or increase, or will advise Customer upon what conditions service can be supplied for such change or increase. Failure to secure Company's approval shall make Customer liable for any damage to Company's facilities.

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SECTION V - COMPANY'S INSTALLATION

32. **Installation and Maintenance:** Except as otherwise provided in these Service Regulations, in Service Agreements or Rate Schedules, Company will install and maintain its lines and equipment on its side of the point of delivery, but shall not be required to install or maintain any lines or equipment, except meters, on Customer's side of the point of delivery. Only Company's agents are authorized to connect Company's service drop to Customer's service entrance conductors and to connect Company's meters.

    A. Electrical Permit: The Company is prohibited from connecting its service drop to Customer's service entrance conductors until permitted by the governmental authority having jurisdiction.

    B. Standard Connection: The ordinary method of connection between Company's distribution mains and Customer's service entrance conductors will be by overhead wires. If Customer desires to have connection made in any other manner, special arrangements will be made between Customer and Company by which the connection will be made and maintained at Customer's expense.

    C. Suitable Space: The Customer shall provide at no cost to Company a suitable room or space for Company's transformers and equipment specifically used in providing service to Customer when such room or space is deemed necessary by Company.

33. **Protection by Customer:** Customer shall protect Company's wiring and apparatus on Customer's premises and shall permit no one except Company's agents or persons authorized by law to inspect or handle same. In the event of any loss or damage to such property of Company or other person caused by or arising out of carelessness, neglect or misuse by Customer or other unauthorized persons, the cost of making good such loss or repairing such damage shall be paid by Customer.

    Company shall not be responsible to Customer or any other party because of any damage resulting from such installations which are not readily subject to inspection from the ground and the exterior of the premises, or from the meter location, unless Customer shall have notified Company of a condition which, in the reasonable opinion of the Customer, requires attention and the Company shall have had a reasonable time within which to inspect and, if necessary, repair the same.

34. **Customer Extensions:** The Company, at its own expense, makes extensions where the revenue therefrom is sufficient, in Company's opinion, to justify the necessary expenditure.

Where the Company cannot be assured that the business offered is of sufficient duration, where unusual expenditures are necessary to supply service because of location, size or character of installation, or where area requirements of regulatory bodies may control, the Customer or Customers shall make arrangements satisfactory to Company dependent upon the particular conditions of each situation.

35. **Alteration of Facilities:** Company will, at its discretion, alter, relocate, convert to underground, or remove Company's facilities as may be requested in writing by Customer. Customer shall pay Company for all costs, except as limited below, associated with such alteration, relocation, conversion to underground, or removal including any new facilities required to provide service after the alteration, relocation, conversion, or removal.

    Customers requesting the alteration, relocation, conversion, or removal shall pay the estimated cost for the change, less salvage, of the facilities required to effect such change prior to Company committing funds for the work. Where the actual cost is different from the estimated cost upon which the advance payment was based, as determined upon completion of the requested alteration, relocation, conversion, or removal, Company will refund any excess payment made by Customer or render a bill for any additional amount due.

SECTION VI - METERING

36. **Installation:** Company shall furnish and install the necessary meter or meters, and Customer shall provide and maintain a location, free of expense and satisfactory to Company, all in accordance with Company's Metering Standards.

37. **Evidence of Consumption:** Unless proven to be inaccurate, the registration of Company's meter shall be accepted and received at all times and places as prima facie evidence of the amount of power and energy taken by Customer.

38. **Tests:** Company tests its meters and maintains their accuracy of registration in accordance with good practice. On request of Customer, Company will make a special test which will be done at the expense of the Company. If the Customer requests another test before the expiration of a twelve-month period, the Customer shall bear the cost of the test if the meter is found to be in error by less than 2%, fast or slow. The average registration accuracy of a meter is taken as the mean of full load (100% of rated load) accuracy, and light load (5-10% of rated load) accuracy. At Company's discretion, tests may be made under average load conditions.

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SECTION VII - PARALLEL GENERATION

39. **Design:** Customer's electric generating equipment shall be designed (1) to operate in synchronization with Company's system and (2) to automatically disconnect the facility from Company's system in the event Company's system becomes de-energized unless by mutual agreement between the Customer and Company. All synchronizing and protective devices to accomplish this mode of operation shall be provided and maintained by Customer.

40. **Disconnection:** Customer shall provide and maintain a manual, lockable disconnect switch providing a visible open and capable of isolating the Customer's generator from the Company's electrical system. This disconnect switch shall be readily accessible to Company personnel at all times, shall include a provision for padlocking it in the open position, and shall meet all other reasonable requirements established by Company.

41. **Customer Responsibility:** Customer shall pay for the cost of rebuilding and/or modifying Company facilities to provide adequate capacity for the parallel generation system and adequate protection for the Company's electrical system.

    Customer shall be subject to the State of Minnesota Distributed Energy Resources Interconnection Process and Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements or the most recent version of Minnesota's interconnection standards. Copies of such standards shall be made available to Customer upon request and are available at www.mnpower.com.

SECTION VIII - BILLING

42. **Billing Periods:** Bills ordinarily are rendered regularly at monthly intervals, but may be rendered more or less frequently at Company's option. Non-receipt of bills by Customer does not release or diminish the obligation of Customer with respect to payment thereof.

43. **Separate Billing for Each Point of Delivery:** At each point of delivery the use of service is metered separately for each Customer served. Whenever for any reason Company furnishes two or more meter installations for a single Customer, or supplies service under a Rate Schedule which does not require a meter, each point of metering and/or point of delivery where no meter is required is considered as a separate service. A separate Service Agreement is required, and bills are separately calculated, for each such separate service, except where Company may, under special circumstances, waive this requirement.

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44. **Adjustment for Inaccurate Meter Registration:** Meter too fast or too slow: In the event that any routine or special test of a Company meter discloses its average accuracy of registration to be in error by more than 2%, fast or slow, Company will refund the overcharge for a fast meter or charge for electricity consumed, but not included in the bills previously rendered for a slow meter. The refund or charge for both fast and slow meters will be based on corrected meter readings for a period equal to one-half the time elapsed since the last previous test but not to exceed six (6) months, unless it can be established that the error was due to some cause, the date of which can be fixed with reasonable certainty, in which case the refund or charge will be computed to that date, but in no event for a period longer than one (1) year.

    Whenever any bill or bills have been adjusted or corrected as provided above, the Company will refund to existing Customer any amount due when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due when the amount due exceeds two ($2.00) dollars or Company will bill Customer for any amount owed when the amount owed exceeds ten ($10.00) dollars, as the case may be.

    Meter fails to register or registers intermittently: When the average error cannot be determined by test because the meter is not found to register or is found to register intermittently, the Company may charge for an estimated amount of electricity used, which shall be calculated by averaging the amounts registered over corresponding periods in previous years or in the absence of such information, over similar periods of known accurate measurement preceding or subsequent thereto, but in no event shall such charge be for a period longer than one year.

    If a Customer has called to the Company's attention doubts as to the meter's accuracy and the Company has failed within a reasonable time to check it, there shall be no back billing for the period between the date of the Customer's notification and the date the meter was checked.

45. **Late Payment Charge:** Company shall assess a Late Payment Charge of 1.5% per monthly billing period, on that portion of a retail Customer's account representing charges for Company service(s) past due, if the unpaid balance exceeds $10.00. All late payments received will be credited against the oldest outstanding account balance before the application of any Late Payment Charge. The unpaid Company account balance for a Customer under the Budget Billing Plan or another Company approved payment plan shall mean that the Company budget arrears balance and not the accumulated actual Company balance will be subject to a Late Payment Charge. No Late Payment Charge will be charged on the portion of the Company balance in dispute while dispute procedures are underway. A Late Payment Charge may be retroactively charged on the settled amount after dispute procedures are

completed. At Company's discretion, any Late Payment Charge, or portion thereof, may be waived provided such waiver is consistent with the Minnesota Public Utilities Act.

A. Residential Customer: A Late Payment Charge shall be added to any Company account for which payment is not received and credited by Company within fifteen (15) days from the current billing date, plus ten (10) days of grace period, or a total of twenty-five (25) days. Residential customer who qualifies for assistance under the Low Income Home Energy Assistance Program (LIHEAP) may request waiver of the Late Payment Charge on the "current bill" portion of each monthly bill. Self-qualification using LIHEAP income guidelines will be permitted for Senior Citizens at age 62 or older. Efforts will be made by Company to work with local governmental agencies to pre-qualify Customers where administratively feasible. Customer accounts must be re-qualified annually.

B. Nonresidential Customer: A Late Payment Charge shall be added to any Nonresidential Customer account for which bill payment is not received and credited by Company within fifteen (15) days from the current billing date.

46. **Delinquent Bills:** Bills become delinquent if not paid on or before the past due date as shown on bill and service may be discontinued upon five (5) days written notice, excluding Sundays and legal holidays, to Customer after becoming delinquent. During the Cold Weather Rule months, October 1 through April 30, service may be disconnected only as provided in section 60 and Minnesota Statutes, section 216B.096. For residential customers, such written notice of disconnection shall specify a disconnection date not earlier than the third working day after the next scheduled billing date.

47. **Unlawful Use of Service:** In any case of tampering with meter installation or interfering with the proper functioning thereof or any other unlawful use or diversion of service by any person, or evidence of any such tampering, interfering, unlawful use or service diversion, Customer is liable to immediate discontinuance of service, without notice, and to prosecution under applicable laws, and Company shall be entitled to collect from Customer at the appropriate rate for all power and energy not recorded on the meter by reason of such tampering, interfering, or other unlawful use or service diversion (the amount of which may be estimated by Company from the best available data), and also for all expenses incurred by the Company on account of such unauthorized act or acts.

48. **Charge for Restoring Service:** If service to Customer is discontinued by Company for valid cause, then before service is restored, Customer shall pay Company all permitted costs of discontinuing and restoring service. There will be no charge for reconnection when service has been discontinued in the event of a condition

determined to be hazardous to Customer, to other Customers of Company, to Company's equipment, or to the public.

If Customer requests that service be discontinued and subsequently requests restoration of service at same premises within twelve (12) months of discontinuance, the charge for restoring service will be the sum of minimum bills during the elapsed period but not less than all costs of discontinuing and restoring service.

49. **Selection of Schedule:** The Company's Rate Schedules are designed for service supplied to Customer on a continuous annual basis. Customer may elect to take service under any of the Rate Schedules applicable to such service. Company will advise Customer of the Rate Schedules which, in its judgment, are best adapted to Customer's needs on an annual basis, but such advice must be based upon Customer's statements as to Customer's installation and requirements for service and Company assumes no responsibility for the selection of the Rate Schedule made by Customer. If Customer changes selection of a Rate Schedule, Customer may not go back to the previous Rate Schedule for a period of twelve (12) months; provided, however, that a Large Light and Power Customer whose normal monthly firm demand is below 50,000 kW shall be billed on the Large Power Service Schedule in months in which its measured demand, as adjusted for power factor, exceeds 50,000 kW, and shall go back to the Large Light and Power Service Schedule when its demand falls below 50,000 kW. Rules applicable to specific Rate Schedules shall apply when Customer desires service on other than a continuous annual basis, or the term of service provision of the Rate Schedule is greater than one (1) year.

If, for any cause a Service Agreement is entered into in which is specified a Rate Schedule not applicable to the class of service taken, on discovery of the error all bills rendered during the preceding twelve (12) months will be recalculated in accordance with the properly applicable Rate Schedule and Company will refund to existing Customer any amount due, when the amount due exceeds one ($1.00) dollar or to previous Customer any amount due, when the amount due exceeds two ($2.00) dollars, or Company will bill Customer for any amount owed, when the amount owed exceeds ten ($10.00) dollars, as the case may be. If the amount due Company is not paid within ten (10) days from presentation of bill, or Customer does not agree to payment over a reasonable period of time, or Customer fails to sign a new Service Agreement, Company may, after five (5) days written notice excluding Sundays and legal holidays, disconnect service.

50. **Proration of Bills:** Bills for energy used during a billing period that is longer or shorter than the normal billing period by more than five (5) days shall be prorated on a daily basis, but no billing will be made for three (3) or less days when no energy is used. However, in no event will the total length of service between initial and final

service be taken as less than one (1) month. No bill will be prorated for change in operating level within the billing period.

51. **Company Billing Errors:** When a Customer has been overcharged or undercharged as a result of incorrect reading of the meter, incorrect application of rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant or other similar reasons, the amount of the overcharge shall be refunded to the Customer or the amount of the undercharge may be billed to the Customer as detailed in Minnesota Administrative Rules 7820.3800 subparts 2 through 4.

    A. Remedy for Overcharge: If a Customer was overcharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, plus interest up to a maximum of three years from the date of discovery. Interest will be calculated as prescribed by Minnesota Statutes, section 325E.02(b). If the recalculated amount indicates that more than $1.00 is due an existing Customer or $2.00 is due a person no longer a Customer of the Company, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the Customer.

    B. Remedy for Undercharge: If a Customer was undercharged, the Company shall calculate the difference between the amount collected for service rendered and the amount the Company should have collected for service rendered, for the period beginning one year before the date of discovery. If the recalculated amount due the Company exceeds $10.00, the Company may bill the Customer for the amount due. The Company must not bill any undercharge incurred after the date of a Customer inquiry or complaint if the Company failed to begin investigating the matter within a reasonable time and the inquiry or complaint ultimately resulted in the discovery of the undercharge.

    C. Exception if Error Date Known: If the date the error occurred can be fixed with reasonable certainty, the remedy shall be calculated on the basis of payments for service rendered after that date, but in no event for a period beginning more than three years before the discovery of an overcharge or one year before the discovery of an undercharge.

SECTION IX - DEPOSITS AND GUARANTEES

52. **When Required:** Company may require Customer to make a deposit or guarantee satisfactory to Company to secure the payment of bills as they become due. Specific conditions requiring deposits or guarantees are identified in Regulation 54. The amount of such deposit shall not exceed twice the average monthly bill of Customer

as estimated by Company from Customer's statement in his or her application or as thereafter ascertained.

53. **When Refunded:** The deposit shall be refunded to Customer after twelve (12) consecutive months of prompt payment of all Company bills. Company may, at its option, refund the deposit by direct payment or as a credit on the bill. Upon termination of service, the deposit with accrued interest shall be credited to Customer's final bill and the balance, if any, shall be returned within forty-five (45) days to Customer with a written receipt as required under Minn. Stat. 325E.02(b).

54. **Interest on Deposits:** Interest shall be paid annually on all deposits at the rate specified by Minn. Stat. 325E.02(b) or other applicable laws of the State of Minnesota and will be applied against the electric service bill. Any unpaid interest at time of final settlement of Customer's accounts will be credited to Customer's accounts.

55. **Conditions Requiring a Deposit or Guarantee:** Company may require a deposit or guarantee of payment as condition of obtaining new service or continuing existing service under Minn. Rules Part 7820.4300, 7820.4400 or as may otherwise be provided below.

    A. Customer has outstanding a prior utility service account with another electric or gas utility which at the time of request for service remains unpaid and not in dispute.

    B. Information requested under Minn. Rules Part 7820.4300 or 7820.4400 is not provided within twenty (20) days of the request for service (except where Customer has sought but not yet received credit information from a prior utility).

    C. Information provided pursuant to Minn. Rules Part 7820.4300 or 7820.4400 is determined to be false or erroneous.

56. **Conditional Service Prior to Establishment of Credit:** Conditional service shall be provided expeditiously upon receipt of an application for service, and for up to twenty (20) days until credit has been satisfactorily established. Conditional service may be disconnected immediately without notice if required information or a required deposit or guarantee has not been received twenty (20) days after Company's request.

SECTION X – COLD WEATHER RULE

57. **Applicability:** This section applies only to residential customers of the Company.

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58. **Definitions:**

A. The terms used in this section have the meanings given them in Minnesota Statute, 216B.096.

B. “Cold weather period” means the period from October 1 through April 30 of the following year.

C. “Customer” means a residential customer of the Company.

D. “Disconnection” means the involuntary loss of Company heating service as a result of a physical act by the Company to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts Company service in any way.

E. “Household income” means the combined income, as defined in Minnesota Statutes 290A.03, subdivision 3, of all residents of the Customer’s household, computed on an annual basis. Household income does not include any amount received for energy assistance.

F. “Reasonably timely payment” means payment within five working days of agreed-upon due dates.

G. “Reconnection” means the restoration of Company heating service after it has been disconnected.

H. “Summary of rights and responsibilities” means a Commission-approved notice that contains, at a minimum, the following:

i. an explanation of the provisions of subdivision 5;

ii. an explanation of no-cost and low-cost methods to reduce the consumption of energy;

iii. a third-party notice;

iv. ways to avoid disconnection;

v. information regarding payment agreements;

vi. an explanation of the Customer’s right to appeal a determination of income by the Company and the right to appeal if the Company and the Customer cannot arrive at a mutually acceptable payment agreement, and a list of

names and telephone numbers for county and local energy assistance, and weatherization providers in each county served by the Company.

I. "Third-party notice" means a commission-approved notice containing, at a minimum, the following information;

i. a statement that the Company will send a copy of any future notice of proposed disconnection of Company heating service to a third party designated by the residential customer;

ii. instructions on how to request this service; and

iii. a statement that the residential customer should contact the person the Customer intends to designate as the third-party's name.

J. "Company" means Minnesota Power.

K. "Company heating service" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the Customer's primary residence.

L. "Working days" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing a notice shall not be counted in calculating working days.

59. **Company Obligations Before Cold Weather Period:** Each year, between August 15 and October 1, the Company must provide all Customers, personally or by first class mail, a summary of rights and responsibilities. The summary must also be provided to all new residential customers when service is initiated.

60. **Notice Before Disconnection During Cold Weather Period:** Before disconnecting Company heating service during the cold weather period, the Company must provide, personally or by first class mail, a commission-approved notice to a Customer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of right and responsibilities.

61. **Cold Weather Rule:**

A. During the cold weather period, the Company may not disconnect and must reconnect Company heating service of a Customer whose household income is at or below 50 percent of the state median income if the Customer enters into and makes reasonably timely payments under a mutually acceptable payment

agreement with the Company that is based on the financial resources and circumstances of the household; provided that, the Company may not require a Customer to pay more than ten percent of the household income toward current and past Company bills for Company heating service.

B. The Company may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the Customer.

C. The Customer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the Customer's financial circumstances have changed or the Customer is unable to make reasonably timely payments.

D. The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the Customer and the Company.

E. The Company shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration Customer availability.

62. **Verification of Income:**

A. In verifying a Customer's household income, the Company may:

1. accept the signed statement of a Customer that the Customer is income eligible;

2. obtain income verification from a local energy assistance provider or a government agency;

3. consider one or more of the following:

i. the most recent income tax return filed by members of the Customer's household;

ii. for each employed member of the Customer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;

iii. documentation that the Customer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension

provider; a letter showing the Customer's dismissal from a job or other documentation of unemployment; or

iv. other documentation that supports the Customer's declaration of income eligibility.

B. A Customer who receives energy assistance benefits under any federal, state or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

63. **Prohibitions and Requirements:**

A. Section 63 applies during the cold weather period.

B. The Company may not charge a deposit or delinquency charge to a Customer who entered into a payment agreement or a Customer who has appealed to the Commission under Minnesota Statutes 216B.096 subdivision 8.

C. The Company may not disconnect service during the following periods:

i. during the pendency of any appeal under Minnesota Statutes 216B.096 subdivision 8;

ii. earlier than ten working days after the Company has deposited in first class mail, or seven working days after the Company has personally served, the notice required under Minnesota Statutes 216B.096 subdivision 4 to a Customer in an occupied dwelling;

iii. earlier than ten working days after the Company has deposited in first class mail the notice required under Minnesota Statutes 216B.096 subdivision 4 to the recorded billing address of the Customer, if the Company has reasonably determined from an on-site inspection that the dwelling is unoccupied;

iv. on a Friday, unless the Company makes personal contact with and offers a payment agreement consistent with this section to the Customer;

v. on a Saturday, Sunday, holiday , or the day before the holiday;

vi. when Company offices are closed;

vii. when no Company personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service, or;

viii. when Commission offices are closed.

D. The Company may not discontinue service until the Company investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the Company to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the Company must attempt a second contact during non-business hours. If personal contact is made, the Company representative must provide notice required under Minnesota Statutes 216B.096 subdivision 4 and, if the Company representative is not authorized to enter into a payment agreement, the telephone number the Customer can call to establish a payment agreement.

E. The Company must reconnect Company service if, following disconnection, the dwelling is found to be occupied and the Customer agrees to enter into a payment agreement or appeals to the Commission because the Customer and the Company are unable to agree on a payment agreement.

64. **Disputes, Customer Appeals:**

A. The Company must provide the Customer and any designated third party with a Commission-approved written notice of the right to appeal:

i. the Company determination that the Customer's household income is more than 50 percent of state median household income; or

ii. when the Company and Customer are unable to agree on the establishment or modification of a payment agreement.

B. A Customer's appeal must be filed with the Commission no later seven working days after the Customer's receipt of a personally served appeal notice, or within ten working days after the Company has deposited a first class mail appeal notice.

C. The Commission must determine all Customer appeals on an informal basis, within 20 working days of receipt of a Customer's written appeal. In making its determination, the Commission must consider one or more of the factors in Minnesota Statutes 216B.096 subdivision 6.

D. Notwithstanding any other law, following an appeals decision adverse to the Customer, the Company may not disconnect Company heating service for seven

working days after the Company has personally served a disconnection notice, or for ten working days after the Company has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

65. **Customers Above 50 Percent of State Median Income:** During the cold weather period, a Customer whose household income is above 50 percent of state median income:

    A. has the right to a payment agreement that takes into consideration the Customer's financial circumstances and any other extenuating circumstances of the household; and

    B. may not be disconnected and must be reconnected if the Customer makes timely payments under a payment agreement accepted by the Company.

SECTION XI – RESIDENTIAL CUSTOMER PROTECTIONS

66. **Applicability:** The provisions of this section apply to residential customers of the Company.

67. **Budget Billing Plans:** The Company shall offer a Customer a budget billing plan for payment of charges for service, including adequate notice to Customer prior to changing budget payment amounts.

68. **Payment Agreements:** In compliance with Minnesota Statute 216B.098, the Company shall offer a payment agreement for the payment of arrears for past due customers that have not yet been disconnected, or to customers disconnected during non-Cold Weather Rule months. During Cold Weather Rule months, Cold Weather Rule provisions will apply. Payment agreements must consider a Customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to reconnect or continue service to a Customer who has entered and is reasonably on time under an accepted payment agreement. If a Customer has a broken payment agreement immediately preceding disconnection or has a history of repeatedly breaking payment agreements (two or more times in a twelve month period), a payment agreement may not be offered to be reconnected. Under these circumstances, to be reconnected, all past due accounts, deposits and reconnection fees, where applicable, shall have been paid.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

69. **Undercharges:**

A. In compliance with Minnesota Statutes 216B.098, the Company shall offer a payment agreement to Customers who have been undercharged if no culpable conduct by the Customer or resident of the Customer's household caused the undercharge. The agreement must cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the Customer and the Company, except that the duration of a payment agreement offered by the Company to a Customer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the Customer's household.

B. No interest or delinquency fee may be charged as part of an undercharge agreement under this subdivision.

C. If a Customer inquiry or complaint results in the Company's discovery of the undercharge, the Company may bill for the undercharges incurred after the date of the inquiry or complaint only if the Company began investigating the inquiry or complaint within a reasonable time after it was made.

70. **Medically Necessary Equipment:** The Company shall reconnect or continue service to a Customer's residence where a medical emergency exists or where medical equipment requiring electricity necessary to sustain life is in use, provided that the Company receives from a medical doctor written certification, or initial certification by telephone and written certification within five business days, that failure to reconnect or continue service will impair or threaten the health or safety of a resident of the Customer's household. The Customer must enter into a payment agreement.

71. **Commission Authority:** In addition to any other authority, the Commission has the authority to resolve Customer complaints against the Company, whether or not the complaint involves a violation of this Chapter 216B of Minnesota Statutes. The Commission may delegate this authority to Commission staff as it deems appropriate.

SECTION XII - MISCELLANEOUS REGULATIONS

72. **Conflicts:** In case of conflict between any provision of these approved Service Regulations, Customer's Service Agreement or a Rate Schedule, the provision of the Service Agreement takes precedence, followed by the provision of the Rate Schedule. The Customer's Service Agreement will identify all such conflicts with the Service Regulations or Rate Schedule.

ELECTRIC SERVICE REGULATIONS OF MINNESOTA POWER

73. **Franchise Limitations:** All Service Agreements are subject to existing franchise limitations.

74. **Franchise Fees Notification:** The Company will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Company receives less than 60 days' notice of a repealed or reduced fee from a city, the Company will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

75. **Franchise Fees Customer Notification:** The following language will be included with the first customer bills on which a new or amended franchise fee is collected:

    The City of _____granted Minnesota Power a franchise to operate within the City limits. An electric franchise fee of (____% OF GROSS REVENUES or $_____ PER METER or $_____ PER KWH) will be imposed on customers effective MM/DD/YYYY. The line item appears on your bills as "_____Franchise Fee." Minnesota Power remits 100% of this fee to the City of _____.

76. **Regulation and Jurisdiction:** Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable Rate Schedule or other superseding Rate Schedules in effect from time to time. All the rates and regulations referred to herein are subject to amendment and change by Company. Any such amendments or changes may be subject to acceptance or approval by any regulatory body having jurisdiction thereof.

EXTENSION RULES

I. GENERAL

The following rules shall govern the extension of Company's electric transmission/distribution lines and service connections in all areas served by Company to all classes of retail Customers requiring Company's standard single or three phase electric transmission/distribution service.

The standard type of extension shall be the most feasible and economical as determined by the Company and shall be constructed in accordance with Company's Distribution Construction Standards. When conditions require extensions from or connections to lines of voltages other than the standard voltage or where line construction other than Company's standard construction is required, Company reserves the right to make adjustments to these rules for such non-standard extensions such that adequate revenues are provided to fund the extension cost for a single point of delivery. The Company's standard extension does not include a second service point.

Except when meter pedestals for underground service have been installed, all facilities installed by Company on either side of the service point and not expressly sold and conveyed to Customers by written agreement shall at all times remain the sole property of Company, regardless of any Contributions in Aid of Construction paid by Customers. When meter pedestals have been installed by Company, Customer shall be responsible for installing and will remain the sole property owner of all facilities on Customer's side of the meter. In case of cancellation of Customer's service agreement for any cause, Company shall have the right to remove all facilities installed for serving Customer.

Service will be supplied in accordance with Company's schedules for the respective classes of service in the respective rate areas, Company's Electric Service Regulations and the provisions of these Extension Rules.

II. EXTENSION COST

The "Extension Cost" is the estimated cost of extending lines and the addition or relocation of facilities to serve new Customers or new loads. This shall be the total cost of extending the line, including all branch or lateral lines, but excluding the cost of transformer, meter and any system betterments. The Extension Cost shall include the customer's choice of either an overhead or underground service point and estimation of special condition costs anticipated.

III. EXTENSION COST CALCULATION

The Extension Cost shall be calculated by Company as follows:

1. All single phase line extensions of 1,000 feet or less shall be calculated using a unit cost of $37.00 per foot. The unit cost of $37.00 per foot may be adjusted for non-standard extensions or special conditions.

2. All single phase line extensions over 1,000 feet and all three phase line extensions shall be estimated based on Company's Compatible Unit Estimator (CUE). The CUE consists of Compatible Units Identifications (CU IDs), which contain descriptions and costs of service-extension components such as distribution materials, labor, and vehicle usage. The service-extension designer chooses the necessary CU IDs needed for the line extension. A total job cost is estimated using the CUE based on data for the applicable CU IDs. The distribution material cost is the actual cost of items listed in the Company's inventory data base, based on actual purchase prices. The labor cost is based on one lead lineman and two linemen, the typical crew used to install a new service extension. The vehicle use cost is based on a percentage of labor based on prior year actual labor overheads.

IV. CONTRIBUTIONS

The "Contribution in Aid of Construction," hereafter referred to as Contribution, is the amount required to support the Company's Extension Cost excluding allowance if applicable and including any applicable fees. Where a line extension other than Company's standard type extension is requested by the customer, a Contribution shall be required to support all additional costs of such non-standard extension. A customer may request an upgrade to existing service or an additional service point. An advanced Contribution is required to support costs of all additional facilities requested by the customer.

Any customer may pay all or part of a Contribution required of another Customer with such other Customer's authorization, and subject to acceptance by Company.

V. BASIS FOR MAKING EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS ARE $30,000 OR LESS

If the Company's standard type construction is used in making the extension, Customer shall not be required to make payment to Company for the Extension Cost if:

The Extension Cost is for a Residential customer and does not exceed $751 for single-phase;

The Extension Cost is for a General Service or Commercial Electric Vehicle Charging Service customer and does not exceed $1,020 for single-phase and $3,152 for three-phase; or

EXTENSION RULES

The Extension Cost is for a Large Light and Power customer and does not exceed $30,000.

If the extension cost exceeds the respective rate class service-extension allowance specified above and is for single phase service, customer must pay the Company in advance a Contribution for the Extension Cost in excess of the respective rate class service-extension allowance.

If the Extension Cost exceeds the respective rate class service-extension allowance specified above and is for three phase non-refundable line extension service, Customer has the following options:

1. Pay Company in advance a Contribution for the Extension Cost in excess of the rate class service-extension allowance, or

2. No advance contribution for extension costs will be required, if the customer enters into a five year Electric Service Agreement where the Company's costs relating to the entire extension are equal to or less than three times the Customer's Guaranteed Annual Revenues (GAR), as defined below, or

3. If the Customer enters into a five-year Electric Service Agreement where the Company's costs relating to the entire extension are greater than three times the Customer's guaranteed annual revenues, the Customer will be required to pay the Company in advance a Contribution for the balance of the Extension Cost not supported by GAR.

The Guaranteed Annual Revenue (GAR) is the minimum annual amount of revenue from billings under the applicable rate schedule that a Customer who enters into an Electric Service Agreement (ESA) commits to pay to Minnesota Power to support extension costs for installing a three phase line extension.

To determine the required GAR, the Company estimates the costs of the service extension from which the revenue is derived. The service-extension job is estimated using the Compatible Unit Estimator (CUE). The cost estimate is divided by three according to the three-times-annual-revenue methodology. This is the annual amount the Customer will pay under the GAR agreement.

The GAR used in the ESA shall be estimated by the Company and determined under the existing rate schedule for providing service to the Customer.

Developers of Residential Housing Sites

A Developer of residential housing sites requiring electric service must make a Contribution equal to the Extension Cost. As customers are connected Developer is entitled to receive a refund for each customer connected of the current residential allowance amount. However, in no event will the total refund exceed the Contribution. After Developer has received the maximum allowable refund or after the initial five years, whichever occurs first, customers requesting service to additional lots for which the extension was made shall make appropriate arrangements directly with Company in order to satisfy additional extension costs related to the respective service connections.

VI. BASIS FOR MAKING EXTENSIONS FOR TEMPORARY SERVICE

"Temporary Service," for purposes of these Extension Rules, is service to a Customer whose use of that service, in the Company's judgment, may be of less than five years duration, or is service to a Customer who is unwilling to enter into an Electric Service Agreement having a minimum term of five years.

Customers expected to take service for less than one year duration shall be required to take such service in accordance with Company's Temporary Service Rider to the applicable General Service Schedules.

Customers expected to take Temporary Service for more than one year but less than five years will be served under the Company's standard rate schedules. Such customers with requirements of 500 kW or more shall enter into a contract for a minimum term of one year.

Prior to installation Temporary Service Customers shall pay a Contribution equal to the estimated cost of installation and removal of the facilities required to render Temporary Service.
A connection to a permanent service for power used during construction is not considered to be Temporary Service under these rules.

VII. REAPPORTIONMENT AND REFUNDS

When the Extension Cost is $30,000 or less and additional Customer(s) are connected to a line extension during the initial five year period of any Customer on the extension, the Extension Cost(s) of all previously connected Customer(s) on the extension will be reapportioned among all Customers served from the combined line extension, including the Customer(s) who are being added to the extension. The reapportionment shall be calculated such that each individual customer on the line extension shall be responsible for:

EXTENSION RULES

1. The cost of that portion of the extension which services only that individual Customer; plus

2. The cost of that portion of the line extension which that individual Customer shares with other Customers on the line extension divided by the total number of Customers who share such portion of the line extension.

After reapportionment it will be determined whether the previously connected Customer(s) are entitled to a refund. If a refund is due, the amount to be refunded shall be the difference between the previous and reapportioned Extension Costs, provided that such refunds will not:

1. Exceed the actual Contribution paid by the respective Customer.

2. Be made to any Customer after the expiration of the initial five year period of that Customer.

3. Be made after Customer terminates service.

When a Customer who has paid a Contribution terminates service within the initial five year period and another Customer immediately commences taking service at the same premises, such Customer may transfer his right to future refunds, if any, to the new Customer, provided an agreement covering such transfer is executed by the Customers and accepted by the Company at the time the new Customer applies for service.

Following the initial five year period of the most recently connected Customer(s) on the extension, any line extension necessary to serve additional Customers will be considered as a separate extension not affecting Customers connected previously.

When the Extension Cost is $30,000 or less and the Customer has entered into an Electric Service Agreement and paid a Contribution, the Company will, through its Customer Information System, at the end of the each year of the Electric Service Agreement, compare the Customer's average annual revenue for the first year and thereafter, to the minimum annual revenue which Customer elected to guarantee. The Company will, at the election of the Customer:

1. Collect an additional contribution from the Customer not to exceed an amount equal to the difference between the extension cost supported by the revenue for the first year and the extension cost supported by the minimum annual revenue the Customer elected to guarantee; or

2. Continue the minimum guaranteed annual revenues set forth in the existing Electric Service Agreement.

In no event will the minimum annual guarantee be greater than the amount necessary to satisfy the Extension Cost.

VIII. SPECIAL CONDITIONS

Construction of an extension will commence when the following conditions have been met.

1. Agreements, when required, shall have been executed by each Customer and accepted by Company specifying initial contract period, guaranteed annual revenue, and any Contribution.

2. Each Customer has paid to Company his share of any Contribution.

3. Satisfactory right-of-way necessary for the construction, operation and maintenance of the extension (including any vegetation management rights) both for the purpose of providing access to the extension on Customers' premises and for continuing the extension to other Customers, has been furnished without expense to the Company.

4. Each Customer has made satisfactory credit arrangements with the Company. In the case of tenants, the Company may require owner to guarantee payment.

5. The extension cost will include excess installation costs incurred by the Company because of special conditions that impede the installation of distribution facilities. Such special conditions include, but are not limited to ground frost, surface or subsurface impediments and submarine installations. Surface or subsurface impediments may include, but are not limited to: rock, bedrock, subsurface structures and wetlands.

6. Winter charges will be assessed October 15 through April 1 of each year. In no event will Customer costs exceed line extension costs.

IX. BASIS FOR MAKING DISTRIBUTION EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS EXCEED $30,000

The above rules shall be applicable except where specifically stated otherwise and except that the Extension Cost will be the actual cost determined upon completion of the extension. The amount of Extension Costs relating to the extension which will be recovered by the Company through application of its rate schedule will be determined on an individual customer basis. Electric Service Agreements will be required and will be for

sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

If the Extension Cost exceeds the Extension Cost Credit as determined by the Company, the Customer(s) shall pay the Company a Contribution equal to the amount of the Extension Cost that exceeds the Extension Cost Credit. Where more than one Customer is served from the extension, the Contribution will be apportioned in the ratio of each Customer's Contract Demand to total Contract Demand for all Customers initially served from the extension. If there are circumstances unique to an extension in which application of the above rules would not be appropriate or would not properly recover costs, the Company will make necessary adjustments in the application of the rules such that adequate revenues are provided to fund Extension Costs through a combination of Extension Cost Credits and/or Contributions. Similarly, any refund which may be due, as a result of increased Customer Contract Demand during the initial ten year period, or as a result of additional Customers being served subsequently but during the initial ten year period, will be determined by the Company based upon all relevant dates such that revenue recovery is adequate to fund the Extension Costs through a combination of Extension Cost Credits and/or Contributions.

X. BASIS FOR MAKING TRANSMISSION EXTENSIONS FOR PERMANENT SERVICE

"Transmission" service for purposes of these Extension Rules is service to a Customer taken at 115 kV or higher. Customer connections involving loads served at transmission voltage will be considered on an individual customer basis. Electric Service Agreements will be required and will be of sufficient duration and at sufficient revenue levels to support extension and other costs required to provide service.

REQUEST FOR BUDGET BILLING PLAN FORM

Any all-year retail customer may apply for service to be billed in accordance with Company's Budget Billing Plan by completing the applicable form available at:

http://www.mnpower.com/CustomerService/BudgetBilling

Billing under this plan shall commence upon acceptance of the application by Company. Company may require partial payment of arrears for those customers who wish to include a large arrears balance in a newly established budget billing plan.

The amount of the monthly budget billings shall be determined as follows:

1. Where sufficient billing history is available,

   A. Company will determine Customer's average monthly billing during the preceding 12 months

   B The average monthly billing determined in Step A shall be adjusted for anticipated changes in rate level during the following 12 months.

   C. An existing arrears or credit balance shall be divided by twelve and added to or deducted from the amount determined in Step B.

   D. The amount of the monthly budget billing shall then be the amount determined in Step C rounded to the nearest dollar.

2. Where insufficient billing history is available, Company will determine Customer's connected load for use in estimating the first year's consumption upon which to base budget billings.

Customer's budget billings shall be reviewed and recalculated annually on the date following preparation of the twelfth billing under an existing budget billing plan. Company may also review Customer's account at times other than the normal review date and, where an unusually large arrears or credit balance exists, adjust the budget billing amount accordingly. Customer shall be notified of such adjustment made in the budget billing amount. When there is an unusually large credit balance, Customer may request a refund and/or reduction of budget billings.

Customer may discontinue budget billing at any time by notifying Company. Company may discontinue budget billing upon failure of the Customer to make timely payments of budget billings. Any credit balance remaining at the time of discontinuance in the Plan shall be carried forward unless Customer requests a refund. Any amount past due shall be treated under Company's normal notice and collection procedures.

STANDARD CONTRACTS AND AGREEMENTS

The application for Residential electric service can be found at:
https://www.mnpower.com/CustomerService/ResidentialConstruction

The application for Commercial electric service can be found at:
https://www.mnpower.com/CustomerService/CommercialConstruction

Sample Electric Service Agreement Form:

Form 351 Rev. 1/00

ELECTRIC SERVICE AGREEMENT

THIS AGREEMENT, made this _____ day of _____ , _____, between Minnesota Power, a Minnesota corporation, and _____, hereafter called Customer, in consideration for the covenants and promises made herein creates the obligation of Minnesota Power to furnish electric service and Customer to pay for said electric service in accordance with the following terms and conditions.

1. Electric service shall be furnished to Customer's premises located at _____
_____
in the County of _____ and State of Minnesota, described as follows:

2. Electric service shall be furnished at a point of delivery described as _____
_____

3. Annual revenues paid to Minnesota Power by Customer inclusive of payments for electric service received, billed at the applicable rate schedule plus any adjustments shall not be less than _____ per year, for a period of not less than _____ years, commencing from the date Minnesota Power begins providing electric service or 90 days from the date of installation of said electric service, whichever occurs first. An annual billing will be rendered for any deficit to the above annual revenue guarantee.

4. An advance payment of _____ shall be made to cover that portion of Minnesota Power's investment not covered by the revenue guarantee.

5. This electric service shall be billed at the current applicable rate and class at the time the electric service is used or as approved by any regulating body having jurisdiction thereof.

6. Meter-Special Conditions: _____
_____
_____

7. The parties hereto mutually agree to abide by any and all applicable statutes, agency rules and Minnesota Power's Electric Service Regulations which are hereby incorporated by reference.

8. This Agreement is not assignable to any other party without the express written consent of Minnesota Power.

9. This Agreement shall be in full force and effect for the term above specified and each party shall be bound unless an express written release is executed by the party not requesting said release.

MINNESOTA POWER

By _____
Title _____

CUSTOMER

_____
By _____
Title _____

RESERVED FOR FUTURE USE

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

TERRITORY

Applicable to Community-Based Energy Development (C-BED) projects located in the State of Minnesota.

APPLICATION

To any qualifying owner of a C-BED project who meets Company's Electric Service Regulations and any applicable Riders, technical standards and rules. Service under this Schedule is closed to new customers.

A C-BED project must be a new renewable energy project that utilizes an eligible energy technology, as defined in Minn. Stat. § 216B.1691, subd. 1(a). A C-BED project may either be a stand-alone project or part of a community energy partnership that allows Company participation as an owner, equity partner, or provider of technical or financial assistance:

(1) has no single qualifying owner owning more than 15 percent of a C-BED wind energy project unless: (i) the C-BED wind energy project consists of only one or two turbines; or (ii) the qualifying owner is a public entity listed under Minn. Stat. § 216B.1612, subd. 2(c)(5), that is not a municipal utility;
(2) demonstrates that at least 51 percent of the gross revenues from a power purchase agreement over the life of the C-BED project will flow to qualifying owners and other local entities;
(3) includes a qualifying owner, or any combination of qualifying owners, that may develop a joint venture project with a nonqualifying renewable energy project developer. However, the terms of this Schedule may only apply to the portion of the energy production of the total project that is directly proportional to the equity share of the C-BED project owned by the qualifying owners; and
(4) has a resolution of support adopted by the county board of each county in which the C-BED project is to be located, or in the case of a C-BED project located within the boundaries of a reservation, the tribal council for that reservation;

Where a qualifying owner means:

(1) a Minnesota resident;
(2) a limited liability company that is organized under Minn. Stat. Chapter 322B and that is made up of members who are Minnesota residents;
(3) a Minnesota nonprofit organization organized under Minn. Stat. Chapter 317A;
(4) a Minnesota cooperative association organized under Minn. Stat. Chapter 308A or 308B, including a rural electric cooperative association or a generation and transmission cooperative on behalf of and at the request of a member distribution utility;
(5) a Minnesota political subdivision or local government including, but not limited to, a municipal electric utility, or a municipal power agency on behalf of and at the request of a member distribution utility, a county, statutory or home rule charter city, town,

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

school district, or public or private higher education institution or any other local or regional governmental organization such as a board, commission, or association; or

(6) a tribal council.

TYPE OF SERVICE

Output of the C-BED project shall be provided at 60 hertz and at the voltage and phase relationship as agreed to by Company and a qualifying owner.

RATE

A qualifying owner may sell all the energy produced by the C-BED project to Company or use a portion of the energy from the C-BED project and sell the remaining to Company. The following information provides guidelines for the negotiated power purchase agreements for service under this C-BED Schedule.

Company may purchase all or a portion of the energy made available by the qualifying owner from the C-BED project. A qualifying owner and Company shall negotiate the rate and power purchase agreement terms consistent with this Schedule. In the alternative, at the discretion of a qualifying owner, the qualifying owner and Company may negotiate a power purchase agreement with terms different from this Schedule. Company must receive Minnesota Public Utilities Commission approval of a power purchase agreement for a C-BED project. Nothing in this Schedule shall be construed to obligate Company to enter into a power purchase agreement.

The energy rate shall equal the net present value of the nominal payments to the C-BED project divided by the total expected energy production of the C-BED project over the 20-year life of the power purchase agreement with a rate higher in the first ten years of the power purchase agreement than in the last ten years. The receipt of the payment of this rate constitutes a transfer of the property rights of all renewable and other attributes/credits associated with the generation from the C-BED project to Company, unless otherwise agreed to by the qualifying owners of the C-BED project and Company.

Qualifying and nonqualifying owners shall provide sufficient security as determined by Company based on standard industry practice, risk-adjusted for the C-BED project, that considers such things as ownership arrangement, project accreditation, credit rating and experience of financing sources and project management and project development experience to secure performance under the power purchase agreement, and shall not transfer the C-BED project to a nonqualifying owner during the initial 20 years of the power purchase agreement.

COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED)

A C-BED project that is operating under a power purchase agreement under this Schedule is not eligible for net energy billing under Minn. Stat. § 216B.164, subd. 3, or for production incentives under Minn. Stat. § 216C.41.

SERVICE CONDITIONS

1. A C-BED project must be: (1) safely integrated into and operated within Company's grid without causing any adverse or unsafe consequences; and (2) consistent with Company's resource needs as identified in Company's most recent resource plan submitted under Minn. Stat. § 216B.2422 and meet Company's cost and reliability requirements to fulfill some or all of the identified need at a minimal impact to customer rates.

2. All electricity delivered to Company by a qualifying owner shall be measured by one or more meters installed at a single point of common coupling or as determined by Company. The meter(s) for C-BED service shall measure the flow of capacity and energy from a qualifying owner to Company only. Any flow of capacity and energy from Company to a qualifying owner shall be separately metered.

3. Service shall be provided under this Schedule if Company has sufficient capacity available in existing transmission and distribution facilities to provide such service at the location where service is requested.

4. A qualifying owner shall pay Company the installed cost of any additional required facilities, including any required studies and testing which, at a minimum, demonstrate upfront the C-BED project's technical feasibility and resource adequacy.

5. Company shall not be liable for any loss or damage, including consequential damages, caused by or resulting from any limitation in providing service under this Schedule.

RATE, SERVICE, PROCESS AND TECHNICAL DOCUMENTS AVAILABILITY

Related Company rate, service, process and technical documents for distributed generation are available by contacting Company at 218-722-2625.

SOLARSENSE CUSTOMER SOLAR PROGRAM

APPLICATION

The goal of the Low Income ("LI") Solar Grant Program is to increase the accessibility of solar energy to Customers by creating a viable, long-term solar market for low-income customers in northern Minnesota. Starting in 2021, the annual budget is $120,000 per year, with a maximum individual grant cap of $30,000. This allows for up to four projects per year to be funded at the $30,000 level. A Low Income Solar Grant Committee ("Committee") comprised of both external stakeholders and Minnesota Power employees make project funding recommendations.

GRANT COMMITTEE CONFLICTS OF INTEREST

In order to evaluate possible conflicts, all Low Income Solar Grant Committee candidates must complete a Conflict of Interest disclosure. If it is determined the candidate has a conflict of interest, or the appearance of a conflict of interest, they will not be eligible to join the Committee. The following Conflict of Interest Policy applies to all Grant Committee members.

Existence of Conflict of Interest or Appearance of Conflict of Interest

A conflict of interest exists if a Committee member:

1. Is an applicant for a Low Income Solar Grant, intends to apply for a grant (as an individual or with an organization) in the next two years, or is personally involved as a partner to the project, or
2. Serves on the Board of Directors or other governing or advisory board of an applicant organization, or
3. Is a volunteer or paid employee of an organization being considered for funding, or
4. Is a paid consultant or service provider of an organization being considered for funding, or
5. Has an immediate family member or relation with an applicant that would impair their ability to make a grants award decision.

Minnesota Power also reserves the right to determine when a Grant Committee member's relationship with an individual or organization creates an appearance of a conflict of interest that, in its judgment, could compromise the integrity of the grant process and should be treated as a conflict of interest.

Remedies for Conflicts of Interest

If a Committee member has a conflict of interest as defined above, they must notify Minnesota Power as soon as they are aware of a conflict. Committee members with a conflict of interest have one of two options to remedy the conflict 1) recuse themselves from the entire grant process for that cycle (including the meeting, discussion, and voting) or 2) resign from the committee. Committee members will only be allowed to recuse themselves

SOLARSENSE CUSTOMER SOLAR PROGRAM

from one grant cycle. If conflicts persist, the member will no longer be eligible to serve on the Grants Committee.

If Minnesota Power or the committee member identifies a perceived conflict of interest, the Company will make a determination on how to proceed. Possibilities include, but are not limited to:

- Allowing the committee member to remain on the committee and review applications without limitation
- Having the committee member recuse themselves from reviewing the application(s) where a perceived conflict of interest exists but allowing them to review all others
- Recusing the committee member from the entire grant process for that grant cycle.

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

APPLICATION

Available to all customers taking service at Company owned Electric Vehicle Service Equipment (EVSE) charging stations. Service shall be delivered at publicly available charging stations operated by the Company. Stations may include Direct Current Fast Charging (DCFC) and Level 2 EVSE infrastructure served by Company owned facilities.

TYPE OF EQUIPMENT

For purposes of this tariff, Electric Vehicle Service Equipment means the installed device used to deliver electricity for electric vehicle charging and includes the ungrounded, grounded, and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets or apparatuses associated with the installed devices.

PAYMENT COLLECTION METHODS

All Electric Vehicle Service Equipment will have a minimum of two payment options for taking service at Company owned EVSE charging stations.

RATES

Connection Fees:

Level 2 Charger Only:	$3.00
DCFC 100 kW or less:	$5.00
DCFC 101-200 kW:	$6.00
DCFC 200 kW plus:	$7.00

Charge per kWh:	Level 2	DCFC
On-peak (kWh)	31.896¢	45.930¢
Off-peak (kWh)	22.832¢	32.878¢
Super Off-Peak (kWh)	16.183¢	23.304¢

PILOT FOR RETAIL COMPANY-OWNED ELECTRIC VEHICLE CHARGING SERVICE

EVSE TIME OF DAY PERIODS

On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. CST Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. CST Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak.

Weekdays	Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Legend	Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
-1 Super off-peak	Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
0 Off-peak	Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
1 Peak	Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1
	Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	-1

Weekends & Holidays	Hour (ending)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Legend	Jan	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
-1 Super off-peak	Feb	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
0 Off-peak	Mar	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
1 Peak	Apr	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	May	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Jun	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Jul	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Aug	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Sep	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Oct	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Nov	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1
	Dec	-1	-1	-1	-1	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1

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SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

Contact Theodore Widmer
Title: Account Analyst II
Phone: (218) 355-3197 FAX: Email: twidmer@allete.com

REPORT FOR: ALLETE, Inc. 12647
REPORTING PERIOD: 2024

Supervisor Josh Rostollan
Title: Supervisor
Phone: (218) 355-3151 FAX: Email: jrostollan@allete.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	ALLETE, Inc.	**Submission Status/Date:**	Submitted	04/30/2025
2	Current Address of Principal Business Office	30 West Superior Street Duluth MN 55802 0000			
3	Preparer's Legal Name Operator (if different than line 1)				
4	Current Address of Preparer's Office (if different than line 2)				
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility	☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator	☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator	

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] NPCC [ ] SPP [ ] FRCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] WECC [x] MRO [ ] SERC
2	Name of RTO or ISO	[ ] California ISO [ ] Southwest Power Pool [ ] Electric Reliability Council of Texas [X] Midwest ISO [ ] PJM Interconnection [ ] ISO New England [ ] New York ISO [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [ ] Buying distribution on other electrical system [x] Transmission [x] Wholesale power marketing [x] Buying transmission services on other electrical system [ ] Retail power marketing [x] Distribution using owned/leased electric wires [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 1,532.0 Prior Year 1,551.0 Winter (Megawatts) 1,532.0 Prior Year 1,528.0
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes [ ] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No
	If "Yes", Please Provide Additional Contact Information	Name: Andy Scheidel Title: Fleet Administrator Telephone: 218 - 355 - 2753 Fax: - - Email: ascheidel@mnpower.com

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SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	5,832,104	11	Sales to Ultimate Consumers	8,391,265
2	Purchases from Electricity Suppliers	7,147,244	12	Sales For Resale	4,182,855
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	16,352
5	Exchanged Net				
6	Wheeled Received (In)	2,647,577			
7	Wheeled Delivered (Out)	2,567,216	15	Total Energy Losses (positive number)	469,237
8	Wheeled Net	80,361			
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	13,059,709	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	13,059,709

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SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	884,002.2
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	249,963.6
4	Electric Credits/Other Adjustments	$	-22,045.6
5	Revenue from Transmission	$	74,495.4
6	Other Electric Operating Revenue	$	15,864.0
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	1,202,279.6

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INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **MN**

1	Total Number of Distribution Circuits	340.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	1.0

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SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

	State	MN
3a.	SAIDI value including Major Event days	119.900
3b.	SAIDI value excluding Major Event days	119.900
4	SAIDI value including Major Event days minus loss of supply	109.430
5a.	SAIFI value including Major Event days	1.300
5b.	SAIFI value excluding Major Event days	1.300
6.	SAIFI value including Major Event days minus loss of supply	1.110
7.	Total number of customers used in these calculations	138,546.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)	69.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[ ] Yes [x] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

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SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State MN Balancing Authority	56669				
Revenue (thousand dollars)	154,078.7	174,471.2	555,452.3	0.0	884,002.2
Megawatthours	983,680	1,204,294	6,203,291	0	8,391,265
Number of Customers	125,896	26,027	419	0	152,342
Are your rates decoupled?	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	15.663	14.487	8.954		10.535
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					
Total					
Revenue (thousand dollars)	154,078.7	174,471.2	555,452.3	0.0	884,002.2
Megawatthours	983,680	1,204,294	6,203,291	0	8,391,265
Number of Customers	125,896	26,027	419	0	152,342

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SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total
Revenue (thousand dollars)
Megawatthours
Number of Customers

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SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **MN** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	11,828.397	57,972.080			69,800.477
2	Peak Demand Savings (MW)	1.412	4.004			5.416
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	141089.292	794,654.670			935,743.962
4	Peake Demand Savings (MW)	0.924	2.692			3.616
	Reporting Year Incremental Costs					
5	Customer Incentives	1,710.748	2,847.528			4,558.276
6	All other costs	2,220.539	941.877			3,162.416
	Incremental Life Sycle Costs					
7	Customer Incentives	1,710.748	2,847.528			4,558.276
8	All other costs	2,220.539	941.877			3,162.416
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	11.928	13.708			26.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **MN** **Balancing Authority** **56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	7,084	473	6		7,563
2	Energy Savings (Mwh)	61.210	55.990	0.540		117.740
3	Potential Peak Demand Savings (MW)	19.146	2.987	303.031		325.164
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

5	Customer Incentives	1,842.697	597.102	11,496.440		13,936.239
6	All other costs					

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory MN **Balancing Authority** 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	15,596				15,596

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State MN **Balancing Authority** 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	56	1	0	0	57
2	Number of AMI Meters	125,840	26,026	419	0	152,285
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	0	0	0	0	0
5	Total Number of Meters (All Types), line 1+2+4	125,896	26,027	419	0	152,342
6	Energy Served Through AMI	983,242	1,204,248	6,203,291	0	8,390,781
7	Number of Customers able to access daily energy usage through a webportal or other electronic means	125,896	26,027	419	0	152,342
8	Number of customers with direct load control					

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State	MN	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photo voltaic	Net Metering Installed Capacity (MW)			9.589	8.987	0.020	0.000	18.596
	Net Metering Installations			1,014	191	1	0	1,206
	Virtual NM Installed Capacity (1 MW and greater)							0.000
	Virtual NM Customers (1 MW and greater)							0
	Virtual NM Installed Capacity (less than 1MW)			0.518	0.522	0.000	0.000	1.040
	Virtual NM Customers (less than 1MW)			95	3	0	0	98
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)			3,422.875	1,025.631	0.000	0.000	4,448.506
Battery Storage	PV-Paired Net Metering Installed Capacity (MW)			0.554	0.006	0.000	0.000	0.560
	PV-Paired Energy Capacity (MWh)							0.000
	PV-Paired Installations			30.000	1.000	0.000	0.000	31.000
	Not PV-Paired Net Metering Installed Capacity (MW)							0.000
	Not PV-Paired Energy Capacity (MWh)							0.000
	Not PV-Paired Net Metering Installations							0.000
	Total Battery Storage Capacity			0.554	0.006	0.000	0.000	0.560
	Total Battery Storage Energy Capacity (MWh)			0.000	0.000	0.000	0.000	0.000
	Total Battery Storage Installations			30	1	0	0	31
Wind	Installed Net Metering Capacity (MW)			0.072	0.093	0.000	0.000	0.165
	Number of Net Metering Customers			7	7	0	0	14
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)							0.000
Other	Installed Net Metering Capacity (MW)							0.000
	Number of Net Metering Customers							0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)							0.000

SCHEDULE 7. PART A. NET METERING Continued

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Total	Installed Net Metering Capacity (MW)	10.179	9.602	0.020	0.000	19.801
	Number of Net Metering Customers	1116	201	1	0	1318
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	3,422.875	1,025.631	0.000	0.000	4,448.506
Grand Total All States	**Net Metering Installed Capacity (MW)**	10.179	9.602	0.020	0.000	19.801
	Net Metering Installations/customers	1116	201	1	0	1318
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	3,422.875	1,025.631	0.000	0.000	4,448.506

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REPORT FOR ALLETE, Inc.

REPORT PERIOD ENDING:

SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	Balancing Authority	< 1MW

1. Number of generators	3. Capacity that consists of backup-only units
2. Total combined capacity (MW)	4. Capacity owned by respondent

Capacity by Technology and Sector (MW)

	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10. Photovoltaic						
10a. Nature of PV Data:						
11. Battery Capacity (MW)						
11a. *Energy Capacity(MWh)						
12. Wind turbine(s)						
13. Other						
14. Total						

*Line 11a Energy Capacity is not included in the toal on line 14.

REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Aitkin				
2	MN - Benton				
3	MN - Carlton				
4	MN - Cass				
5	MN - Cook				
6	MN - Crow Wing				
7	MN - Hubbard				
8	MN - Itasca				
9	MN - Koochiching				
10	MN - Lake				
11	MN - Morrison				
12	MN - Otter Tail				
13	MN - Pine				
14	MN - St Louis				
15	MN - Stearns				
16	MN - Todd				
17	MN - Wadena				

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REPORT FOR: ALLETE, Inc. 12647

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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REPORT FOR: ALLETE, Inc. 12647

REPORT PERIOD ENDING: 2024

EIA861 ERROR LOG

Part	State	BA ID	Error No.	Error Description/Override Comment	Type	Override

Info

Submission #:
20258-221641

On Behalf Of:
Minnesota Power

Submission date/time:
08/01/2025 09:31 AM

Filer

Name:
Brodin, Matthew

Organization:
Minnesota Power

Email:
mbrodin@allete.com

Phone Number:
(218) 722-5642

Service Lists

Docket #	Service List Name
25-1	PR-25-1

Dockets

Docket #	Type	Industry
25-11	Periodic Reports	Energy

Documents

Name	Classification	Document Type	Additional Info	Document Date
Cvr Ltr,METHOD24,Affidavit,Lrg Customer,Map,861,Ratebook – PUBLIC.pdf	Public	Compliance Filing	Annual Compliance Filing-Cvr Ltr,METHOD24,Affidavit,Lrg Customer,Map,861,Ratebook – PUBLIC	08/01/2025
ELEC_68_2024 Annual Report.xlsx	Public	Compliance Filing	2024 Annual Report	08/01/2025
ELEC_68_2024 Forecast_PUBLIC.xlsx	Public	Compliance Filing	Forecast for Annual filing	08/01/2025
ELEC_68_2024 Monthly Power Cost Adjustments.xlsx	Public	Compliance Filing	Power Cost Adjustments	08/01/2025
Cvr Ltr,METHOD24,Affidavit,Map,861,Ratebook – TRADE SECRET.pdf	Trade Secret	Compliance Filing	Cvr Ltr,METHOD24,Affidavit,Map,861,Ratebook – TRADE SECRET	08/01/2025
ELEC_68_2024 Forecast_TRADE SECRET.xlsx	Trade Secret	Compliance Filing	Forecast-Trade Secret	08/01/2025
ELEC_68_2024 LargeCustomer_TRADE SECRET.xlsx	Trade Secret	Compliance Filing	Large Customer-Trade Secret	08/01/2025

Service List - Electronic Service

Last Name	First Name	Email	Organization	View Trade Secret
Bull	Mike	mike.bull@state.mn.us		Yes
Commerce Attorneys	Generic	commerce.attorneys@ag.state.mn.us		Yes
Residential Utilities Division	Generic Notice	residential.utilities@ag.state.mn.us		Yes

Service List - Paper Service

No master contacts with paper service.

GREAT RIVER ENERGY®



Model Report

John Williams
Senior Forecaster
7/2025

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EXECUTIVE SUMMARY

In 2025, Great River Energy (GRE) developed the demand and energy forecasts for use in its 2025 MN7610 filing. This report presents an overview of the forecasting approach, a description of the forecast models, and forecast results. GRE is a generation and transmission cooperative that serves its member owners that serves ultimate consumer. For the purposes of the MN7610 Filing GRE considers the All Requirements members for forecasting and all other allocations are accounted for in the sales tabs of the Forecast Report.

ALL REQUIREMENTS FORECAST

The All Requirements (AR) forecast consists of multiple forecasts. The monthly class sales forecast is developed by modelling customers and average use and combining the results into the monthly AR system forecast. The AR Peak forecast is modeled separately and is dependent on the class sales forecast. The AR forecasts consist of demand and load for the following cooperatives.

- Arrowhead Electric Cooperative
- Benco Electric Cooperative
- Brown County Rural Electric Association
- Cooperative Light and Power
- Dakota Electric Association
- East Central Energy
- Goodhue County Cooperative Electric Association
- Itasca-Mantrap Cooperative Electrical Association
- Kandiyohi Power cooperative
- Lake County Power
- Lake Region Electric Cooperative
- McLeod Cooperative Power Association
- Mille Lacs Energy Cooperative
- North Itasca Electric cooperative
- Nobles Cooperative Electric
- Runestone Electric Association
- Stearns Electric Association
- Steele-Waseca Cooperative Electric
- Todd-Wadena Electric Cooperative

AR MONTHLY CLASS SALES FORECAST

This section describes the method used for each class forecast and their key assumptions. For each class, the monthly sales forecast is developed using an econometric or a Statistically Adjusted End-Use (SAE) model. The class models are described in *AR Models*. The modelled classes are defined using the AR cooperatives' Form 7 data which divides their sales into the following classes.

- Residential

- Seasonal
- Irrigation
- Small Commercial
- Large Commercial
- Street and Highway
- Public Authority
- Resale
- Own Use

Once the class forecasts are complete, the class forecasts are summed together for the system sales forecast.

The key drivers in the monthly sales models include weather data, economic data, and SAE data. The weather data is obtained from The Weather Company (WSI). The economic data are obtained from Woods and Poole Inc (Woods and Poole), and the SAE data are obtained from Itron Inc (Itron). The driver data and their derivations are described below.

MONTHLY WEATHER FORECAST

Hourly weather for Alexandria (AXN), Hibbing (HIB), Mason City (MCW), and Minneapolis (MSP) from January 1, 1995, through December 31, 2024, are acquired from WSI by GRE. These data are converted to monthly weather and used to calculate the normal weather forecast. The following steps are used to develop the weather data for each station.

1. **Daily Average Temperature**. Calculate daily average temperatures from the original hourly temperatures. The daily average temperature is the average of the 24-hourly values.
2. **Daily HDD and CDD**. Daily heating and cooling degree days (HDD and CDD) are calculated using different temperature reference points (i.e., 50, 55, 60, 65 degrees) and the daily average temperature.
3. **Monthly HDD and CDD**. Monthly HDDs and CDDs are calculated by summing the daily HDD and CDD values over the calendar month. Monthly HDDs and CDDs are used to estimate the sales models.
4. **Normal Monthly HDD and CDD**. Normal monthly HDDs and CDDs are calculated by averaging historical monthly HDDs and CDDs from 1992 through 2021. The Normal HDDs and CDDs are 30-year normal values.

System weather is the weighted average of the 4 weather stations. The weights are determined using a screening model to identify the relative impact of each weather station. The screening model is a neural network model estimated with daily data from 2020 through 2024. As an output, the neural network produces weather slopes for each station as first order derivatives. The weather station weights are calculated using the first order derivatives. Table 1 shows the weather stations weights.

TABLE 1: WEATHER STATION WEIGHTS

Weather Station	Weight

AXN	23%
HIB	18%
MCW	1%
MSP	58%

Within several models, multipart splines variables are used to model the non-linear response between sales and weather. Multipart splines variables weight together HDD and CDD variables with different temperature reference points into aggregate variables to avoid multicollinearity. The weights are developed using a system energy regression model estimated with daily data from January 2017 through December 2024. The relative sizes of the HDD and CDD coefficients are used to develop the weighting scheme.

Table 2 shows the weighting scheme. These weights show that the heating slope begins at 55°F and accelerates at 50°F. Similarly, the cooling slope begins at 60°F and accelerates through 70°F. The cooling slope declines at 80°F capturing the cooling saturation effect.

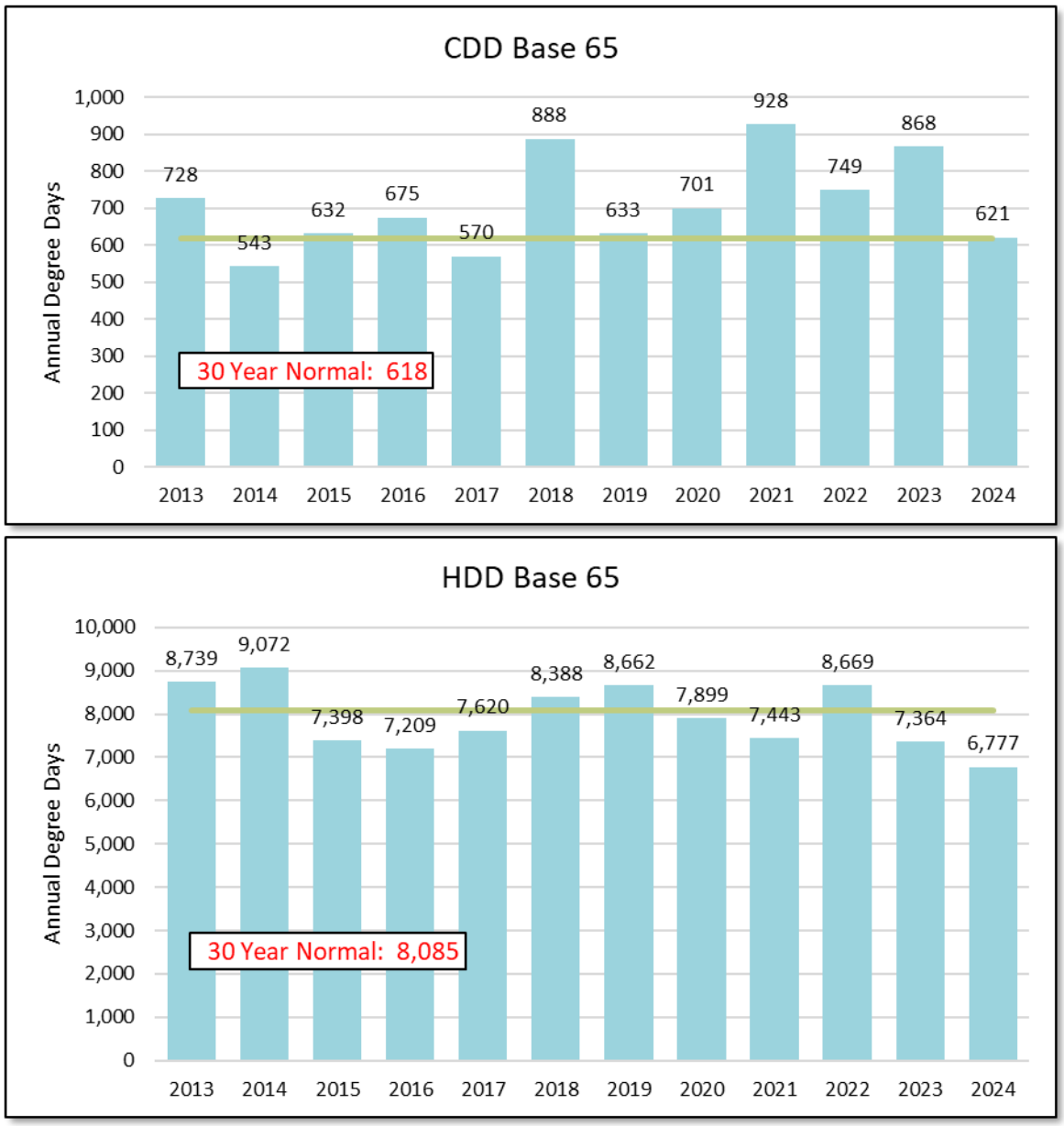
TABLE 2: WEIGHTED HDD AND CDD SPLINES

Variable	Spline	Weight
WtHDD	HDD Base 55°F	61%
	HDD Base 45°F	39%
WtCDD	CDD Base 60°F	7%
	CDD Base 65°F	42%
	CDD Base 70°F	31%
	CDD Base 80°F	-21%

The final system monthly weather contains both historical and normal HDD and CDD variables representing different temperature reference points and the weighted HDD and CDD results.

Figure 1 compares the recent historical (2013-2024) and normal (30-year average) weather results. This figure shows the HDD and CDD data with a temperature reference point of 65 degrees aggregated to annual values.

FIGURE 1: NORMAL HDD AND CDD COMPARISON



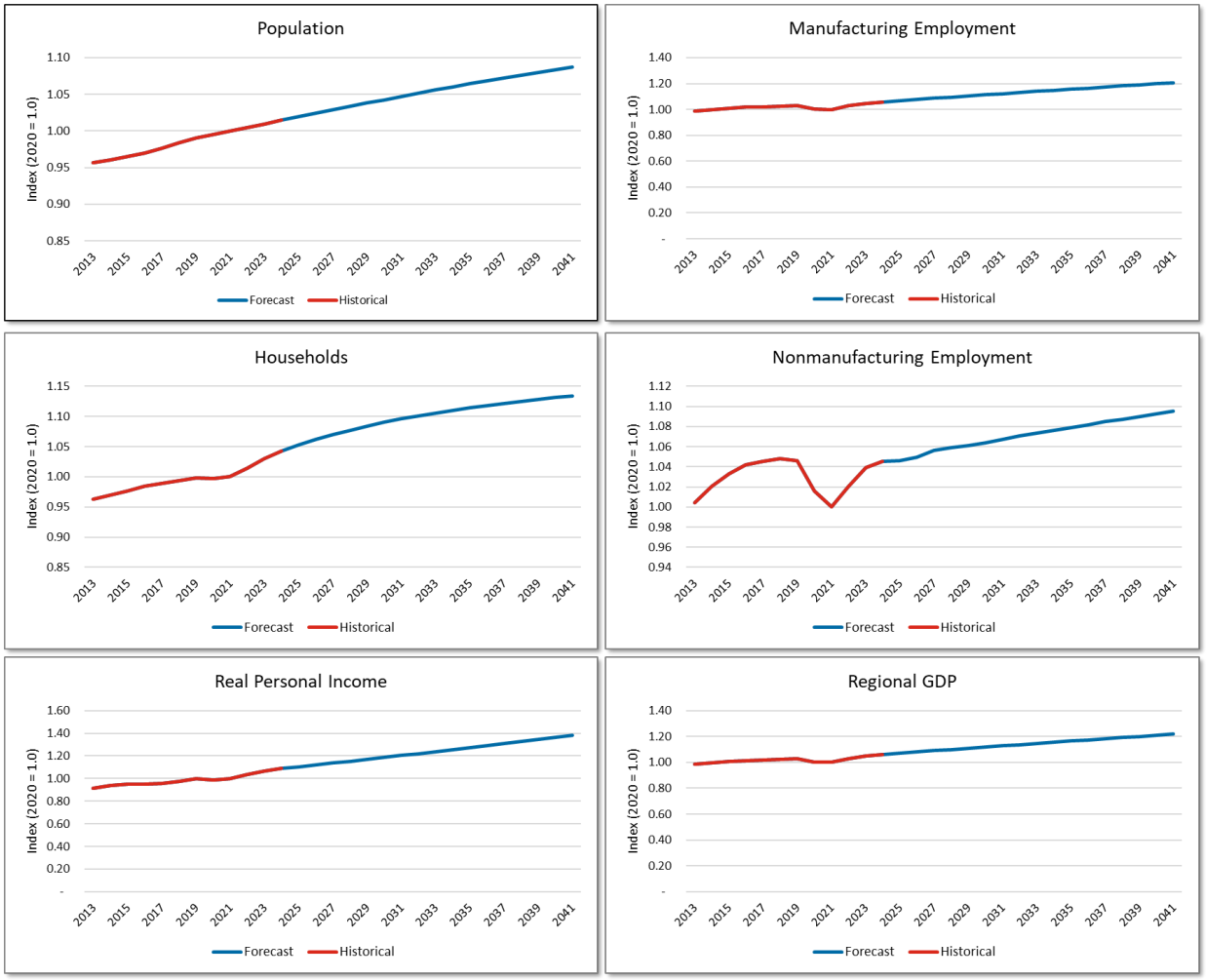
ECONOMIC FORECAST

The economic forecast is a primary driver of long-term growth in the class sales forecast. The economic forecast is obtained from Woods and Poole and reflects the economic conditions as of 2024. The economic data contains annual county-level data for multiple economic concepts. Woods and Poole largely viewed COVID to have short term impacts to the forecast and only showed minimum impacts to the long-term forecast. For the monthly sales forecast, the following economic concepts are used.

- Population
- Households
- Income
- Manufacturing Employment
- Nonmanufacturing Employment
- GDP

System economic data is developed by summing cooperative-level economic data. Cooperative economic data is developed by summing together a portion of the county data that are served by each cooperative. The portion of a county served by a cooperative is calculated using the ratio of 2022 residential customers in a county to 2022 households in the county. Figure 2 shows the historical and forecast economic data for the primary drivers used in the sales models. These data are converted to 1.0 based indices for comparative purposes.

FIGURE 2: ECONOMIC DRIVERS



END USE DATA

The SAE data captures energy efficiency changes for residential and commercial end-uses. The SAE data are provided by Itron and based on the Energy Information Administration's (EIA) 2022 Annual

Energy Outlook (AEO). The SAE data are applied to the residential, seasonal, small commercial, and large commercial class average use models.

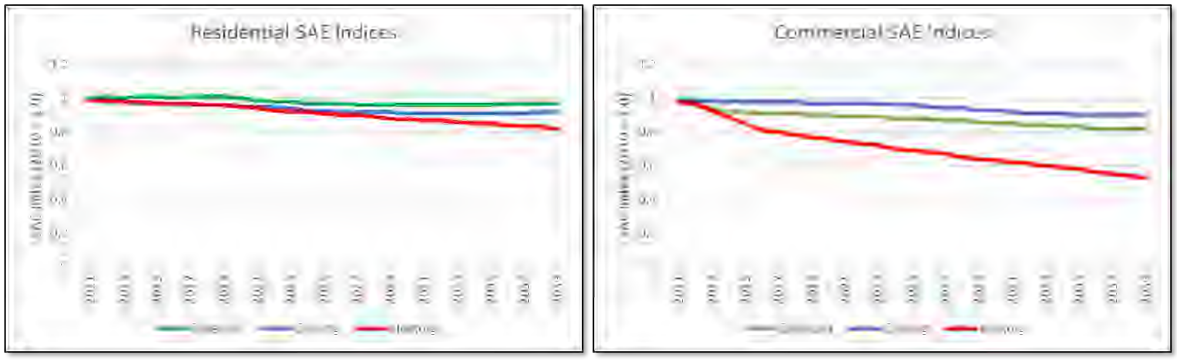
The SAE data are detailed end-use data derived from the EIA forecast for the northwest central census region and used to construct end-use intensities (kWh per household or kWh per square foot) that are then integrated into monthly heating, cooling, and base load model variables. These variables are then used to forecast residential and commercial sales using linear regression models. Using the constructed model variables, the forecast captures improvements in end-use efficiency driven by new standards, declining cost of high efficiency technology options, and availability of new end-use technologies. Table 3 shows the end-uses that are represented in the SAE data.

TABLE 3: SAE DATA: END USES

Residential	Commercial
▪ Resistance heating/furnaces ▪ Air-source heat pumps (heating) ▪ Ground-source heat pumps (heating) ▪ Secondary heating ▪ Central air conditioning ▪ Air-source heat pumps (cooling) ▪ Ground-source heat pumps (cooling) ▪ Room air conditioning ▪ Water heating ▪ Cooking ▪ 1st & 2nd refrigerators ▪ Freezers ▪ Dishwashers ▪ Clothes washers ▪ Clothes dryers ▪ TVs and related equipment ▪ Furnace fans ▪ Lighting ▪ Miscellaneous	▪ Heating ▪ Cooling ▪ Ventilation ▪ Water Heating ▪ Cooking ▪ Refrigeration ▪ Lighting ▪ Office Equipment ▪ Miscellaneous

Figure 3 shows in the SAE data converted to 1.0 based indices for comparative purposes. Generally, these indices capture a downward trend representing the improving energy efficiency of end-uses through adopted codes and standards.

FIGURE 3: SAE DRIVER DATA



SMEC LOAD ADOPTION

The Southern Minnesota Electrical Cooperative (SMEC) forecast consists of additional load that will be served by five AR cooperative members beginning in 2025. The additional load requirement results from the formation of SMEC. SMEC is formed by 12 electric distribution cooperatives as the single point of contact for the purchase of electric service in southern Minnesota from Alliant Energy. Five of the 12 distribution cooperatives are AR members of GRE. At the end of 2024, a supply agreement with Alliant Energy will be terminated and five All Requirement Members in SMEC will be required to serve this load. This forecast is accounted for in the following AR Models.

TABLE 4 SMEC LOAD FORECAST

Year	Res Cust	Res Sales	Sea Cust	Sea Sales	SCom Cust	SCom Sales	LCom Cust	LCom Sales	StHwy Cust	StHwy Sales	PA Cust	PA Sales	Own Sales	Peak
2025	2,269	23,571	91	1,560	581	18,581	1	16,141	15	234	10	306	1	25
2026	5,446	56,589	217	3,514	1,394	41,571	3	38,784	37	572	23	785	2	26
2027	5,445	56,589	215	3,495	1,394	41,571	3	38,784	37	571	23	785	2	26
2028	5,445	56,588	214	3,477	1,394	41,571	3	38,784	37	569	23	785	2	26
2029	5,445	56,588	213	3,458	1,394	41,571	3	38,784	37	568	23	785	2	26
2030	5,445	56,587	212	3,440	1,394	41,571	3	38,784	37	564	23	785	2	26
2031	5,445	56,586	211	3,421	1,394	41,571	3	38,784	37	559	23	785	2	26
2032	5,445	56,584	210	3,403	1,394	41,571	3	38,784	37	555	23	785	2	26
2033	5,445	56,583	209	3,385	1,394	41,571	3	38,784	37	552	23	785	2	26
2034	5,445	56,581	207	3,367	1,394	41,571	3	38,784	37	551	23	785	2	26
2035	5,445	56,579	206	3,350	1,394	41,571	3	38,784	37	550	23	785	2	26
2036	5,444	56,577	205	3,332	1,394	41,571	3	38,784	37	550	23	785	2	26
2037	5,444	56,575	204	3,315	1,394	41,571	3	38,784	37	550	23	785	2	26
2038	5,444	56,573	203	3,298	1,394	41,571	3	38,784	37	551	23	785	2	27
2039	5,444	56,572	202	3,282	1,394	41,571	3	38,784	37	553	23	785	2	27
2040	5,444	56,570	201	3,265	1,394	41,571	3	38,784	37	554	23	785	2	27

STATISTICALLY ADJUSTED END-USE MODEL

The traditional approach to forecasting monthly sales for a customer is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historic trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturations, dwelling square footage and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.

- Data for short-term models are often not sufficiently robust to estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$Use_m = a + b_1 XHeat_m + b_2 XCool_m + b_3 XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated usage levels can be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

Energy Use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month (since GRE used calendar month not billing cycle month sales data, the average number of days in the billing cycle are set equal to the number of days in each calendar month),
- Thermal integrity and footage of homes, and
- Average household size, household income, and energy price *(Energy prices are given as the moving average of GRE-specific real electricity prices)*.

The heating variable is represented as the product of annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

Where

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
- $HeatIndex_y$ is the annual index of heating equipment, and

- $HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), and building structural index (*Structural Index*). Formally, the equipment index is defined as:

$$HeatIndex_y = StructualIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} / Eff_{15}^{Type}\right)} \quad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2015 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{15} \times SurfaceArea_{15}} \quad (5)$$

Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average 25% two-story and 75% single-story. Given these assumptions, the approximate linear for surface area is:

$$Surface\ Area_y = 892 + 1.44\ X\ Footage_y \quad (6)$$

In Equation 4, 2015 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2015. In other years, rising saturation levels will drive the index up. This will be counteracted by higher efficiency levels, which will drive the index downward. The resulting ratio will be greater than one if saturation levels since 2015 have grown at a faster rate than efficiency gains. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times HeatShare_{15}^{Type} \quad (7)$$

These weights are referred to as Intensities. With these intensities, the HeatIndex value in 2015 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values. For electric heating equipment, the SAE spreadsheets contain equipment types: electric resistance furnaces/room units, electric space heating heat pumps, secondary electric space heating and furnace fans.

Efficiency Data

The efficiency for electric space heating heat pumps is given in terms of Heating Seasonal Performance Factor [BTU/Wh], the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh, and the efficiency for electric secondary space heating is given in UEC values (kWh/year). Historic values for the efficiency values are from the default SAE spreadsheets. Forecast values are from the 2022 AEO.

Heating system usage levels are impacted monthly by several factors, including weather, income levels, prices, and billing days. Using the REEPS default elasticity parameters, the estimate for space heating equipment usage levels is computed as follows:

$$HeatUse_{y,m} = \left(\frac{Bdays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{10}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_{y,m}}{Income_{09}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{09}}\right)^{-0.30} \quad (8)$$

Where

- BDays is the number of billing days in a year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days,
- WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the HDD spline,
- HDD is the annual heating degree days for 2010,
- Income is average real disposable income per household in month (m) and year (y), and
- Price is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year. The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in the economic driver changes, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about 0.985 (computed as 1.10 to the -.015 power).

CONSTRUCTING XCOOL

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month,
- Thermal integrity and footage of homes, and
- Average household income and energy price.

The cooling variable is represented as the produce of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \quad (9)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year ($_y$) and month ($_m$)
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructualIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \Big/ Eff_{15}^{Type} \right)} \quad (10)$$

Data values in 2015 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2015. In other years, rising saturation levels will drive the index up. This will be counteracted by higher efficiency levels, which will drive the index downward. The resulting ratio will be greater than one if saturation levels since 2015 have grown at a faster rate than efficiency gains. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times CoolShare_{15}^{Type} \quad (11)$$

With these weights, the CoolIndex value in 2015 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, there are 3 types: central air conditioning, space cooling heat pump, and room air conditioning. These values are derived using the method described under the construction of the space heating variables.

Like space heating, the air conditioning shares are calibrated to the GRE 2017 end-use equipment shares. The efficiency for space cooling heat pumps and central air conditioning (A/C) units given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and for room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted monthly by several factors, including weather, income levels, and prices. Using the REEPS default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{Bdays_{y,m}}{30.5} \right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{10}} \right) \times \left(\frac{HHSize_{y,m}}{HHSizeD_{09}} \right)^{0.25} \times \left(\frac{Income_{y,m}}{Income_{09}} \right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{09}} \right)^{-0.30} \quad (12)$$

Where

- *WgtCDD* is the weighted number of cooling degree days in a (y) and month (m). This is constructed as the weighted sum of the CDD spline, and
- CDD is the annual degree days for 2010

By construction, the CoolUse variable has an annual sum that is close to one in the base year. The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in the economic driver changes.

CONSTRUCTING XOTHER

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by

- Appliance and equipment saturation levels,
- Appliance efficiency levels,
- Average number of days in the billing cycle for each month, and
- Average real income and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y} \times OtherUse_{y,m} \quad (13)$$

The first term on the right-hand side of the expression (*OtherEqpIndex* $_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtheRUSe*) captures the impact in price, income, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE Spreadsheets. Apart from water heating, the end-use indices are combined into an aggregate stock index (NonHVAC) that is then inputted into the MetricND project file.

The equipment index for water heaters (EWHeat) and appliances are given in Equation 14 and 15, respectively.

$$EWHeatIndex_{y,m} = Weight \times \frac{\left({Sat_y}/{Eff_y}\right)}{\left({Sat_{15}}/{Eff_{15}}\right)} \times MoMult_m \quad (14)$$

$$ApplianceIndex_{y,m} = Weight \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}}\right)}{\left(Sat_{15}^{Type} \Big/ \frac{1}{UEC_{15}^{Type}}\right)} \times MoMult_m^{Type} \quad (15)$$

Where

- Weight is the weight for each appliance type,
- Sat represents the fraction of households who own appliance type,
- MoMultm is a monthly multiplier for the appliance type in month (m),
- Eff is the average operating efficiency for water heaters, and
- UEC is the unit energy consumption for appliances.

The index for other uses is derived by summing the above equations:

$$NonHVAC_{y,m} = EWHeatIndex_{y,m} + ApplianceIndex_{y,m} \quad (16)$$

The index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration. As with heating and cooling, the weights are defined as follows,

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times EqupmentShare_{15}^{Type} \quad (17)$$

The appliance saturation and efficiency trends data are presented on the Shares and Efficiencies tabs of the SAE spreadsheets. The efficiency for electric water heating units is given in terms of Efficiency Factor (%). UEC's are used as a proxy for efficiency change in other appliances and are given in terms of kWh/year.

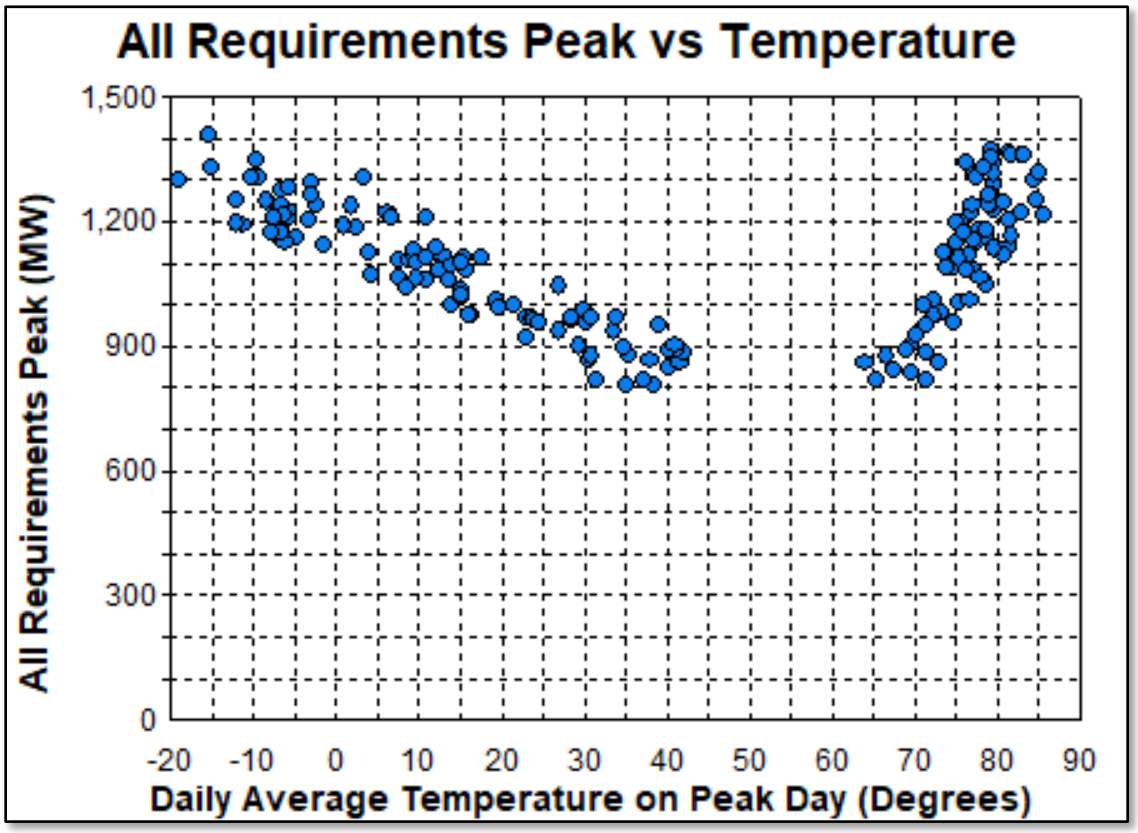
$$OtherUse_{y,m} = \left(\frac{Bdays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_{y,m}}{Income_{09}}\right)^{0.10} \times \left(\frac{Price_{y,m}}{Price_{09}}\right)^{-0.15} \quad (18)$$

In this expression, the elasticities on income and real price are computed from the REEPS default values.

AR PEAK FORECAST

The monthly system peak forecast uses an econometric model based on historical monthly peak day events from January 2011 through April 2025. The historical dataset is obtained from the historical system weather data and the AR hourly system loads. Figure 4 shows the historical system monthly peaks plotted against the daily average temperature on the monthly peak day. This figure shows strong linear relationships between the monthly peaks and their peak producing weather.

FIGURE 4: HISTORICAL AR PEAKS AND TEMPERATURE



The peak model is described in Section 0. The peak model consists of two main drivers: sales and weather. The next sections describe the main drivers of the peak model.

Sales Forecast

Historical and forecast sales drivers are obtained from the monthly class modelling process as described in *AR Models*. The sales forecast is decomposed into heating, cooling, and baseload components based on the sales models' coefficients. By using the forecast sales, the peak model captures the changing impact of energy efficiency and the growth from the economic forecast.

Peak Weather Forecast

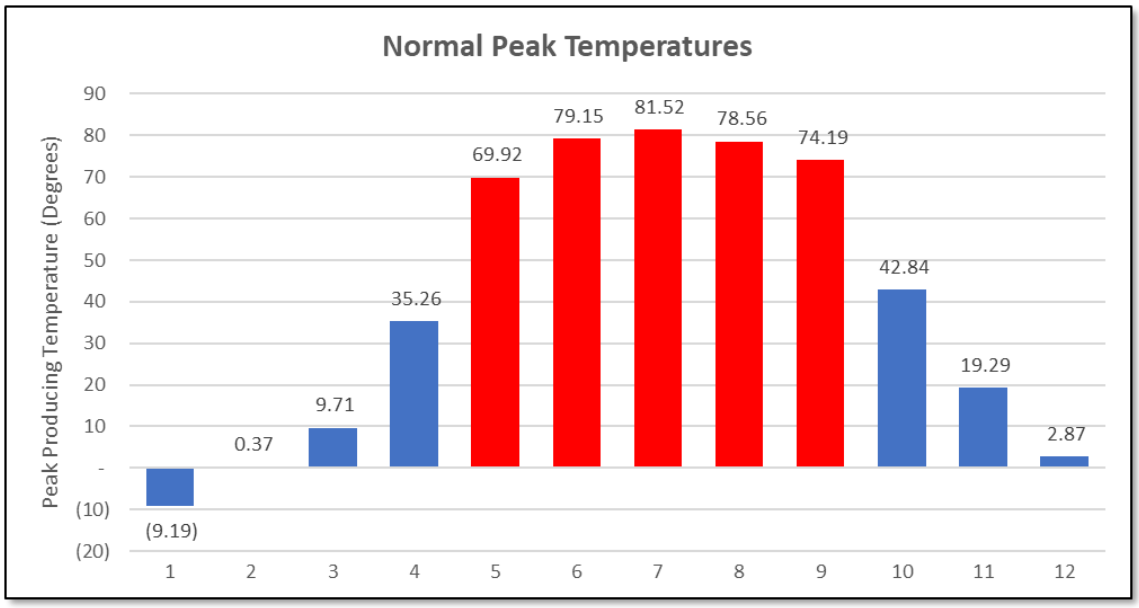
The peak weather forecast (normal peak weather) is obtained by averaging the monthly peak producing weather at the time of the monthly system peak. The following steps are used to develop the normal peak weather.

1. **Monthly Peak Weather Conditions**. Identify the daily average temperature on the monthly peaks from 2009 through 2024.
2. **Normal Monthly Peak Weather**. The normal peak weather is the average of historical peak weather conditions over the prior 15 years (2009-2024). For example, the March peak weather is the average of the 15 historical March peak producing temperatures.
3. **Correct Shoulder Month Weather**. Shoulder month peaks may be driven by hot or cold weather. For instance, April peaks are driven by hot weather in 2 of the 15 historical years.

For normal peak weather in April, May and October, the normal weather is modified by removing historical years from the average that do not match the primary weather effect. In April, the predominate peak weather effect is heating. As a result, the cooling peak weather is removed from the April normal weather calculation. May is designated as a cooling month, and October is designated as a heating month.

4. **Correct Seasonal Peak**. Because January and July are considered the seasonal peaks, their normal values are replaced using the seasonal peak averages. The seasonal peaks are the historical average of the temperatures on the seasonal annual peaks. Figure 5 shows the normal peak temperatures for each month. The summer peak temperatures are shown in red represent peaks driven by hot weather. The winter peak temperatures are shown in blue and represent peaks driven by cold weather.

FIGURE 5: NORMAL PEAK TEMPERATURES



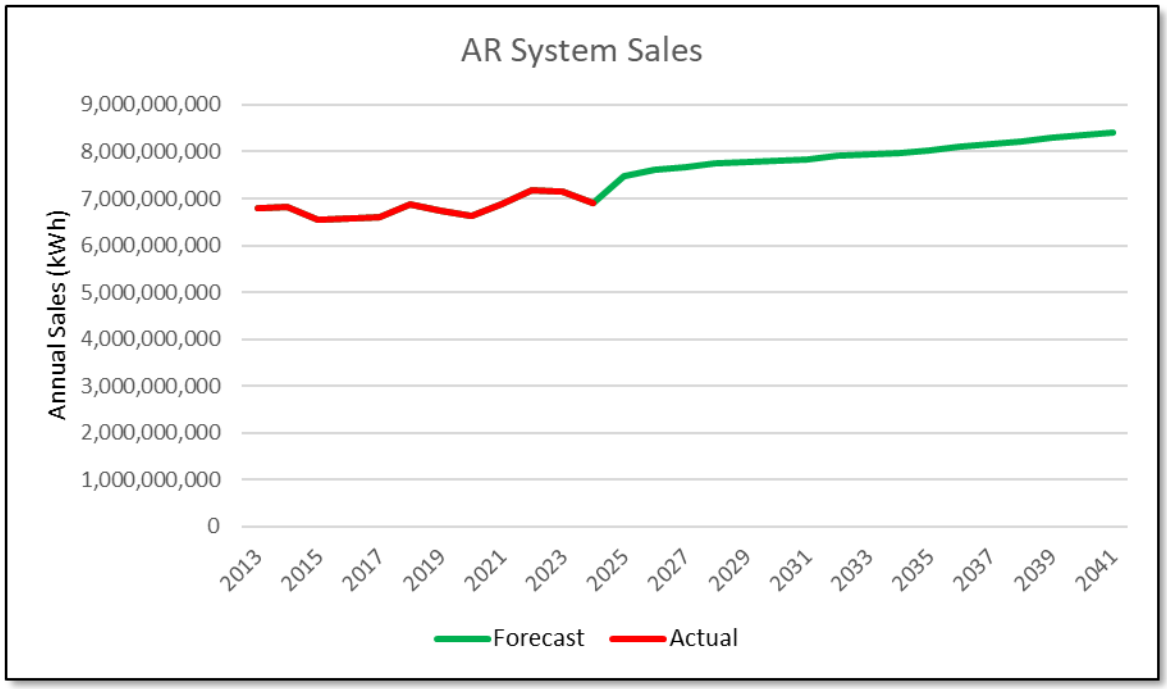
SYSTEM FORECAST SUMMARY

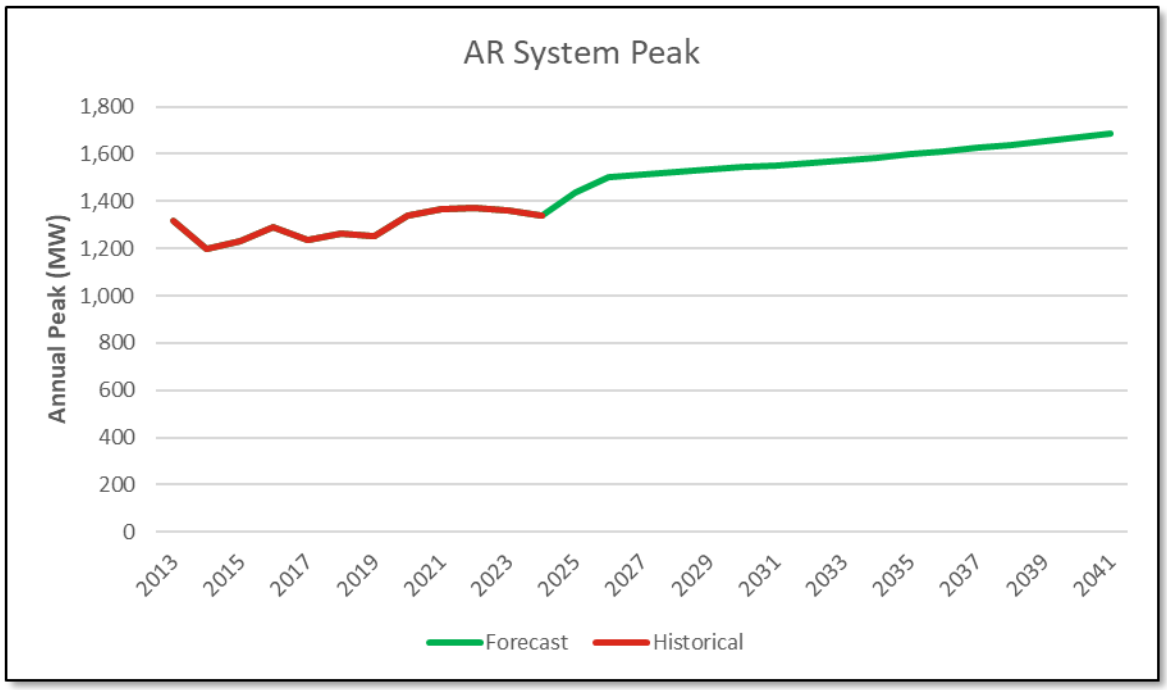
System forecast consists of the all the components forecasted as described before. The total system grows from 7,485,064,428 kWh in 2025 to 8,366,699,039 kWh in 2040 with an average annual growth rate (2025-2040) of 0.75%. The system peak is consistent with the energy forecast with average annual growth rate (2024-2040) of 1.01% (summer peak). Table 4 and Figure 6 show the All Requirements forecast including historical data from 2013-2024.

TABLE 5: ANNUAL SALES AND PEAK (ALL REQUIREMENTS)

Year	AR Sales (MWh)	AR Coincident Peak (MW)
2013	6,797,477	1,316
2014	6,830,669	1,200
2015	6,557,888	1,229
2016	6,581,508	1,288
2017	6,604,841	1,237
2018	6,868,658	1,263
2019	6,738,316	1,254
2020	6,639,619	1,340
2021	6,870,391	1,366
2022	7,167,104	1,370
2023	7,152,349	1,361
2024	6,913,293	1,340
2025	7,485,064	1,437
2026	7,624,504	1,502
2027	7,677,864	1,514
2028	7,740,182	1,525
2029	7,771,397	1,536
2030	7,808,546	1,544
2031	7,847,255	1,553
2032	7,903,420	1,564
2033	7,932,902	1,574
2034	7,983,542	1,585
2035	8,039,047	1,597
2036	8,114,014	1,612
2037	8,159,083	1,625
2038	8,224,141	1,640
2039	8,290,253	1,655
2040	8,366,699	1,670
5YR CAGR (2025,2030)	**0.85%**	**1.45%**
10YR CAGR (2025,2035)	**0.72%**	**1.06%**
15YR CAGR (2025,2040)	**0.75%**	**1.01%**

FIGURE 6: SCENARIOS: ANNUAL SALES AND PEAK (ALL REQUIREMENTS)





AR MODELS

The AR forecast is developed using statistical models for each class (e.g., residential, seasonal). The statistical models are regression models and are developed in MetrixND. This section describes the statistical models and their results.

RESIDENTIAL SALES FORECAST AND MODELS

The Residential class consists of all AR cooperative Residential sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. Data is complete for all AR cooperatives through July 2024. The Residential sales forecast is modelled with two models - a customer model and an average use (i.e., Use-Per Customer, or UPC) model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models captures both the class growth based on a changing number of customers (Customer Model) and usage changes based on end-use information (UPC Model).

RESIDENTIAL CUSTOMER MODEL

The Customer Model is a regression model estimated with monthly historical data from January 2012 through July 2024. Table 5 shows the Customer Model specification and Table 6 shows the Customer Model statistics.

TABLE 6: RESIDENTIAL CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	-169301.09	6462.49	-26.197
Household Index	465187.69	6090.59	76.378
Year2016	-4152.67	556.22	-7.466
Year2017	-3683.70	554.93	-6.638
Year2018	-2777.46	555.11	-5.003
Covid	3078.82	417.36	7.377

TABLE 7: RESIDENTIAL CUSTOMER MODEL STATISTICS

Statistics	Residential Customer Model
Estimation	1/2012 – 7/2024
R^2	0.978
Adj. R^2	0.977
MAPE	0.43%
DW	0.112

The residential model is driven by households and incorporates four binary adjustments. The variables included in the model are described below.

- **Household Index.** This variable is the household forecasts.
- **Binary Adjustments**. The binary adjustments variables are **Year2016**, **Year2017**, **Year2018** and **COVID**. The **COVID** binary variable captures the impact of COVID during 2020 and 2021. The **Year2016**, **Year2017** and **Year2018** binary variables capture short term level shifts in 2016, 2017 and 2018.

RESIDENTIAL UPC MODEL

The UPC Model is an SAE model estimated with historical data from January 2010 through July 2024. Table 7 shows the UPC Model specification and Table 8 shows the UPC Model statistics.

The SAE model contains end-use information for heating, cooling, and base load technologies from Itron's 2022 SAE West North Central region. The following data are included in the model.

- **End-Use Efficiencies.** End-use efficiencies by technology type are based on Energy Information Administration (EIA) data.
- **End-Use Saturations and Intensities.** End-use saturations and intensities by technology type are based on EIA data.
- **Economic data.** Historical and forecasted population and household income data are based on Woods and Poole's 2024 forecasts.
- **Energy Prices.** Class energy prices are based on historical revenues and energy consumption. The energy price forecast is held constant in real dollars.

TABLE 8: RESIDENTIAL UPC MODEL

Variable	Coefficient	StdErr	T-Stat
XHeat	1.198	0.031	39.182
XCool	0.890	0.044	20.196
XOther	0.769	0.008	94.292
Year2010	61.987	14.138	4.385
May	-57.611	13.767	-4.185

TABLE 9: RESIDENTIAL UPC MODEL STATISTICS

Statistics	Residential UPC Model
Estimation	1/2010 – 7/2024
R2	0.935
Adj. R2	0.934
MAPE	3.57%
DW	1.175

The UPC Model includes the SAE variables (XHeat, XCool, and XOther) and two binary adjustments.

- **SAE Variables.** The SAE variables are **XHeat**, **XCool**, and **XOther**. **XHeat** captures the heating response and includes the effects of heating technology efficiencies, saturations, thermal shell, weather, price, income, and household size. **XCool** captures the cooling response and captures the effects of cooling technology efficiencies, saturations, thermal shell, weather, price, income, and household size. **XOther** captures the baseload response for all non-heating and non-cooling technologies.
- **Binary Adjustments**. Two binary adjustments variables, **Year2010** and **May**, capture shifts in the underlying data. Year2010 captures the recovery from the 2008-2009 recession. May captures a recurring decline in May usage.

RESIDENTIAL BASE SALES FORECAST

The Residential sales forecast is the product of the customer and UPC forecasts. The annual sales forecast, customer forecast, and use-per-customer forecast are shown in Figure 7, Figure 8, and Figure 9. Table 9 shows the annual sales, customer, and average use forecast with average growth rates.

FIGURE 7: RESIDENTIAL SALES FORECAST (ACTUAL AND FORECAST)

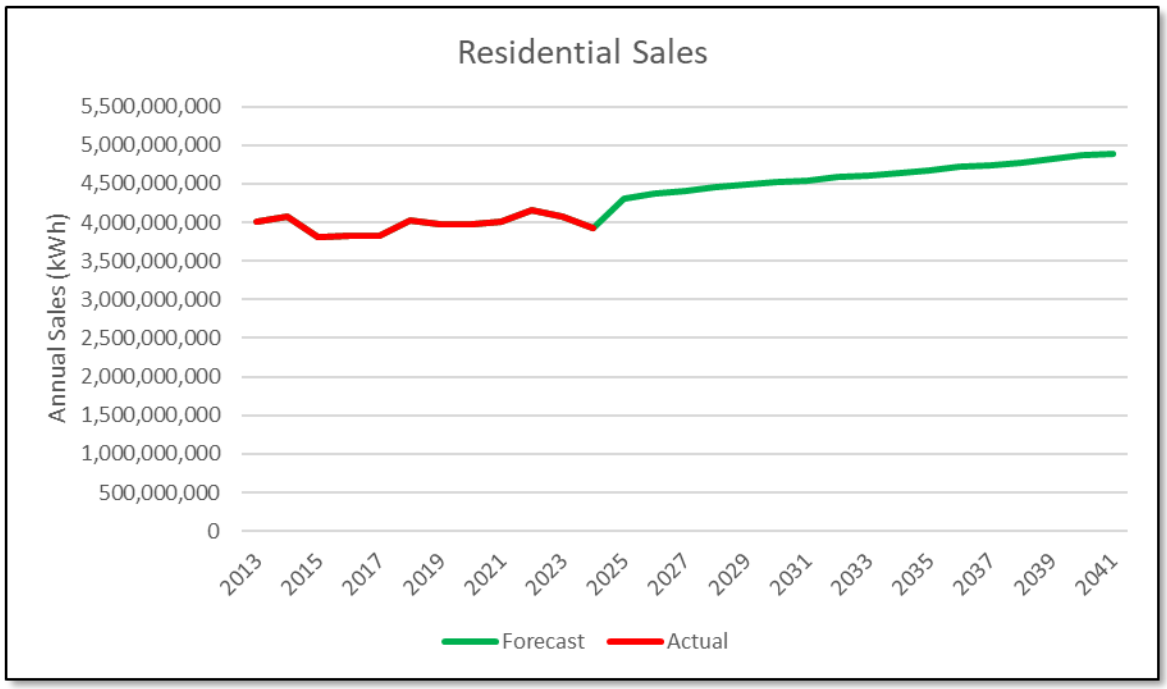


FIGURE 8: RESIDENTIAL CUSTOMER FORECAST (ACTUAL AND FORECAST)

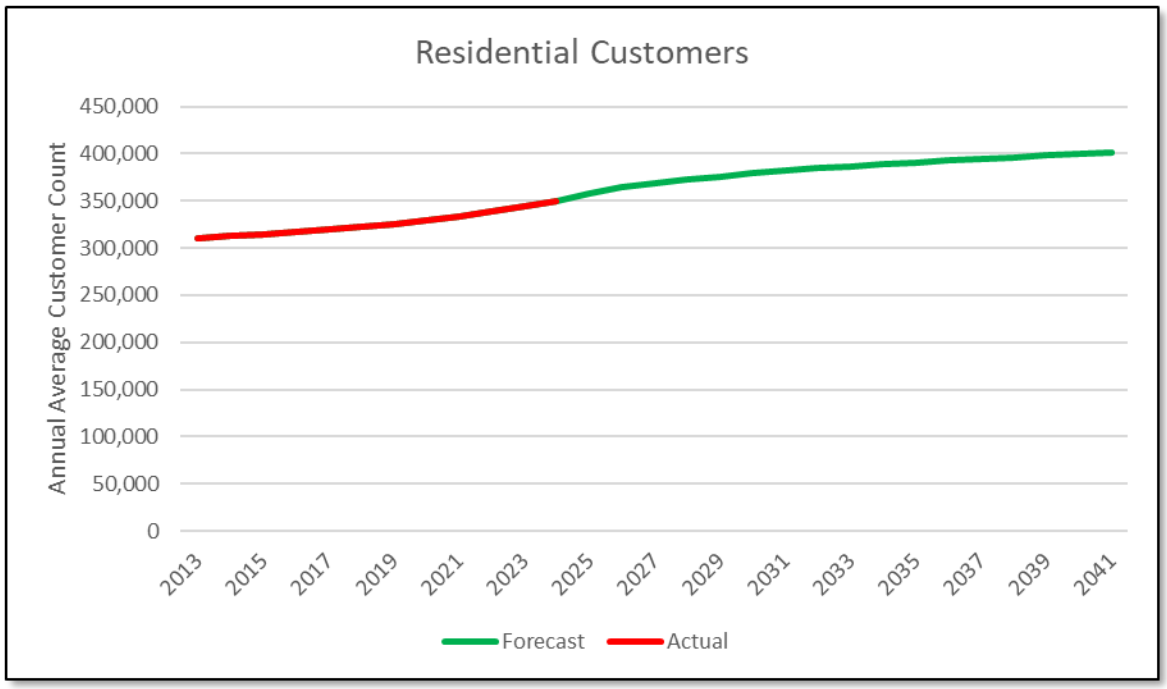


FIGURE 9: RESIDENTIAL UPC FORECAST (ACTUAL AND FORECAST)

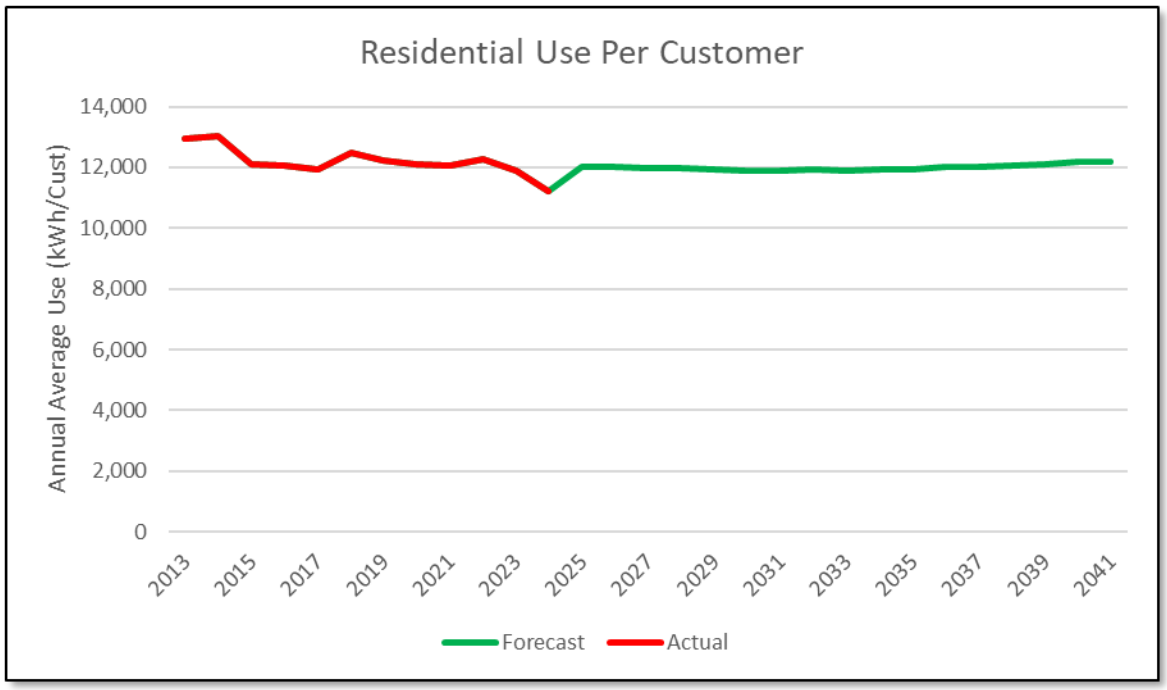


TABLE 10: RESIDENTIAL SALES FORECAST SUMMARY

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	4,298,260,261	9.38%	357,172	2.04%	12,034	7.19%
2026	4,377,242,990	1.84%	364,714	2.11%	12,002	-0.27%
2027	4,412,801,789	0.81%	368,739	1.10%	11,967	-0.29%
2028	4,463,636,032	1.15%	372,481	1.01%	11,984	0.14%
2029	4,483,698,699	0.45%	375,938	0.93%	11,927	-0.47%
2030	4,514,428,303	0.69%	379,081	0.84%	11,909	-0.15%
2031	4,543,330,604	0.64%	381,919	0.75%	11,896	-0.11%
2032	4,587,058,424	0.96%	384,476	0.67%	11,931	0.29%
2033	4,602,616,370	0.34%	386,793	0.60%	11,899	-0.26%
2034	4,635,319,349	0.71%	388,934	0.55%	11,918	0.16%
2035	4,669,705,320	0.74%	390,947	0.52%	11,945	0.22%
2036	4,720,537,400	1.09%	392,846	0.49%	12,016	0.60%
2037	4,741,506,687	0.44%	394,631	0.45%	12,015	-0.01%
2038	4,778,634,239	0.78%	396,305	0.42%	12,058	0.36%
2039	4,815,697,102	0.78%	397,873	0.40%	12,104	0.38%
2040	4,865,218,833	1.03%	399,358	0.37%	12,183	0.65%
Average (2014,2024)		**-0.15%**		**1.10%**		**-1.23%**
Average (2025,2040)		**1.36%**		**0.83%**		**0.53%**
5YR CAGR (2025,2030)		**0.99%**		**1.20%**		**-0.21%**
10YR CAGR (2025,2035)		**0.83%**		**0.91%**		**-0.07%**
15YR CAGR (2025,2040)		**0.83%**		**0.75%**		**0.08%**

SEASONAL SALES MODEL

The Seasonal class consists of all AR cooperative Seasonal sales. The Seasonal class is composed of seasonal residential customers. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The seasonal sales forecast is modelled with two models, a Customer Model and a UPC Model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models captures both the class growth based on a changing number of customers (Customer Model) and usage changes based on end-use information (UPC Model).

SEASONAL CUSTOMER MODEL

The Customer Model is a regression model estimated with monthly historical data from January 2013 through July 2024. Table 10 shows the Customer Model specification and Table 11 shows the Customer Model statistics.

TABLE 11: SEASONAL CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	9143.129	908.296	10.066
Population Index	26429.025	872.282	30.299
JanToMar2013	993.138	107.891	9.205
Apr2013	-3307.049	181.627	-18.208
Year2024Plus	-2838.176	74.743	-37.972

TABLE 12: SEASONAL CUSTOMER MODEL STATISTICS

Statistics	Seasonal Customer Model
Estimation	1/2013 – 12/2022
R^2	0.944
Adj. R^2	0.942
MAPE	0.34%
DW	0.271

The Seasonal model is driven by population and incorporates binary adjustments in 2013. The variables included in the model are described below.

- **Population Index.** This variable is the population forecasts. Because seasonal customers are primarily seasonal residential customers, population growth captures customer count growth.
- **Binary Adjustments**. The binary adjustments variables are **JanToMar2013** and **Apr2013**. The **JanToMar2013** and **Apr2013** binary variables correct for anomalous data in the early part of 2013.
- **Data Shift Variable**. Data shift variable, **Year2024Plus**, captures a sustained decrease in customers seen in 2024 and continuing through the forecast period.

SEASONAL UPC MODEL

The UPC Model is an SAE model estimated with historical data from January 2009 through July 2024. Table 12 shows the UPC Model specification and Table 13 shows the UPC Model statistics.

TABLE 13: SEASONAL UPC MODEL

Variable	Coefficient	StdErr	T-Stat
XHeat	0.524	0.021	24.753
XCool	0.378	0.027	14.063
XOther	0.257	0.004	68.752
FebMar2016Trinary	150.952	16.664	9.059
Jul	52.798	8.242	6.406
Winter	45.865	6.458	7.102
Year2017Plus	31.607	4.523	6.988
Year2020Plus	16.161	5.006	3.228

TABLE 14: SEASONAL MODEL STATISTICS

Statistics	Seasonal UPC Model
Estimation	1/2009 – 12/2022
R2	0.947
Adj. R2	0.945
MAPE	4.66%
DW	1.289

Like the Residential UPC model, the Seasonal UPC Model includes the SAE variables (XHeat, XCool, and XOther). In addition to the SAE variables, the model includes variables to correct for anomalous data, seasonal patterns, and data shifts.

- **SAE Variables.** The SAE variables are **XHeat**, **XCool**, and **XOther**. **XHeat** captures the heating response and includes the effects of heating technology efficiencies, saturations, thermal shell, weather, price, income, and household size. **XCool** captures the cooling response and captures the effects of cooling technology efficiencies, saturations, thermal shell, weather, price, income, and household size. **XOther** captures the baseload response for all non-heating and non-cooling technologies.
- **Trinary Variable**. One trinary variable, **FebMar2016Trinary,** captures opposing data shifts in the underlying data. This variable captures the February 2016 increase in usage which is offset by the March 2016 decrease in usage.
- **Seasonal Variables**. Two seasonal variables (**Jul** and **Winter**) capture recurring monthly patterns in the usage. **Jul** captures a regular increase in usage in the month of July. **Winter** captures a regular increase in usage from November through February.

- **Binnary Shift Variables**. Binary shift variables, **Year2017Plus and Year2020Plus**, captures a sustained increase in usage beginning in 2017 and again in 2020 continuing through the forecast period.

Seasonal Base Sales Forecast

The Seasonal sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 10, and Figure 12. Table 14 shows the annual sales, customer, and average use forecast with average growth rates.

Figure 10: Seasonal Sales Forecast (Actual and Forecast)

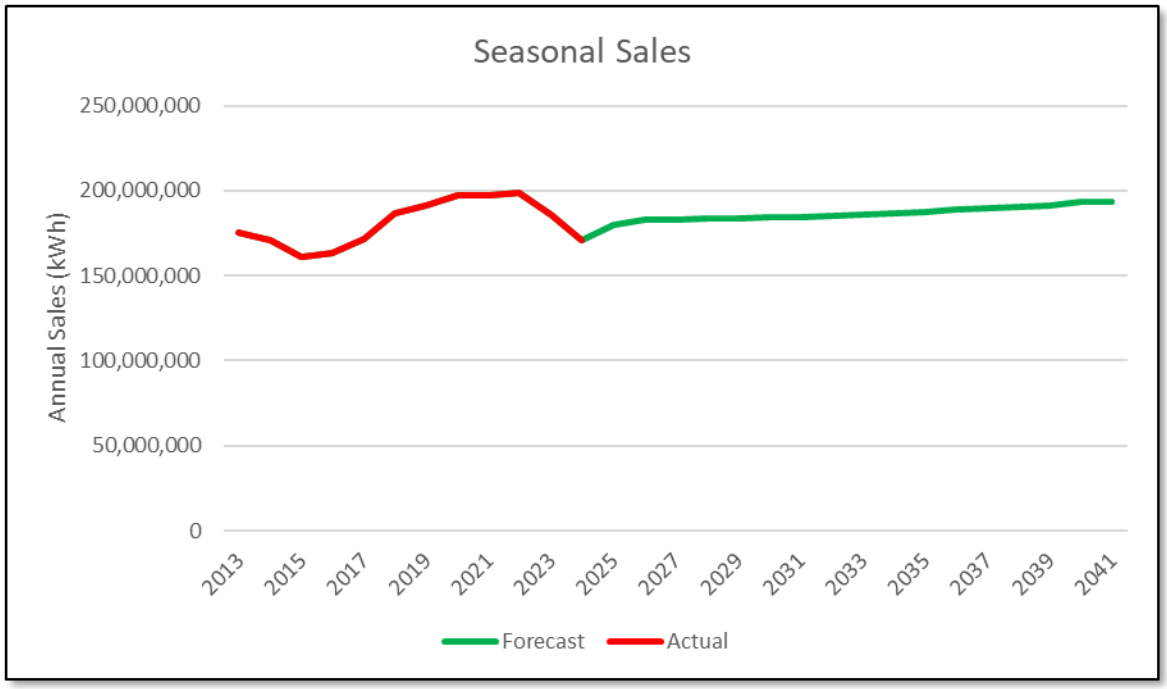


FIGURE 11: SEASONAL CUSTOMER FORECAST (ACTUAL AND FORECAST)

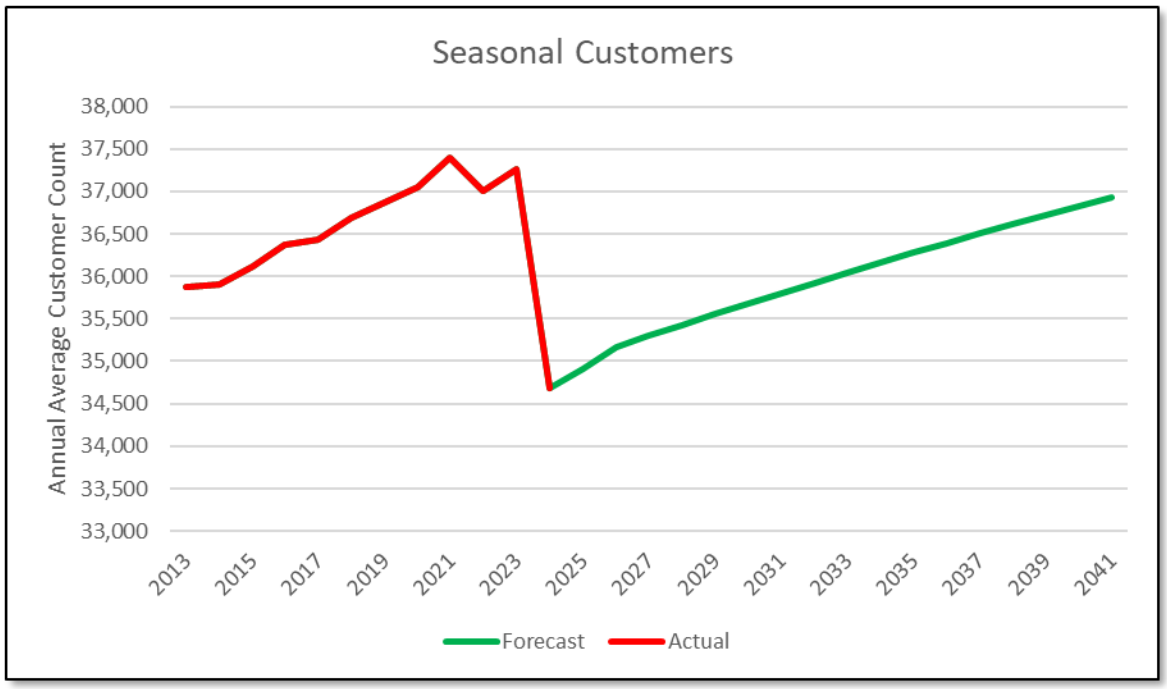


FIGURE 12: SEASONAL UPC FORECAST (ACTUAL AND FORECAST)

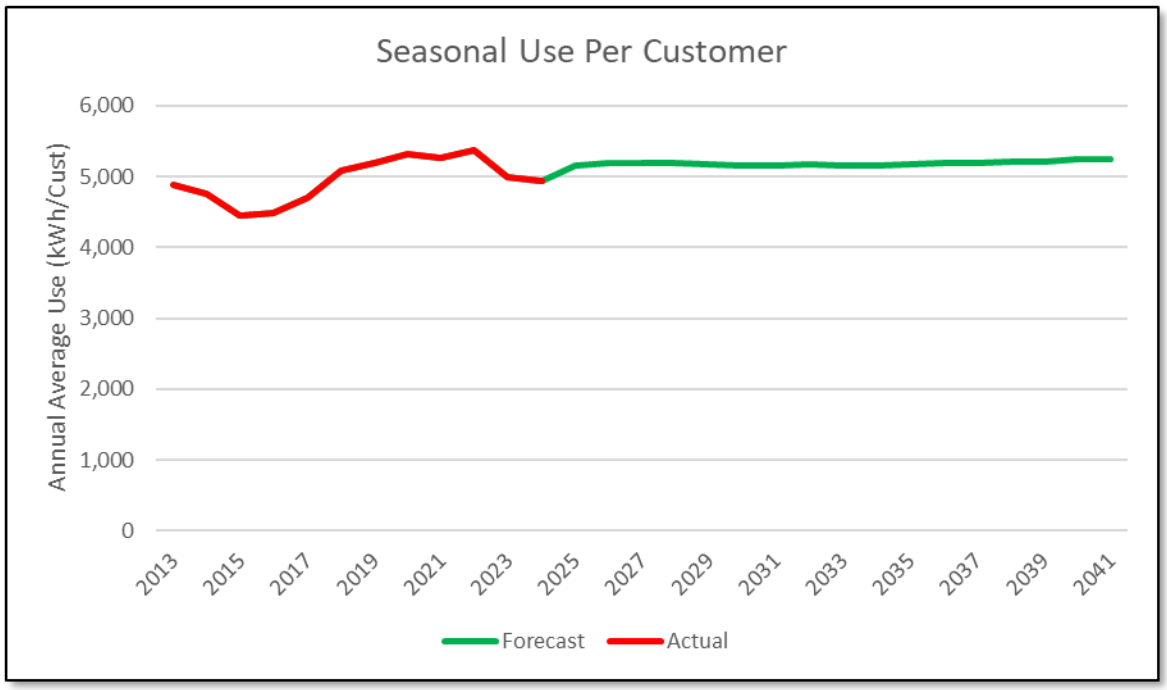


TABLE 15: SEASONAL SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	180,257,646	5.42%	34,907	0.64%	5,164	4.75%
2026	182,734,532	1.37%	35,166	0.74%	5,196	0.63%
2027	182,944,930	0.12%	35,298	0.37%	5,183	-0.26%
2028	183,801,381	0.47%	35,427	0.37%	5,188	0.10%
2029	183,675,947	-0.07%	35,554	0.36%	5,166	-0.43%
2030	184,063,465	0.21%	35,680	0.35%	5,159	-0.14%
2031	184,505,442	0.24%	35,804	0.35%	5,153	-0.11%
2032	185,564,207	0.57%	35,926	0.34%	5,165	0.23%
2033	185,715,593	0.08%	36,046	0.33%	5,152	-0.25%
2034	186,520,808	0.43%	36,164	0.33%	5,158	0.11%
2035	187,420,188	0.48%	36,280	0.32%	5,166	0.16%
2036	188,915,686	0.80%	36,394	0.31%	5,191	0.48%
2037	189,406,412	0.26%	36,504	0.30%	5,189	-0.04%
2038	190,480,896	0.57%	36,612	0.30%	5,203	0.27%
2039	191,581,465	0.58%	36,718	0.29%	5,218	0.29%
2040	193,145,327	0.82%	36,823	0.29%	5,245	0.53%
Average (2014,2024)		**-0.09%**		**-0.28%**		**0.19%**
Average (2025,2040)		**0.77%**		**0.37%**		**0.39%**
5YR CAGR (2025,2030)		**0.42%**		**0.44%**		**-0.02%**
10YR CAGR (2025,2035)		**0.39%**		**0.39%**		**0.00%**
15YR CAGR (2025,2040)		**0.46%**		**0.36%**		**0.10%**

IRRIGATION SALES MODEL

The Irrigation class consists of all AR cooperative Irrigation sales. The Irrigation class is composed of agriculture customers who use electricity through the summer season. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The irrigation sales forecast is modelled with two models - a Customer Model and a UPC Model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models captures both the class growth based on a changing number of customers (Customer Model) and usage changes based on seasonal patterns (UPC Model).

IRRIGATION CUSTOMER MODEL

The Customer Model is a regression model estimated with monthly historical data from January 2015 through July 2024. Table 15 shows the Customer Model specification and Table 16 shows the Customer Model statistics.

TABLE 16: IRRIGATION CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	-571.702	71.182	-8.032
May	490.031	8.326	58.856
Jun	492.919	8.327	59.195
Jul	498.685	8.329	59.875
Aug	491.113	8.712	56.372
Sep	489.188	8.711	56.155
Oct	488.560	8.711	56.085
Residential Customers	0.010	0.000	44.024

TABLE 17: IRRIGATION CUSTOMER MODEL STATISTICS

Statistics	Irrigation Customer Model
Estimation	1/2015 – 7/2024
R^2	0.992
Adj. R^2	0.992
MAPE	0.69%
DW	0.391

The Irrigation model is driven by residential customers, incorporates season adjustments, and includes binary adjustments. The variables included in the model are described below.

- **Residential Customers.** This variable is the residential customer count forecast using the residential customer model described in Section 0.
- **Seasonal Adjustments**. Six binary adjustments variables (**May**, **Jun**, **Jul**, **Aug**, **Sep**, and **Oct**) capture the seasonal increase in customers. During the summers, the customer count increases by almost 500 customers.

IRRIGATION UPC MODEL

The UPC Model is regression model estimated with historical data from January 2014 through July 2024. Table 17 shows the UPC Model specification and Table 18 shows the UPC Model statistics.

TABLE 18: IRRIGATION UPC MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	-28.601	98.815	-0.289
Jul	2049.109	429.058	4.776
Aug	2426.830	372.116	6.522
CDD65	23.205	1.487	15.605

TABLE 19: IRRIGATION UPC MODEL STATISTICS

Statistics	Irrigation UPC Model
Estimation	1/2014 – 12/2022
R2	0.901
Adj. R2	0.899
MAPE	173.67%
DW	1.187

The UPC Model captures the summer energy usage pattern and forecasts a constant average use through the forecast period. While the model shows a strong correlation between average use and the model variables (i.e., R^2=0.901), the high errors result from the highly uncertain beginning and ending of the irrigation season and the level of irrigation necessary for the season. The following variables are used in the model.

- **CDD65.** The class's weather response is modelled using the CDD variable with a temperature reference point of 65 degrees.
- **Seasonal Variables.** Two seasonal adjustment variables (**Jul** and **Aug**) capture the increased electric use above the **CDD65** variable impact.

IRRIGATION BASE SALES FORECAST

The Irrigation sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 13, Figure 14, and Figure 15. Table 19 shows the annual sales, customer, and average use forecast with average growth rates.

FIGURE 13: IRRIGATION SALES FORECAST (ACTUAL AND FORECAST)

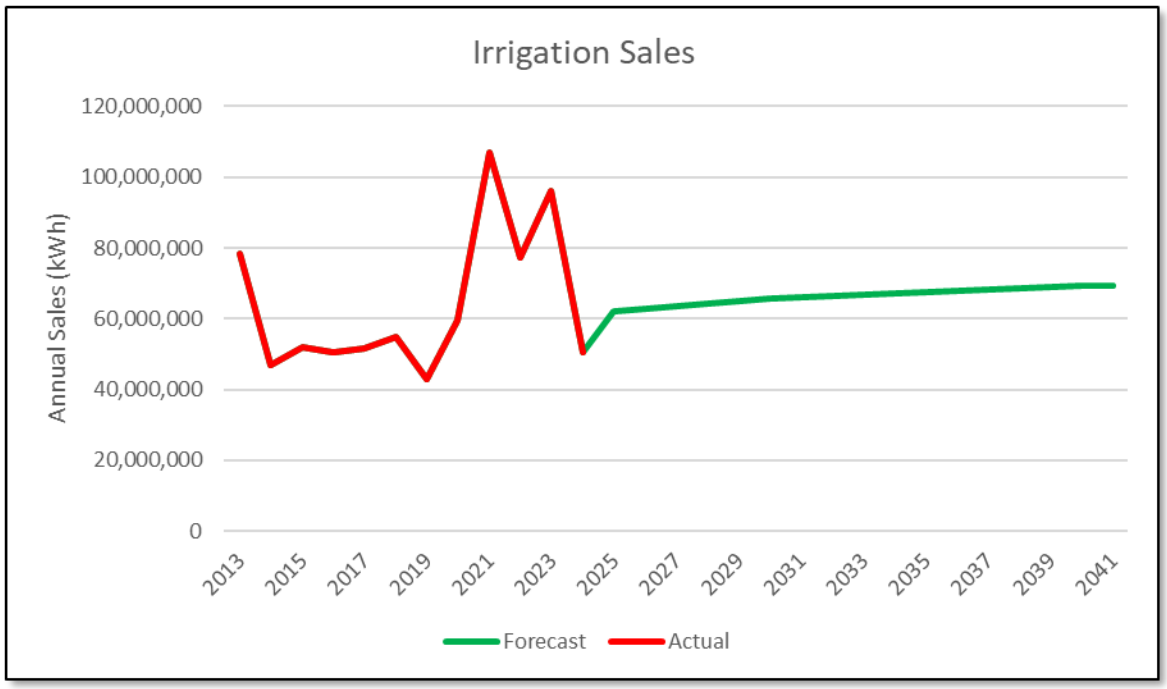


FIGURE 14: IRRIGATION CUSTOMER FORECAST (ACTUAL AND FORECAST)

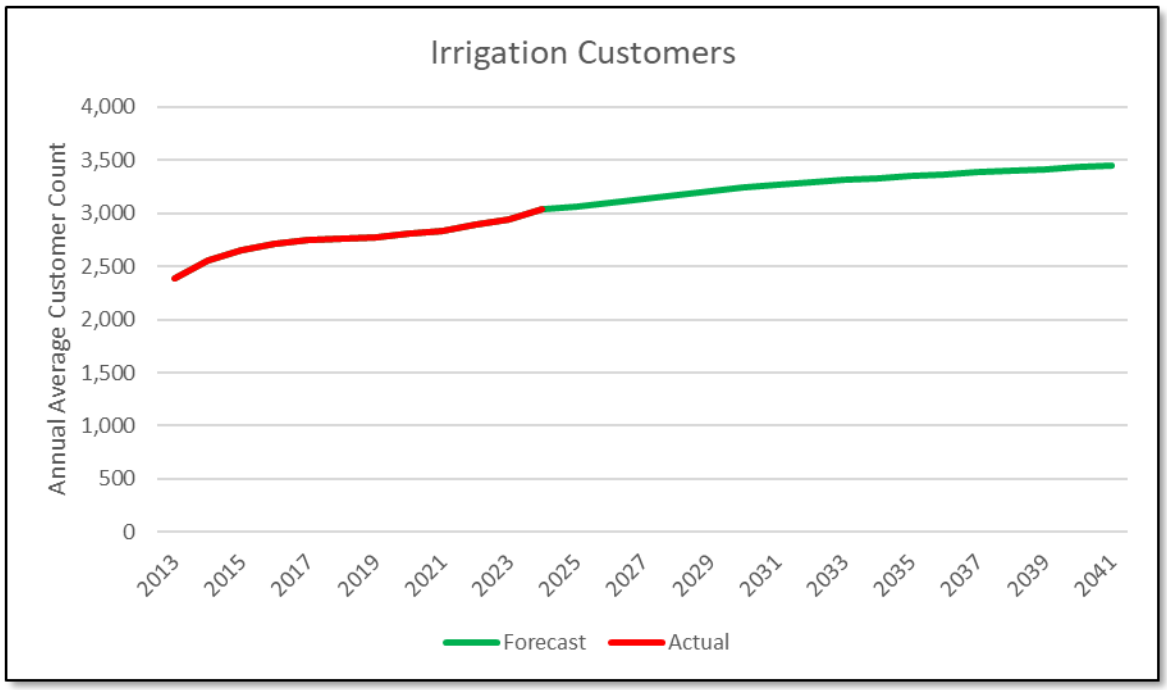


FIGURE 15: IRRIGATION UPC FORECAST (ACTUAL AND FORECAST)

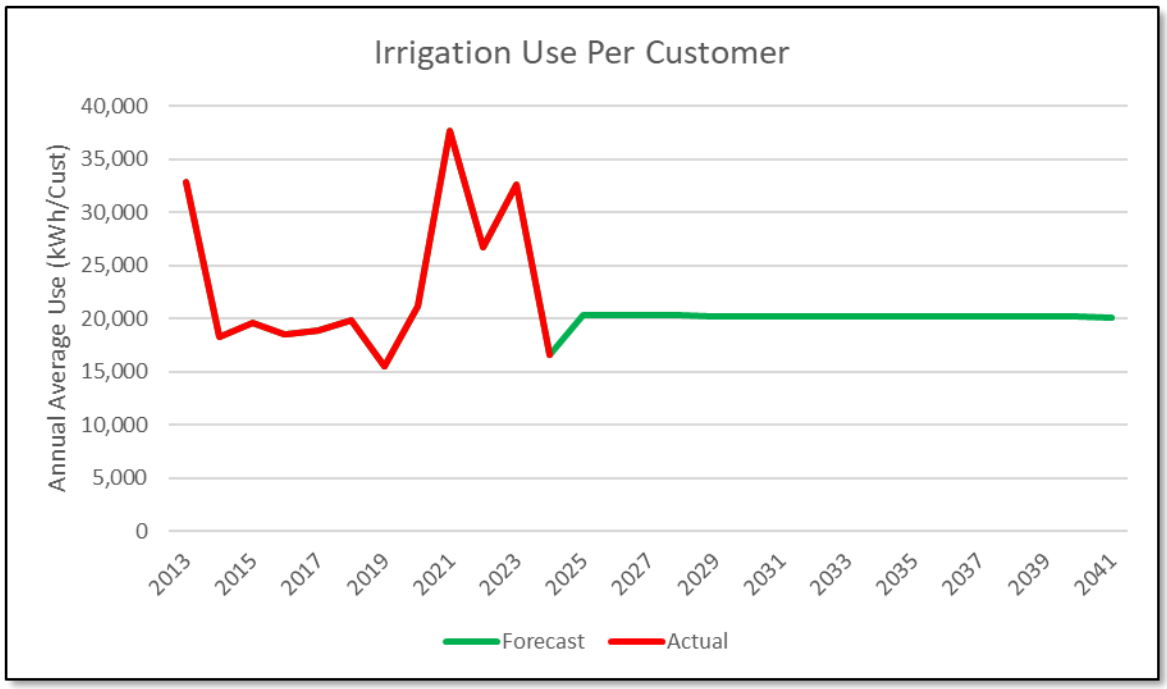


TABLE 20: IRRIGATION SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	62,060,331	-23.06%	3,059	0.51%	20,289	22.52%
2026	62,983,062	0.82%	3,100	1.36%	20,314	0.12%
2027	63,700,348	0.53%	3,139	1.24%	20,294	-0.10%
2028	64,367,656	0.50%	3,175	1.14%	20,276	-0.09%
2029	64,983,049	0.47%	3,207	1.04%	20,260	-0.08%
2030	65,542,470	0.43%	3,237	0.93%	20,245	-0.07%
2031	66,047,283	0.40%	3,265	0.84%	20,232	-0.07%
2032	66,502,105	0.37%	3,289	0.75%	20,220	-0.06%
2033	66,914,582	0.34%	3,311	0.67%	20,210	-0.05%
2034	67,296,362	0.32%	3,331	0.62%	20,200	-0.05%
2035	67,655,479	0.30%	3,351	0.58%	20,192	-0.04%
2036	67,994,496	0.28%	3,369	0.54%	20,184	-0.04%
2037	68,312,852	0.26%	3,386	0.51%	20,176	-0.04%
2038	68,611,273	0.25%	3,402	0.47%	20,170	-0.03%
2039	68,891,047	0.24%	3,417	0.44%	20,163	-0.03%
2040	69,156,177	0.23%	3,431	0.41%	20,157	-0.03%
Average (2014,2024)		**2.01%**		**2.27%**		**0.07%**
Average (2025,2040)		**2.13%**		**0.75%**		**1.37%**
5YR CAGR (2025,2030)		**1.10%**		**1.14%**		**-0.04%**
10YR CAGR (2025,2035)		**0.87%**		**0.92%**		**-0.05%**
15YR CAGR (2025,2040)		**0.72%**		**0.77%**		**-0.04%**

SMALL COMMERCIAL SALES MODEL

The Small Commercial class consists of all AR cooperative Small Commercial sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Small Commercial sales forecast is modelled with two models, a Customer Model and a UPC Model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models capture both the class growth based on a changing number of customers (Customer Model) and usage changes based on end-use information (UPC Model).

SMALL COMMERCIAL CUSTOMER MODEL

The Customer Model is a regression model estimated with historical data from January 2011 through July 2024. Table 20 shows the Customer Model specification and Table 21 shows the Customer Model statistics.

TABLE 21: SMALL COMMERCIAL CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	7003.293	1190.927	5.881
GDP	15225.135	1060.422	14.358
Year2011	441.738	124.879	3.537
Year2016Plus	658.453	87.807	7.499
Year2020	1386.322	100.216	13.833
Year2021	1716.523	105.756	16.231
Year2022Plus	1439.376	129.326	11.130
Year2024Plus	-522.779	138.329	-3.779

TABLE 22: SMALL COMMERCIAL CUSTOMER MODEL STATISTICS

Statistics	Small Commercial Customer Model
Estimation	1/2011 – 12/2022
R^2	0.974
Adj. R^2	0.973
MAPE	0.90%
DW	0.262

The customer model is driven by gross domestic product and incorporates binary adjustments. The variables included in the model are described below.

- **Gross Domestic Product Index.** The GDP index is the historical and forecast GDP for MN.
- **Binary Adjustments.** Three binary shifts are capture accelerating customer counts. These binary shift variables are **Year2011, Year2020, Year2021, and**.
- **Data Shift Variable**. Data shift variables**, Year2016Plus**, **Year2022Plus** and **Year2024Plus**, captures a sustained shift in customers seen in corresponding year and continuing through the forecast period.

SMALL COMMERCIAL UPC MODEL

The UPC Model is an SAE model estimated with historical data from January 2008 through July 2024. The SAE model applies the same theoretical foundation as the Residential SAE model but modified for commercial end-use information. Table 22 shows the UPC Model specification and shows the UPC Model statistics.

The Small Commercial SAE model contains end-use information for heating, cooling, and base load technologies from Itron's 2022 SAE West North Central region. The model includes the following data.

- **End-use Saturations and Efficiencies.** End-use saturations and efficiencies by technology type are based on Energy Information. Administration (EIA) data.
- **Economic data.** Historical and forecast nonmanufacturing employment trends are based on Woods and Poole's forecast.
- **Energy Prices.** Price is based on historical revenue and energy consumption. The energy prices are held constant in real dollars through the forecast period.

TABLE 23: SMALL COMMERCIAL UPC MODEL

Variable	Coefficient	StdErr	T-Stat
XHeat	2941.291	325.065	9.048
XCool	1392.299	148.899	9.351
XOther	353.169	2.911	121.336
Year2009	-559.192	44.296	-12.624
Year2010	-552.081	44.046	-12.534
Year2011	-442.858	43.715	-10.131
Year2020Plus	-529.025	43.609	-12.131
Jan	-237.260	23.536	-10.081
Feb	61.112	48.910	1.249
Mar	-69.851	44.585	-1.567
Apr	-155.290	39.424	-3.939
May	-226.756	39.419	-5.752

TABLE 24: SMALL COMMERCIAL UPC MODEL STATISTICS

Statistics	Small Commercial UPC Model
Estimation	1/2008 – 12/2022
R2	0.795
Adj. R2	0.782
MAPE	2.94%
DW	0.872

The UPC Model includes SAE variables (XHeat, XCool, and XOther), annual binary variables, seasonal binary variables, and a binary shift. These variables are described below.

- **SAE Variables.** The SAE variables are **XHeat**, **XCool**, and **XOther**. **XHeat** captures the heating response and includes the effects of heating technology efficiencies, saturations, price, and nonmanufacturing employment. **XCool** captures the cooling response and captures the effects of cooling technology efficiencies, saturations, price, and nonmanufacturing employment. **XOther** captures the baseload response for all non-heating and non-cooling technologies.
- **Annual Binary Variables.** Three annual binary variables (**Year2009**, **Year2010**, and **Year 2011**) adjust the model for the 2008 recession and recovery.
- **Seasonal Binary Variables.** Five seasonal binary variables (**Jan** through **May**) capture additional seasonal usages not included in the SAE variables.
- **Binary Shift Variable**. Data shift variable **Year2020Plus**, captures a sustained shift in average usage seen in the corresponding year and continuing through the forecast period.

Small Commercial Base Sales Forecast

The Small Commercial sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 16, Figure 17, and Figure 18. Table 24 shows the annual sales, customer, and average use forecast with average growth rates.

FIGURE 16: SMALL COMMERCIAL SALES FORECAST (ACTUAL AND FORECAST)

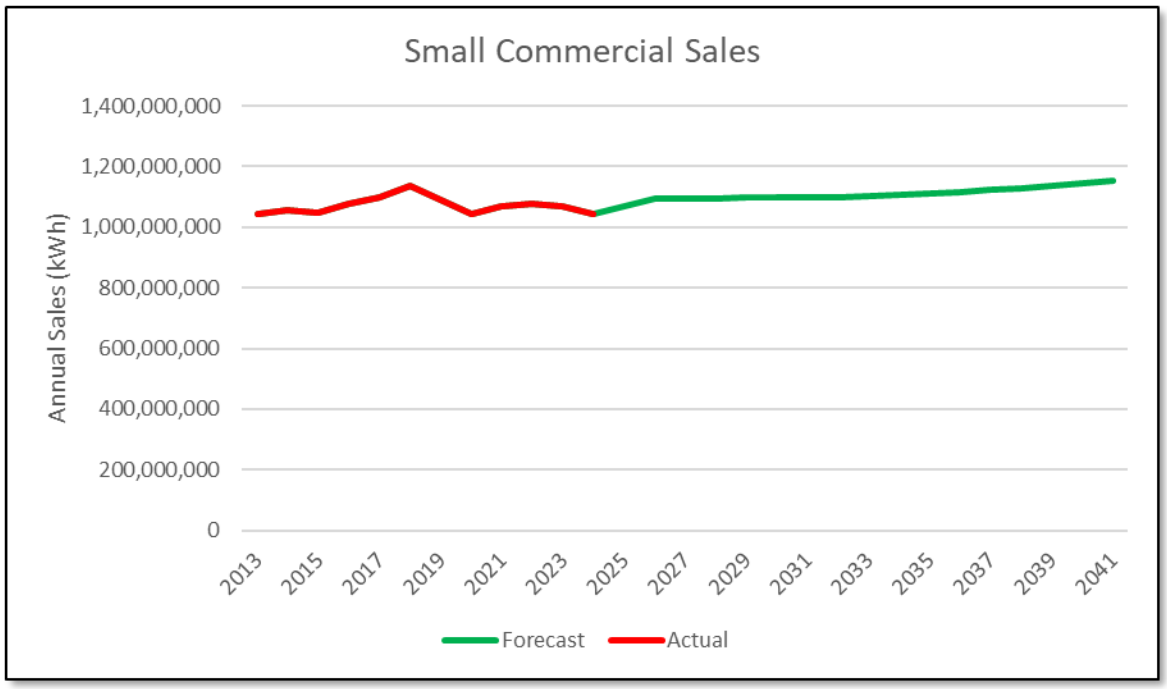


FIGURE 17: SMALL COMMERCIAL CUSTOMER FORECAST (ACTUAL AND FORECAST)

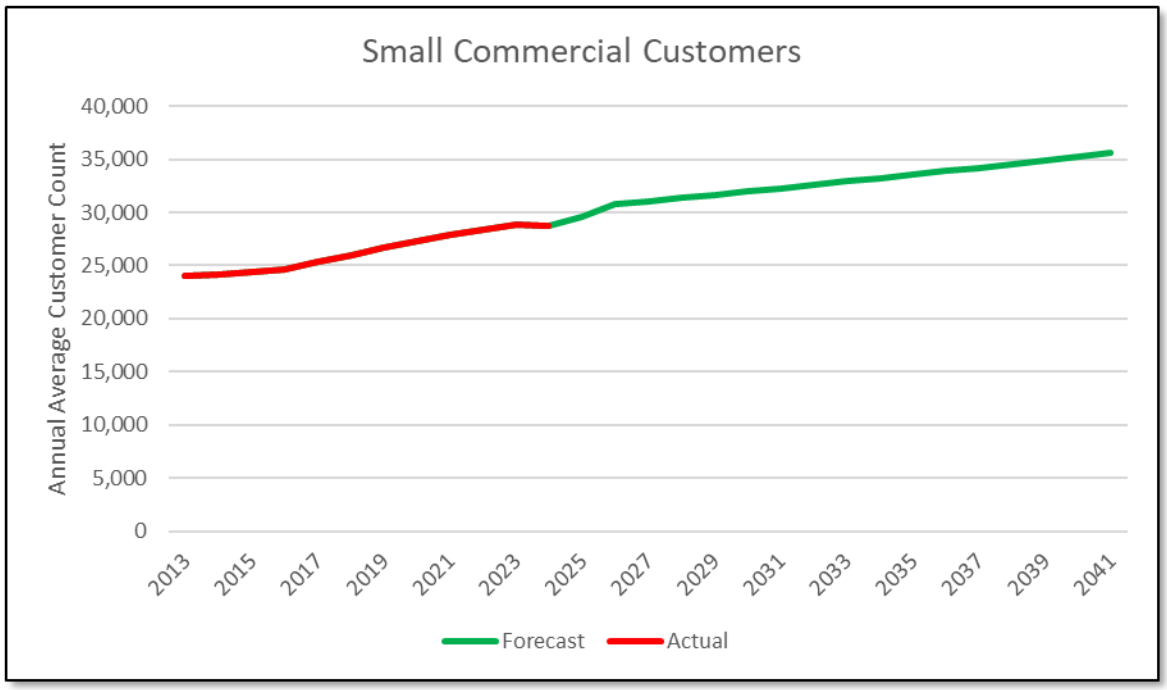


FIGURE 18: SMALL COMMERCIAL UPC FORECAST (ACTUAL AND FORECAST)

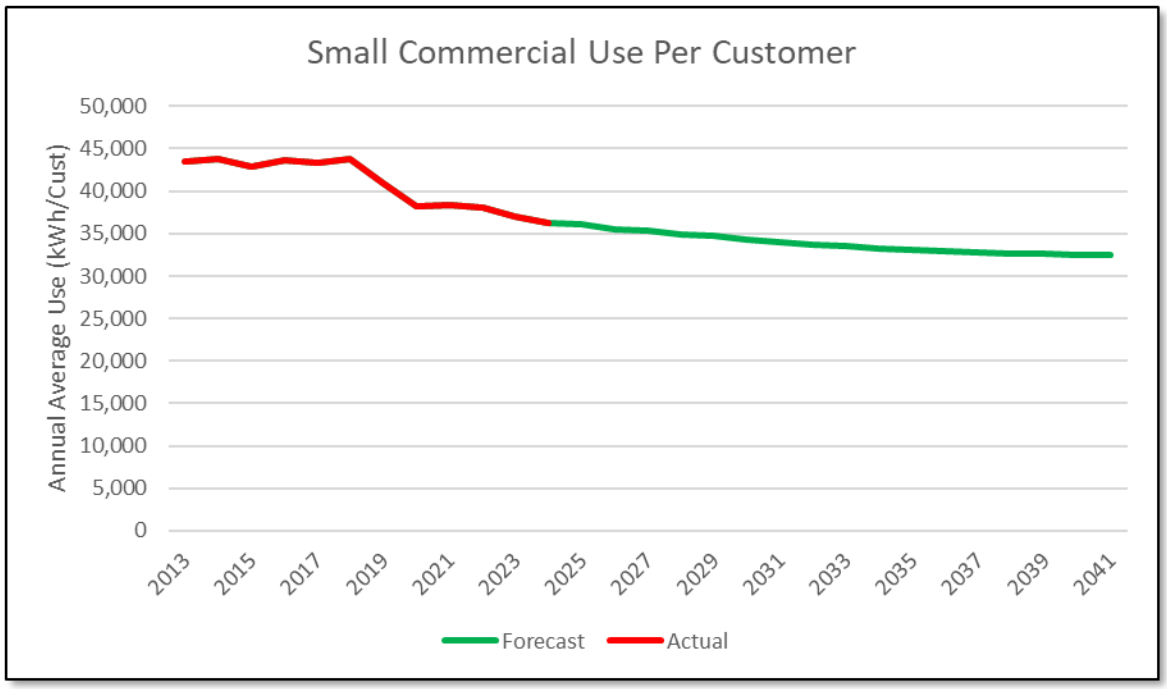


TABLE 25: SMALL COMMERCIAL SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	1,068,856,118	2.50%	29,617	3.15%	36,089	-0.64%
2026	1,092,846,302	2.24%	30,730	3.76%	35,563	-1.46%
2027	1,094,498,563	0.15%	31,031	0.98%	35,272	-0.82%
2028	1,095,481,413	0.09%	31,333	0.97%	34,963	-0.88%
2029	1,097,636,453	0.20%	31,639	0.98%	34,693	-0.77%
2030	1,097,044,094	-0.05%	31,950	0.98%	34,337	-1.03%
2031	1,097,547,461	0.05%	32,262	0.98%	34,020	-0.92%
2032	1,098,658,785	0.10%	32,577	0.98%	33,725	-0.87%
2033	1,101,114,101	0.22%	32,895	0.98%	33,473	-0.75%
2034	1,104,972,004	0.35%	33,218	0.98%	33,265	-0.62%
2035	1,109,919,257	0.45%	33,544	0.98%	33,089	-0.53%
2036	1,115,800,146	0.53%	33,873	0.98%	32,940	-0.45%
2037	1,122,109,231	0.57%	34,206	0.98%	32,804	-0.41%
2038	1,129,769,572	0.68%	34,543	0.98%	32,706	-0.30%
2039	1,137,876,850	0.72%	34,882	0.98%	32,620	-0.26%
2040	1,144,970,943	0.62%	35,225	0.98%	32,504	-0.36%
Average (2014,2024)		**0.03%**		**1.64%**		**-1.57%**
Average (2025,2040)		**0.59%**		**1.29%**		**-0.69%**
5YR CAGR (2025,2030)		**0.52%**		**1.53%**		**-0.99%**
10YR CAGR (2025,2035)		**0.38%**		**1.25%**		**-0.86%**
15YR CAGR (2025,2040)		**0.46%**		**1.16%**		**-0.70%**

LARGE COMMERCIAL SALES MODEL

The Large Commercial class consists of all AR cooperative Large Commercial sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Large Commercial sales forecast is modelled with two models, a Customer Model and a UPC Model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models captures both the class growth based on a changing number of customers (Customer Model) and usage changes based on end-use information (UPC Model).

LARGE COMMERCIAL CUSTOMER MODEL

The Customer Model is a regression model estimated with historical data from January 2013 through July 2024. Table 25 shows the Customer Model specification and Table 26 shows the Customer Model statistics.

TABLE 26: LARGE COMMERCIAL CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	-2758.375	257.946	-10.694
Manufacturing Employment Index	5396.477	239.745	22.509
Regional GDP Index	-67.485	19.889	-3.393
Year2013	-86.257	16.734	-5.155
Year2014	335.926	21.736	15.455
Year2024Plus	172.727	11.459	15.074
COVID	-2758.375	257.946	-10.694

TABLE 27: LARGE COMMERCIAL CUSTOMER MODEL STATISTICS

Statistics	Large Commercial Customer Model
Estimation	1/2013 – 7/2024
R^2	0.958
Adj. R^2	0.956
MAPE	1.17%
DW	0.290

The Customer Model growth is driven by the two economic variable, manufacturing employment and regional GDP. The additional variables capture data shifts in the historical data series. The variables are described below.

- **Economic Variables.** The **Manufacturing Employment Index** and Regional **GDP Index** capture the manufacturing and production output for the GRE service territory.
- **Annual Binary Variables.** Two annual binary variables, **Year2013** and **Year2014**, capture the increase in customer counts beginning in 2013. The **COVID** binary variable captures the impact of COVID during 2020 and 2021.
- **Binary Shift Variable**. Binary shift variable **Year2024Plus**, captures a sustained shift in customers seen in the corresponding year and continuing through the forecast period.

LARGE COMMERCIAL UPC MODEL

The UPC Model is an SAE model estimated with historical data from January 2008 through July 2024. The SAE model uses the same SAE inputs as the Small Commercial SAE model. Table 27 shows the UPC Model specification and Table 28 shows the UPC Model statistics.

The Large Commercial SAE model contains end-use information for heating, cooling, and base load technologies from Itron's 2022 SAE West North Central region. Included in the model are the following data.

- **End-use Saturations and Efficiencies.** End-use saturations and efficiencies by technology type are based on Energy Information. Administration (EIA) data.
- **Economic data.** Historical and forecast manufacturing employment trends are based on Woods and Poole's forecast.
- **Energy Prices.** Price is based on historical revenue and energy consumption. The energy prices are held constant in real dollars through the forecast period.

TABLE 28: LARGE COMMERCIAL UPC MODEL

Variable	Coefficient	StdErr	T-Stat
XHeat	2907.491	2488.260	1.168
XCool	27526.901	1421.569	19.364
XOther	4149.953	24.619	168.569
Feb	-2219.653	404.627	-5.486
Apr	-2339.924	390.474	-5.993
Year2017Plus	-2187.254	232.455	-9.409
Oct2021Plus	5309.059	340.836	15.577
Year2024	-2878.354	620.798	-4.637

TABLE 29: LARGE COMMERCIAL UPC MODEL STATISTICS

Statistics	Large Commercial UPC Model
Estimation	1/2008 – 7/2024
R2	0.887
Adj. R2	0.883
MAPE	2.72%
DW	1.153

The UPC Model includes SAE variables (XHeat, XCool, and XOther), annual binary variables, dummy variables, seasonal variables, and shift variables. These variables are described below.

- **SAE Variables.** The SAE variables are **XHeat**, **XCool**, and **XOther**. **XHeat** captures the heating response and includes the effects of heating technology efficiencies, saturations, price, and manufacturing employment. **XCool** captures the cooling response and captures the effects of cooling technology efficiencies, saturations, price, and manufacturing employment. **XOther** captures the baseload response for all non-heating and non-cooling technologies.
- **Seasonal Binary Variables.** Two seasonal binary variables (**Feb** and **Apr**) capture additional seasonal usage not included in the SAE variables.
- **Binary Shift Variables**. Two binary shift variables, **Year2017Plus** and **Oct2021Plus** capture sustained decreases beyond the SAE energy efficiency variables. These capture the usage decreases beginning in 2017 and the increase beginning in October 2021.
- **Annual Binary Variables. A**nnual binary variable **Year2024**, capture the increase in average use seen in 2024.

Large Commercial Base Sales Forecast

The Large Commercial sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 19, Figure 20, and Figure 21. Table 29 shows the annual sales, customer, and average use forecast with average growth rates.

FIGURE 19: LARGE COMMERCIAL SALES FORECAST (ACTUAL AND FORECAST)

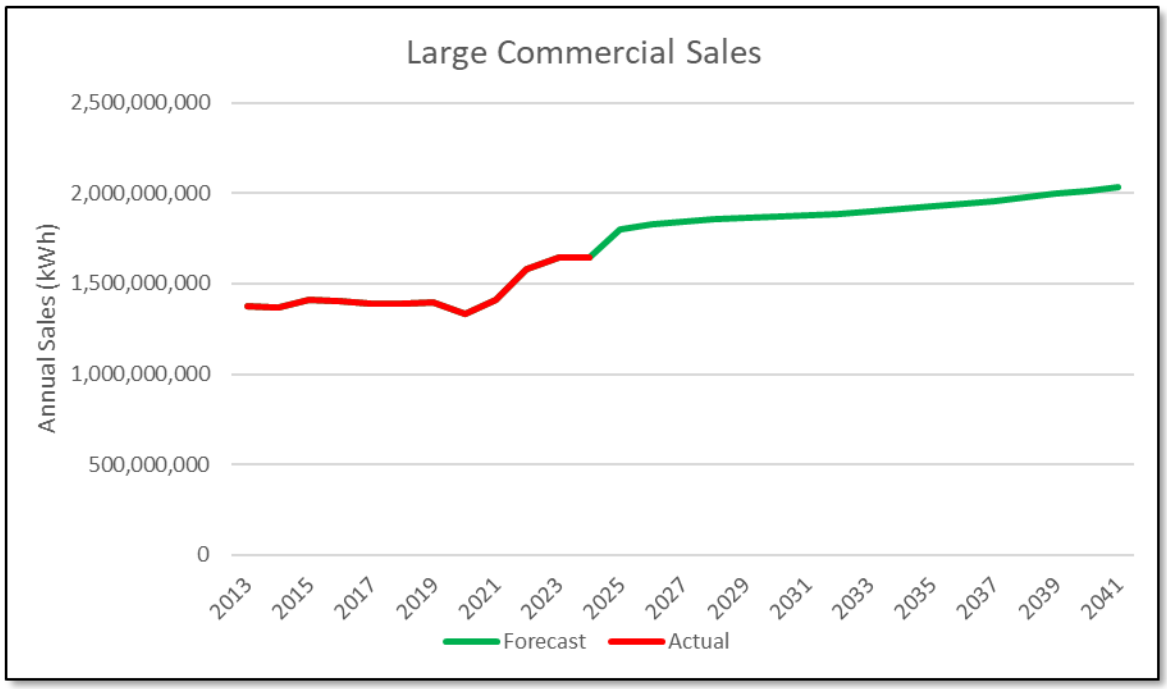


FIGURE 20: LARGE COMMERCIAL CUSTOMER FORECAST (ACTUAL AND FORECAST)

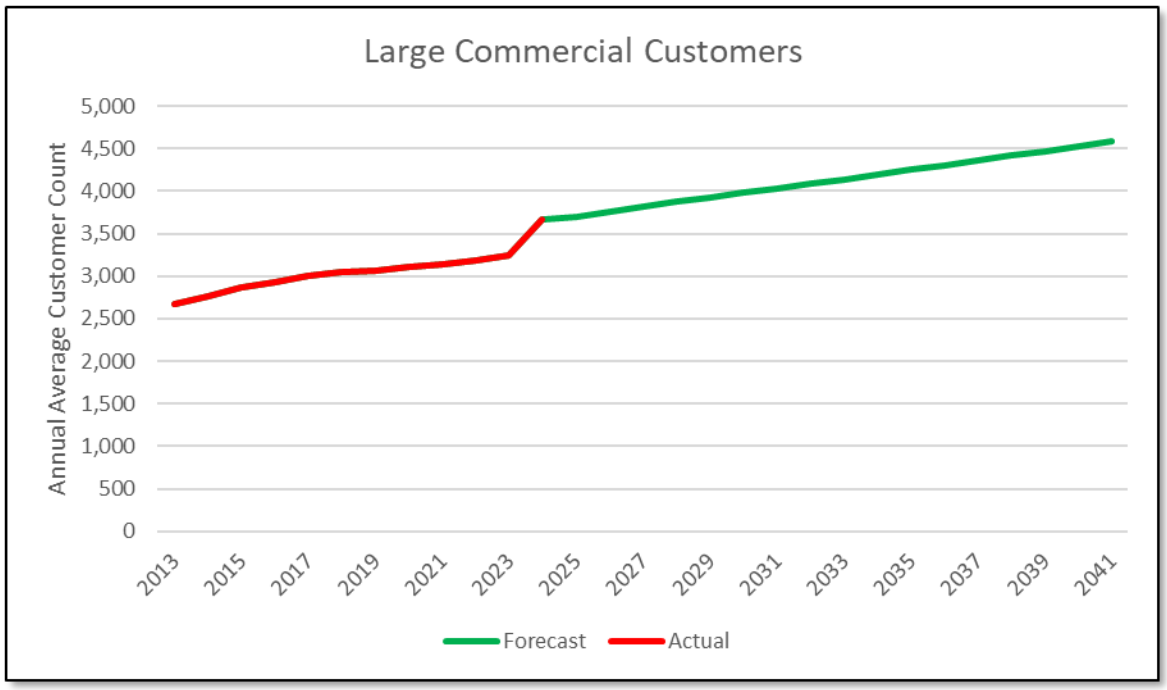


FIGURE 21: LARGE COMMERCIAL UPC FORECAST (ACTUAL AND FORECAST)

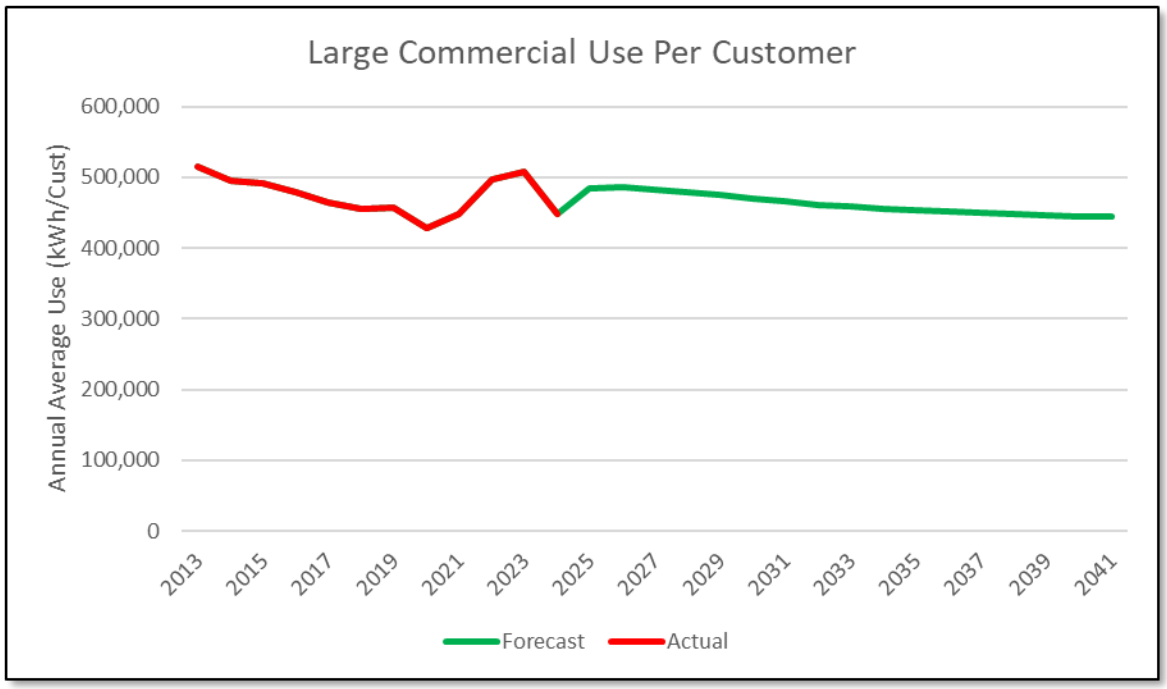


TABLE 30: LARGE COMMERCIAL SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	1,796,710,115	9.36%	3,704	0.99%	485,042	8.29%
2026	1,828,973,828	1.80%	3,760	1.51%	486,400	0.28%
2027	1,844,252,985	0.84%	3,822	1.64%	482,528	-0.80%
2028	1,853,291,777	0.49%	3,875	1.37%	478,317	-0.87%
2029	1,861,862,683	0.46%	3,924	1.27%	474,511	-0.80%
2030	1,868,011,528	0.33%	3,977	1.36%	469,703	-1.01%
2031	1,876,466,119	0.45%	4,032	1.38%	465,402	-0.92%
2032	1,886,365,186	0.53%	4,087	1.36%	461,573	-0.82%
2033	1,897,346,485	0.58%	4,140	1.31%	458,244	-0.72%
2034	1,910,304,962	0.68%	4,195	1.31%	455,429	-0.61%
2035	1,925,274,891	0.78%	4,250	1.31%	453,046	-0.52%
2036	1,941,744,201	0.86%	4,305	1.31%	451,028	-0.45%
2037	1,958,768,833	0.88%	4,361	1.30%	449,162	-0.41%
2038	1,977,704,014	0.97%	4,417	1.28%	447,761	-0.31%
2039	1,997,298,696	0.99%	4,473	1.27%	446,506	-0.28%
2040	2,015,335,335	0.90%	4,530	1.27%	444,904	-0.36%
Average (2014,2024)		**1.40%**		**2.99%**		**-1.10%**
Average (2025,2040)		**0.05%**		**1.33%**		**-0.02%**
5YR CAGR (2025,2030)		**0.03%**		**1.43%**		**-0.64%**
10YR CAGR (2025,2035)		**0.02%**		**1.38%**		**-0.68%**
15YR CAGR (2025,2040)		**0.15%**		**1.35%**		**-0.57%**

STREET AND HIGHWAY SALES MODEL

The Street and Highway class consists of all AR cooperative Street and Highway sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Street and Highway sales forecast is modelled with two models, a Customer Model and a UPC model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month. Using two models captures both the class growth based on a changing number of customers (Customer Model) and usage changes based on end-use information (UPC Model).

STREET AND HIGHWAY CUSTOMER MODEL

The Customer Model is a regression model estimated with historical data from January 2014 through July 2024 and designed to forecast a constant number of customers. Table 30 shows the Customer Model specification and Table 31 shows the Customer Model statistics.

TABLE 31: STREET AND HIGHWAY CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	980.104	1.019	962.097
Year2016	10.479	2.278	4.600
Year2017	40.896	2.278	17.953
Year2020Plus	34.655	1.400	24.752
Year2024Plus	9.241	7.123	1.297

TABLE 32: STREET AND HIGHWAY CUSTOMER MODEL STATISTICS

Statistics	Street & Highway Customer Model
Estimation	1/2014 – 7/2024
R^2	0.861
Adj. R^2	0.857
MAPE	0.52%
DW	0.601

The Street and Highway customer model is designed to forecast a constant number of customers based on the 2024 number of customers. The binary variable used in the model capture shifts in customer counts throughout the estimation period.

- **Annual Binary Variables.** Two annual binary variables, **Year2016** and **Year2017**, capture a short-term shift in customer counts.
- **Binary Shift Variable**. Binary shift variables **Year2020Plus** and **Year2024Plus**, captures a sustained shift in customers seen in the corresponding year and continuing through the forecast period.

STREET AND HIGHWAY UPC MODEL

The UPC Model is a regression model estimated with historical data from January 2014 through July 2024. Table 32 shows the UPC Model specification and Table 33 shows the UPC Model statistics.

TABLE 33: STREET AND HIGHWAY UPC MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	1197.357	93.096	12.862
Commercial SAE Lighting	161.041	55.744	2.889
Jan	113.614	13.020	8.726
Feb	67.070	13.103	5.119
Mar	46.096	13.084	3.523
Apr	10.730	13.074	0.821
May	-30.379	12.959	-2.344
Jun	-34.736	12.955	-2.681
Jul	-19.313	12.956	-1.491
Sep	21.698	13.257	1.637
Oct	43.923	13.264	3.311
Nov	63.915	13.276	4.814
Dec	90.722	13.293	6.825
Year2018Plus	66.767	10.706	6.236
FebMarApr2020Trinary	245.319	18.204	13.476
Year2020	-80.567	11.765	-6.848
Year2021Plus	-118.113	14.765	-8.000

TABLE 34: STREET AND HIGHWAY UPC MODEL STATISTICS

Statistics	Street & Highway UPC Model
Estimation	1/2014 – 7/2024
R2	0.906
Adj. R2	0.893
MAPE	1.36%
DW	0.784

The UPC Model captures both the historical declining average usage and seasonal pattern. There are multiple variables used to capture the short and long term impacts of COVID. The following variables are used in the model.

- **Commercial SAE Lighting.** This variable is the commercial SAE lighting intensity component used in the commercial (small and large commercial) SAE models. The lighting intensity captures the improving energy efficiency of commercial lighting technologies.
- **Seasonal Variables**. The monthly binary variables (**Jan** through **Dec**) model the seasonal usage pattern.
- **Annual Variable**. Annual binary variable **Year2020**, Captures a short-term shift in average use.
- **Shift Variables**. Two binary shift variables, **Year2018Plus** and **Year2021Plus** capture sustained shifts beyond the SAE energy efficiency variables.
- **Special Variable.** The trinary variable **FebMarApr2020Trinary** captures an outlier in the data where there is short-term variability related to COVID in this case.

Street and Highway Base Sales Forecast

The Street and Highway sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 22, Figure 23, and Figure 24. Table 34 shows the annual sales, customer, and average use forecast with average growth rates.

Figure 22: Street and Highway Sales Forecast (Actual and Forecast)

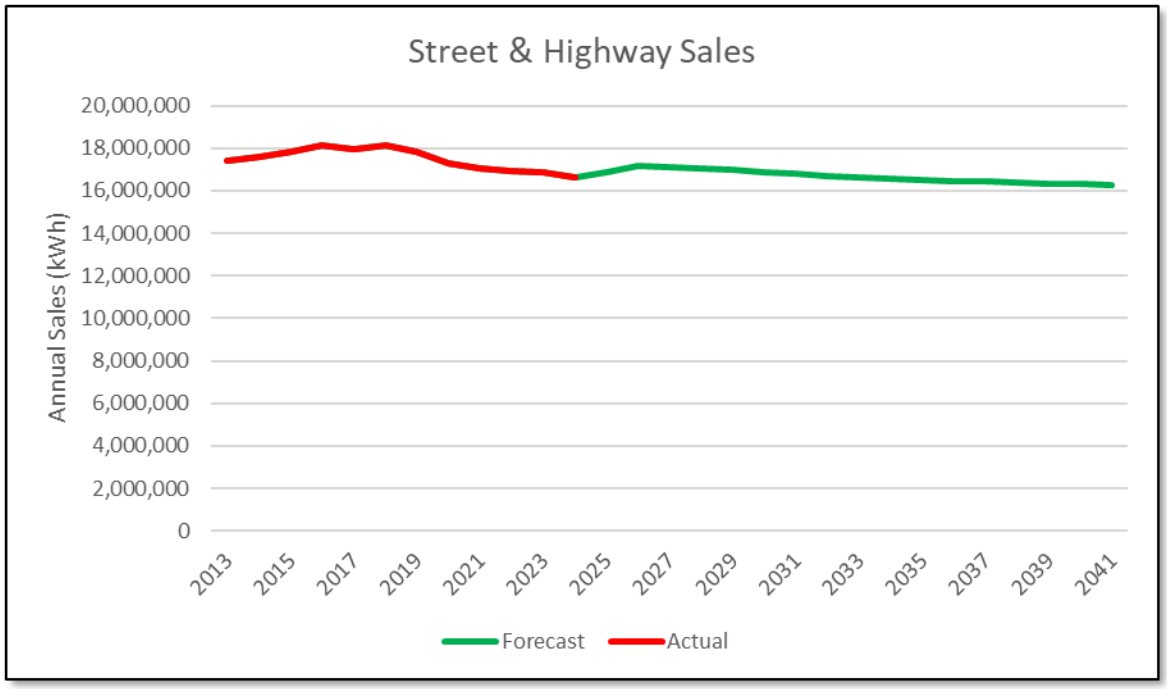


FIGURE 23: STREET AND HIGHWAY CUSTOMER FORECAST (ACTUAL AND FORECAST)

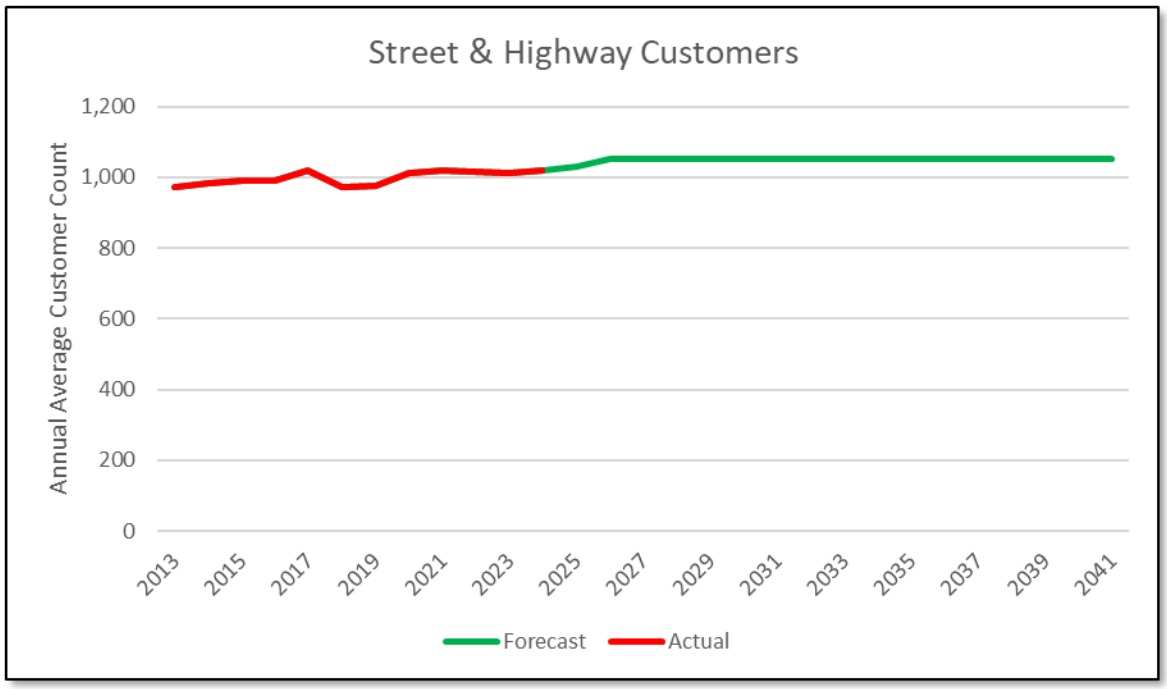


FIGURE 24: STREET AND HIGHWAY UPC FORECAST (ACTUAL AND FORECAST)

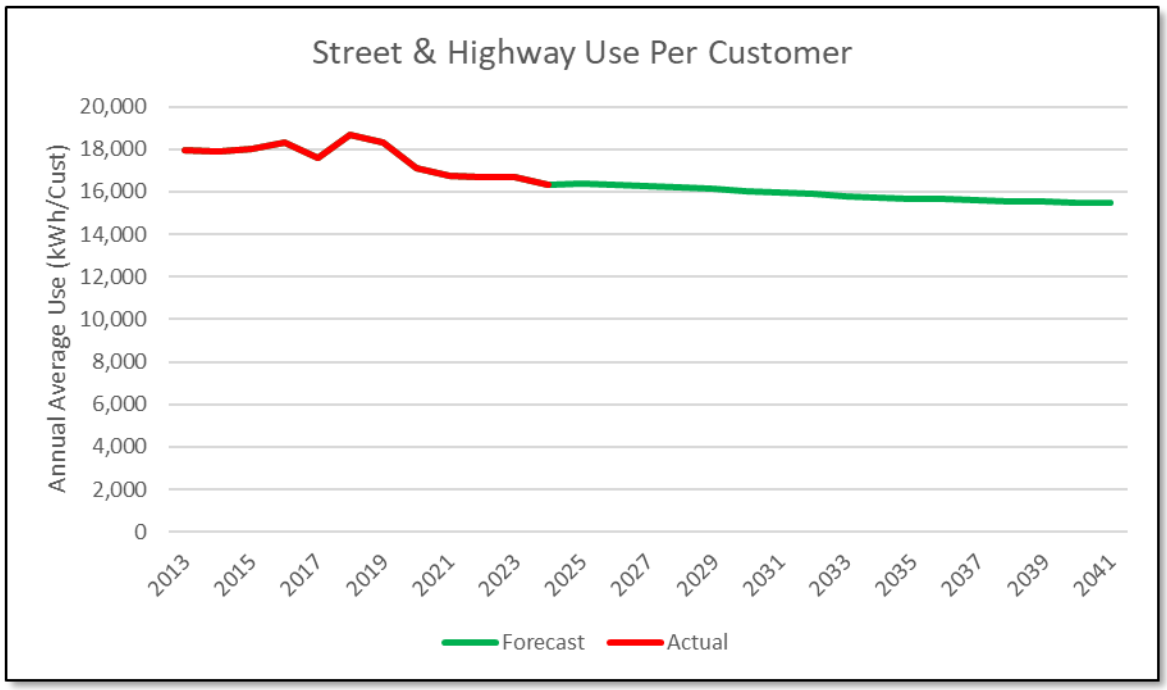


TABLE 35: STREET AND HIGHWAY SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	16,890,401	1.60%	1,031	1.06%	16,383	0.53%
2026	17,162,364	1.61%	1,053	2.09%	16,306	-0.47%
2027	17,104,270	-0.34%	1,053	0.00%	16,251	-0.34%
2028	17,042,448	-0.36%	1,053	0.00%	16,192	-0.36%
2029	16,979,089	-0.37%	1,053	0.00%	16,132	-0.37%
2030	16,895,343	-0.49%	1,053	0.00%	16,052	-0.49%
2031	16,797,004	-0.58%	1,053	0.00%	15,959	-0.58%
2032	16,710,005	-0.52%	1,053	0.00%	15,876	-0.52%
2033	16,634,064	-0.45%	1,053	0.00%	15,804	-0.45%
2034	16,568,023	-0.40%	1,053	0.00%	15,741	-0.40%
2035	16,510,640	-0.35%	1,053	0.00%	15,687	-0.35%
2036	16,461,012	-0.30%	1,053	0.00%	15,639	-0.30%
2037	16,417,809	-0.26%	1,053	0.00%	15,598	-0.26%
2038	16,380,122	-0.23%	1,053	0.00%	15,563	-0.23%
2039	16,347,056	-0.20%	1,053	0.00%	15,531	-0.20%
2040	16,311,472	-0.22%	1,053	0.00%	15,497	-0.22%
Average (2014,2024)		**-0.41%**		**0.46%**		**-0.81%**
Average (2025,2040)		**-0.12%**		**0.20%**		**-0.31%**
5YR CAGR (2025,2030)		**0.01%**		**0.42%**		**-0.41%**
10YR CAGR (2025,2035)		**-0.23%**		**0.21%**		**-0.43%**
15YR CAGR (2025,2040)		**-0.23%**		**0.14%**		**-0.37%**

PUBLIC AUTHORITY SALES MODEL

The Public Authority class consists of all AR cooperative Public Authority sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Public Authority sales forecast is modelled with two models, a Customer Model and a UPC model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month.

PUBLIC AUTHORITY CUSTOMER MODEL

The Public Authority customer model is an exponential smoothing model designed to forecast a constant number of customers through the forecast period. Since 2014, the number of customers remained consistent with 271 customers in 2014 and 283 customers in 2022. The forecast assumes the number of customers remains will remain constant throughout the forecast period with the exception of SMEC load that will become GRE load starting in August of 2025.the following tables

show the model coefficients and statistics: Table 35 Public Authority Customer Model, Table 36 Public Authority Customer Model Statistics.

TABLE 36 PUBLIC AUTHORITY CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Simple	1.009	0.089	11.322

TABLE 37 PUBLIC AUTHORITY CUSTOMER MODEL STATISTICS

Statistics	Public Authority UPC Model
Estimation	1/2015 – 7/2024
R2	0.892
Adj. R2	0.892
MAPE	0.29%
DW	1.999

PUBLIC AUTHORITY UPC MODEL

The UPC Model is a regression model estimated with historical data from January 2015 through July 2024. Table 37 shows the UPC Model specification and Table 38 shows the UPC Model statistics.

TABLE 38: PUBLIC AUTHORITY UPC MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	409.918	125.812	3.258
WtHDD	0.945	0.170	5.564
WtCDD	1.863	0.887	2.100
Feb2021Plus	13045.595	132.949	98.125
Apr2021Plus			

TABLE 39: PUBLIC AUTHORITY UPC MODEL STATISTICS

Statistics	Public Authority UPC Model
Estimation	1/2015 – 7/2024
R2	0.991
Adj. R2	0.990
MAPE	8.75%
DW	2.663

The UPC Model captures the class weather response and corrects for serial correlation. The following variables are used in the model.

- **Weather Variables.** Weather variables **WtCDD** and **WtHDD,** captures **t**he class's weather response is modelled using the multipart spline CDD/HDD variable based on the average weather of the 4 weather stations.
- **Shift Variable.** TheBinary shift variable **Feb2021Plus, captures** a long-term shift that extends the length of the forecast period.
- **Seasonal Variable.** The seasonal binary variable **Apr2021Plus** captures the decreased usage in April seen annually starting in 2021.

PUBLIC AUTHORITY BASE SALES FORECAST

The Public Authority sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 25, Figure 26, and Figure 27. Table 39 shows the annual sales, customer, and average use forecast with average growth rates.

FIGURE 25: PUBLIC AUTHORITY SALES FORECAST (ACTUAL AND FORECAST)

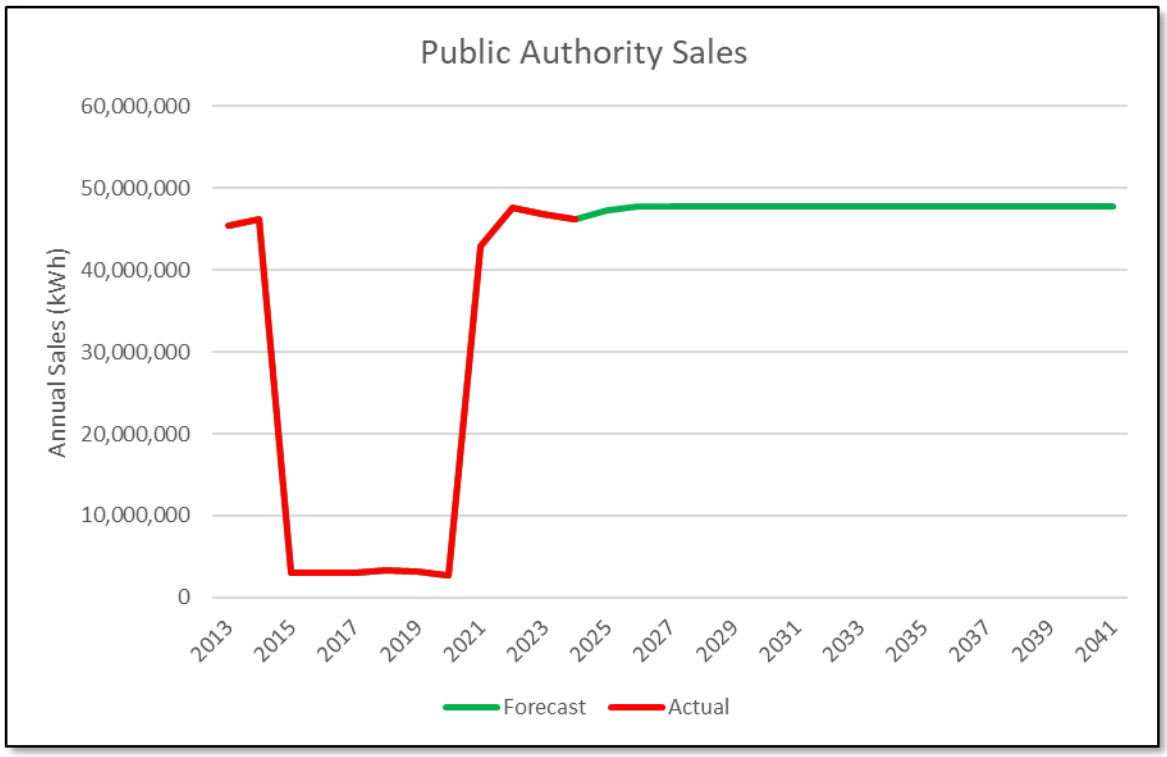


FIGURE 26: PUBLIC AUTHORITY CUSTOMER FORECAST (ACTUAL AND FORECAST)

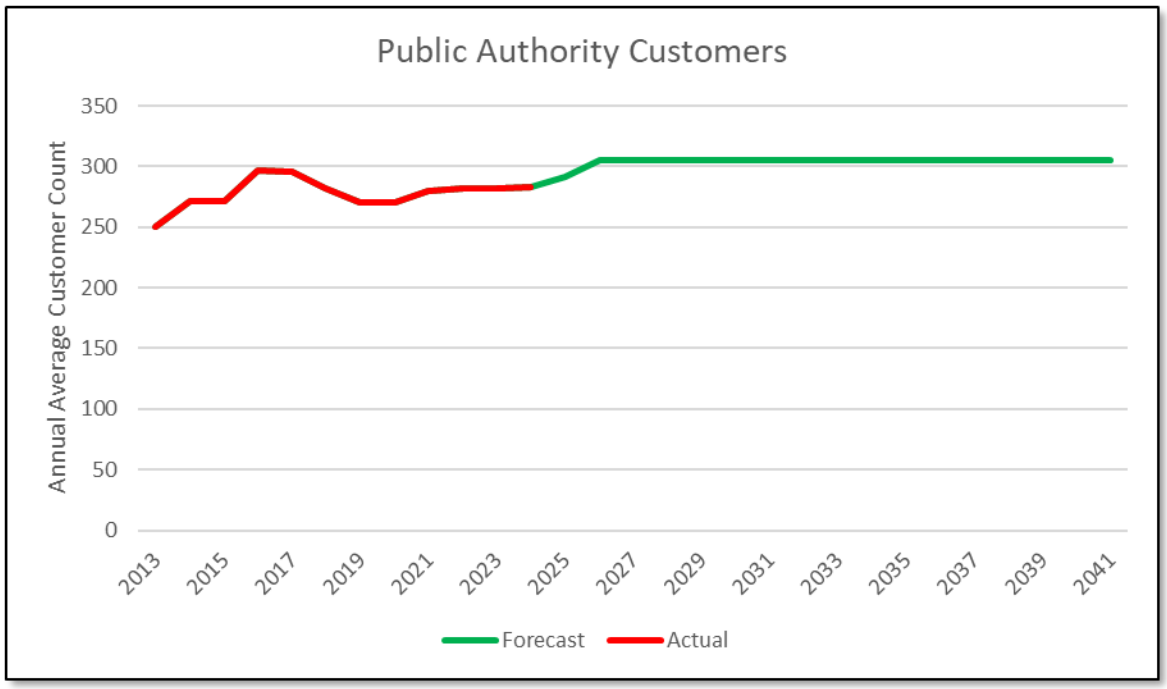


FIGURE 27: PUBLIC AUTHORITY UPC FORECAST (ACTUAL AND FORECAST)

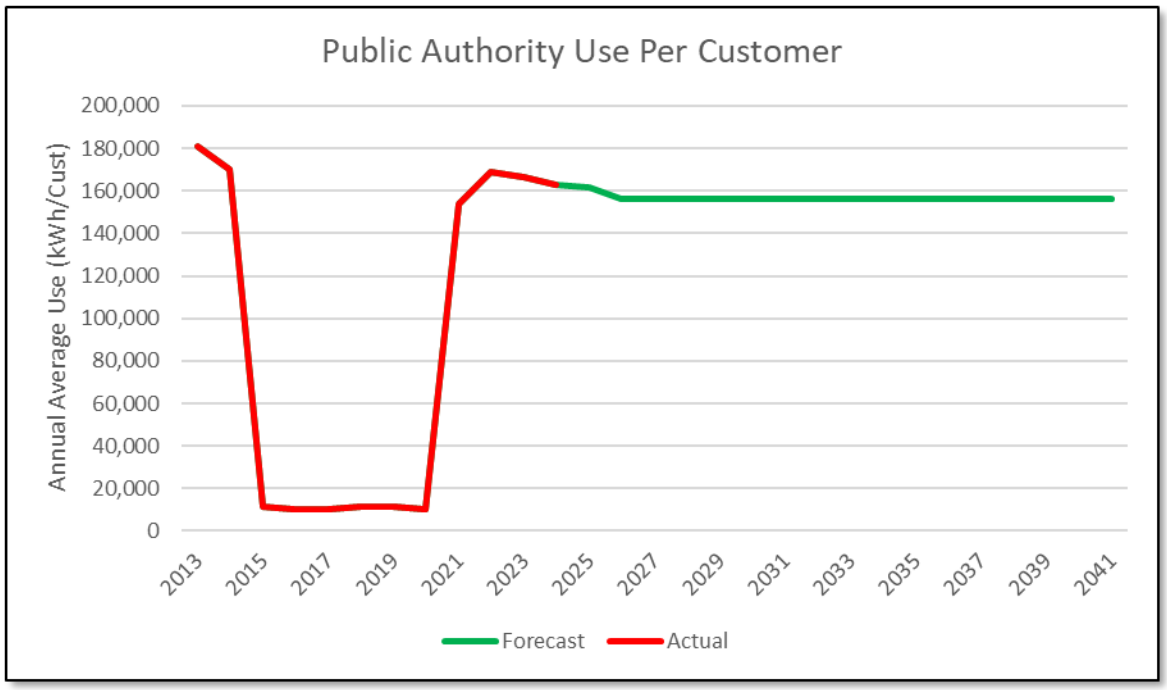


Table 40: Public Authority Sales Forecast

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	47,214,982	2.31%	292	3.03%	161,926	-0.70%
2026	47,703,384	1.03%	305	4.60%	156,405	-3.41%
2027	47,703,384	0.00%	305	0.00%	156,405	0.00%
2028	47,703,384	0.00%	305	0.00%	156,405	0.00%
2029	47,703,384	0.00%	305	0.00%	156,405	0.00%
2030	47,703,384	0.00%	305	0.00%	156,405	0.00%
2031	47,703,384	0.00%	305	0.00%	156,405	0.00%
2032	47,703,384	0.00%	305	0.00%	156,405	0.00%
2033	47,703,384	0.00%	305	0.00%	156,405	0.00%
2034	47,703,384	0.00%	305	0.00%	156,405	0.00%
2035	47,703,384	0.00%	305	0.00%	156,405	0.00%
2036	47,703,384	0.00%	305	0.00%	156,405	0.00%
2037	47,703,384	0.00%	305	0.00%	156,405	0.00%
2038	47,703,384	0.00%	305	0.00%	156,405	0.00%
2039	47,703,384	0.00%	305	0.00%	156,405	0.00%
2040	47,703,384	0.00%	305	0.00%	156,405	0.00%
Average (2014,2024)		**125.88%**		**1.20%**		**120.66%**
Average (2025,2040)		**0.21%**		**0.48%**		**-0.26%**
5YR CAGR (2025,2030)		**0.21%**		**0.90%**		**-0.69%**
10YR CAGR (2025,2035)		**0.10%**		**0.45%**		**-0.35%**
15YR CAGR (2025,2040)		**0.07%**		**0.30%**		**-0.23%**

RESALE SALES MODEL

The Resale class consists of all AR cooperative Resale sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Resale sales forecast is modelled with two models, a Customer Model and a UPC model. The class forecast is calculated by multiplying the customer forecast by the UPC forecast to obtain the total sales in each month.

RESALE CUSTOMER MODEL

The Customer Model is a regression model designed to forecast a constant number of customers. Since 2010, the number of customers has ranged between 2 and 5. Beginning in 2019, only 2 customers are reported. The model is designed to produce a forecast of 2 customers. Table 40 Resale Customer Model shows the Customer Model specification and Table 41 shows the Customer Model statistics.

TABLE 41 RESALE CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	4.028	0.030	134.073
Year2018Plus	-0.694	0.060	-11.558
Year2019Plus	-1.333	0.057	-23.598

TABLE 42 RESALE CUSTOMER MODEL STATISTICS

Statistics	Public Authority UPC Model
Estimation	1/2015 – 7/2024
R2	0.965
Adj. R2	0.964
MAPE	1.73%
DW	0.987

The following variables are used in the model.

- **Shift Variable.** TheBinary shift variable **Year2018Plus** and **Year2019Plus, captures** long-term shifts that extends the length of the forecast period.

RESALE UPC MODEL

Like the Customer Model, the UPC model is designed to forecast average use based on the most recent use of the 2 resale customers. In 2019, the annual average historical UPC is 1,230 MWh. The model captures the 2019 to 2024 average use. Table 42 shows the UPC Model specification and Table 43 shows the UPC Model statistics.

TABLE 43: RESALE UPC MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	796921.265	11493.527	69.337
Year2019Plus	-718007.542	8052.123	-89.170
AprToDec2018	238218.552	17883.719	13.320
Jan	45175.249	12809.122	3.527
Feb	29595.131	12791.868	2.314
Mar	18381.153	12774.774	1.439
Apr	-15367.098	12743.445	-1.206
Jun	16976.417	12709.918	1.336
Jul	52661.480	12693.385	4.149
Aug	36652.486	13277.921	2.760
Sep	6477.893	13258.773	0.489
Oct	18878.156	13239.803	1.426
Nov	22306.743	13221.007	1.687
Dec	36583.324	13202.382	2.771

TABLE 44: RESALE MODEL STATISTICS

Statistics	Resale UPC Model
Estimation	1/2014 – 7/2024
R2	0.986
Adj. R2	0.984
MAPE	7.99%
DW	1.424

The UPC Model includes an annual binary variable, seasonal binary variables, and a binary shift. These variables are described below.

- **Annual Variable.** Special binary variable **AprToDec2018** adjust the model for short term spike prior to a succeeding shift.
- **Shift Variable.** Binary variable **Year2019Plus** adjusts the model for a decline in use per customer that has continued in the forecast period.
- **Seasonal Variables.** Monthly binary variables (excluding **May**) capture seasonal variation.

Resale Base Sales Forecast

The Resale sales forecast is developed as the product of the customer and UPC forecasts. The annual energy forecast, customer forecast, and use-per-customer forecast are shown in Figure 28, Figure 29, and Figure 30. Table 44 shows the annual sales, customer, and average use forecast with average growth rates.

Figure 28: Resale Sales Forecast (Actual and Forecast)

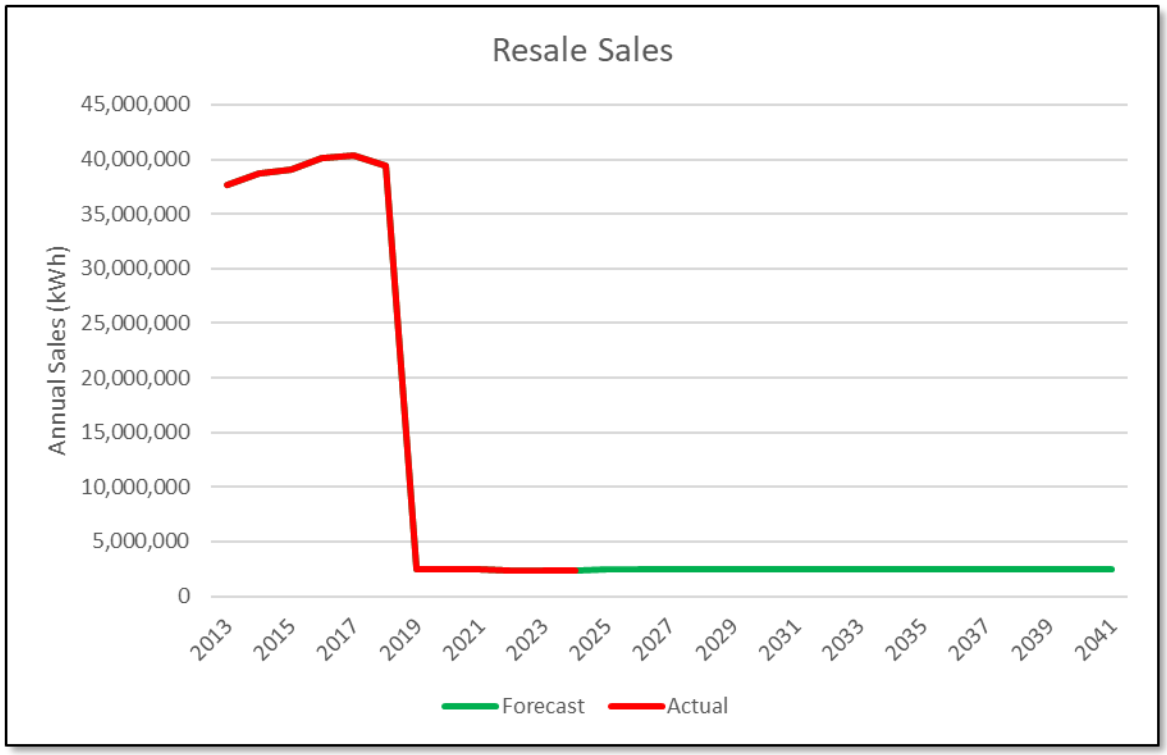


FIGURE 29: RESALE CUSTOMER FORECAST (ACTUAL AND FORECAST)

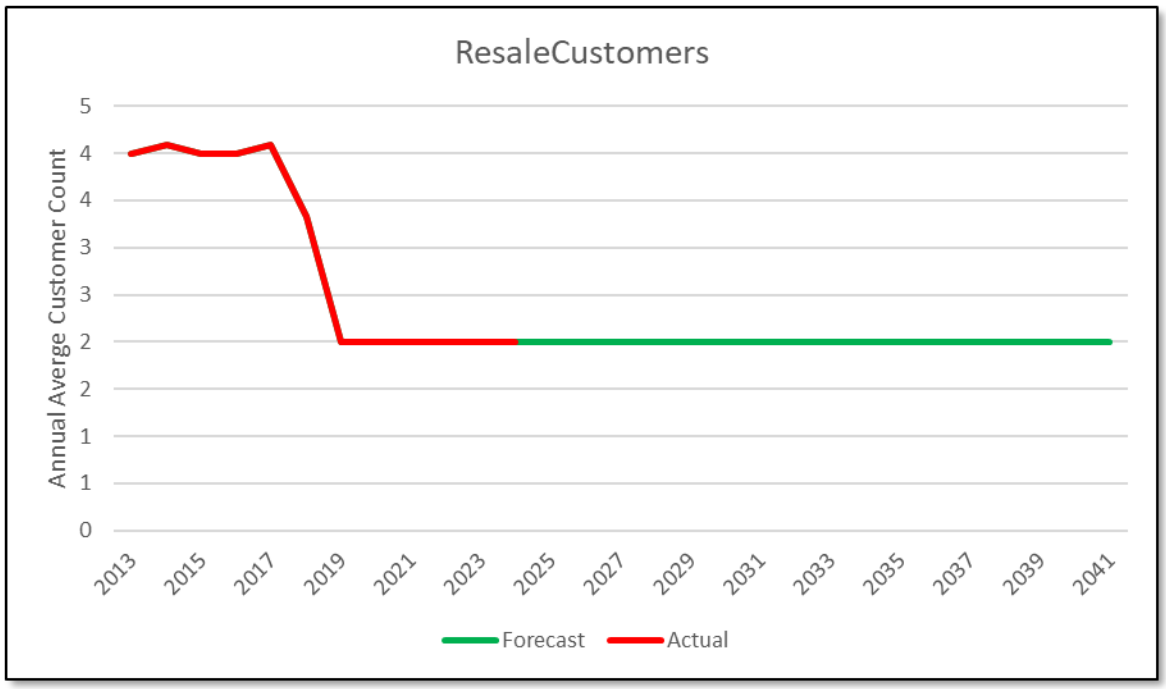


FIGURE 30: RESALE UPC FORECAST (ACTUAL AND FORECAST)

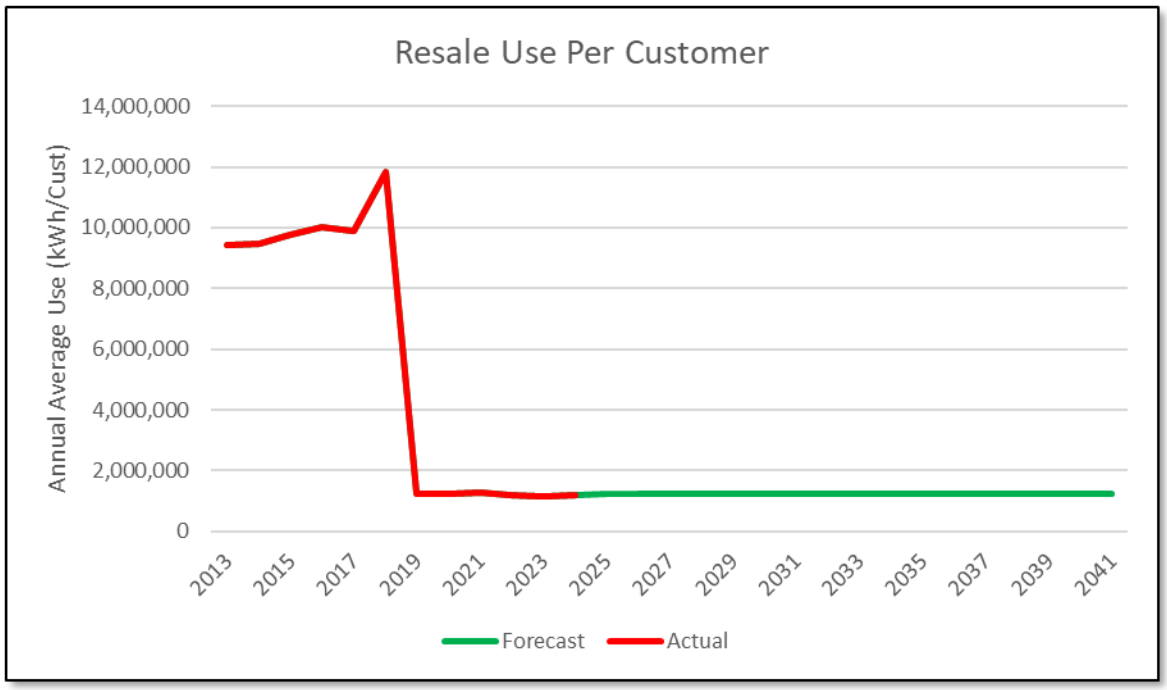


TABLE 45: RESALE SALES FORECAST

Year	Sales (kWh)	Sales Growth	Customers	Customer Growth	AvgUse (kWh)	AvgUse Growth
2025	2,430,571	0.98%	2	0.00%	1,215,286	0.98%
2026	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2027	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2028	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2029	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2030	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2031	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2032	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2033	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2034	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2035	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2036	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2037	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2038	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2039	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
2040	2,430,571	0.00%	2	0.00%	1,215,286	0.00%
Average (2014,2024)		**-8.28%**		**-5.11%**		**-6.09%**
Average (2025,2040)		**0.06%**		**0.00%**		**0.06%**
5YR CAGR (2025,2030)		**0.00%**		**0.00%**		**0.00%**
10YR CAGR (2025,2035)		**0.00%**		**0.00%**		**0.00%**
15YR CAGR (2025,2040)		**0.00%**		**0.00%**		**0.00%**

OWN USE SALES MODEL

The Own Use class consists of all AR cooperative Own Use sales. The AR cooperatives provided historical sales and customer counts from their Form 7 data reports. The Own Use sales forecast is modelled with a single sales model. Table 45 shows the Sales Model specification and Table 46 shows the Sales Model statistics.

TABLE 46: OWN USE SALES MODEL

Variable	Coefficient	StdErr	T-Stat
Constant	593431.287	18361.443	32.319
WtHDD	1039.142	21.437	48.474
WtCDD	75.742	150.036	0.505
Year2012	-97211.987	27280.692	-3.563
Year2016	-272692.362	27232.459	-10.014
MaytoSepYear2017Plus	-118764.431	23646.510	-5.022
Year2017Plus	73289.068	18511.396	3.959

TABLE 47: MUNICIPAL MODEL STATISTICS

Statistics	Own Use Model
Estimation	1/2012 – 7/2024
R2	0.973
Adj. R2	0.971
MAPE	7.19%
DW	1.222

The sales model is designed to create a constant forecast over the forecast period. The model includes weather response variables, binary shifts variables, and binary variables. The variables are described below.

- **Weather Variables.** Weather variables **WtCDD** and **WtHDD,** captures **t**he class's weather response is modelled using the multipart spline CDD/HDD variable based on the average weather of the 4 weather stations.
- **Shift Binary Variables.** The binary shift variable **Year2017Plus,** captures increased usage beginning in January 2017.
- **Binary Variables.** Two annual binary variables (**Year2016** and **Year2012**) adjust historical years (2016 and 2012) for short-term data shifts.
- **Seasonal Variable.** The seasonal binary variable **MaytoSepYear2017Plus** captures the decreased usage in during summer annually starting in 2021.

OWN USE SALES FORECAST

Figure 31 shows the Own Use annual energy forecast and Table 47 shows the Own Use annual sales forecast with average growth rates.

FIGURE 31: OWN USE SALES FORECAST (ACTUAL AND FORECAST)

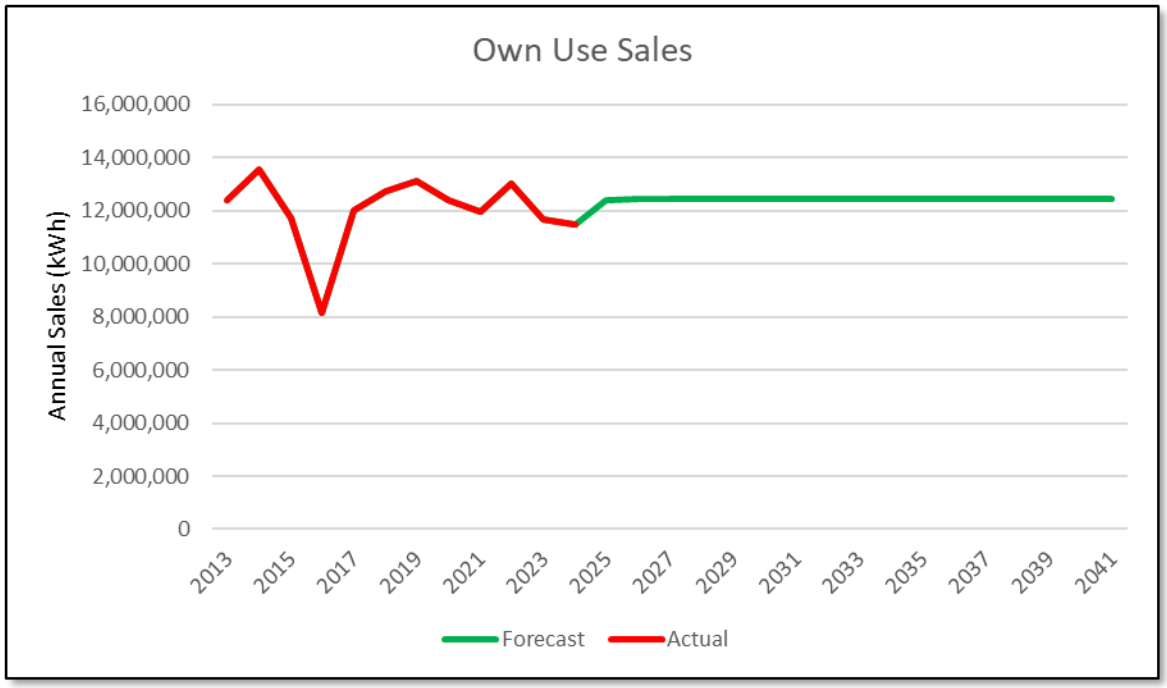


TABLE 48: OWN USE SALES FORECAST

Year	Sales (kWh)	Sales Growth
2025	12,384,003	7.64%
2026	12,426,995	0.35%
2027	12,426,995	0.00%
2028	12,426,995	0.00%
2029	12,426,995	0.00%
2030	12,426,995	0.00%
2031	12,426,995	0.00%
2032	12,426,995	0.00%
2033	12,426,995	0.00%
2034	12,426,995	0.00%
2035	12,426,995	0.00%
2036	12,426,995	0.00%
2037	12,426,995	0.00%
2038	12,426,995	0.00%
2039	12,426,995	0.00%
2040	12,426,995	0.00%
Average (2014,2024)		**0.88%**
Average (2025,2040)		**0.50%**
5YR CAGR (2025,2030)		**0.07%**
10YR CAGR (2025,2035)		**0.03%**
15YR CAGR (2025,2040)		**0.02%**

AR PEAK MODEL

The AR Peak Model is a regression model that is designed to forecast the monthly AR peaks. The AR peaks are defined as the maximum monthly values for the aggregated AR cooperatives. The maximum values are restored for peak day curtailments. The model is estimated with data from January 2011 through April 2025. The model is shown in Table 48 and the model statistics are shown in Table 49.

TABLE 49: SYSTEM PEAK MODEL

Variable	Coefficient	StdErr	T-Stat
HDD50_HeatIndex	7.436	0.231	32.184
CDD65_CoolIndex	19.100	1.244	15.348
Base_Index	262.721	3.353	78.360
JunBaseTrend	29.106	7.399	3.934
JulAugBaseTrend	56.066	6.885	8.144
SepBaseTrend	22.600	6.541	3.455
Year2017	-27.850	14.991	-1.858

TABLE 50: SYSTEM PEAK MODEL STATISTICS

Statistics	Peak Model
Estimation	1/2011 – 4/2025
R2	0.898
Adj. R2	0.895
MAPE	3.60%
DW	1.464

The System Peak Model is driven by the sales forecast and peak producing weather. An additional seasonal adjustment is included to differentiate the summer baseload trend from the winter baseload trend. The variables are discussed below.

- **HDD50_HeatIndex.** This variable is an interaction between the average temperature on the monthly peak day for temperatures below 50 degrees and the heating components of the sales models. The heating components are derived by multiplying the heating variable coefficients from the class sales models by normal heating degree days. The results are smoothed using a 12-month moving average. This variable captures the heating contribution to peak growth.
- **CDD65_CoolIndex.** This variable is an interaction between average temperature on the monthly peak day for temperatures above 65 degrees and the cooling components of the energy models. The cooling components are derived by multiplying the cooling variable coefficients from the class sales models by normal cooling degree days. The results are smoothed using a 12-month moving average. This variable captures the cooling contribution to peak growth.

- **Base_Index.** Base_Index is the non-heating and non-cooling sales from class sales models. The sales results are smoothed using a 12-month moving average. This variable captures the base load contribution to peak growth.
- **Summer Baseload Trend Adjustment.** Three variables are used to differentiate the summer baseload trend from the winter baseload trend. These variables are **JunBaseTrend**, **JulAugBaseTrend**, and **SepBaseTrend**. These variables are constructed by interacting the monthly binary (e.g., Jun) with the **Base Index** variable. The significant coefficients increase the summer month trends.

Peak Base Forecast Results

Figure 32 shows the annual summer and winter peaks for the AR system. The AR system is summer peaking system with stronger long-term growth in the summer than winter. Table 50 shows the summer and winter peaks and their annual growth rates.

Figure 32: System Peak Forecast



TABLE 51: AR PEAK FORECAST

Year	Summer Peak (MW)	Summer Peak Growth	Winter Peak (MW)	Winter Peak Growth
2025	1,437	7.22%	1,407	8.04%
2026	1,502	4.52%	1,408	0.03%
2027	1,514	0.79%	1,419	0.76%
2028	1,525	0.79%	1,429	0.71%
2029	1,536	0.67%	1,441	0.87%
2030	1,544	0.57%	1,445	0.28%
2031	1,553	0.59%	1,452	0.47%
2032	1,564	0.68%	1,459	0.49%
2033	1,574	0.64%	1,470	0.72%
2034	1,585	0.68%	1,472	0.20%
2035	1,597	0.79%	1,480	0.53%
2036	1,612	0.90%	1,489	0.60%
2037	1,625	0.85%	1,502	0.86%
2038	1,640	0.86%	1,507	0.32%
2039	1,655	0.93%	1,516	0.63%
2040	1,670	0.95%	1,526	0.65%
2011-2021		**0.25%**		**0.68%**
2023-2038		**1.40%**		**1.01%**
5 Yr CAGR (2023-2028)		**1.45%**		**0.53%**
10 Yr CAGR (2023-2033)		**1.06%**		**0.51%**
15 Yr CAGR (2023-2038)		**1.01%**		**0.54%**

7610 CLASS DISTRIBUTION

The AR load forecast is done on a class level prior to be summed together to make the total forecast. These classes are distributed amongst the MN7610 Filing categories. The classes are broken up as follows.

- Non-Farm Residential: 80% of Residential and 90% of seasonal
- Residential Space Heating: 10% of Residential and seasonal
- Farm: 10% of residential
- Small Commercial: 100% Small Commercial
- Irrigation: 100% of Irrigation
- Large Commercial: 100% of Large Commercial
- Street and Highway: 100% of Street and Highway
- Other: 100% of Public Authority and Resale

CONCLUSION

The 2025 MN7610 forecast is based on GRE's AR class sales. This report summarizes the forecast models and results from 2025 through 2040. This forecast is based on a portion of the forecasting methodology utilized for GRE's Integrated Resource Plan.

The strength of the forecast is its theoretical basis. First, by using the SAE modelling approach for the residential, seasonal, small commercial, and large commercial classes, the forecast captures the improving efficiencies/saturations of end-use technologies. Second, the economic drivers represent economic activity in the GRE service territory.

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July 1, 2025

NOT PUBLIC DOCUMENT -
NOT FOR PUBLIC DISCLOSURE

Ms. Anne Sell
Minnesota Department of Commerce
85-7th Place East – Suite 500
St. Paul, MN 55101-2145

RE: ANNUAL ELECTRIC UTILITY REPORT
DOCKET NO. E999/PR-25-11

Dear Ms. Sell,

Otter Tail Power Company (Otter Tail) submits the enclosed 2024 Electric Utility Annual Report required under Minn. Rule 7610.0130.

This report contains sections that are considered Trade Secret and are not for public disclosure, according to Minn. Stat. Sec. 13.37, subd.1 (b). This statute protects certain "government data," as that term is defined at Minn. Stat. Sec. 13.02, subd.7, from being disclosed by an administrative agency to the public. The attachments are considered to be a compilation of data, that (1) was supplied by Otter Tail, (2) is the subject of reasonable efforts by Otter Tail to maintain its secrecy, and (3) derives independent economic value, actual or potential, from not being generally known to or accessible by the public. Non-Public and Public versions are being submitted.

Otter Tail has also marked our service area and transmission maps as Critical Energy Infrastructure Information. Federal Regulations restrict the disclosure of Critical Energy Infrastructure Information (CEII). These maps contain information that is considered CEII under 18CFR§338.113(c).

We have electronically filed this report with the Minnesota Public Utilities Commission.

Please feel free to contact me at njensen@otpco.com or (218) 739-8989, if you have any questions regarding this report.

Sincerely,

/s/ NATHAN JENSEN
Nathan Jensen P.E.
Manager, Resource Planning

kaw
Enclosures
By electronic filing

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7610.0320 FORECAST DOCUMENTATION.

Subpart 1. Forecast methodology. *An applicant may use the forecast methodology that yields the most useful results for its system. However, the applicant shall detail in written form the forecast methodology employed to obtain the forecasts provided under parts 7610.0300 to 7610.0315, including:*

A. ***the overall methodological framework that is used;***

Aggregate econometric models of use-per-meter and number of meters were developed for each customer class, using historical data on monthly sales and number of meters, economic and demographic activity, and weather conditions to develop the energy sales forecast. The monthly use-per-meter and number of meters forecasting models were estimated as a function of these explanatory variables, plus month-specific variables to capture any seasonal patterns that are not related to the other explanatory variables. The total monthly sales forecasts were developed by multiplying use-per-meter forecasts by meter forecasts for each customer class. Two exceptions to those models were the Large Commercial class, which was a forecast of kWh directly, and Street Lights, which incorporated knowledge of the migration to LED fixtures. To forecast system peak demand, an econometric model using historical data was developed that explains monthly system peak demands as a function of weather, economic conditions, and month-specific variables.

B. the specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied;

1. **Econometric Analysis.** Otter Tail Power Company used econometric analysis to develop jurisdictional MWh sales forecasts for the following classes: Residential, Farm, Small Commercial, Large Commercial, Other Public Authority and Unclassified. We used standard ordinary least squares (OLS) regression models. The Street Light forecast was created using historical sales and known changes throughout the current projects migrating existing fixtures to LED fixtures.

2. **Judgment.** Judgment is inherent to the development of any forecast. Whenever possible, Otter Tail Power Company tries to use appropriate statistical tests of quantitative models to structure its judgment in the forecasting process.

3. **Loss Factor Methodology.** Loss factors were applied to convert the sales forecasts into system energy requirements. A MWh sales forecast was developed for each customer class and jurisdiction. Summing the various jurisdictional class forecasts yields the total system sales forecast. A monthly loss factor is applied to convert MWh sales to MWh native energy requirements.

4. **Peak Demand Forecast.** Econometric analysis was used to produce a total system MW demand forecast for each month of the forecast period. A standard ordinary least squares (OLS) regression model is used to forecast system demand. The purpose of this model is to estimate the relationship between a dependent variable and explanatory variables (*e.g.*, heating degree days or GDP).

C. the manner in which these specific techniques are related in producing the forecast;

The econometric techniques described in Section B are applied to historical data to produce estimated effects of weather, economic factors, and demographic factors on class usage or system demand. Forecast values for the explanatory values (derived either from Woods and Poole forecasts or based on normal weather conditions) are then inserted into the equation estimations to produce forecast values of class-level sales and system-level demand.

D. where statistical techniques have been used, the purpose of the technique, typical computations (e.g., computer printouts, formulas used) specifying variables and data, and the results of appropriate statistical tests;

Models used

The basic structure for the use-per-meter models estimates monthly meter energy usage as a function of economic conditions, weather conditions, and month-specific variables. The economic variables that are most often used are Gross Regional Product, Net Earnings, and Total Personal Income. Weather conditions are represented using monthly heating degree days and cooling degree days. In some cases, indicator variables were included in the equation to account for unique events in the historical time period.

The basic form of the use-per-meter models is represented by the equation below. In this equation "m2" equals one in February (month 2) and zero in all other months.

$$\text{Use-per-meter} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The basic structure for the meter models estimates monthly meters as a function of economic conditions and month-specific variables. The economic variables that are most often used are Number of Households and Total Population. The meter model is shown in the equation below.

$$\text{Meters} = a + b_1 * \text{Economic Variable} + b_2 * m2 + \ldots + b_{12} * m12$$

The system peak demand model uses the equation below.

$$kW = a + b_1 * Winter * HDD\ Buildup + b_2 * Summer * Temperature\ Humidity\ Index\ Buildup + b_3 * Swing\ Month * CDD\ \&\ HDD\ Buildup + b_4 * Gross\ Regional\ Product + b_5 * m2 + \ldots + b_{15} * m12$$

The weather buildup variables are constructed as follows:

$$40/75 * X_t + 20/75 * X_{t-1} + 10/75 * X_{t-2} + 5/75 * X_{t-3},$$

where X is the weather variable in question, t is the peak day and t-3 is three days prior to the peak day. The CDD & HDD variable used in the swing months (May and September) is constructed by adding the HDD value to three times the CDD value.

The models use information from Woods and Poole Economics, Inc. for its forecast of economic and demographic variables.

The table under Subp. 2 (data base for forecasts) shows the variables that are included in each model. Specifications that included more variables were also tested to determine the final model used.

E. forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption; and

The estimated effect of each variable in the equations above (*e.g.*, the effect of heating degree days on system peak demand) has a standard error associated with it that is used to generate a confidence interval around the forecasted demand value (*e.g.*, there is some probability that the "true" value of the parameter is actually larger than the estimated value, which would imply that the effect of weather on demand would be larger, leading to a higher peak demand for a given assumed weather condition). In calculating the confidence intervals around the demand forecast, the values of the explanatory variables, such as weather, economic growth, and demographics are all maintained at fixed assumed or expected levels. TABLE 1 (below) shows the results of the confidence levels in 5-year increments.

Table 1
Forecast Confidence Levels
2024 Econometric Forecasts
Percent Deviation from Base

	Low Scenario		High Scenario	
Year	Demand Peak	Electric Consumption Sales	Demand Peak	Electric Consumption Sales
2024	-9.5%	-9.4%	9.5%	9.7%
2029	-9.9%	-9.7%	9.9%	9.9%
2034	-9.9%	-9.9%	9.9%	10.2%
2039	-10.0%	-10.1%	10.0%	10.4%

F. a brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant by the utility.

Methodology As discussed in item A above, the Company uses econometric models to forecast energy sales requirements and system peak demand. This method is used as it is a standard methodology in the industry and thus facilitates review.

Strengths and Weaknesses As mentioned above, one of the main strengths is the ability of the econometric model to be understood as it is an industry standard. The model is reasonably easy to fine tune as it was developed in-house. One of the weaknesses is that the data it uses is not as detailed as the data used in an end-use forecast.

Suitability to the system The econometric methodology is a very good fit for Otter Tail Power Company's system. Serving three states with distinct economic differences, the econometric model makes it easy to utilize the different economic data for each state individually and determine whether particular variables are drivers for each state.

Cost Considerations The econometric approach, relative to an end-use model approach, is inexpensive to maintain while being very reliable.

Data Requirements The forecast utilizes 20 years of monthly historical energy sales and demand data along with their corresponding weather and econometric variables. As described in detail in subpart 2, the sources of data for the explanatory variables were the Otter Tail Power Company Customer Information System for billing sales and meter counts; weather data from DTN; and Woods and Poole Economics, Inc for econometric and demographic data.

Past Accuracy Otter Tail Power Company does look back to see how each model predicts past energy and demand. If the model predicts backwards well, there is a reasonable confidence that it will predict well in the future. We've looked at the 20 year backcast for the energy and demand forecasts models. The energy model has an Average Absolute Error of 0.47% over the past ten years. The demand model has an Average Absolute Error of 3.48% over the past ten years.

Subp. 2. Data base for forecasts. The utility shall discuss in written form the data base used in arriving at the forecast presented in part 7610.0310, including:

A. a complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer); and

B. a clear identification of any adjustments made to raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.

Sales Forecast

Table 2

Independent Variables Used in the Sales Forecast Models											
		State	CDD65	HDD55	Number Of Households	Farm Employment	Gross Regional Product	Billing Days	AR Terms	Trend Variable	Miscellaneous Binaries
Residential	Meters	MN			X				X		X
		ND							X		X
		SD							X	X	X
	Use-per-Meter	MN	X	X				X		X	X
		ND	X	X				X			X
		SD	X	X				X	X		X
Farm	Meters	MN				X			X		X
		ND				X					X
		SD							X	X	X
	Use-per-Meter	MN	X	X				X	X	X	X
		ND		X				X		X	X
		SD	X	X				X	X	X	X
Small Commercial	Meters	MN							X	X	X
		ND							X	X	X
		SD							X	X	X
	Use-per-Meter	MN	X	X			X	X	X		X
		ND	X	X			X	X			X
		SD	X	X				X	X	X	X
Large Commercial	KWH	MN	X	X			X	X	X		X
		ND	X	X				X			X
		SD					X	X	X		X
Other Public Authority	Meters	MN							X		X
		ND							X	X	X
		SD							X	X	X
	Use-per-Meter	MN		X				X	X		X
		ND		X				X	X	X	X
		SD		X				X	X	X	X

Database: Otter Tail Power Company's Customer Information/Billing System (CIS)
Variable(s) Used:
Use-per-meter: kWh sales divided by the number of meters
Meters: number of meters
Description/Source:
kWh and the number of meters were read from SAS (SAS Institute Inc.) data sets created from customer and billing data extracts of the CIS taken the last day of each month. Each record was assigned to one of 40 rate groups within each state based on rate and revenue class combinations. Records were summed to the rate group level within each state. Each rate group was then assigned to one of the eight classes used in the forecast. The variable *use-per-meter* was calculated by dividing the monthly kWh by the monthly number of meters.
Adjustments Made:
Each record was checked to be sure it was assigned a rate group. Any record not assigned a rate group had its rate and/or revenue class corrected so a rate group was properly assigned. Monthly group kWh data was graphed and values were reviewed for errors due to meters not being billed, being billed twice in one month, etc. In most cases the data used for corrections was taken from a second CIS download that was run the following month after billing corrections had been made. In some instances, judgment was used.

Database: Degree Days
Variable(s) Used:
cdd65: average cooling degree days for each month with a 65 degree base
hdd55: average heating degree days for each month with a 55 degree base
Description/Source:
Hourly temperature data was obtained from 14 locations throughout our service territory in Minnesota, North Dakota and South Dakota. The data comes from DTN, who does multiple data "cleansing" processes to ensure the data is correct and that missing values are filled. Scheduled billing cycle start and stop dates were obtained from the CIS system. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on a 55 degree and 65 degree base, respectively, and the rounded average of the twenty-four hourly temperatures. Daily degree days were then averaged and weighted for each state and added to calculate billing month and calendar month heating degree days and cooling degree days. Average monthly *hdd* and *cdd* were calculated over a 20-year period to calculate normal billing month and calendar month *hdd* and *cdd*. Billing month *hdd* and *cdd* were used for the historical period and calendar month *hdd* and *cdd* were used for the forecast period.
Adjustments Made:
Hourly temperatures for each of the 14 requested locations are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected when necessary.

Database: Woods and Poole
Variable(s) Used:
Number of Households
Farm Employment
Gross Regional Product
Description/Source:
2024 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The state profile data contains annual historical data beginning 1969, 1970 or 1990 to 2022 and annual forecast data for 2023-2060 at the county level.
Adjustments Made:
Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10% of the population of the county. County and city population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a percentage of less than 10% were not included. Towns served were obtained from an internal customer database. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Demand Forecast

Table 3

Independent Variables Used in the Peak Demand Forecast Model						
	w_hdd55buildup	s_thibuildup	sw_cdd65hdd55buildup	Gross Regional Product	AR Terms	Monthly Binaries
System Peak Demand	X	X	X	X	X	X

Database: Otter Tail Power Company's System Load Data
Variable(s) Used:
System Peak Demand
Description/Source:
Annual hourly system load (MAPP) files and annual hourly net controlled load (NCL) files were obtained from Otter Tail Power Company's System Operations department. System load data was combined with the net controlled load data to give hourly system demands without control.
Adjustments Made:
The hourly system load files are graphed and reviewed for accuracy by System Operations personnel each month.

Database: Woods and Poole
Variable(s) Used:
Gross Regional Product
Description/Source:
2024 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The state profile data contains annual historical data beginning 1969, 1970 or 1990 to 2022 and annual forecast data for 2023-2060 at the county level.
Adjustments Made:
Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10% of the

population of the county. County and city population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a percentage of less than 10% were not included. Towns served were obtained from an internal customer database. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Database: Fargo Weather Data
Variable(s) Used:
s_thibuildup: summer temperature humidity index buildup
Description/Source:
Hourly weather data files were obtained from DTN for Fargo, ND. Fargo is used as a proxy for the system average weather data. The hourly temperature humidity index (*thi*) was calculated from the hourly dry bulb temperatures and the hourly relative humidity (*thi*=*db*-(.55-.55**rh*/100)*(*db*-58)). The average daily temperature humidity index (*thi*) was calculated from the hourly values. The variable *thibuildup* was calculated from *thi* for the day of monthly system peak and *thi* from the previous three days so that each previous day has half the influence of following day ((40/75)**thi* + (20/75)**lag1thi* + (10/75)**lag2thi* + (5/75)**lag3thi*). The variable *s_thibuildup* has the value of *thibuildup* for the months of June, July and August and zero for all other months. The forecast period *s_thibuildup* variable was calculated by determining the value of *thi* for each monthly system peak day and the three days previous to the peak for the last 20 years.
Adjustments Made:
DTN atmospheric data was used rather than the High Plains Climatic Center data to use consistent data across the organization via the purchased service. Data was graphed and reviewed for reasonableness. Any missing or obviously bad data was corrected.

Database: Degree Days
Variable(s) Used:
w_hdd65buildup: winter heating degree day buildup
sw_cdd65hdd65buildup: swing month cooling & heating degree day buildup
Description/Source:
Average hourly temperature data was obtained by averaging hourly temperatures across 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on a 55 degree and 65 degree base, respectively, and the rounded average of the twenty-four hourly temperatures. The variables *hddbuildup* and *cddbuildup* were calculated from the degree days for the day of monthly system peak and the degree days from the previous three days so that each previous day has half the influence of following day (for

example, (40/75)**hdd* + (20/75)**lag1hdd* + (10/75)**lag2hdd* + (5/75)**lag3hdd*). The variable *w_hdd65buildup* has the value of *hddbuildup* for the months of January, February, March, April, October, November and December and zero for all other months. The variable *cddhdd* was calculated by adding 3 times *cdd* to 1 times *hdd* (3**cdd* + 1**hdd*). The variable *sw_cdd65hdd65buildup* has the value *cddhdd* for the months of May and September and zero for all other months. Forecast period *w_hdd65buildup* and *sw_cdd65hdd65builup* variables were calculated by determining the value of *hdd* and *cdd* for each monthly system peak day and the three days previous to the peak for the last 20 years.

Adjustments Made:

Hourly temperatures for each of the 14 requested locations are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected when necessary.

Subp. 3. Discussion. The utility shall discuss in writing each essential assumption made in preparing the forecasts, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions.

Some assumptions need be listed individually for emphasis.

1) **Load Management:**

   Need: Load management control is used at Otter Tail Power during peak conditions. The use of the control is not always predictable. To build a forecast to match a load subject to load management control is not practical.

   Assumption: The forecast is developed to match uncontrolled load. Therefore, to match forecast to load, the observed load must have the estimated controlled load added. This simplifies the process of reconciling the forecast.

   Sensitivity: There is nothing to test.

2) **Woods and Poole Economics, Inc.**

   Need: Economic forecasts are needed to provide projections of population and employment. The forecasts must be consistent among county, state, and national projections, so the forecasts need to be from similar sources or be based on similar assumptions. For this reason, these elements of the forecast are taken from a single source.

   Assumption: Woods and Poole data provides a consistent scenario of the future that connects national, state and county projections. Population and employment follow this story of the future economy.

   Sensitivity: No other alternatives are provided.

See also the above discussions and the discussion below regarding 'subject of assumption'.

Subp. 4. Subject of assumption. The utility shall discuss the assumptions made regarding the availability of alternative sources of energy, the expected conversion from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will likely have on the utility's system demand, the assumptions made in arriving at any data requested in part 7610.0310 that is not available historically or not generated by the utility in preparing its own internal forecast, the effect of existing energy conservation programs under federal or state legislation on long term electrical demand, the projected effect of new conservation programs that the utility deems likely to occur through future state and federal legislation on long term electrical demand, and any other factor considered by the utility in preparing the forecast. In addition the utility shall state what assumptions were made, if any, regarding current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area. If a utility makes no assumptions in preparing its forecast with regard to current and anticipated saturation levels of major electrical appliances and electric space heating it shall simply state this in its discussion of assumptions.

Otter Tail Power Company's forecast assumes availability of alternative sources of energy will continue in similar patterns as have been historically.

Otter Tail Power Company did not assume any changes in the availability of alternative sources of energy, the expected conversions from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will have on the utility's system demand. The current forecast, by default, assumes any price changes would be in small increments where demand would not be noticeably impacted. While price changes due to rate cases are not necessarily smooth in the short-term, for the purposes of the long-term forecast any price changes smooth out over time. This reality is due to the long-term planning process. The utility itself and regulatory bodies are involved in the Integrated Resource Planning process in part to mitigate significant price changes.

Otter Tail Power Company's forecast does not make any explicit assumptions about current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area.

Subp. 5. Coordination of forecasts with other systems.
The utility shall provide in writing:

A. a description of the extent to which the utility coordinates its load forecasts with those of other systems, such as neighboring systems, associate systems in a power pool, or coordinating organizations; and
B. a description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.

Otter Tail Power Company does not coordinate its long-term load forecasts with other systems.

STAT AUTH: MS s 216C.10
HIST: L 1987 c 312 art 1 s 9; 16 SR 1400

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT
CY 2024

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2024

Number of Power Plants	15

UTILITY DETAILS

UTILITY NAME	Otter Tail Power Co
STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION

CONTACT NAME	Nathan Jensen
CONTACT TITLE	Manager, Resource Planning
CONTACT STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8989
CONTACT EMAIL ADDRESS	njensen@otpco.com

UTILITY OFFICERS

NAME	TITLE

PREPARER INFORMATION (do not type "Same as Above")

PERSON PREPARING FORMS	Tim Beddow
PREPARER'S TITLE	Senior Resource Planner
DATE	6/12/2025
PREPARER'S EMAIL ADDRESS	tbeddow@otpco.com

COMMENTS

ALLOWABLE UTILITY TYPES

Code*

Private
Public
Co-op

THIS ANNUAL REPORT MUST BE SUBMITTED TO COMMERCE AS AN EXCEL WORKBOOK.
DO NOT SUBMIT THIS ANNUAL REPORT AS A PDF OR IN ANY OTHER FORMAT.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

CY 2024

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.
Please remember that the number of customers should reflect the ***actual number of customers*** the utility has in that category at year's end, ***not the number of meters*** .

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2024	No. of Customers	1,688	62,507	11,760		672	700	555	77,882	77,882
		MWH	45,716	465,551	329,117		1,811,105	4,777	66,435	2,722,707	2,722,701
Present Year	2025	No. of Customers	1,684	62,541	11,849		679	700	552	78,005	78,005
		MWH	50,170	538,107	342,646		1,773,169	4799	27,919	2,736,810	2,736,810
1st Forecast Year	2026	No. of Customers	1,681	62,577	11,921		679	700	553	78,111	78,111
		MWH	50,826	535,864	343,051		1,814,425	4799	27,984	2,776,949	2,776,949
2nd Forecast Year	2027	No. of Customers	1,678	62,612	11,984		679	700	553	78,206	78,206
		MWH	51,124	533,618	343,947		1,803,419	4799	27,969	2,764,876	2,764,876
3rd Forecast Year	2028	No. of Customers	1,677	62,648	12,044		679	700	553	78,301	78,301
		MWH	51,438	531,369	344,927		1,837,988	4799	27,963	2,798,484	2,798,484
4th Forecast Year	2029	No. of Customers	1,675	62,684	12,103		679	700	553	78,394	78,394
		MWH	51,765	529,123	345,943		1,835,423	4799	27,960	2,795,013	2,795,013
5th Forecast Year	2030	No. of Customers	1,674	62,721	12,161		679	700	553	78,488	78,488
		MWH	52,103	526,882	346,959		1,839,276	4799	27,959	2,797,978	2,797,978
6th Forecast Year	2031	No. of Customers	1,674	62,760	12,218		679	700	553	78,584	78,584
		MWH	52,449	524,645	347,963		1,840,382	4799	27,959	2,798,197	2,798,197
7th Forecast Year	2032	No. of Customers	1,673	62,799	12,276		679	700	553	78,680	78,680
		MWH	52,802	522,412	348,950		1,841,505	4799	27,959	2,798,427	2,798,427
8th Forecast Year	2033	No. of Customers	1,673	62,838	12,333		679	700	553	78,776	78,776
		MWH	53,161	520,176	349,919		1,842,646	4799	27,959	2,798,660	2,798,660
9th Forecast Year	2034	No. of Customers	1,673	62,876	12,391		679	700	553	78,872	78,872
		MWH	53,524	517,933	350,879		1,843,794	4799	27,959	2,798,888	2,798,888
10th Forecast Year	2035	No. of Customers	1,673	62,914	12,448		679	700	553	78,967	78,967
		MWH	53,892	515,677	351,826		1,844,953	4799	27,959	2,799,106	2,799,106
11th Forecast Year	2036	No. of Customers	1,673	62,950	12,505		679	700	553	79,060	79,060
		MWH	54,261	513,411	352,760		1,846,125	4799	27,959	2,799,315	2,799,315
12th Forecast Year	2037	No. of Customers	1,673	62,985	12,563		679	700	553	79,153	79,153
		MWH	54,633	511,133	353,679		1,847,309	4799	27,959	2,799,512	2,799,512
13th Forecast Year	2038	No. of Customers	1,673	63,020	12,620		679	700	553	79,245	79,245
		MWH	55,008	508,847	354,586		1,848,505	4799	27,959	2,799,704	2,799,704
14th Forecast Year	2039	No. of Customers	1,673	63,055	12,678		679	700	553	79,338	79,338
		MWH	55,383	506,553	355,481		1,849,711	4799	27,959	2,799,886	2,799,886

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

THIS ANNUAL REPORT MUST BE SUBMITTED TO COMMERCE AS AN EXCEL WORKBOOK.
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MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - LARGEST CUSTOMER LIST
CY 2024

WHEN E-FILING THIS FORM, IT SHOULD BE UPLOADED AS TRADE SECRET

ENTITY ID#	87
REPORT YEAR	2024

UTILITY DETAILS	
UTILITY NAME	Otter Tail Power Company
STREET ADDRESS	215 S Cascade St, PO Box 496
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[PROTECTED DATA BEGINS…

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2024 MWH

…PROTECTED DATA ENDS]

COMMENTS

THIS LARGEST CUSTOMER LIST SHOULD BE SUBMITTED TO COMMERCE AS AN EXCEL WORKBOOK.
DO NOT SUBMIT THIS LARGEST CUSTOMER LIST AS A PDF OR IN ANY OTHER FORMAT.

APPENDIX I

MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

CONSERVATION AND DEMAND SIDE MANAGEMENT FILINGS

Appendix I

Conservation and Demand-Side Management Reports

APPENDIX I
MINNESOTA POWER'S DEMAND-SIDE MANAGEMENT AND CONSERVATION

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. Applicants requested and were granted an exemption to this rule requirement by the Minnesota Public Utilities Commission. In lieu of the information required by Minn. R. 7849.0290, Applicants agreed to provide a summary of the conservation and demand-side management information that was provided as part of Applicants' individual Energy Conservation and Optimization filings. The Applicants also agreed to provide information regarding how conservation and energy efficiency was considered by Midcontinent Independent System Operator, Inc. ("MISO") in its evaluation of the Project. A summary of this information is provided in this appendix and discussed in Section 3.5 of the Application.

Minnesota Power

Minnesota Power filed its 2024 Energy Conservation and Optimization Plan with the Commission on April 1, 2025 in Docket No. E015/M-25-48. A copy of the "Summary" section and the "Status Report" section of this filing is provided in this appendix. Minnesota Power filed its 2025 Integrated Resource Plan ("IRP") ("2025 IRP") with the Commission on March 3, 2025 in Docket No. E015/RP-25-127. Appendix B of the 2025 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP. A copy of Appendix B of the 2025 IRP filing is provided in this appendix. Additional information regarding Minnesota Power's conservation and demand-side management programs can be found on Minnesota Power's website at: https://www.mnpower.com/ProgramsRebates.

Otter Tail Power Company

Otter Tail Power Company filed its 2024 Energy Conservation and Optimization Status Report with the Commission on April 1, 2025 in Docket No. E017/M-25-49. A copy of the "Summary" section and the "Status Report" section of this filing is provided in this appendix. Otter Tail Power Company filed its 2021 IRP ("2021 IRP") with the Commission on September 1, 2025 in Docket No. E017/RP-21-339. Section 4.8 of the 2021 IRP filing contained information regarding Otter Tail Power Company's demand side management and conservation efforts. A copy of Section 4.8 of the 2021 IRP filing is provided in this appendix.

Great River Energy

Great River Energy's most recent IRP was filed with the Commission on March 31, 2023.[1] The Commission accepted Great River Energy's 2023 through 2027 IRP on June 11, 2024.[2] Department of Commerce review of Great River Energy's 2020 Conservation Improvement Plan was included as Appendix D to Great River Energy's IRP. A copy of Appendix D is provided in this appendix.

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[1] *In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan*, Docket No. ET2/RP-22-75, INTEGRATED RESOURCE PLAN (Mar. 31, 2023), eDockets ID 20233-194396-01, 20233-194396-06.

[2] *In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan*, Docket No. ET2/RP-22-75, ORDER ACCEPTING 2023-2027 RESOURCE PLAN AND SETTING FUTURE FILING REQUIREMENTS (June 11, 2024), eDockets ID 20246-207588-01.

MISO Energy Efficiency Considerations

MISO's annual transmission planning process develops multiple future scenarios to study transmission needs under a variety of economic, policy, and technological possibilities. Each future scenario contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and technological possibilities.

As part of the development of these future scenarios, MISO develops forecasts for conservation, energy efficiency, and demand response, collectively referred to as "Distributed Energy Resources" ("DER") by MISO. These forecasts are developed by aggregating each MISO member's load forecasts. To consider a broader range of potential DER outcomes, MISO creates forecasts considering varying adoption rates, technological advancements, and economic factors. MISO's forecasts are developed for each of MISO's 10 Local Resource Zones, to consider regional differences, and then are aggregated to a MISO-wide forecast.

For the Series 1 futures developed to support Tranche 1, MISO commissioned Applied Energy Group ("AEG") to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities ("LSE") and secondary research.

To support Series 1A modeling used to support Tranche 2.1, AEG compiled DER programs by type and cost into program blocks for Electric Generation Expansion Analysis System ("EGEAS") – an integrated resource planning tool – through study period ending in 2042.

According to AEG data, Future 1 DER program levels represent minimum expected resource levels. Therefore, Future 1A programs are included as minima within the base model of all Series 1A scenarios. Futures 2A and 3A employ all Future 1A program amounts and allow incremental program blocks (the difference of total Future 2A or Future 3A programs and Future 1A levels) for selection. Previously referred to as demand-side additions or management ("DSM"), these resources were modeled as program blocks in three main categories: Demand Response ("DR"), Energy Efficiency ("EE"), and Distributed Generation ("DG"). Programs also fall into two sectors: Residential and Commercial and Industrial ("C&I").

During the program selection phase for the Future 2A and 3A models, incremental program blocks were offered against supply-side alternatives to determine economic viability. For both Future 2A and 3A, EGEAS selected the following program blocks: C&I Price Response, Residential Direct Load Control, and Residential Price Response. Future 2A also selected C&I Demand Response. Additionally, Future 3A selected C&I Utility Incentive PV; C&I High-, Mid-, and Low-Cost Energy Efficiency; and Residential High- and Low-Cost Energy Efficiency. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of the DER programs considered by MISO in MTEP24 is provided below in Table I-1.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals in Table I-2 below. Table I-2 and Table I-3 show total DER technical potential and additions modeled in MISO by the end of the study period.

Table I-1 MTEP24 Distributed Energy Resource Programs[3]

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table N-2 DER Capacity (GW): 20-Year Technical Potential Additions in MISO in Series 1A Futures[4]

Series 1A DERs Capacity (GW) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	10.8	11.2	11.2	11.2	11
Energy Efficiency (EE)	17.7	19.4	17.7	20.5	20.5
Distributed Generation (DG)	19.9	19.9	19.9	28.6	20.5

[3] Available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf
[4] *Id*.

Table N-3 DER Energy (GWh): 20-Year Technical Potential Additions in MISO in Series 1A Futures[5]

Series 1A DERs Energy (GWh) Technical Potential & Added	Future 1A	Future 2A		Future 3A	
	Added	Potential	Added	Potential	Added
Demand Response (DR)	1,051	1,147	1,147	1,154	1,142
Energy Efficiency (EE)	75,620	80,247	75,620	78,763	78,763
Distributed Generation (DG)	34,977	34,977	34,977	48,173	35,993

[5] *Id*.

2024 CONSOLIDATED FILING

ENERGY CONSERVATION AND OPTIMIZATION PLAN











minnesota power

AN ALLETE COMPANY

April 1, 2025

Docket Nos. E-015/M-25-48, E-015/CIP-23-93, E,G-999/CI-22-624

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

April 1, 2025

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

Deputy Commissioner Pete Wyckoff
Minnesota Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101-2198

Re: 2024 Conservation Improvement Program Consolidated Filing
Docket Nos. E015/M-25-48, E015/CIP-23-93

In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act
Docket No. E,G-999/CI-22-624

Dear Mr. Seuffert and Mr. Wyckoff:

Attached please find via eFiling Minnesota Power's 2024 Energy Conservation and Optimization Program ("ECO") Consolidated Filing. This submittal includes an ECO Tracker Activity Report, a Financial Incentives Report, a Proposed Conservation Program Adjustment Factor, 2024 ECO Project Evaluations and a compliance with Department of Commerce ("DOC") orders section. Minnesota Power is filing this information pursuant to Minn. Stat. §§ 216B.241, 216B.16, subd, 6c, 216B.2401, and 216B.2411 and in compliance with Minnesota Public Utilities Commission ("MPUC") and DOC rules and orders relating to annual filings associated with Company-sponsored conservation program activities, including Minn. Rule 7690.0550.

Minnesota Power requests that the MPUC review the filed material and approve Minnesota Power's 2024 ECO Tracker Activity, Financial Incentives, and proposed Conservation Program Adjustment factor. Further, Minnesota Power requests that the DOC review and approve the evaluations of the various ECO projects included herein and the compliance with prior DOC orders. Minnesota Power has electronically filed this document and copies of this Cover Letter along with the Summary of Filing have been served on the parties on the attached service list.

Also included in this filing on page 23 is compliance for Order Point 3 from the September 12, 2023 order in Docket No. E,G-999/CI-22-624, In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act.

If you have any questions regarding this filing, please contact me at (218) 591-4870 or avang@mnpower.com.

Sincerely,



Analeisha Vang
Regulatory Compliance Specialist, Senior

AMV:th
Attach.

SUMMARY

Minnesota Power

2024 Energy Conservation and Optimization Program ("ECO") Consolidated Filing

EXECUTIVE SUMMARY

Minnesota Power (or, "the Company") is pleased to report its 2024 energy conservation program results:

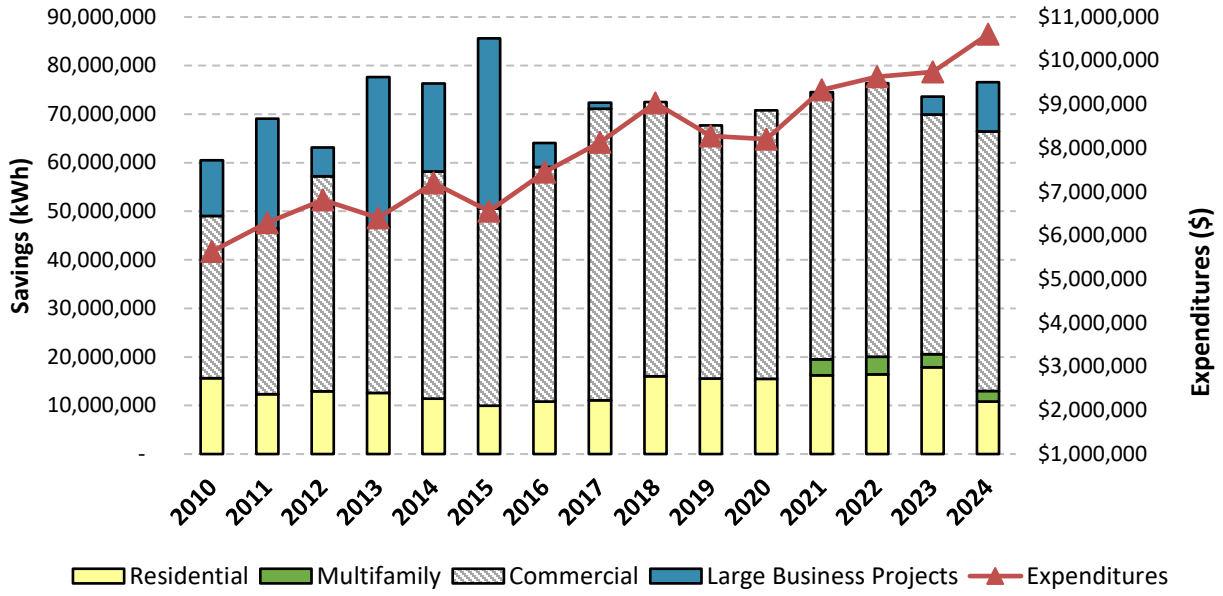
- Minnesota Power achieved energy savings of **3.0%** of gross annual retail energy sales,[1] well above the 1.75% minimum energy-savings goal set in the 2021 Energy Conservation and Optimization Act and detailed in the 2024-2026 Triennial Plan.[2]
- The Company achieved energy savings totaling **76,582,710 kilowatt hours ("kWh")**, which is **105%** of the approved energy-savings goal for the year. The Company also achieved demand savings of **5,942 kilowatts ("kW")**, which is **87%** of the approved demand-savings goal.
- Expenditures totaled **$10,604,663**, which was **84%** of the approved budget for 2024.

The following figure illustrates historical and recent kWh energy-savings achievements, along with ECO expenditures. While Minnesota Power continues to have a successful track record of exceeding the state energy savings goal, the cost of delivering on these goals continues to increase. The Company anticipates the trend of increasing costs will continue as economic changes impact the cost of both products and labor and more cost-effective measures reach market saturation. While Minnesota Power's ECO portfolio continues to be cost-effective overall, higher cost programs – especially those serving income-qualified customers – are becoming increasingly less cost-effective.

[1] In accordance with Minnesota Rules part 7690.1200, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2024–2026 Triennial Plan.

[2] Minnesota Power's minimum goal was updated due to a newly ECO-exempt customer effective January 1, 2024. A Courtesy Notification was approved by the Department July 5, 2024.

Minnesota Power's 2010–2024 ECO Achievements



Minnesota Power's 2024 ECO Expenditures and Energy Savings

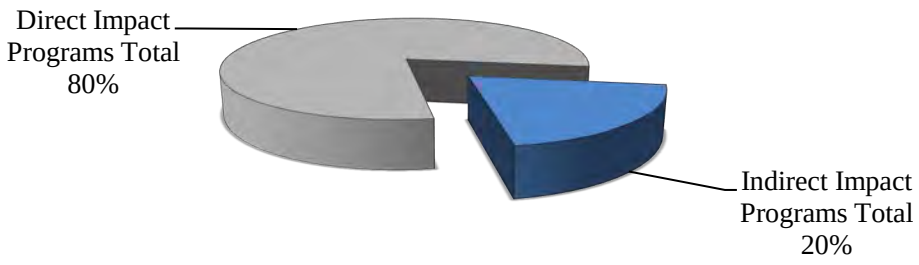
2024	*Expenditures*	*Energy Savings (kWh) at busbar*
Direct Savings Programs:		
Residential		
Energy Partners (Income-qualified)	$561,103	735,109
Home Efficiency (Residential)	$1,977,512	10,091,089
Multifamily		
Multifamily Efficiency	$360,725	2,151,517
Commercial		
Business Efficiency (Business/Commercial/Industrial/Agricultural)	$5,443,941	63,604,995
Indirect Savings Programs:		
Community Engagement	$430,399	
Energy Analysis	$497,313	
Research & Development	$230,419	
Evaluation & Planning	$630,717	
Minnesota Efficient Technology Accelerator, "ETA"	$281,840	
Regulatory Charges	$190,694	
Total	**$10,604,663**	**76,582,710**

STATUS REPORT

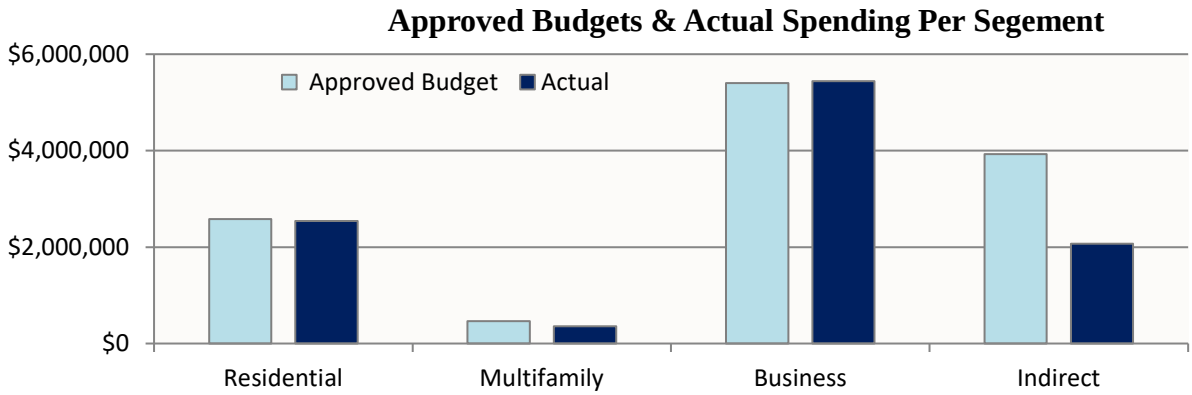
2024 ECO STATUS REPORT

Minnesota Power's energy conservation strategy provides a wide variety of program offerings to best serve its diverse customer mix. Each customer is unique in both their motivations for pursuing energy efficiency opportunities and their ability to engage in different offerings. With this knowledge, Minnesota Power provides a combination of traditional programs and innovative delivery strategies designed to address the needs and barriers of each customer segment including residential, multifamily and business. Minnesota Power's ECO portfolio includes a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a balanced and meaningful customer experience.

2024 Program Spending By Direct and Indirect Savings Programs

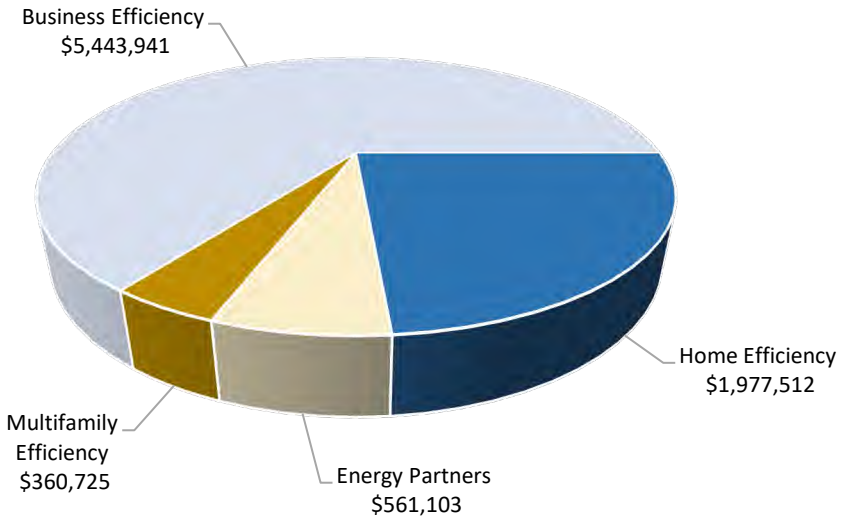


2024 Approved Budgets & Actual Spending Per Segment

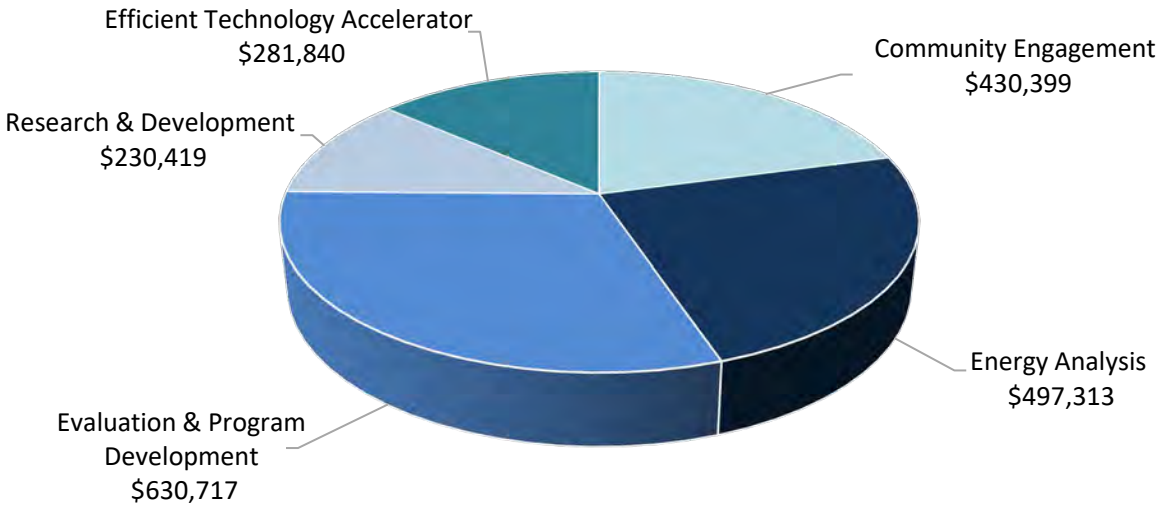


Investing in a range of programs is essential to keep Minnesota Power's program portfolio strong. Minnesota Power has included three vital customer segments along with indirect programs that effectively round out the portfolio in the 2024-2026 Triennial Plan. See the figures below for a breakdown of spending by program.

2024 Direct Programs Spending Breakdown

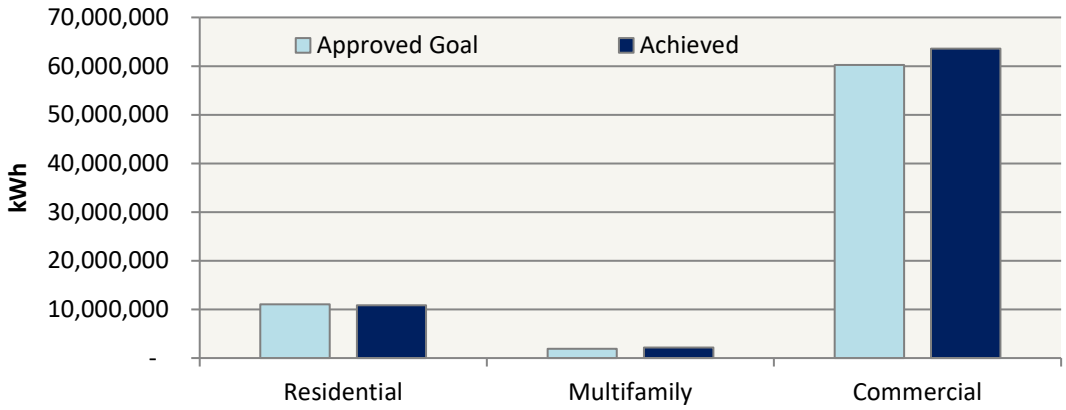


2024 Indirect Programs Spending Breakdown



In 2024, Minnesota Power's ECO portfolio successfully met its overall energy savings goal. Both the Commercial and Multifamily segments surpassed their individual savings goals, while the Residential segment fell slightly short of its target, as illustrated in the chart below. Savings and spending for each program is detailed in each programs section in the filing.

2024 Approved Savings Goals & Achievements per Segment



Looking Forward

There are many factors influencing the energy efficiency environment in Minnesota, including economic pressures leading to rising delivery costs, evolving state and federal policy, and changes in cost effectiveness. Minnesota Power has worked closely with customers, contractors, stakeholders, and regulators to ensure that programs are flexible and responsive to the evolving industry and has taken steps to modify programs as needed. However, additional actions will be required to ensure Minnesota Power's ECO portfolio continues to meet customer needs and encourages equitable access to customer programs as the environment perpetually evolves.

Program delivery costs have increased significantly in recent years. The combination of inflation and economic uncertainty have impacted customers' ability to make capital improvements to their homes and businesses. Additionally, attracting and retaining talent in northern Minnesota has continued to create challenges for customers, delivery partners, and the Company. Encouraging

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customers to make energy-efficient investments has required higher incentives, more costly equipment and more resources than have historically been required.

Minnesota Power's ECO programming is currently undergoing a significant shift and transformation as a result of federal and state policy changes. While adjustments to the ECO statute were approved in the 2024 legislative session, implementation is still in progress. Despite ongoing development and implementation, the Company will be proposing to add efficient fuel switching measures to the ECO portfolio and is exploring load management activities, resulting in a more robust portfolio that further supports utility and state initiatives. Meanwhile, the IRA, which has introduced a significant amount of federal funding for energy efficiency projects, coupled with new state energy programs, present an opportunity for coordination. It will be critical for utilities and the Department to continue to coordinate on the design and eventual implementation of these programs to ensure that customers are able to maximize the benefits of ECO, IRA, and state programs. While effective coordination and implementation of these funds could help address the rising costs of utility conservation programs, there is significant uncertainty around actual impacts.

Meanwhile, the Company continues to assess the implications of the significant modifications made to the ECO evaluation framework and general program cost effectiveness transition from recent years. Recent changes include the addition of a new primary screening test designed to reflect the State's energy policy goals and objectives referred to as the Minnesota Cost Test ("MCT"), inclusion of new utility system and non-utility system impacts within the tests, and potential standardization of existing impacts that historically have been utility specific. In addition, cost effectiveness of efficiency programs overall has been heavily impacted by the increased efficiency standards of general service lighting. These changes, along with rising delivery costs and the new IRA programs described above, make it difficult to predict the overall cost-effectiveness of the ECO portfolio going forward. Flexibility to update and modify programs and portfolios will be more critical than ever as the Company navigates these challenges.

Minnesota Power will continue to work with customers, stakeholders, and regulators to ensure that programs are well-positioned to address challenges and opportunities associated with the rapidly evolving energy conservation and optimization landscape into the future. Minnesota Power remains committed to providing sustainable, inclusive, and cost-effective energy efficiency programs, with ongoing program development and increased efforts to raise program awareness and participation.

Minnestota Power's 2024 ECO Expenditures & Achievements

2024	*Expenditures*				*Energy Savings (kWh @ Busbar)*				*Demand Savings (kW @ Busbar)*				*Participation*			
Direct Impact Programs	***Filed Budget***	***Approved Budget***	***Actual***	***Percent of Approved***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***	***Filed Goal***	***Approved Goal***	***Achieved***	***Percent to Goal***
Home Efficiency	$ 1,930,969	$ 1,933,669	$ 1,977,511.60	102%	10,330,910	10,346,997	10,091,089	98%	1,124	1,126	1,014.3	90%	66,701	66,710	106,536	160%
Energy Partners	$ 642,993	$ 644,687	$ 561,102.87	87%	722,378	725,226	735,109	101%	67	68	71.8	106%	2,156	2,201	2,479	113%
Multifamily Efficiency	$ 465,012	$ 465,612	$ 360,724.81	77%	1,897,574	1,898,945	2,151,517	113%	130	134	462.8	345%	97	99	186	188%
Business Efficiency	$ 5,398,621	$ 5,399,821	$ 5,443,941.07	101%	60,222,957	60,225,700	63,604,995	106%	5,514	5,521	4,393.5	80%	1,344	1,348	1,308	97%
Direct Impact Programs Total	**$ 8,437,594**	**$ 8,443,788**	**$ 8,343,280**	**99%**	**73,173,819**	**73,196,868**	**76,582,710**	**105%**	**6,835.8**	**6,848.7**	**5,942.4**	**87%**	**70,298**	**70,358**	**110,509**	**157%**
Indirect Impact Programs																
Community Engagement	$ 983,500	$ 983,500	$ 430,399	44%									110,800	110,800	98,694	89%
Energy Analysis	$ 1,454,250	$ 1,454,250	$ 497,313	34%									2,362	2,362	3,340	141%
Evaluation & Planning	$ 860,500	$ 860,500	$ 630,717	73%												
Research & Development	$ 350,000	$ 350,000	$ 230,419	66%												
Efficient Technology Accelerator	$ 245,840	$ 281,841	$ 281,840	100%												
Indirect Impact Programs Total	**$ 3,894,090**	**$ 3,930,091**	**$ 2,070,688**	**53%**	-	-	-						**113,162**	**113,162**	**102,034**	**90%**
Regulatory Charges	$ 200,000	$ 200,000	$ 190,694	95%												
Total	**$ 12,531,684**	**$ 12,573,879**	**$ 10,604,663**	**84%**	**73,173,819**	**73,196,868**	**76,582,710**	**105%**	**6,835.8**	**6,848.7**	**5,942.4**	**87%**	**183,460**	**183,520**	**212,543**	**116%**

APPENDIX B: DEMAND SIDE MANAGEMENT AND DISTRIBUTED RESOURCES

This Appendix of the 2025-2039 Integrated Resource Plan ("2025 Plan") contains information regarding Minnesota Power's (or the "Company") planning and strategies for demand side management ("DSM"), including energy efficiency ("EE") and energy conservation and optimization ("ECO"), along with Residential Time-of-Day ("TOD"), alternative demand side management programs, distributed generation ("DG"), and microgrids. This Appendix is broken into five parts as detailed below.

1. Minnesota Power's EE Resource Alternatives and ECO Strategy;
2. Residential TOD;
3. Alternative Demand Side Management Programs;
4. Distributed Generation; and
5. Microgrids.

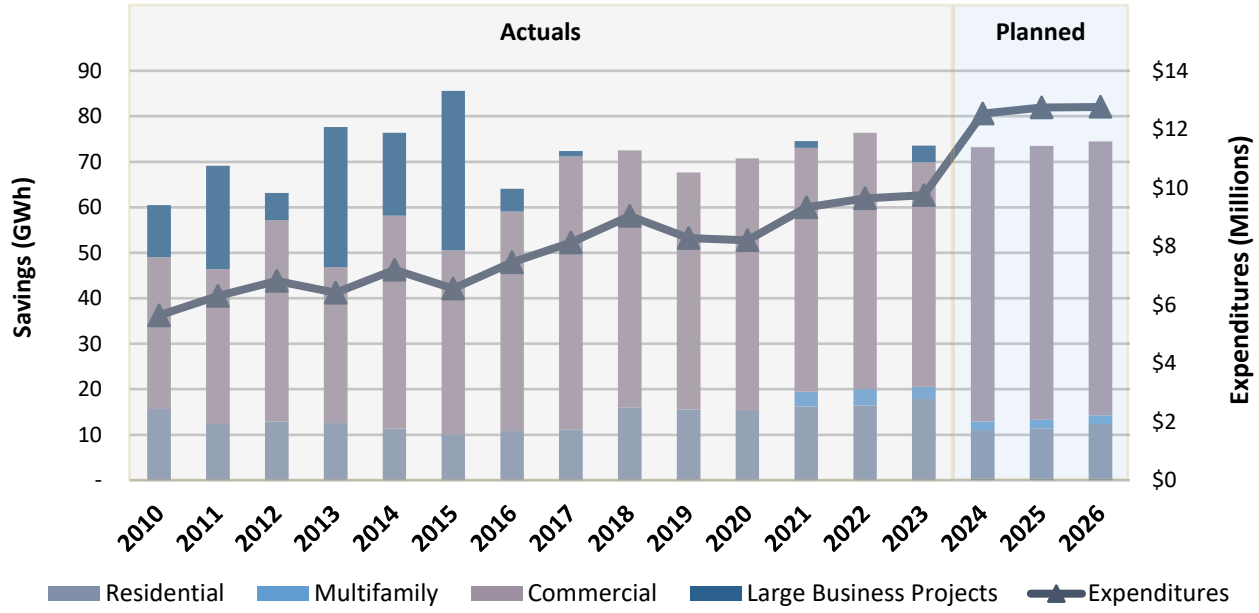
A. Part 1: Minnesota Power's EE Resource Alternatives and ECO Strategy

Minnesota Power is committed to providing sustainable energy-efficiency programs, as demonstrated by its strong historical conservation program achievements. Since the Minnesota Next Generation Energy Act of 2007 ("NGEA"), Minnesota Power has been refining and expanding upon its proven conservation program platform to deliver cost-effective savings, customer value, and environmental benefits. The Energy Conservation and Optimization Act of 2021 ("ECO Act") provided a timely pathway for building on core conservation program offerings and expanding those to reach more customers while providing a broader suite of programs and services. Minnesota Power filed its 2024-2026 Triennial ECO Plan on June 30, 2023,[1] and remains dedicated to continuous program improvement. Ongoing conservation initiatives are part of Minnesota Power's broader *Energy**Forward*** resource strategy – a strategy designed to provide a safe, reliable, and affordable power supply while identifying sustainable solutions for compliance with Minnesota's Carbon-Free Electricity Standard. This part of the appendix discusses the development of the Company's energy conservation targets included in the 2024-2026 ECO Triennial Plan filing[2] and the 2025 IRP baseline assumptions, as well as two increased EE alternative resource scenarios.

Figure 1 below reflects historical (first year) savings achievements and the proposed savings goals for 2024-2026, as filed in the latest ECO Triennial Plan. Minnesota Power, together with its customers, community stakeholders, and trade allies, has achieved great success through its energy conservation programs. The Company has delivered energy savings at or above the state's 1.5 percent energy-savings goal since 2010 when the goal went into effect, all while maintaining focus on targeted program objectives – quality installations, informed decisions, EE, and safety. The proposed goal for 2024-2026 and the assumed EE in the baseline forecast, 2.9 percent of sales, reflect the Company's intent to continue achieving significant savings and is well above the state's new ECO goal of 1.75 percent that became effective with the ECO Act.

[1] *Minnesota Power's 2024-2026 Triennial Energy Conservation and Optimization Program Filing*, Docket No. E-015/CIP-23-93, ECO Triennial Compliance Filing (June 30, 2023)
[2] *Minnesota Power's 2021-2023 Triennial Conservation Improvement Program Filing*, Docket No. E-015/CIP-20-476, Petition (July 1, 2020).

Figure 1. Minnesota Power Historical ECO Achievements and 2024-2026 Goals



2025 IRP Baseline Assumptions and the 2024-2026 ECO Triennial

For purposes of both ECO Triennial planning and 2025 IRP modeling, Minnesota Power started with an approach similar to the 2021 IRP. Assumptions used in the 2021-2023 ECO Triennial and the 2021 IRP were developed using the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Minnesota Department of Commerce and led by the Center for Energy and Environment ("CEE").[3] During the study, Minnesota Power worked closely with CEE to update assumptions used in the Minnesota Power specific projections to more accurately capture the Company's specific territory, customer base, and historical experience with energy efficiency programs. Individual program targets and technology contributions were updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years.[4] Subsequently, the 2021 IRP informed the Company's goals for the 2024-2026 ECO plan, which was used as the baseline EE assumption built into the 2025 IRP customer demand forecast. These savings targets are well above the State of Minnesota's 1.75 percent minimum energy-savings goal for ECO,[5] which equates to roughly 45 gigawatt hours ("GWh") on Minnesota Power's system. The Baseline scenario assumes these savings targets will equate to roughly 74 GWh on Minnesota Power's system in 2024-2026. The savings goals in the ECO Triennial Plan and the efficiency levels assumed in the baseline assumptions for the IRP are aggressive, but the Company believes these

[3] *See* Minnesota Department of Commerce, "Minnesota Energy Efficiency Potential Study: 2020-2029," (December 4, 2018), available at https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf.

[4] The process of updating the CEE potential projections and method used to incorporate them into the 2020 load forecast are documented in the Company's AFR2020, included as Appendix A in the 2021 IRP.

[5] Minn. Stat. § 216B.241, subd. 1c(b) ("A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c).The savings goals must be calculated based on the most recent three-year weather-normalized average.").

are achievable. Individual program targets and technology contributions have been updated to reflect recent historical experience, current policy, industry and market conditions, and realistic expectations for the coming years. As many of these factors are still evolving, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty.

Summary of Alternative Energy Efficiency Scenarios

Based on the current ECO strategy, and analysis of historical performance and future opportunities, Minnesota Power provided two alternative EE scenarios with additional energy and capacity savings above the Baseline Scenario (built into the base/expected 2024 Annual Electric Utility Forecast Report ("AFR2024") forecast). The Company further developed cost projections consistent with each outlook. The two alternative energy efficiency scenarios evaluated in the IRP analysis are:

1. "High" Scenario: modeled to reflect savings of 3.5 percent of sales, and
2. "Very High" Scenario: modeled to reflect savings of 4 percent of sales.

These scenarios were incorporated in the EnCompass modeling process as supply side alternatives in the capacity expansion plan analysis.

The alternative efficiency scenarios ("High" and "Very High") considered in the IRP analysis begin in the year 2027. These alternatives were not modeled as an option for 2024-2026 due to currently approved savings levels and the limited ability to significantly increase EE above the approved 2024-2026 ECO Triennial Plan. All three EE scenarios assume new program implementation costs (and new savings) each year through 2039. For the purposes of modeling the alternative scenarios in the 2025 IRP, only the additional costs and additional first year MWh/MW savings above the baseline are included. A high-level summary of the baseline EE (assumed in the forecast) and the increased efficiency scenarios modeled in the resource plan are shown in Table 1 and includes the following:

- Percentage of Sales: Represents the level of 2027 savings under each scenario as a percentage of average weather normalized 2020-2022, non-ECO exempt retail sales—the baseline for the 2024-2026 ECO Triennial Plan.[6]
- Energy: Total estimated first year energy savings associated with each scenario for the year 2027.
- Energy Above Base: The additional MWh associated with each scenario in terms of first year savings as compared to the baseline plan (EE assumed in forecast).
- Seasonal Peak: Estimated first year MW demand savings coincident with Midcontinent Independent System Operator ("MISO"). Table 1 below shows summer peak for the year 2027 as an example.
- Summer Peak Reduction Above Base: The additional first year MW demand savings associated with the scenario as compared to the baseline plan.
- Incentives: Program costs directly related to incentivizing customers to install/complete an efficiency measure by covering part or all of the incremental costs associated with implementing the measure.
- Non-Incentives: All other costs incurred by the Company to implement the 2027 EE plan.

[6] In accordance with Minn. R. 7690.1200, 2020-2022 weather-normalized average retail energy sales were used to calculate the minimum electric savings goal for Minnesota Power's 2024-2026 Triennial ECO plan. Effective January 1, 2024, adjusted retail energy sales were approved by the Department of Commerce due to a newly exempt ECO Customer. This equated to 2,555,346,232 kWh, net of ECO exempt customers. Savings as a percent of sales in Table 1 were calculated using this figure.

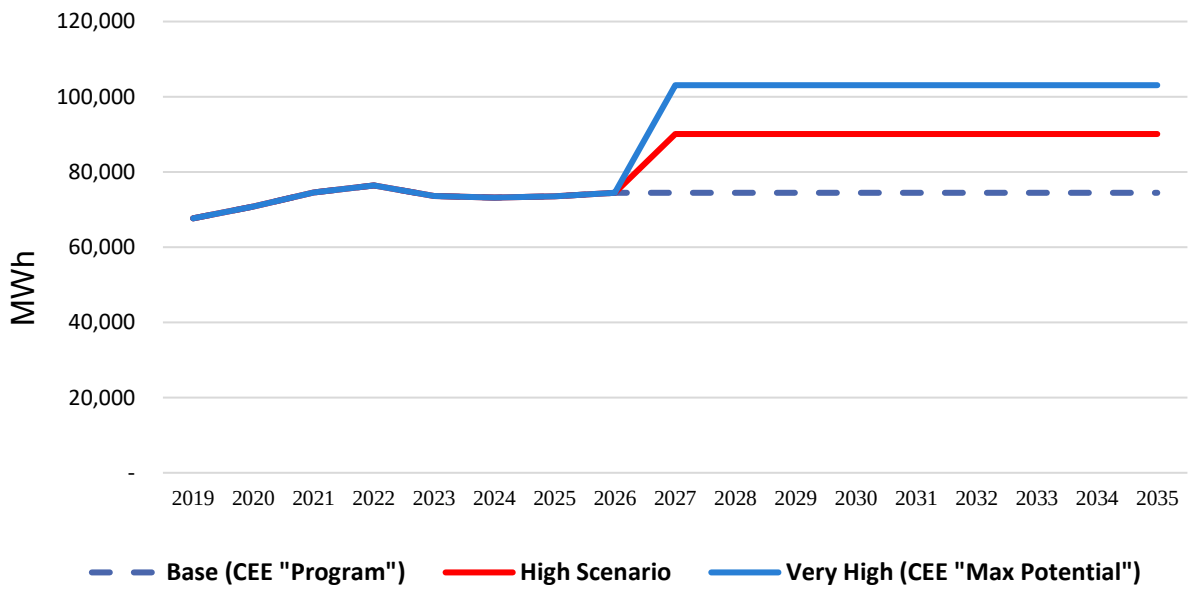
- Total Cost: The estimated total program costs assumed to achieve the level of savings associated with each scenario in the year 2027.
- Total Cost Above Base: The estimated additional spending needed to achieve the incremental savings as compared with the existing plan for the year 2027.

Table 1. Summary of Energy Efficiency Scenarios

		First Year Annual Savings at Generator (Energy: GWh/Peak: MW)				First Year Program Costs (Millions $)			
Scenarios	% of Sales (Rounded)	Energy	Energy Above Base	MP Summer Peak Reduction	Summer Peak Reduction Above Base	Incentives	Non-Incentives	Total Costs	Total Costs Above Base
Base	2.91%	74.5	-	6.8	-	$4.41	$8.15	$12.56	-
High	3.53%	90.1	15.6	8.3	1.5	$14.79	$10.27	$25.06	$12.50
Very High	4.03%	103.1	28.6	9.6	2.8	$32.73	$12.39	$45.12	$32.56

Figure 2 below reflects the first year EE savings (measured at the generator) assumed in each year through 2039 for each of the three scenarios.

Figure 2. 2025 IRP Energy Efficiency Scenarios



Energy Efficiency Scenario Development and Assumptions

As previously noted, Minnesota Power's 2021 IRP was the starting point for developing the 2024-2026 ECO triennial which was used as the Baseline Scenario. The two alternative EE scenarios, which reflect savings levels equivalent to 3.5 percent and 4 percent of eligible sales, were developed by increasing the measure participation assumptions from the baseline scenario

proportionally to arrive at the respective savings levels. The costs for the two higher scenarios were developed using a similar approach to the 2021 IRP EE scenarios. Those incentive costs were increased by setting them to a specific percent of incremental costs and adjusting the non-incentive costs to reflect more aggressive levels of program design, delivery, and marketing efforts anticipated to achieve savings beyond the baseline.

Savings Targets and Contribution

Savings contributions by class and technology for the baseline and planning scenarios align with the savings targets assumed in the 2024-2026 ECO plan. They reflect historical patterns, recent experience, and factors that may impact specific measure or class level savings opportunities including policy changes, market penetration, and updates to approved measures and savings calculations as defined in the Technical Reference Manual ("TRM").[7] Updated avoided costs and net benefit estimates were also taken into account to evaluate changes in cost-effectiveness for various technologies compared to in the past.

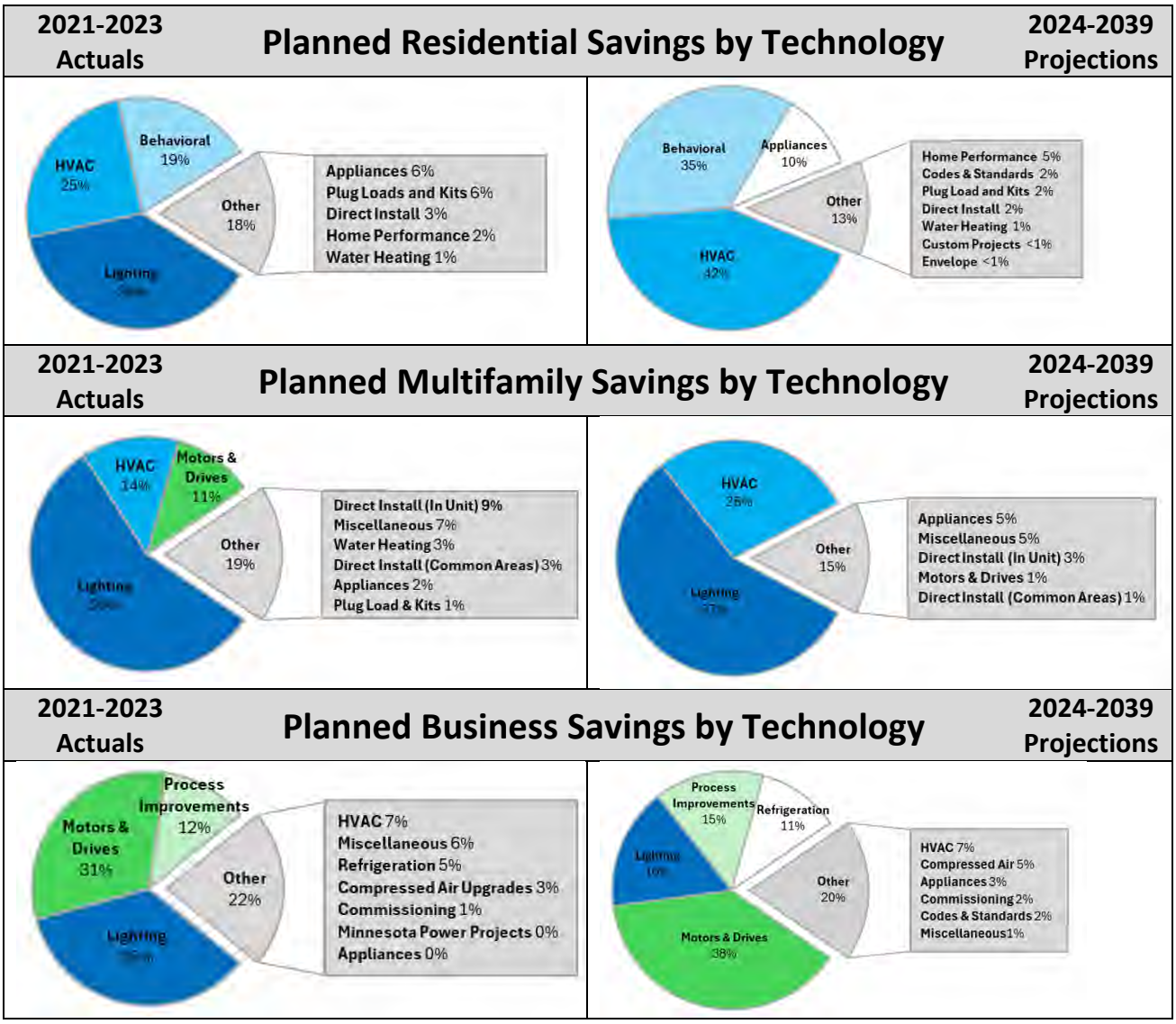
The most significant change to the assumed measure contributions for each EE IRP scenario is the decrease in lighting measures. Minnesota Power updated savings contributions to reflect that new opportunities for lighting savings are significantly less available in residential programs and are diminished in the business program due to changing codes and standards impacting lighting measure baselines and market saturation of commercial and industrial efficient lighting.

Historically, lighting has been a major contributor to all programs requiring a significant shift in measure makeup. For residential, this resulted in a significant shift to heating, ventilation & air conditioning ("HVAC") savings. For business, this resulted in a noticeable shift away from lighting into other evolving technologies such as motors and heating, ventilation, air conditioning & refrigeration ("HVACR"). The impact of lighting measures on the multifamily customer segment is less predictable as multifamily is a relatively small segment and, historically, projects in this segment were incorporated into the business and residential programs. It was first separated out into its own segment in the 2021-2023 Triennial period and future savings contributions are projected to come from similar technology categories. However, given the size of this segment and the limited pool of participants, actual savings contributions could vary from these assumptions in any given year.

Figure 3 reflects actual savings contributions by technology for the 2021-2023 period and the projected savings contributions by technology for 2024 and beyond. For the alternative savings scenarios (High and Very High), all measures in the Baseline scenario were scaled by the same percentage to achieve the targeted savings levels for each program.

[7] Minnesota Department of Commerce, "State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs," (Jan. 20, 2020), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0CDC86F-0000-C832-A29A-F7752BF4A0D9}&documentTitle=20201-159365-02.

Figure 3. Planned Savings by Technology



Scenario Cost Development

Cost assumptions were developed for each scenario for 2027 through 2039. For use in the 2025 IRP analysis, the costs associated with the High and Very High scenarios are incremental to the Baseline scenario. Cost assumptions were made for customer incentives and non-incentive costs which include program design, delivery, administration, evaluation, and marketing. For the baseline scenario, budgets from the approved 2024-2026 ECO Triennial Plan were used. For each of the High and Very High EE scenarios, customer incentives were set to a specific percent of incremental costs (where incremental cost is the difference between the cost of the standard efficiency product or action, or sometimes purchasing nothing/taking no action, compared to the cost of the efficient product or action) and non-incentive costs were increased to reflect the elevated level of program design, delivery, and marketing needed to achieve the additional savings.

Baseline Scenario

2027 cost assumptions for the Baseline scenario were developed to serve as the baseline costs against which the costs for the two higher scenarios would be compared. The Company assumed:

- Customer incentives established in the approved 2024-2026 ECO Triennial Plan. The percent of incremental costs assumed here range based on a variety of factors considered during Triennial planning including cost-effectiveness of the measure, market saturation, customer demand, etc.
- Robust program design and marketing.

High Scenario

This represents anticipated costs associated with increasing savings to 3.5 percent of eligible retail sales. The Company assumed:

- Customer incentives are set to at least 50 percent of incremental measure costs. For measures where the baseline incentive is below 50 percent of the incremental cost, the incentive is increased to 50 percent. For measures where the baseline incentive is already above 50 percent of the incremental cost, the incentive cost is assumed to be the same as in the baseline scenario.
- Aggressive program design and marketing.

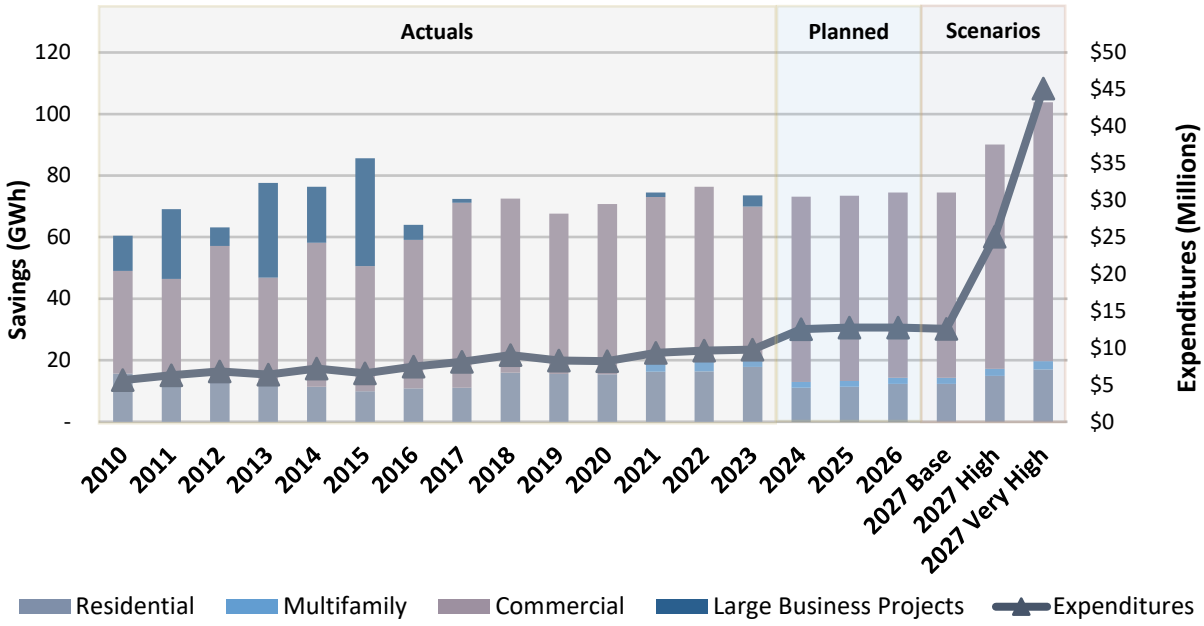
Very High Scenario

This represents the anticipated costs associated with increasing savings to 4 percent of eligible retail sales. The Company assumed:

- Customer incentives are set at 100 percent of incremental measure costs.
- Aggressive program design and marketing.

Figure 4 below expands on the Minnesota Power Historical ECO Performance graph (Figure 1) to include the planned costs and savings for 2024-2026 (as filed in the approved Triennial plan), and 2027 costs and savings as modeled for the Baseline Scenario and two alternative scenarios used in the 2025 IRP analysis:

Figure 4. Historical, Planned, and Modeled CIP Energy Savings (First Year) and Costs

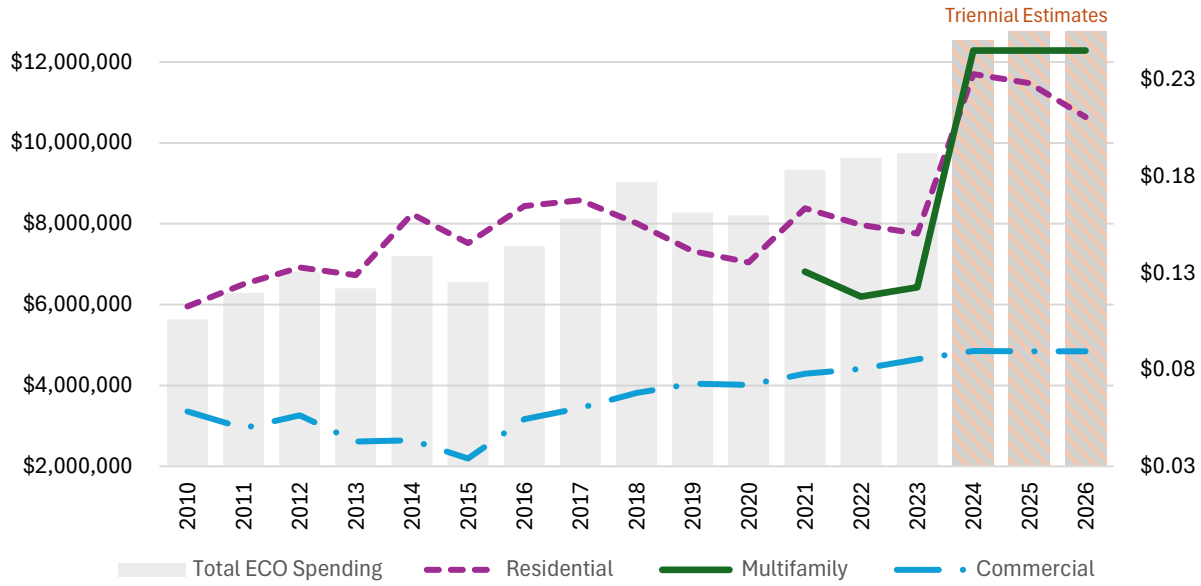


Discussion of Increasing Costs in an Evolving Energy Efficiency Landscape

In developing costs for the 2025 IRP EE scenarios, Minnesota Power started with the budget assumptions approved in the 2024-2026 ECO Triennial filing. Stronger incentive levels and more aggressive program design and marketing will be critical to deliver at the levels discussed in the 2025 IRP. Reduced opportunities for low-barrier measures, changes to measure codes and standards, a changing landscape of market saturation and industry policy, lasting impacts of inflation, and ongoing supply chain and workforce challenges have and continue to impact the need for increased program spending to achieve at or above historical savings levels.

Historical trends show Minnesota Power's overall program costs increasing over time and the Company expects that trend to accelerate. Figure 5 below shows how program costs per kWh have trended over time. Since 2015, commercial and industrial costs per kWh saved have steadily increased and the Company anticipates a significant increase in costs per kWh for the residential and multifamily sectors as well. However, with so many aspects of the energy industry and economy evolving, in order to achieve higher savings goals, the cost per kWh saved will not only continue to trend up, but it will also increase more significantly with higher levels of EE.

Figure 5. Total Spending and Cost per kWh per Program Trending



While Minnesota Power has continued its proven track record of successful program performance, the Company acknowledges that the current energy-efficiency environment is rapidly evolving in ways that will continue to present new challenges. Given that new opportunities for lighting savings are significantly diminished, a transition towards other technologies will be required to maintain savings goals across all programs. Historically, lighting has been one of the most cost-effective and prevalent measures in the ECO portfolio and, in 2023, accounted for nearly 28 GWh in savings (38 percent of total savings). The types of technologies that need to replace these savings are more costly measures that customers may not be as ready (or financially able) to adopt without significant education and incentives to do so. Changing baselines, uncertain economic conditions, high rates of inflation, and workforce constraints will all contribute to Minnesota Power's ability to offer cost-effective, meaningful programs to customers. Increased education and outreach, along with higher rebate levels drive the increase in costs assumed in the 2024-2026 Triennial and 2027 Baseline scenario as compared to the historical costs.

Economic conditions and lasting impacts from the COVID-19 pandemic have affected recent and anticipated program costs in a variety of ways. Increased costs of living for residential customers and higher operating costs for businesses make it more difficult to prioritize energy efficiency investments. Residential customers often must choose between spending money on energy efficiency and other life necessities, both of which have become more expensive. The opportunity cost of updating home appliances or HVAC systems, etc., is greater now than it has been historically. Similarly, commercial customers are facing rising business expenses that impact their ability to spend on energy efficiency measures. To continue achieving high savings levels, Minnesota Power must increase efforts to help customers overcome these financial barriers, while also shouldering higher program delivery costs.

Furthermore, new state and federal policies present both opportunities and challenges for delivering programs that meet customer needs. Specifically, the ECO Act of 2021 and related statute amendments passed during the 2024 legislative session allow for significant expansion of traditional energy conservation programs. While the ECO Act significantly modified the framework for existing utility programs, state and federal energy policies have the potential to be equally as

impactful. Minnesota Power continues to work collaboratively with stakeholders to ensure that new state and federal rebate programs are designed and implemented in a way that maximizes benefits to customers and do not unintentionally cannibalize resources. Additionally, the Company is monitoring federal policy changes to better understand potential impacts to program offerings. As these policies evolve, the Company will continue to monitor and anticipate the impacts on ECO programs and related costs.

Scenario Details

The following tables include the plan parameters for each scenario (savings, costs, participation for Baseline, High, and Very High scenarios).

Table 2. Year 2024 Energy and Demand Savings (MISO Summer Peak)

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
Res	**11,622,274**	**14,062,951**	**16,038,738**	**1,214.0**	**1,468.9**	**1,675.3**
Appliances	893,445	1,081,069	1,232,955	252.3	305.3	348.2
HVAC	4,702,513	5,690,040	6,489,468	386.3	467.4	533.1
Envelope	1,031	1,248	1,423	0.1	0.1	0.1
Home Performance	543,097	657,148	749,474	21.9	26.6	30.3
Water Heating	71,555	86,582	98,746	5.9	7.2	8.2
Plug Load and Kits	176,753	213,872	243,920	14.8	17.9	20.4
Direct Install	201,179	243,426	277,626	16.1	19.5	22.2
Behavioral	4,344,777	5,257,181	5,995,793	495.6	599.7	684.0
Codes and Standards	687,923	832,387	949,334	20.9	25.3	28.8
Administrative Costs	0	0	0	0.0	0.0	0.0
Low Income	**722,378**	**874,078**	**996,882**	**67.2**	**81.3**	**92.8**
Appliances	284,474	344,214	392,575	34.1	41.2	47.0
HVAC	223,213	270,088	308,034	14.7	17.8	20.3
Water Heating	103,214	124,889	142,435	8.6	10.4	11.8
Plug Load and Kits	37,967	45,941	52,395	4.2	5.0	5.7
Home Performance	10,972	13,276	15,141	0.4	0.5	0.6
Custom Project	62,538	75,672	86,303	5.3	6.4	7.3
Administrative Costs	0	0	0	0.0	0.0	0.0
Multi-Family Custom	**1,897,574**	**2,296,064**	**2,618,652**	**130.4**	**157.8**	**180.0**
Lighting	1,077,200	1,303,412	1,486,536	41.7	50.4	57.5
Motors and Drives	24,057	29,109	33,199	0.3	0.3	0.4
HVAC	528,397	639,360	729,188	56.7	68.6	78.2
Miscellaneous	84,105	101,768	116,066	0.3	0.3	0.4
Appliances	99,939	120,926	137,915	22.5	27.2	31.0
Direct Install - In Unit	63,336	76,637	87,404	6.8	8.2	9.4
Direct Install- Common Area	20,539	24,852	28,344	2.3	2.7	3.1
Administrative Costs	0	0	0	0.0	0.0	0.0

	Base kWh	High kWh	Very High kWh	Base kW	High kW	Very High kW
C&I	**60,211,749**	**72,856,216**	**84,150,561**	**5,456.6**	**6,602.5**	**7,661.1**
Lighting	8,464,818	10,242,430	11,681,449	1,232.4	1,491.2	1,700.8
Refrigeration	6,707,469	8,116,038	9,256,308	1,138.7	1,377.8	1,571.4
Motors and Drives	23,108,804	27,961,653	31,890,150	170.8	206.7	235.7
HVAC	4,046,610	4,896,399	5,584,322	561.8	679.8	775.4
Compressed Air Upgrades	2,770,689	3,352,533	3,823,550	302.1	365.5	416.9
Process Improvements	8,985,697	10,872,694	12,400,262	966.3	1,169.2	1,333.4
Appliances	1,599,732	1,935,675	2,207,630	682.6	825.9	942.0
Miscellaneous	852,787	1,031,872	1,176,845	86.5	104.6	119.3
Commissioning	1,126,425	1,362,975	1,554,467	0.0	0.0	0.0
Codes and Standards	2,548,717	3,083,947	4,575,577	315.5	381.7	566.4
Administrative Costs	0	0	0	0.0	0.0	0.0
Indirect	**0**	**0**	**0**	**0.0**	**0.0**	**0.0**
Indirect Program Costs	0	0	0	0.0	0.0	0.0
Grand Total	**74,453,975**	**90,089,309**	**103,804,833**	**6,868.2**	**8,310.6**	**9,609.2**

Table 3. Year 2024 Participation

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Res	**76,701**	**92,809**	**105,849**
Appliances	1,748	2,115	2,412
HVAC	874	1,058	1,206
Envelope	10	12	14
Home Performance	25	30	35
Water Heating	42	51	58
Plug Load and Kits	300	363	414
Direct Install	1,701	2,058	2,347
Behavioral	72,000	87,120	99,360
Codes and Standards	1	2	3
Administrative Costs	0	0	0
Low Income	**2,156**	**2,609**	**2,975**
Appliances	367	444	506
HVAC	380	460	524
Water Heating	607	734	838
Plug Load and Kits	785	950	1,083
Home Performance	2	2	3
Custom Project	15	18	21
Administrative Costs	0	0	0

	Base Scenario Participants	High Scenario Participants	Very High Scenario Participants
Multi-Family Custom	**97**	**117**	**133**
Lighting	32	38	43
Motors and Drives	1	1	1
HVAC	16	19	22
Miscellaneous	4	5	6
Appliances	15	18	20
Direct Install - In Unit	17	21	23
Direct Install - Common Area	13	16	18
Administrative Costs	0	0	0
C&I	**1,269**	**1,535**	**1,753**
Lighting	248	300	342
Refrigeration	157	190	217
Motors and Drives	291	352	402
HVAC	164	198	226
Compressed Air Upgrades	44	53	61
Process Improvements	113	137	156
Appliances	222	269	306
Miscellaneous	10	12	14
Commissioning	19	23	26
Codes and Standards	1	1	3
Administrative Costs	0	0	0
Indirect	**0**	**0**	**0**
Indirect Program Costs	0	0	0
Grand Total	**80,223**	**97,071**	**110,710**

Table 4. Year 2027 Costs

	Base Scenario	High Scenario	Very High Scenario
Residential	**$1,958,077.37**	**$3,043,150.59**	**$5,315,230.58**
Appliances	$118,970.00	$140,969.72	$232,521.72
HVAC	$538,465.00	$1,593,374.00	$3,634,472.88
Envelope	$150.00	$326.70	$745.20
Home Performance	$95,000.00	$95,000.00	$179,986.50
Water Heating	$12,800.00	$20,787.80	$47,416.80
Plug Load and Kits	$9,500.00	$9,500.00	$13,110.00
Direct Install	$16,433.20	$16,433.20	$22,677.82
Behavioral	$35,000.00	$35,000.00	$48,300.00
Codes and Standards	$11,159.17	$11,159.17	$15,399.66
Administrative Costs	$1,120,600.00	$1,120,600.00	$1,120,600.00
Low Income	**$642,992.50**	**$642,992.50**	**$823,333.85**
Appliances	$182,819.50	$182,819.50	$252,290.91
HVAC	$127,797.40	$127,797.40	$176,360.41
Water Heating	$93,645.60	$93,645.60	$129,230.93
Plug Load and Kits	$7,320.00	$7,320.00	$10,101.60
Home Performance	$6,000.00	$6,000.00	$8,280.00
Custom Project	$57,000.00	$57,000.00	$78,660.00
Administrative Costs	$168,410.00	$168,410.00	$168,410.00
Multi-Family Custom	**$465,011.75**	**$549,628.27**	**$828,153.83**
Lighting	$53,556.25	$53,556.25	$92,384.62
Motors and Drives	$1,713.12	$4,200.60	$9,581.52
HVAC	$194,221.94	$194,221.94	$291,959.42
Miscellaneous	$8,528.81	$90,657.85	$206,789.80
Appliances	$12,688.40	$12,688.40	$18,580.09
Direct Install - In Unit	$36,397.50	$36,397.50	$50,228.56
Direct Install - Common Area	$1,905.73	$1,905.73	$2,629.82
Administrative Costs	$156,000.00	$156,000.00	$156,000.00
C&I	**$5,388,111.45**	**$14,602,535.81**	**$29,808,890.51**
Lighting	$572,307.00	$1,516,190.21	$3,458,417.34
Refrigeration	$266,176.00	$1,682,766.61	$3,838,376.73
Motors and Drives	$812,197.00	$3,251,394.30	$7,416,403.53
HVAC	$409,559.00	$1,288,532.44	$2,939,131.84
Compressed Air Upgrades	$49,506.00	$293,713.63	$669,958.37
Process Improvements	$358,483.00	$2,990,051.98	$6,820,283.84
Appliances	$104,440.00	$526,023.77	$1,199,855.88
Miscellaneous	$28,944.00	$267,363.42	$609,853.74
Commissioning	$174,534.00	$174,534.00	$240,856.92
Codes and Standards	$9,965.45	$9,965.45	$13,752.32
Administrative Costs	$2,602,000.00	$2,602,000.00	$2,602,000.00
Indirect	**$4,107,361.00**	$6,227,497.46	$8,347,633.92
Indirect Program Costs	$4,107,361.00	$6,227,497.46	$8,347,633.92
Grand Total	**$12,561,554.07**	**$25,065,804.63**	**$45,123,242.69**

Table 5. Baseline Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,133,865.00	$4,407,183.00	$12,541,048.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,154,371.00	$4,412,814.94	$12,567,185.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	37,878	20,586	20,168	222,256,517
2028	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	50,011	26,958	26,487	292,498,595
2029	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	62,108	33,295	32,772	362,438,953
2030	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	74,097	39,540	39,053	432,251,085
2031	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	86,085	45,784	45,334	502,063,217
2032	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	98,053	52,019	51,598	571,757,129
2033	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	109,882	58,170	57,738	640,729,172
2034	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	121,682	64,302	63,852	709,525,474
2035	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	131,856	69,446	68,936	767,877,919
2036	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	142,023	74,585	74,013	826,192,455
2037	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	150,052	78,128	78,165	873,075,338
2038	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	158,384	81,922	82,454	921,623,798
2039	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,663	6,868	6,815	74,453,975	166,697	85,705	86,726	970,075,651

Table 6. High Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,561,554.00	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,546,679.94	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$8,154,371.00	$4,407,183.00	$12,561,554.00	15,323	8,311	8,246	90,089,309	40,538	22,028	21,599	237,891,852
2028	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	55,327	29,842	29,347	323,763,044
2029	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	70,077	37,621	37,057	409,314,931
2030	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	84,607	45,196	44,658	493,814,538
2031	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	99,136	52,772	52,259	578,314,146
2032	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	113,621	60,317	59,842	662,668,606
2033	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	127,967	67,780	67,301	746,301,196
2034	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	142,280	75,222	74,730	829,733,220
2035	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	154,938	81,657	81,104	902,569,794
2036	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	167,583	88,084	87,465	975,331,553
2037	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	177,749	92,707	92,685	1,034,468,450
2038	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	188,216	97,580	98,040	1,095,262,962
2039	$10,274,507.46	$14,791,297.13	$25,065,804.59	15,323	8,311	8,246	90,089,309	198,285	102,162	103,217	1,153,940,114

Table 7. Very High Scenario Cumulative Effects

				Yearly				Cumulative			
Year	Admin	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2025	$8,154,371.00	$4,407,183.00	$12,546,679.93	12,593	6,856	6,575	73,491,547	12,593	6,856	6,575	73,491,547
2026	$8,133,865.00	$4,412,814.94	$12,561,554.06	12,663	6,868	6,815	74,453,975	25,247	13,724	13,382	147,915,898
2027	$12,394,643.92	$32,728,598.77	$45,123,242.69	17,607	8,311	9,531	103,804,833	42,822	23,327	22,884	251,607,376
2028	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	59,894	32,439	31,916	351,189,056
2029	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	76,922	41,515	40,907	450,437,197
2030	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	93,639	50,299	49,703	547,885,013
2031	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	110,356	59,083	58,499	645,332,829
2032	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	127,010	67,821	67,276	742,613,700
2033	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	143,526	76,477	75,929	839,172,701
2034	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	160,005	85,109	84,550	935,511,038
2035	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	174,805	92,721	92,095	1,021,131,208
2036	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	189,587	100,322	99,622	1,106,646,686
2037	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	201,614	105,950	105,833	1,176,761,847
2038	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	213,940	111,828	112,178	1,248,528,178
2039	$12,394,643.92	$32,728,598.77	$25,065,804.59	17,607	8,311	9,531	103,804,833	225,561	117,188	118,214	1,316,541,301

Summary of Findings

Minnesota Power has a proven track record of successful ECO performance and anticipates continuing this trend into the future, as indicated by the aggressive goals set forth in the 2024-2026 Triennial Plan and assumed in the 2025 IRP baseline forecast. However, the Company acknowledges that the current EE environment is rapidly evolving in ways that will continue to present new challenges. Changing baselines, uncertain economic conditions, evolving policy and incentives, and avoided costs will all affect Minnesota Power's ability to offer cost-effective, meaningful programs to customers. While Minnesota Power continues to build on the successes of its existing programs and adapt to challenges through unique and innovative program offerings and delivery strategies, achieving this higher level of savings through less cost-effective measures will be more resource intensive. Additionally, long-term EE savings require customers to take specific actions year after year, which introduces uncertainty regarding whether these savings will materialize. For these reasons, among others, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty. The Company has done so, while also testing what could be achieved by including alternative scenarios in its IRP analysis.

B. Part 2: Residential TOD

Time-of-Day residential rate impacts are also captured in 2025 IRP scenario planning. The Company's approved Petition for Changes to Minnesota Power's Residential Rate Design[8] included a roughly 2:1 on-peak to super off-peak price ratio, and an on-peak period lasting from 3 p.m. to 8 p.m. on weekdays, which encompasses the most common summer and winter peak times. The rate structure includes time-of-use base energy rates as well as time-of-use fuel and purchased energy adjustments. The associated rate specifications are shown in Table 8.

Table 8. Current TOD Rates ($/kWh) and Hours

	Base Energy Rate	Base Energy Rate + Fuel & Purchased Energy	Weekday Hours	Weekend Hours
Standard (Flat) Rate	$ 0.0940	$ 0.1350	N/A	N/A
On-Peak	$ 0.1307	$ 0.1800	3 pm to 8 pm	N/A
Off-Peak	$ 0.09164	$ 0.1350	5 am to 3 pm; 8 pm to 11 pm	5 am to 11 pm
Super Off-Peak	$ 0.06726	$ 0.0990	11 pm to 5 am	11 pm to 5 am

The approved transition plan consisted of a multi-phased approach to implementing and evaluating the TOD rate. Currently, the Company has completed the first phase of the transition along with an evaluation of the phase's first 12 months. While the first phase focused on operational efficiencies and customer feedback, an analysis of price response was completed as part of the evaluation. Due to the nature of the implementation during this phase, the analysis was limited. The results of this analysis are useful to begin understanding potential long-term impacts of a full roll-out of the TOD rate and were used to develop estimated impacts as part of IRP scenario planning. The Company views these impacts as preliminary and anticipates more refined estimations in the future as later phases of implementation and evaluation with more focus on price response are completed. Due to the preliminary nature of these estimates and the Company still being in the early stages of transitioning to default TOD rates, these impacts are not assumed in the base case.

As part of the February 29, 2024 compliance filing in the residential rate design docket, analysis was completed by third-party consultant Demand Side Analytics ("DSA") to estimate the observed price elasticity using the participant data from Phase I of the transition. As described in Appendix A of the compliance filing:[9]

> This analysis was conducted using a fixed effects model designed to isolate and remove static differences between customer groups, thereby focusing on variations in electricity consumption attributable to the differences in the flat rate and the TOD rate structures.
>
> Equation 3 outlines the specific model utilized estimate the price elasticity. Notably, a temperature coefficient was included to control for variation that can be attributed to

[8] *In the Matter of the Petition for Approval of Changes to Minnesota Power's Residential Rate Design,* Docket No. E-015/M-20-850, Petition (Dec. 1, 2020).
[9] *In the Matter of the Petition for Approval of Minnesota Power's Residential Rate* Design, Docket No. E-015/M-20-850, Compliance Filing at Appendix A at 24 (Feb. 29, 2024).

weather. The customers included in this model were those on the TOD rate and the new customers on the flat rate, starting service after the start of Phase I.

Equation 3 - Price Elasticity Model

$$\ln(kWh_{it}) = \beta_0+\beta_1 \ln(Price_{it})+\beta_2 (TempF_{it})+\alpha_i+\gamma_t+\varepsilon i_{th}$$

Where:

$\ln(kWh_{it})$ is the logged kWh for customer i at datetime t
$\ln(Price_{it})$ is the logged price variable for customer i at datetime t
$TempF_{it}$ represents the temperature in Fahrenheit for customer i at datetime
β_0 is the intercept term.
β_1 is the coefficient for logged price. This value represents the price elasticity
β_2 is the coefficient for temperature, indicating the estimated effects of weather on the dependent variable.
α_i represents the fixed effects for each customer i, capturing unobserved characteristics that are constant over time for a specific customer, but may vary between customers.
γ_t represents the fixed effects for each datetime t, capturing time-specific effects that are constant across all customers but vary over time.
ε_{ith} is the error term for customer i at datetime t

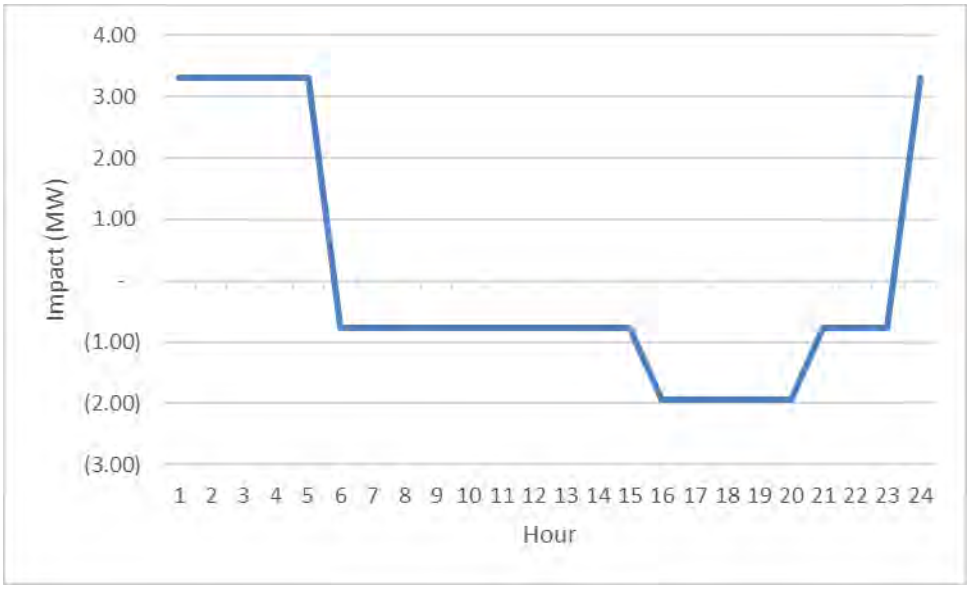
The analysis estimated that participants reduced their load during on-peak periods by 1.88 percent on average. Average impacts during off-peak periods were estimated to be a 0.66 percent reduction in usage and impacts during super off-peak periods were estimated to be a 4.5 percent increase in usage. The super off-peak impact was adjusted such that the total forecasted usage for the residential customer class was net neutral – i.e., the timing of when the usage is occurring is shifted but there is no overall decrease or increase to the forecasted load.

Table 9 below shows the percent kW impacts by TOD period. The on-peak, off-peak, and adjusted super off-peak percent impacts were applied to residential customer use profiles to create the forecasted hourly impacts associated with 100 percent residential customer participation in the TOD rate. The resulting average hourly impact shape is reflected in Figure 6 below.

Table 9. Percent kW Impact by TOD Period

Percent kW Impact			Adjusted % kW Impact
On-Peak	Off-Peak	Super Off-Peak	Super Off-Peak
-1.88%	-0.66%	4.50%	3.84%

Figure 6. Average Hourly Impacts from Residential TOD



C. Part 3: Alternative Demand Side Management

Minnesota Power has a very successful demand response program for industrial, residential, and commercial customers that plays an important role in the annual energy and capacity planning for Minnesota Power operations. Today, Minnesota Power has approximately 250 MW of interruptible demand response capability with industrial customers on its system, which is typically procured under one-year contract terms. The 2025 IRP evaluated as alternatives to supply side resources a new enhanced industrial demand response program and two demand response programs for residential and small commercial/industrial customers.

Central air conditioner ("CAC") cycling and electric hot water heater ("HW") demand response programs for residential and commercial customers were screened in the capacity expansion analysis. A demand response program that is expanded to include economic energy curtailments for industrial customers was also screened in the capacity expansion analysis.

Estimates of participation, saturation of CACs in homes and businesses, and anticipated percent of customers called on at any given time indicate a potential of 7.4 MW of capacity reduction for the CAC cycling program. This accounts for cycling the unit off for 15 minutes then on for 45 minutes which allows flexibility for CAC units to keep up with cooling demand while avoiding a post-event rebound period.

The HW program does not assume an on/off cycle during the event and instead would disconnect the HW for the duration of the event. Estimated customer participation and saturation of electric HWs indicates a potential of 4.5 MW of demand reduction.

Both programs require the installation of equipment that allows for the Company to control the CAC or HW load. The total cost of the equipment, labor, and necessary programming is estimated at $400 per participant, in 2024 dollars, based current equipment and labor rates. After this initial cost, ongoing costs include a bill incentive of $30 per participant per year for CAC cycling program customers and $60 per participant per year for HW program customers.

The utility cost of implementing these demand response programs would include, in 2024 dollars, an initial program capital expenditure of $143,000 (approximate) and annual O&M of $72,000 (approximate). This would be needed to support interface and control application software. The initial program cost and annual O&M were allocated between the CAC and HW programs based on participation.

The industrial demand response alternative modeled in the IRP expands Minnesota Power's program for industrial customers to include energy curtailment, along with emergency curtailment – it is referred to as "Product B" in the IRP analysis. This capacity is available in 2028, when the Product C demand response program subscription ends. The Product C program was approved by the Commission in 2021.[10]

Product B includes long-term capacity with economic energy curtailment. This product would offer a meaningful demand payment to customer for the opportunity to utilize their industrial capability for meeting the broader system needs. For this proxy program incorporated into the IRP evaluation there was a $7 per kW-month capacity credit and provides a $30 per MWh energy credit for curtailed energy. These parameters would be refined further when an actual tariff is brought forward with customers.

D. Part 4: Distributed Generation

The 2025 IRP includes assumptions for residential and commercial/industrial adoption of distributed solar generation, these assumptions are what comprises the "Base Case." The forecast methodology for distributed solar adoption and a resulting decrease in Minnesota Power sales are described below for both the Base Case and a Scenario which assumes a more aggressive adoption of distributed generation.

New DG solar installations were projected using the U.S. Energy Information Administration's forecast for distributed solar generation. This outlook for the number of new installs is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installations (i.e., installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company's Base Case forecast assumes about 4,220 new small-scale DG solar installations, adding almost 44,000 kW of nameplate capacity, will be connected to the Minnesota Power grid by 2038 (i.e., installed in years 2024-2038). These new installations would generate about 46,000 megawatt hours ("MWh") per year and reduce sales to residential and commercial sectors by an equivalent amount. The Base Case forecast assumes cumulative capacity expands at an 11 percent compound annual growth rate ("CAGR") from 2023 to 2038.

The Company's Scenario forecast utilizes the same U.S. Energy Information Administration's DG solar generation forecast but with a doubled growth rate. This updated growth rate projects approximately 5,590 new small-scale DG solar installations which adds approximately 58,000 kW of nameplate capacity that will be connected to the Minnesota Power grid by 2038. The new installations would generate almost 61,000 MWh per year of reduced sales to residential and commercial sectors, as shown in Figure 7. The Scenario forecast assumes a 13 percent CAGR from 2023 to 2038.

[10] *In the Matter of the Petition by Minnesota Power for Approval of its Industrial Demand Response Product C Contracts*, Docket No. E015/M-21-28, Order Establishing Pilot Program (Oct. 29, 2021).

Figure 7. Distributed Solar Generation Lost Sales

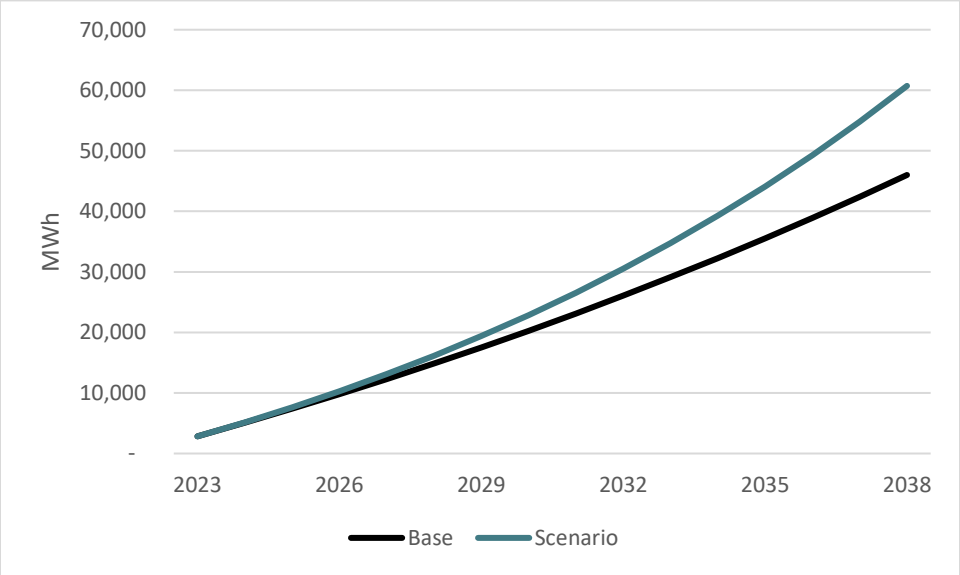
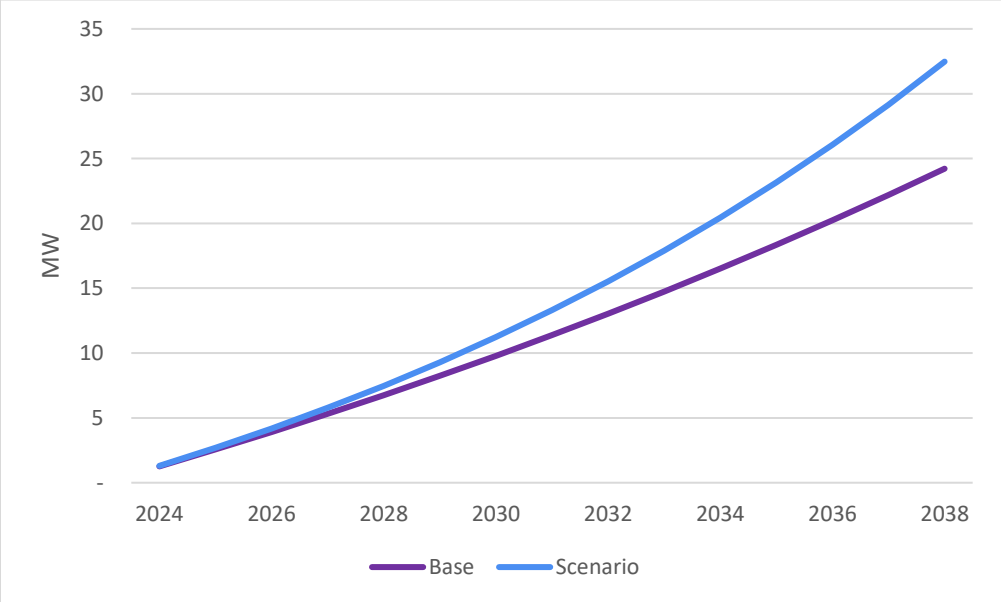


Figure 8. Distributed Solar Generation (Summer Peak)



E. Part 5: Microgrids

Microgrids provide an alternative energy solution for a clean, resilient, and reliable grid. Microgrids also interconnect loads and distributed energy resources to provide electric power when needed either connected or disconnected to the grid. Minnesota Power is exploring the benefits of microgrids, which includes pacing with customer interest. Microgrids are poised to

enhance energy sustainability and meet evolving customer demands and Minnesota Power will continue investigating the potential of microgrids on its system.

APPENDIX D

2020 CIP Approval Letter

2023-2037 INTEGRATED RESOURCE PLAN

Submitted to the Minnesota Public Utilities Commission
Docket No. **ET-2/RP-22-75**
March 31st, 2023

COMMERCE DEPARTMENT

June 23, 2022

Jeffrey Haase
Great River Energy - All-requirements members
12300 Elm Creek Blvd.
Maple Grove, MN 55369

RE: Electric Conservation Improvement Program (CIP) 2020 Results and 2022 Plans

Dear Jeffrey Haase:

Thank you very much for Great River Energy - All-requirements members' (GRE) efforts and those of its members to report 2020 Conservation Improvement Program (CIP) results and a 2022 CIP plan in ReportingESP. My Staff at the Minnesota Department of Commerce, Division of Energy Resources (Department) have finished reviewing this information.

Minnesota Statutes Section 216B.241 Subd 1b(f) provides that a generation and transmission cooperative electric association, a municipal power agency, or other not-for-profit entity that provides energy service to cooperative or municipal utilities that provide electric service at retail to consumers may invest in energy conservation improvements on behalf of the associations it serves and may fulfill the CIP conservation, spending, reporting, and energy-savings goals on an aggregate basis. The information presented in this letter reflects the aggregate effort of the members of GRE indicated. There may be additional retail utilities that GRE provides electric services to that are not represented in the aggregate results included in this letter. The Department notes that the following exempt utilities are continuing to offer programs and report with GRE:

- Arrowhead Electric Coop. Inc
- Brown Co Rural Electrical Assn
- Goodhue County Coop Electric Assn
- North Itasca Electric Coop

2020 CIP RESULTS

The CIP accomplishments for GRE members for 2020 are summarized in the graphs and tables below. The statutory energy savings goal and spending amounts are outlined in Table 1.

Table 1. Minnesota Utility Energy Savings Goal and Spending Amounts

Metric	Amount	Baseline Year(s)	Citation
Energy Savings (kWh)	1.5% of average weather-normalized retail sales at the generator, less sales to CIP exempt customers	2016-2018	Minn. Stat. § 216B.241 subd. 1c(b)
Total Spending ($)	1.5% of retail gross operating revenue, less revenues from exempt customers	2018	Minn. Stat. § 216B.241 subd. 1b
Low-Income Spending ($)	0.2% of average residential gross operating revenue of each member utility	2016-2018	Minn. Stat. § 216B.241 subd. 1(l) Minn. Stat. § 216B.241 subd. 7(a)

Additionally, my Staff have provided an appendix at the end of this letter summarizing these and additional components of the CIP statute.

2020 Energy Savings Results

Figure 1 shows GRE's aggregate CIP energy savings for 2020.

Figure 1. 2020 Energy Savings (kWh)

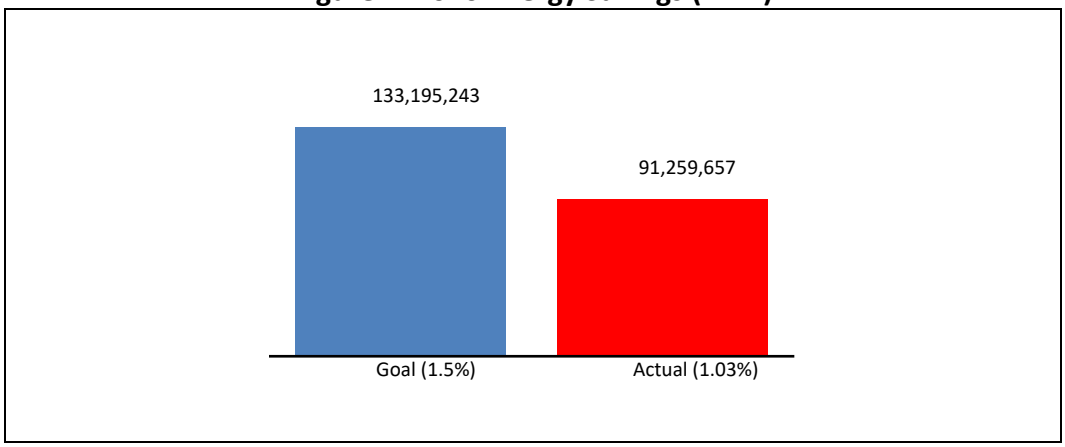


Table 2 provides a summary of GRE's CIP energy savings achievements by member.

Table 2. 2020 Energy Savings Results

Member Organization	Energy Savings Goal (kWh)	Actual Energy Savings (kWh)
Arrowhead	1,082,058	174,443
BENCO	4,793,971	1,974,881
Brown	2,050,960	420,991
Connexus	29,792,581	20,001,915
Cooperative	1,493,400	381,609
Dakota	27,470,825	28,459,203
East Central	13,941,203	7,167,618
Goodhue	1,417,211	432,009
Itasca Mantrap	3,197,861	4,024,216
Kandiyohi	2,405,905	1,072,969
Lake Country	9,076,233	5,781,964
Lake Region	6,528,771	2,430,160
McLeod	2,539,060	458,385
Mille Lacs	2,941,447	2,212,315
Nobles	2,266,249	1,181,298
North Itasca	4,092,620	137,731
Runestone	3,426,778	2,503,493
Stearns	7,773,376	6,259,670
Steele Waseca	4,295,555	4,475,674
Todd Wadena	2,609,179	1,709,115
Total	133,195,243	91,259,657

2020 Total Spending Results

Figure 2 shows GRE's aggregate CIP spending for 2020.

Figure 2. 2020 Total Spending

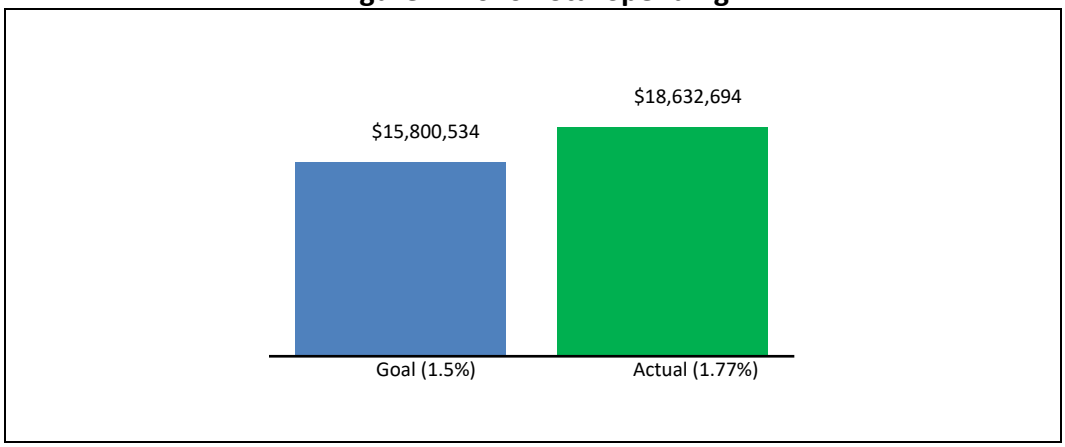


Table 3 provides a summary of GRE's CIP spending by member.

Table 3. 2020 Spending Results

Member Organization	Minimum Spending	Actual Spending
Arrowhead	$150,142	$130,373
BENCO	$561,713	$780,152
Brown	$207,851	$192,273
Connexus	$3,751,089	$4,603,458
Cooperative	$192,120	$209,597
Dakota	$3,027,333	$3,843,375
East Central	$1,831,421	$2,061,806
Goodhue	$188,586	$94,467
Itasca Mantrap	$374,389	$477,516
Kandiyohi	$307,109	$222,274
Lake Country	$1,316,127	$1,682,957
Lake Region	$762,287	$769,925
McLeod	$301,632	$234,208
Mille Lacs	$385,620	$503,721
Nobles	$215,987	$301,210
North Itasca	$128,959	$167,548
Runestone	$421,389	$737,322
Stearns	$880,623	$721,355
Steele Waseca	$492,018	$526,746
Todd Wadena	$304,140	$372,411
Total	$15,800,534	$18,632,694

2020 Low-Income Spending Results

While Department policy currently allows cooperatives and municipalities to count a portion of general residential spending as spending on low-income customers, the Department strongly encourages all utilities to meet their low-income spending amounts through programs that directly serve the needs of low-income persons. Figure 3 shows low-income CIP spending for 2020 for each of GRE's members. Please note that the low-income spending metric applies to each member utility individually.

Figure 3. 2020 Low-Income Spending

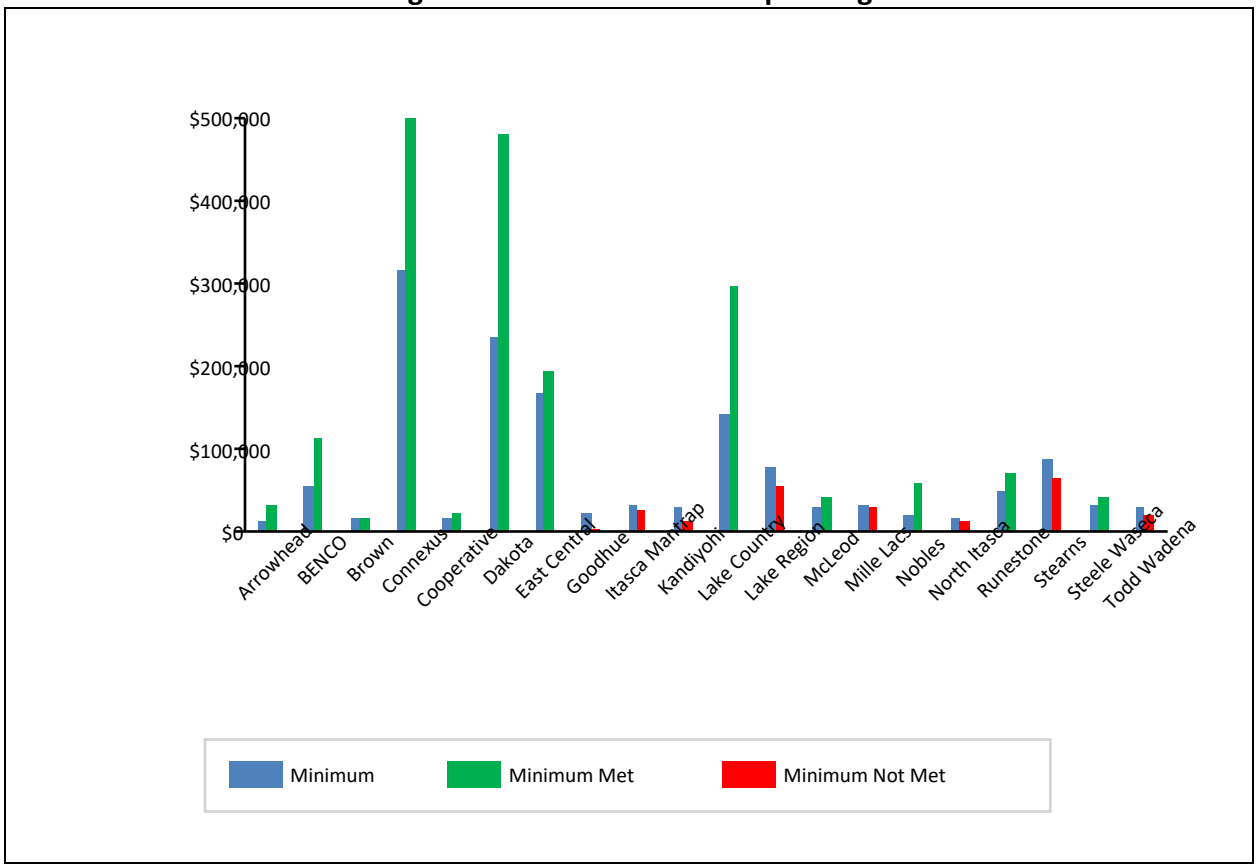


Table 4 provides a summary of GRE's low-income CIP spending by member.

Table 4. 2020 Low-Income Spending Results

Member Organization	Minimum Spending	Actual Spending	Passed
Arrowhead	$12,527	$31,620	Yes
BENCO	$53,787	$112,211	Yes
Brown	$15,596	$16,521	Yes
Connexus	$316,200	$498,718	Yes
Cooperative	$15,172	$22,639	Yes
Dakota	$234,443	$480,496	Yes
East Central	$167,412	$191,366	Yes
Goodhue	$22,487	$2,559	No
Itasca Mantrap	$30,718	$24,286	No
Kandiyohi	$27,311	$12,688	No
Lake Country	$139,701	$297,016	Yes
Lake Region	$76,436	$54,730	No
McLeod	$28,884	$42,021	Yes
Mille Lacs	$33,046	$27,160	No
Nobles	$20,348	$58,113	Yes
North Itasca	$14,335	$10,982	No
Runestone	$46,412	$70,556	Yes
Stearns	$85,379	$63,547	No
Steele Waseca	$32,352	$41,115	Yes
Todd Wadena	$28,264	$18,086	No
Total	$1,400,809	$2,076,429	N/A

2020 Spending Caps on Optional Investments

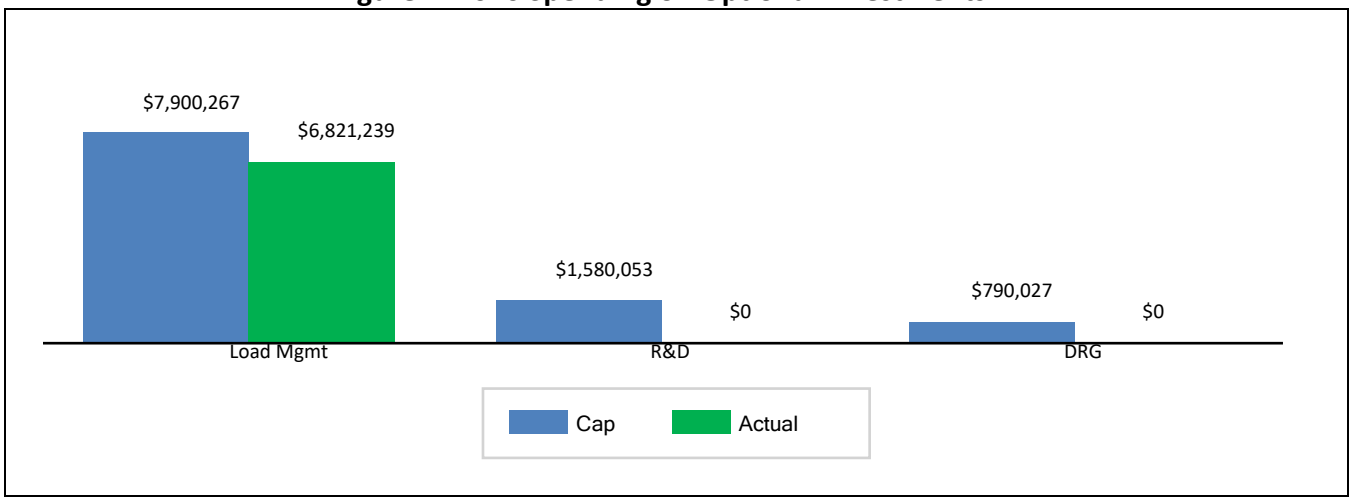
In addition to the energy savings goal, and the total and low-income spending amounts, there are some caps on spending amounts for certain optional investments. These spending caps are listed in Table 5.

Table 5. CIP Spending Caps on Optional Investments

Optional Investment	Spending Cap	Citation
Load Management Programs	Up to 50% of minimum spending	Minn. Stat. § 216B.241 subd. 1(k) Minn. Stat. § 216B.241 subd. 1b(e)
R&D Activities	10% of minimum spending	Minn. Stat. § 216B.241 subd. 2(c)
Distributed and Renewable Generation (DRG) Programs	5% of minimum spending	Minn. Stat. § 216B.2411 subd. 1

Figure 4 shows GRE's aggregate spending on load management, research and development, and distributed and renewable generation investments.

Figure 4. 2020 Spending on Optional Investments



2020 Summary of Results

Table 6 provides a summary of GRE's accomplishments concerning the components of the CIP statute.

Table 6. Summary of 2020 Results Compliance

Metric	Passed
Energy Savings (kWh)	No
Total Spending ($)	Yes
Low-Income Spending ($)	No
R&D Spending Cap ($)	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes
Load Management Spending ($)	Yes

2022 PLAN REVIEW

The CIP plan for 2022 presented by GRE is summarized in the graphs and tables below.

2022 Energy Savings Goal

Figure 5 shows GRE's planned aggregate CIP energy savings for 2022.

Figure 5. 2022 Energy Savings (kWh)

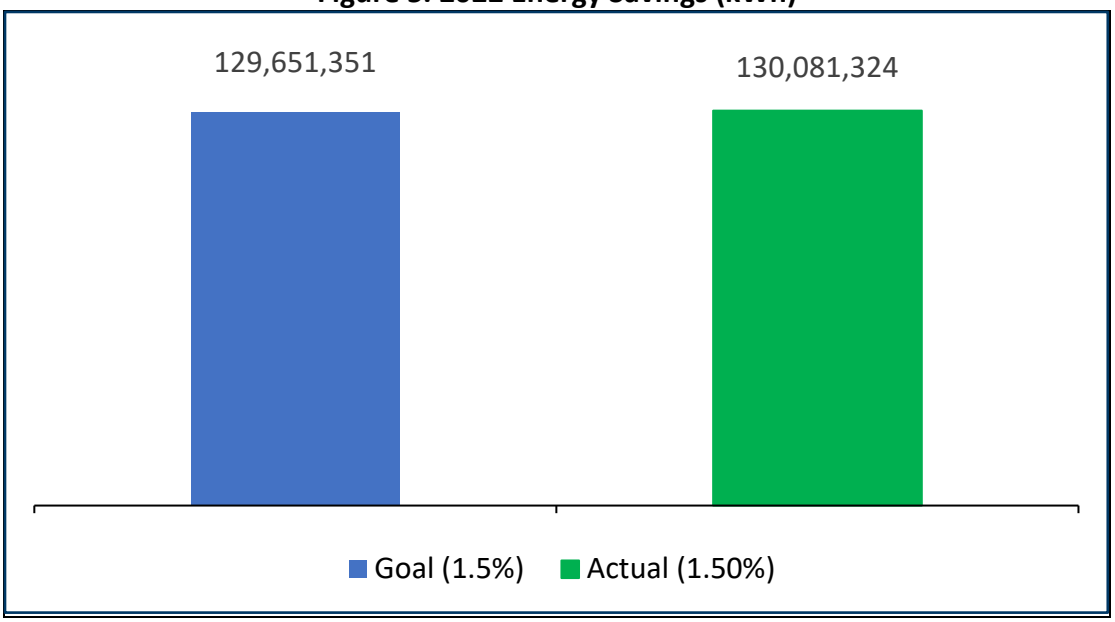


Table 7 provides a summary of GRE's planned CIP energy savings by member.

Table 7. 2022 Planned Energy Savings

Member Organization	Energy Savings Goal (kWh)	Planned Energy Savings (kWh)
Arrowhead	1,103,669	1,080,713
BENCO	4,590,878	5,068,592
Brown	1,628,046	1,728,379
Connexus	30,173,589	30,173,591
Cooperative Light & Power	1,520,153	1,488,783
Dakota	27,161,843	26,873,210
East Central	14,192,518	14,074,519
Goodhue	1,462,070	1,480,817
Itasca Mantrap	3,234,808	3,204,141
Kandiyohi	2,466,888	2,477,320
Lake Country	9,369,928	9,072,413
Lake Region	6,838,365	6,719,939
McLeod	2,188,070	2,164,945
Mille Lacs	3,035,643	3,022,939
Nobles	1,839,741	1,825,828
North Itasca	784,355	950,442
Runestone	3,577,172	3,535,235
Stearns	7,964,238	7,947,181
Steele Waseca	3,698,625	4,429,619
Todd Wadena	2,820,752	2,762,718
Total	129,651,351	130,081,324

2022 Total Spending Amounts

Figure 6 shows GRE's planned aggregate CIP spending for 2022.

Figure 6. 2022 Total Spending

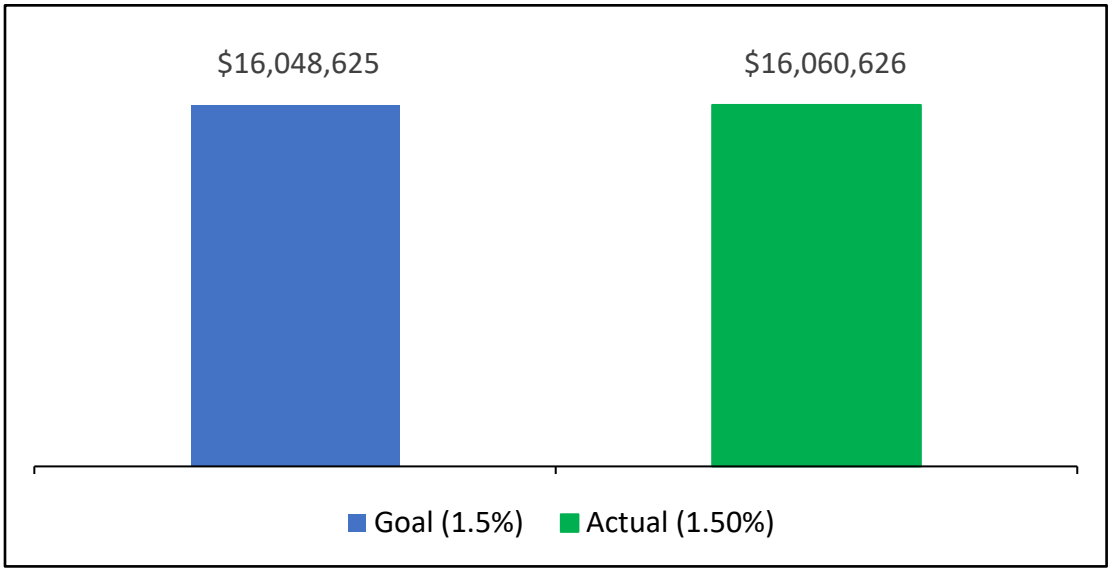


Table 8 provides a summary of GRE's planned CIP spending by member.

Table 8. 2022 Planned Spending

Member Organization	Minimum Spending	Planned Spending
Arrowhead	$151,003	$106,807
BENCO	$667,116	$701,368
Brown	$204,638	$196,968
Connexus	$3,680,604	$3,669,976
Cooperative Light & Power	$189,845	$192,169
Dakota	$3,109,722	$3,109,816
East Central	$1,850,060	$1,834,894
Goodhue	$188,754	$212,074
Itasca Mantrap	$363,589	$378,128
Kandiyohi	$313,903	$319,667
Lake Country	$1,340,467	$1,343,217
Lake Region	$794,039	$798,939
McLeod	$275,484	$278,276
Mille Lacs	$412,829	$420,261
Nobles	$250,846	$208,805
North Itasca	$130,804	$131,122
Runestone	$432,845	$428,255
Stearns	$899,207	$903,218
Steele Waseca	$499,595	$521,403
Todd Wadena	$293,275	$305,262
Total	$16,048,625	$16,060,626

2022 Low-Income Spending Amounts

Figure 7 shows GRE's planned low-income CIP spending for 2022. Please note that the low-income spending metric applies to each member utility individually.

Figure 7. 2022 Low-Income Spending

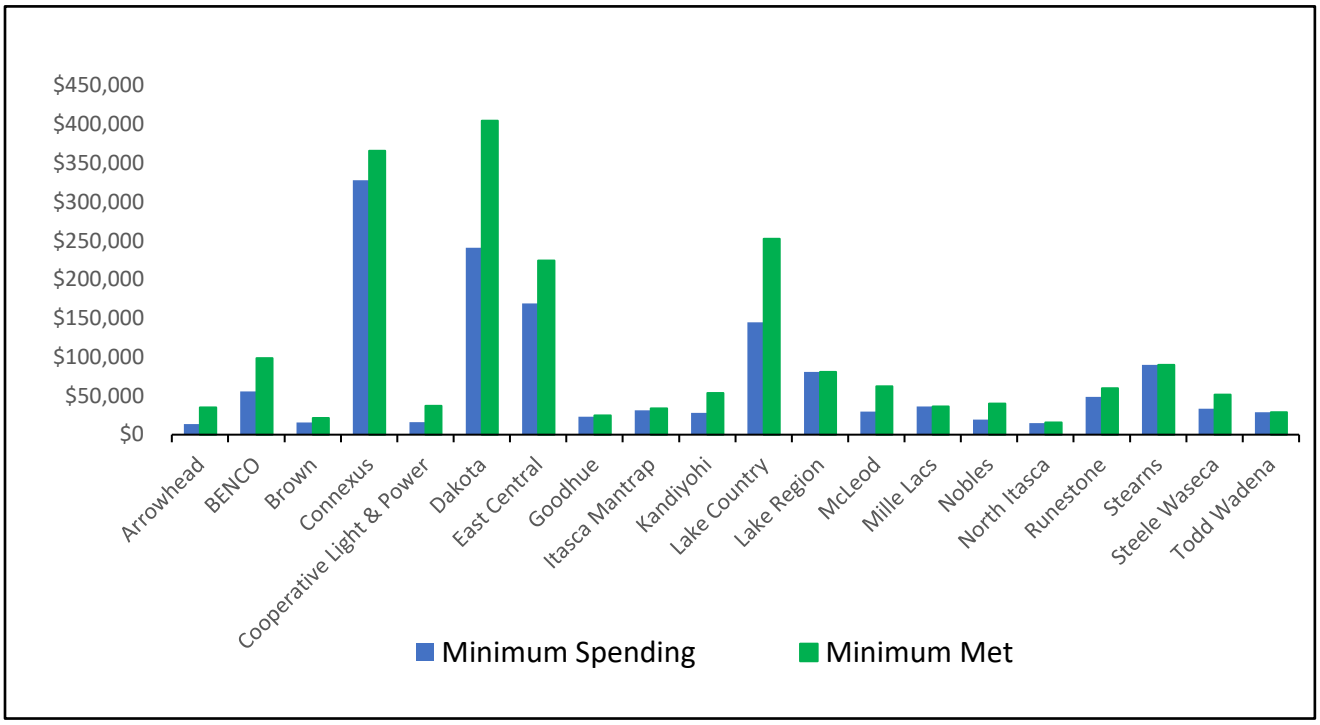


Table 9 provides a summary of GRE's planned low-income CIP spending by member.

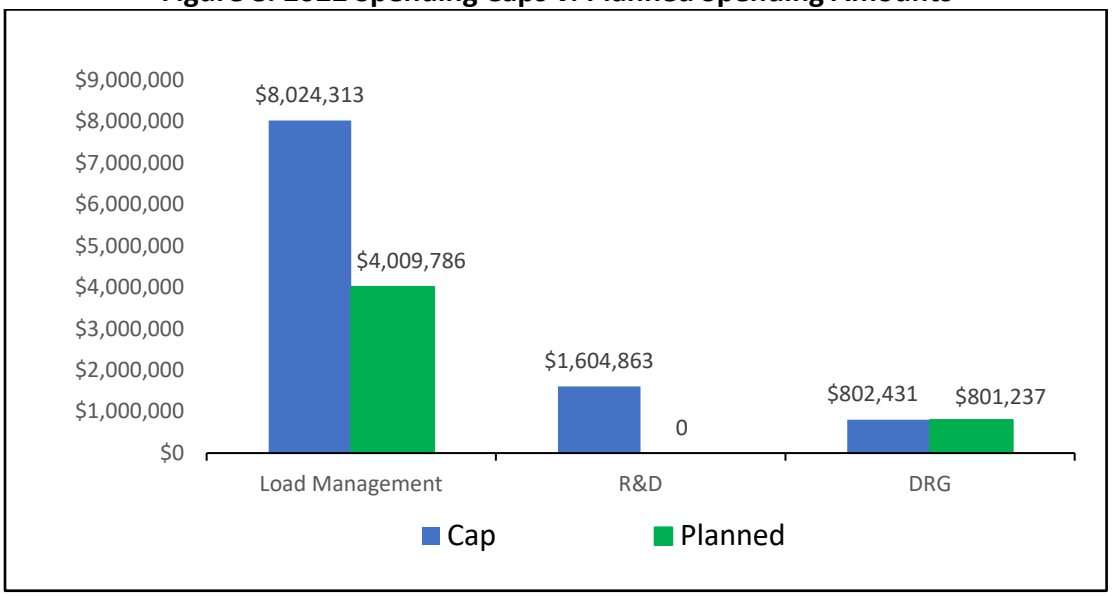
Table 9. 2022 Planned Low-Income Spending

Member Organization	Minimum Spending	Planned Spending	Passed
Arrowhead	$13,701	$35,296	Yes
BENCO	$55,604	$98,821	Yes
Brown	$15,739	$21,553	Yes
Connexus	$327,844	$366,061	Yes
Cooperative Light & Power	$16,153	$37,078	Yes
Dakota	$240,757	$404,668	Yes
East Central	$169,080	$224,478	Yes
Goodhue	$23,188	$24,630	Yes
Itasca Mantrap	$31,324	$33,749	Yes
Kandiyohi	$28,175	$53,554	Yes
Lake Country	$144,823	$252,406	Yes
Lake Region	$80,906	$81,027	Yes
McLeod	$29,612	$62,529	Yes
Mille Lacs	$36,469	$36,475	Yes
Nobles	$19,507	$40,171	Yes
North Itasca	$14,827	$15,893	Yes
Runestone	$48,832	$59,820	Yes
Stearns	$89,774	$90,019	Yes
Steele Waseca	$33,508	$51,510	Yes
Todd Wadena	$28,804	$28,822	Yes
Total	$1,448,627	$2,018,559	N/A

2022 Spending Caps on Optional Investments

Figure 8 shows GRE's planned aggregate spending on load management, research and development, and distributed and renewable generation investments.

Figure 8. 2022 Spending Caps v. Planned Spending Amounts



2022 Summary of Plan

Table 10 provides a summary of GRE's plan concerning the components of the CIP statute.

Table 10. Summary of 2022 Plan Compliance

Requirement	Passed
Energy Savings (kWh)	Yes
Total Spending ($)	Yes
Low-Income Spending ($)	Yes
R&D Spending Cap ($)	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes
Load Management Spending ($)	Yes

Green Building Standards

Each utility and association must offer one or more programs that meet the following provisions to support green building standards.

Facilitate professional engineering verification to qualify a building for green building certification	§ 216B.241 subd. 1f(c)
Support goals consistent with Sustainable Buildings 2030 (SB 2030) performance standards	§ 216B.241 subd. 9(e)

My Staff recommend that utilities offer a subsidy for design assistance and/or certification expenses on a case by case basis within their commercial and industrial program(s).

FUTURE REPORTING

The next scheduled report will be on August 1, 2022, when GRE will need to report expenditures and energy savings for 2021, budgets and energy savings goals for 2023, and updated program designs for 2023.

DECISION

With this letter, I accept GRE's reporting of results for the 2020 CIP program year, noting that GRE did not meet all the components of the statutes, and approve GRE's CIP plan for 2022. Thank you for GRE's continued contributions to Minnesota's energy efficiency and conservation goals. Please contact Anthony Fryer at anthony.fryer@state.mn.us or 651-539-1858 or Laura Silver at laura.silver@state.mn.us or 651-539-1873 with any questions or concerns.

Sincerely,



KEVIN LEE
Deputy Commissioner
Minnesota Department of Commerce,
Division of Energy Resources

KL/LNS

SUMMARY OF CIP FOR ELECTRIC UTILITIES[1]

Minnesota Statutes § 216B.241 apply to municipal electric utilities that provide electric service to more than 1,000 retail customers and to cooperative electric associations that provide retail service to more than 5,000 members.

Energy Savings

- *Minimum Annual Energy Savings Goals:* Minnesota Statutes § 216B.241 subd. 1c(b) requires each non-exempt utility and association to have an annual energy savings goal equal to 1.5 percent of gross annual retail sales. The energy savings goal should be calculated using the most recent 3-year weather-normalized average. Please refer to the summary table in the section below for the 3-year average used to calculate the savings requirement.

- *Electric Utility Infrastructure (EUI) Projects:* Minnesota Statutes § 216B.241 subd. 1c(d) allows a utility or association to claim energy savings resulting from EUI projects on top of a minimum energy savings goal of 1 percent from energy conservation improvements, provided the EUI projects result in energy efficiencies greater than what would occur through normal maintenance activity. For further information, please review the Department's Decision filed on February 20, 2018 in docket 17-856 in the matter of Claiming Energy Savings through Electric Utility Infrastructure Improvements and the Carry Forward Provision and the Department's Decision filed on October 22, 2018 in docket 18-543 in the matter of Determining Normal Maintenance Activities and CIP Review Process for Electric Utility Infrastructure Projects.

- *Carry Forward Provision:* Minnesota Statutes § 216B.241 Subd. 1c(b) allows a utility or association to elect to carry forward energy savings in excess of 1.5 percent for a year to the succeeding three calendar years, except that savings from EUI projects may be carried forward for five years. For further information, please review the Department's Decision filed on

[1] The statutes are available at the website for the Office of the Revisor of Statutes: https://www.revisor.mn.gov/statutes/?id=216B.241.

February 20, 2018 in docket 17-856 in the matter of Claiming Energy Savings through Electric Utility Infrastructure Improvements and the Carry Forward Provision.

CIP Spending

- *Minimum Spending:* Minnesota Statutes § 216B.241 subd. 1b requires each non-exempt cooperative electric association and electric municipal utility to invest a minimum of 1.5 percent of its Minnesota gross operating revenues (GOR), excluding revenue from any CIP-exempt customers, on CIP. Please refer to the summary table in the section below for the baseline year used to calculate the spending requirement.

- *Low-Income Spending:* Minnesota Statutes § 216B.241 subd. 7(a) and (c) require each non-exempt electric utility to invest a minimum of 0.2 percent of its residential Minnesota GOR on CIP programs that directly serve the needs of low-income persons, including renters. Please refer to the summary table in the section below for the baseline years used to calculate the low-income spending requirement.[2]

- *Electric Utility Infrastructure (EUI) Projects:* Minnesota Statutes § 216B.241 subd. 1(e) does not allow spending on EUI projects to count towards the CIP spending requirement.

Spending Caps on Optional Investments

- *Research and Development (R&D) Spending Cap:* Minnesota Statutes § 216B.241 subd. 2(c) allows each utility and association to spend up to 10 percent of a utility's minimum spending requirement on R&D projects.

- *Distributed and Renewable Generation (DRG) Cap:* Minnesota Statutes § 216B.2411 subd. 1 allows each utility and association to spend up to 5 percent of a utility's minimum spending requirement on DRG.[3]

[2] While Department policy currently allows cooperatives and municipalities to count a portion of general residential spending as low-income, the Department strongly encourages all utilities to meet their low-income spending requirements through programs that directly serve the needs of low-income persons, including renters.
[3] Utilities may not use green pricing programs to achieve CIP requirements.

- *Load-Management Activities:* Minnesota Statutes § 216B.241 subd. 1b(e) allows each utility and association to use load-management activities to achieve up to 50 percent of a utility's minimum spending requirement.

Green Building Standards

- *Green Building Standards:* Minnesota Statutes § 216B.241 subd. 1f(c) and § 216B.241 subd. 9(e) require that each non-exempt utility and association offer one or more programs that support green building certification of commercial buildings and that support goals consistent with Sustainable Buildings 2030 standards.

BASE YEARS FOR CIP CALCULATIONS

Specific base years are used to calculate the statutory minimum requirements for the energy savings, total spending, and low-income spending goals. The table below summarizes the base years to be used to calculate the minimum requirements for CIP results and plans reviewed in this letter.

Base Years for CIP Minimum Requirements Calculations

Filing Type	Minimum Energy Savings Rqmt 1.5% of:	Minimum Spending Rqmt 1.5% of:	Minimum Low-Income Spending Rqmt 0.2% of:
2020 Results	2016-2018 average retail sales	2018 gross operating revenues	2016-2018 residential gross operating revenues
2022 Plan	2018-2020 average retail sales	2020 gross operating revenues	2018-2020 average residential gross operating revenues

COMMERCE DEPARTMENT

June 23, 2022

Jeffrey Haase
Great River Energy - Fixed members
12300 Elm Creek Blvd.
Maple Grove, MN 55369

RE: Electric Conservation Improvement Program (CIP) 2020 Results and 2022 Plans

Dear Jeffrey Haase:

Thank you very much for Great River Energy - Fixed members' (GRE) efforts and those of its members to report 2020 Conservation Improvement Program (CIP) results and a 2022 CIP plan in ReportingESP. My Staff at the Minnesota Department of Commerce, Division of Energy Resources (Department) have finished reviewing this information.

Minnesota Statutes Section 216B.241 Subd 1b(f) provides that a generation and transmission cooperative electric association, a municipal power agency, or other not-for-profit entity that provides energy service to cooperative or municipal utilities that provide electric service at retail to consumers may invest in energy conservation improvements on behalf of the associations it serves and may fulfill the CIP conservation, spending, reporting, and energy-savings goals on an aggregate basis. The information presented in this letter reflects the aggregate effort of the members of GRE indicated. There may be additional retail utilities that GRE provides electric services to that are not represented in the aggregate results included in this letter. The Department notes that the following exempt utilities are continuing to offer programs and report with GRE:

- Agralite Cooperative
- Redwood Electric Cooperative – Redwood is included in GRE's 2020 reporting but not in the 2022 plan.

2020 CIP RESULTS

The CIP accomplishments for GRE members for 2020 are summarized in the graphs and tables below. The statutory energy savings goal and spending amounts are outlined in Table 1.

Table 1. Minnesota Utility Energy Savings Goal and Spending Amounts

Metric	Amount	Baseline Year(s)	Citation
Energy Savings (kWh)	1.5% of average weather-normalized retail sales at the generator, less sales to CIP exempt customers	2016-2018	Minn. Stat. § 216B.241 subd. 1c(b)
Total Spending ($)	1.5% of retail gross operating revenue, less revenues from exempt customers	2018	Minn. Stat. § 216B.241 subd. 1b
Low-Income Spending ($)	0.2% of average residential gross operating revenue of each member utility	2016-2018	Minn. Stat. § 216B.241 subd. 1(l) Minn. Stat. § 216B.241 subd. 7(a)

Additionally, my Staff have provided an appendix at the end of this letter summarizing these and additional components of the CIP statute.

2020 Energy Savings Results

Figure 1 shows GRE's aggregate CIP energy savings for 2020.

Figure 1. 2020 Energy Savings (kWh)

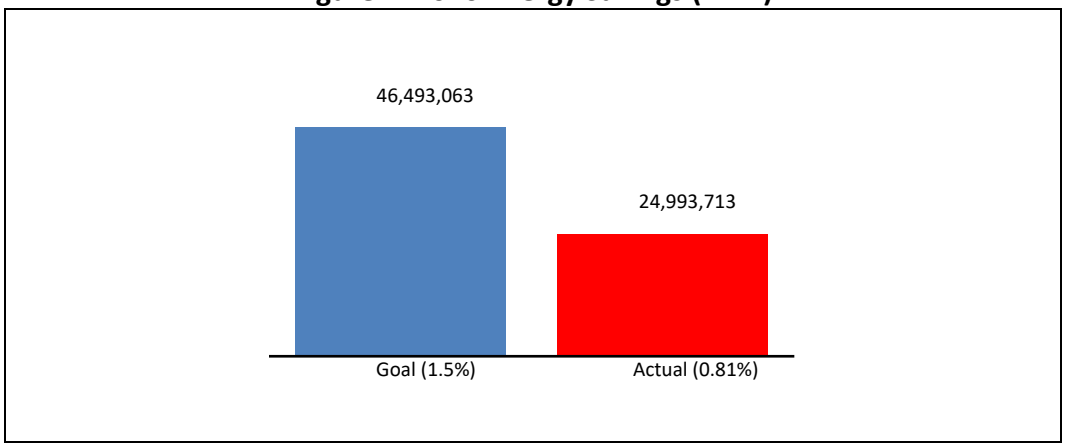


Table 2 provides a summary of GRE's CIP energy savings achievements by member.

Table 2. 2020 Energy Savings Results

Member Organization	Energy Savings Goal (kWh)	Actual Energy Savings (kWh)
Agralite	3,474,854	2,221,749
Crow Wing	8,785,651	3,054,972
Federated	4,408,968	7,401,538
Meeker	2,758,479	638,687
Minnesota Valley	12,101,687	4,840,617
Redwood	1,637,530	0
Wright-Hennepin	13,325,895	6,836,151
Total	46,493,063	24,993,713

2020 Total Spending Results

Figure 2 shows GRE's aggregate CIP spending for 2020.

Figure 2. 2020 Total Spending

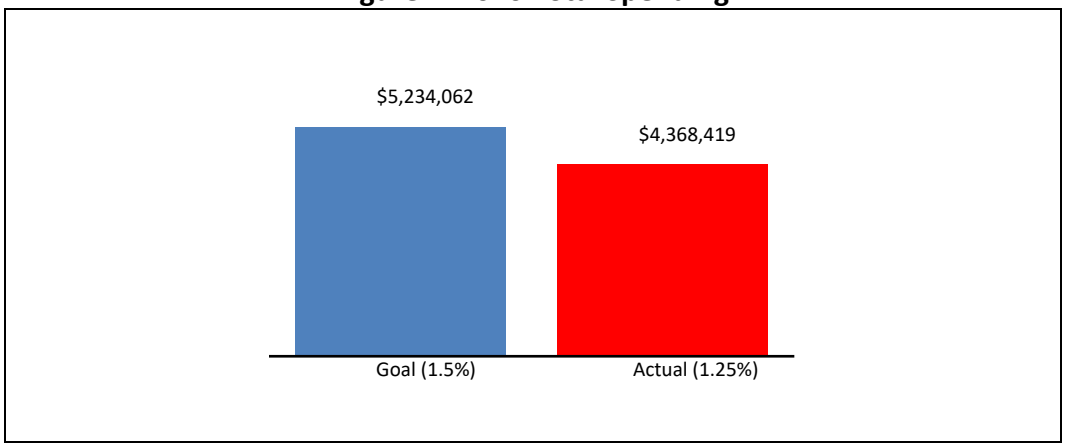


Table 3 provides a summary of GRE's CIP spending by member.

Table 3. 2020 Spending Results

Member Organization	Minimum Spending	Actual Spending
Agralite	$330,183	$360,351
Crow Wing	$1,077,596	$496,406
Federated	$446,539	$549,890
Meeker	$387,600	$262,000
Minnesota Valley	$1,277,135	$1,455,811
Redwood	$156,086	$0
Wright-Hennepin	$1,558,923	$1,243,962
Total	$5,234,062	$4,368,419

2020 Low-Income Spending Results

While Department policy currently allows cooperatives and municipalities to count a portion of general residential spending as spending on low-income customers, the Department strongly encourages all utilities to meet their low-income spending amounts through programs that directly serve the needs of low-income persons. Figure 3 shows low-income CIP spending for 2020 for each of GRE's members. Please note that the low-income spending metric applies to each member utility individually.

Figure 3. 2020 Low-Income Spending

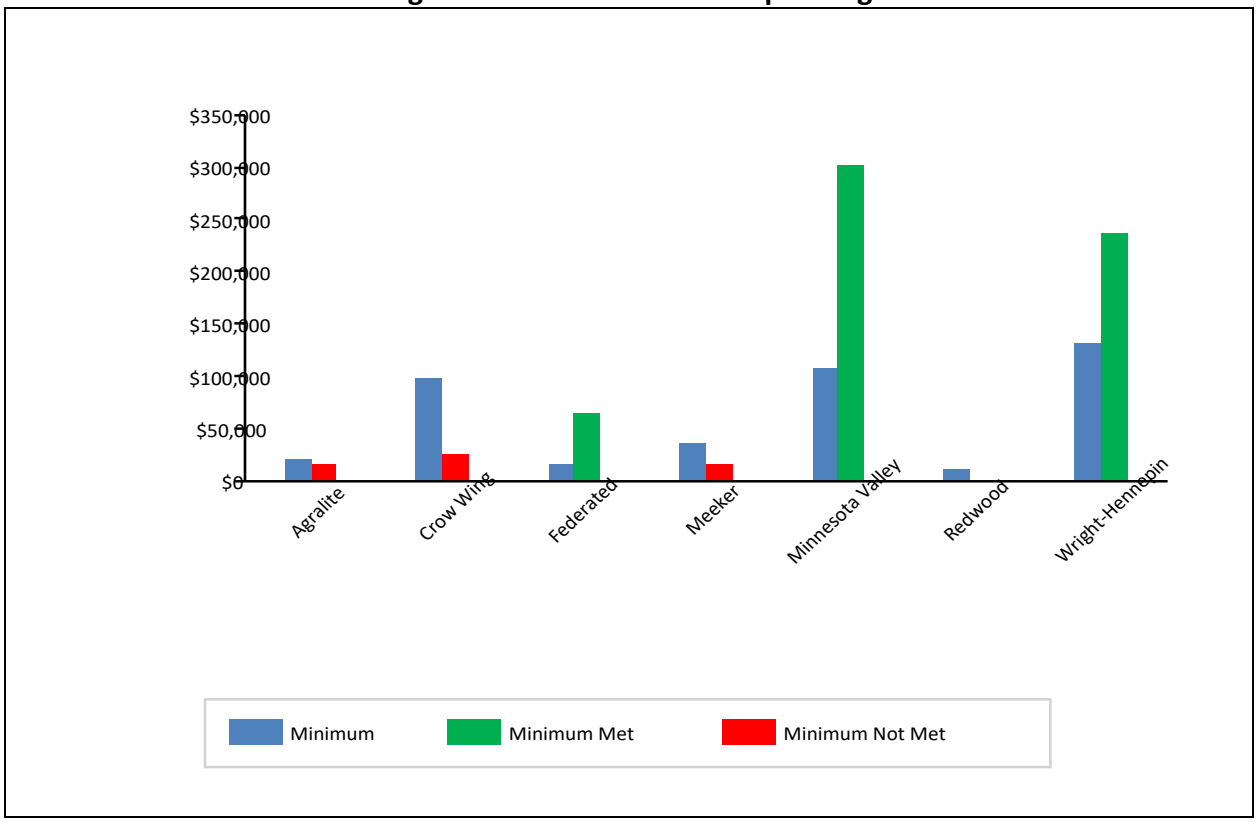


Table 4 provides a summary of GRE's low-income CIP spending by member.

Table 4. 2020 Low-Income Spending Results

Member Organization	Minimum Spending	Actual Spending	Passed
Agralite	$19,964	$16,100	No
Crow Wing	$98,643	$26,909	No
Federated	$16,821	$65,261	Yes
Meeker	$35,248	$15,766	No
Minnesota Valley	$106,918	$300,904	Yes
Redwood	$11,169	$0	No
Wright-Hennepin	$131,395	$236,815	Yes
Total	$420,158	$661,755	N/A

2020 Spending Caps on Optional Investments

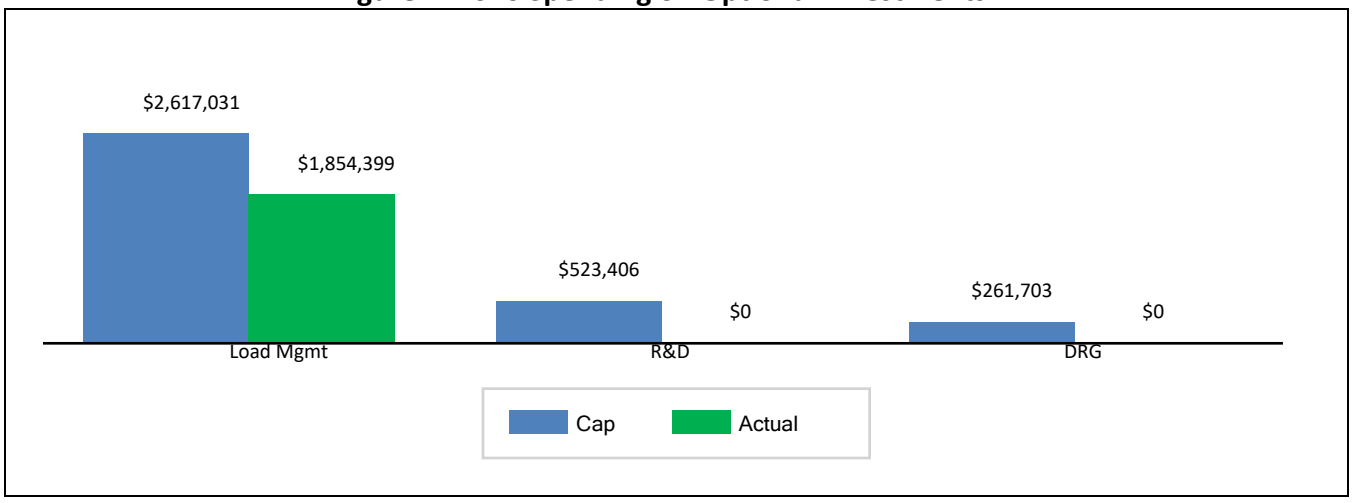
In addition to the energy savings goal, and the total and low-income spending amounts, there are some caps on spending amounts for certain optional investments. These spending caps are listed in Table 5.

Table 5. CIP Spending Caps on Optional Investments

Optional Investment	Spending Cap	Citation
Load Management Programs	Up to 50% of minimum spending	Minn. Stat. § 216B.241 subd. 1(k) Minn. Stat. § 216B.241 subd. 1b(e)
R&D Activities	10% of minimum spending	Minn. Stat. § 216B.241 subd. 2(c)
Distributed and Renewable Generation (DRG) Programs	5% of minimum spending	Minn. Stat. § 216B.2411 subd. 1

Figure 4 shows GRE's aggregate spending on load management, research and development, and distributed and renewable generation investments.

Figure 4. 2020 Spending on Optional Investments



2020 Summary of Results

Table 6 provides a summary of GRE's accomplishments concerning the components of the CIP statute.

Table 6. Summary of 2020 Results Compliance

Metric	Passed
Energy Savings (kWh)	No
Total Spending ($)	No
Low-Income Spending ($)	No
R&D Spending Cap ($)	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes
Load Management Spending ($)	Yes

2022 PLAN REVIEW

The CIP plan for 2022 presented by GRE is summarized in the graphs and tables below.

2022 Energy Savings Goal

Figure 5 shows GRE's planned aggregate CIP energy savings for 2022.

Figure 5. 2022 Energy Savings (kWh)

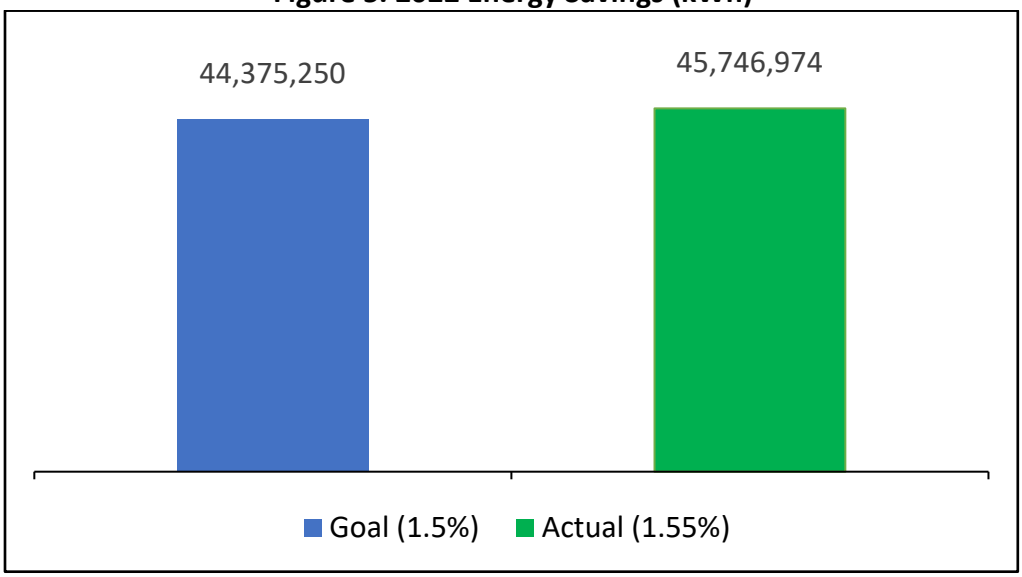


Table 7 provides a summary of GRE's planned CIP energy savings by member.

Table 7. 2022 Planned Energy Savings

Member Organization	Energy Savings Goal (kWh)	Planned Energy Savings (kWh)
Agralite	2,740,446	3,077,035
Crow Wing	9,403,000	9,458,212
Federated	3,208,813	3,835,919
Meeker	3,013,168	3,053,069
MN Valley	12,356,833	12,853,167
Wright Hennepin	13,652,990	13,469,573
Total	44,375,250	45,746,974

2022 Total Spending Amounts

Figure 6 shows GRE's planned aggregate CIP spending for 2022.

Figure 6. 2022 Total Spending

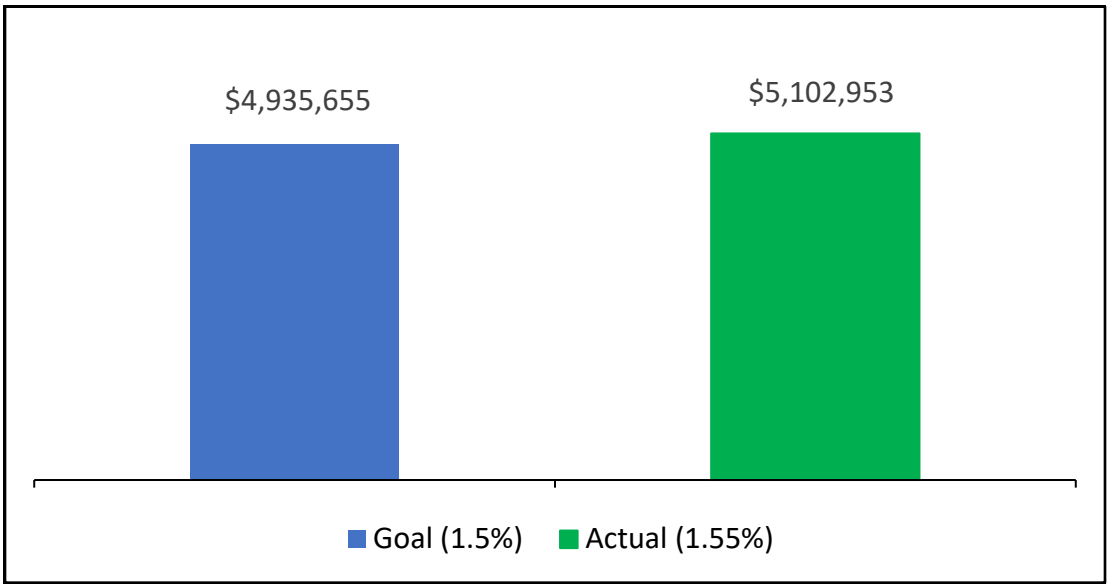


Table 8 provides a summary of GRE's planned CIP spending by member.

Table 8. 2022 Planned Spending

Member Organization	Minimum Spending	Planned Spending
Agralite	$285,896	$339,985
Crow Wing	$1,091,164	$1,117,064
Federated	$351,678	$343,247
Meeker	$326,126	$358,538
MN Valley	$1,364,130	$1,337,889
Wright Hennepin	$1,516,661	$1,606,230
Total	$4,935,655	$5,102,953

2022 Low-Income Spending Amounts

Figure 7 shows GRE's planned low-income CIP spending for 2022. Please note that the low-income spending metric applies to each member utility individually.

Figure 7. 2022 Low-Income Spending

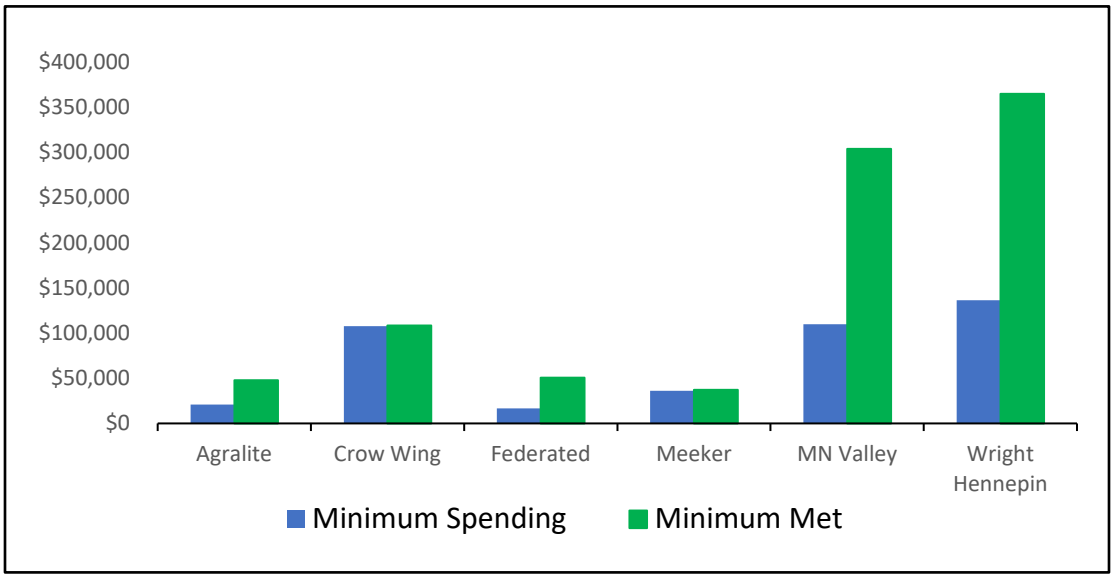


Table 9 provides a summary of GRE's planned low-income CIP spending by member.

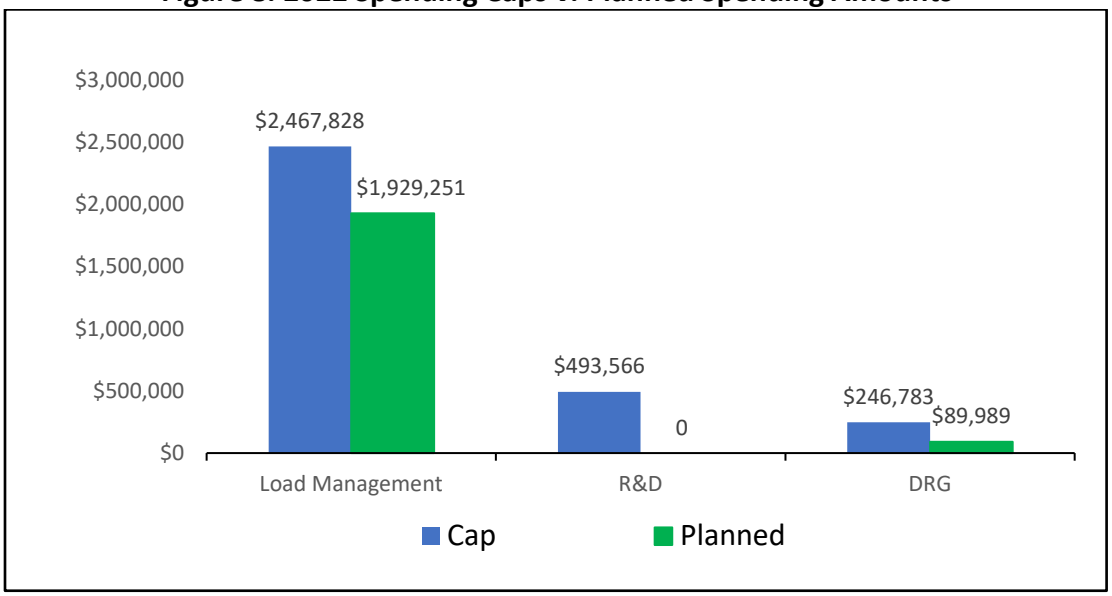
Table 9. 2022 Planned Low-Income Spending

Member Organization	Minimum Spending	Planned Spending	Passed
Agralite	$20,742	$47,673	Yes
Crow Wing	$107,566	$108,264	Yes
Federated	$16,688	$50,504	Yes
Meeker	$36,268	$37,003	Yes
MN Valley	$109,621	$303,877	Yes
Wright Hennepin	$136,494	$364,860	Yes
Total	$427,379	$912,180	N/A

2022 Spending Caps on Optional Investments

Figure 8 shows GRE's planned aggregate spending on load management, research and development, and distributed and renewable generation investments.

Figure 8. 2022 Spending Caps v. Planned Spending Amounts



2022 Summary of Plan

Table 10 provides a summary of GRE's plan concerning the components of the CIP statute.

Table 10. Summary of 2022 Plan Compliance

Requirement	Passed
Energy Savings (kWh)	Yes
Total Spending ($)	Yes
Low-Income Spending ($)	Yes
R&D Spending Cap ($)	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes
Load Management Spending ($)	Yes

Green Building Standards

Each utility and association must offer one or more programs that meet the following provisions to support green building standards.

Facilitate professional engineering verification to qualify a building for green building certification	§ 216B.241 subd. 1f(c)
Support goals consistent with Sustainable Buildings 2030 (SB 2030) performance standards	§ 216B.241 subd. 9(e)

My Staff recommend that utilities offer a subsidy for design assistance and/or certification expenses on a case by case basis within their commercial and industrial program(s).

FUTURE REPORTING

The next scheduled report will be on August 1, 2022, when GRE will need to report expenditures and energy savings for 2021, budgets and energy savings goals for 2023, and updated program designs for 2023.

DECISION

With this letter, I accept GRE's reporting of results for the 2020 CIP program year, noting that GRE did not meet all the components of the statutes, and approve GRE's CIP plan for 2022. Thank you for GRE's continued contributions to Minnesota's energy efficiency and conservation goals. Please contact Anthony Fryer at anthony.fryer@state.mn.us or 651-539-1858 or Laura Silver at laura.silver@state.mn.us or 651-539-1873 with any questions or concerns.

Sincerely,



KEVIN LEE
Deputy Commissioner
Minnesota Department of Commerce,
Division of Energy Resources

KL/LNS

SUMMARY OF CIP FOR ELECTRIC UTILITIES[1]

Minnesota Statutes § 216B.241 apply to municipal electric utilities that provide electric service to more than 1,000 retail customers and to cooperative electric associations that provide retail service to more than 5,000 members.

Energy Savings

- *Minimum Annual Energy Savings Goals:* Minnesota Statutes § 216B.241 subd. 1c(b) requires each non-exempt utility and association to have an annual energy savings goal equal to 1.5 percent of gross annual retail sales. The energy savings goal should be calculated using the most recent 3-year weather-normalized average. Please refer to the summary table in the section below for the 3-year average used to calculate the savings requirement.

- *Electric Utility Infrastructure (EUI) Projects:* Minnesota Statutes § 216B.241 subd. 1c(d) allows a utility or association to claim energy savings resulting from EUI projects on top of a minimum energy savings goal of 1 percent from energy conservation improvements, provided the EUI projects result in energy efficiencies greater than what would occur through normal maintenance activity. For further information, please review the Department's Decision filed on February 20, 2018 in docket 17-856 in the matter of Claiming Energy Savings through Electric Utility Infrastructure Improvements and the Carry Forward Provision and the Department's Decision filed on October 22, 2018 in docket 18-543 in the matter of Determining Normal Maintenance Activities and CIP Review Process for Electric Utility Infrastructure Projects.

- *Carry Forward Provision:* Minnesota Statutes § 216B.241 Subd. 1c(b) allows a utility or association to elect to carry forward energy savings in excess of 1.5 percent for a year to the succeeding three calendar years, except that savings from EUI projects may be carried forward for five years. For further information, please review the Department's Decision filed on

[1] The statutes are available at the website for the Office of the Revisor of Statutes: https://www.revisor.mn.gov/statutes/?id=216B.241.

February 20, 2018 in docket 17-856 in the matter of Claiming Energy Savings through Electric Utility Infrastructure Improvements and the Carry Forward Provision.

CIP Spending

- *Minimum Spending:* Minnesota Statutes § 216B.241 subd. 1b requires each non-exempt cooperative electric association and electric municipal utility to invest a minimum of 1.5 percent of its Minnesota gross operating revenues (GOR), excluding revenue from any CIP-exempt customers, on CIP. Please refer to the summary table in the section below for the baseline year used to calculate the spending requirement.

- *Low-Income Spending:* Minnesota Statutes § 216B.241 subd. 7(a) and (c) require each non-exempt electric utility to invest a minimum of 0.2 percent of its residential Minnesota GOR on CIP programs that directly serve the needs of low-income persons, including renters. Please refer to the summary table in the section below for the baseline years used to calculate the low-income spending requirement.[2]

- *Electric Utility Infrastructure (EUI) Projects:* Minnesota Statutes § 216B.241 subd. 1(e) does not allow spending on EUI projects to count towards the CIP spending requirement.

Spending Caps on Optional Investments

- *Research and Development (R&D) Spending Cap:* Minnesota Statutes § 216B.241 subd. 2(c) allows each utility and association to spend up to 10 percent of a utility's minimum spending requirement on R&D projects.

- *Distributed and Renewable Generation (DRG) Cap:* Minnesota Statutes § 216B.2411 subd. 1 allows each utility and association to spend up to 5 percent of a utility's minimum spending requirement on DRG.[3]

[2] While Department policy currently allows cooperatives and municipalities to count a portion of general residential spending as low-income, the Department strongly encourages all utilities to meet their low-income spending requirements through programs that directly serve the needs of low-income persons, including renters.
[3] Utilities may not use green pricing programs to achieve CIP requirements.

- *Load-Management Activities:* Minnesota Statutes § 216B.241 subd. 1b(e) allows each utility and association to use load-management activities to achieve up to 50 percent of a utility's minimum spending requirement.

Green Building Standards

- *Green Building Standards:* Minnesota Statutes § 216B.241 subd. 1f(c) and § 216B.241 subd. 9(e) require that each non-exempt utility and association offer one or more programs that support green building certification of commercial buildings and that support goals consistent with Sustainable Buildings 2030 standards.

BASE YEARS FOR CIP CALCULATIONS

Specific base years are used to calculate the statutory minimum requirements for the energy savings, total spending, and low-income spending goals. The table below summarizes the base years to be used to calculate the minimum requirements for CIP results and plans reviewed in this letter.

Base Years for CIP Minimum Requirements Calculations

Filing Type	Minimum Energy Savings Rqmt 1.5% of:	Minimum Spending Rqmt 1.5% of:	Minimum Low-Income Spending Rqmt 0.2% of:
2020 Results	2016-2018 average retail sales	2018 gross operating revenues	2016-2018 residential gross operating revenues
2022 Plan	2018-2020 average retail sales	2020 gross operating revenues	2018-2020 average residential gross operating revenues

April 1, 2025

2024 Demand Side Management Financial Incentive Project

Docket No. E017/M-25-49

Annual Filing to Update the ECO Rider

Docket No. E017/M-25-49

2024 ECO Status Report

Docket No. E017/CIP-23-94













OTPCO.COM

OTTER TAIL POWER COMPANY

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April 1, 2025

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

Dr. Pete Wyckoff
Deputy Commissioner
Minnesota Department of Commerce
Division of Energy Resources
85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198

RE: Status Report – 2024 ECO Activities
Docket No. E017/CIP-23-94

In the Matter of Otter Tail Power Company's Annual Filing of the Demand Side Management Financial Incentive Project
Docket No. E017/M-25-49

In the Matter of Otter Tail Power Company's Annual Filing to Update the Energy Conservation and Optimization Rider
Docket No. E017/M-25-49

Dear Mr. Seuffert and Dr. Wyckoff:

Enclosed please find Otter Tail Power Company's filing in the above referenced matter which includes:

- Executive Summary
- Summary of Filing
- Petition of Otter Tail Power Company
- Financial Incentive
- Status Report
- Conservation Cost Recovery Adjustment
- Appendix A – Tables
- Appendix B – Third Party Evaluations
- Appendix C – Project Information Sheets
- Appendix D – Customer Notice

A Certificate of Service is also enclosed. Otter Tail Power Company has served a copy of this filing on all parties listed on the enclosed Service List. If you or Commission Staff have any questions, please contact me at (218) 739-8240 or czuniga@otpco.com.

Sincerely,

/s/ CRISTINA ZUNIGA
Cristina Zuniga, Supervisor, DSM Administration
Retail Energy Solutions

sjw
Enclosures
By electronic filing
c: Service List

2024 STATUS REPORT, DSM INCENTIVE, AND FILING TO UPDATE THE RIDER EXECUTIVE SUMMARY

On April 1, 2025, Otter Tail Power Company (Otter Tail Power or the Company) files with the Minnesota Public Utilities Commission (Commission or MPUC) and the Minnesota Department of Commerce, Division of Energy Resources (Department) its annual report detailing the Company's previous year's Energy Conservation and Optimization (ECO) activities.

On April 1, 2025, Otter Tail Power Company files its 2024 Status Report.

On April 1, 2025, Otter Tail Power also files its annual filing to update the ECO Rider.

Otter Tail Power would like to emphasize the following points concerning the 2024 Energy Conservation and Optimization activities:

- The Company achieved 3.11 percent energy savings as a percent of retail energy sales, which is on par with our approved goal level of 3.15 percent.[1]
- The Company achieved energy savings of 50,321,324 kWh, achieving 99 percent of the goal. Demand savings were 36 percent of goal.[2]
- The cost per kWh for *first year* savings is $0.16 (16 cents) compared to a budgeted cost of $0.20 (20 cents). Costs are in line with historical averages of $0.14 (14 cents).
- Expenditures were under budget (78 percent) at $7,895,824 based on an approved budget of $10,064,451.[3]
- Net benefits of $35,831,011 were achieved excluding net benefits from regulatory assessments, Efficient Fuel Switching (EFS) Programs, and our Publicly-Owned Property Solar Program.

[1] Adjusted for one-third energy savings from behavioral change programs and includes energy savings from POP Solar.

[2] This is due in large part to a policy shift in what Demand Response Participants are eligible to be captured in Load Management Programs.

[3] Includes modifications approved by the Deputy Commissioner's January 31, 2022, Decision and November 2, 2022, Decision in Docket No. E017/CIP-20-475.

Requests for Approval

- The Company is requesting approval for $ $1,964,142 in performance incentives for 2024 ECO activities, a small share of the total net benefits delivered to customers from investments in ECO.
- The Company is requesting the Average Conservation Cost Recovery Adjustment (CCRA) factor of $0.00585/kWh be reflected on customers' bills using the applicable rate in Exhibit 3 of the Conservation Cost Recovery Adjustment through the Resource Adjustment starting with bills rendered (dated) on and after November 1, 2025.
- Approval of the administrative changes requested below to our Energy Conservation and Optimization Rider.
- The Company is requesting approval of the 2024 ECO Tracker, resulting in a year-end balance of negative $3,194,439.

Otter Tail Power has committed resources and developed new, creative approaches in pursuit of higher conservation goals. This pursuit includes an appropriate balance of direct and indirect impact programs. New technologies, delivery mechanisms, and segmentation strategies emphasize Otter Tail Power's commitment to energy efficiency. Recent accomplishments are particularly noteworthy in the face of new building codes and equipment efficiencies and saturated markets. A consistent regulatory environment is critical to overcoming these challenges as utilities continue to pursue Minnesota's Next Generation Act and ECO goals. Otter Tail Power appreciates the support from Minnesota's regulatory agencies as we work together to sustain Minnesota's energy future.

Please note that this filing is available through the eDockets system maintained by the Minnesota Department of Commerce and the Minnesota Public Utilities Commission. Access this document by going to eDockets through the websites of the Department of Commerce or the Public Utilities Commission or going to the eDockets homepage at:

https://www.edockets.state.mn.us/EFiling/home.jsp

Once on the eDockets homepage, this document can be accessed through the Search Documents link and entering in docket number: 23-94.

Please contact Otter Tail Power at 800-493-3299 to request a complete copy of this filing.

Status Report

Status Report

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STATUS REPORT – 2024 ECO PROGRAMS

The 2024 Energy Conservation Optimization (ECO) Status Report has been combined with the 2024 Financial Incentive Filing, produced annually on April 1. The Status Report covers all 2024 programs, including direct impact, indirect impact, and miscellaneous programs. Participation, program costs, and energy and demand savings for all programs are outlined in Appendix A, Table 5. The programs described in this Status Report are approved for the 2024 ECO Plan unless stated otherwise.

Direct Impact Conservation Programs

Residential

- Home Appliance
- Home Direct Install
- Home Energy Feedback
- Home Energy Management
- Home Heating and Cooling
- Home Lighting
- Residential Code Support

Low-Income

- House Therapy
- Low-Income Home Energy Feedback

Commercial

- Commercial Audits and Studies
- Commercial Direct Install
- Commercial Energy Management
- Commercial Heat Pumps
- Commercial Lighting
- Commercial & Industrial Focused Efficiency
- Compressed Air Efficiency
- Custom Efficiency Grants (Custom Projects)
- Drive Power
- Refrigeration
- Commercial Code Support

Other

- Publicly Owned Property (POP) Solar
- Emerging Technology Accelerator

Load Management Program

Indirect Impact Conservation Programs / Regulatory Requirements

- Advertising & Education
- Financing
- Implementation & Training
- Integrated Building Design Plus
- Program Development
- PUC / Regulatory (NGEA) Assessments
- Transmission & Distribution Cost Study

Miscellaneous / Inactive Program Costs

- Accounting Adjustments
- Otter Tail Power ECO Projects
- Carrying Charges

DIRECT IMPACT – RESIDENTIAL

HOME APPLIANCE

The Company's Home Appliance program continued to offer customers an incentive to recycle inefficient but operating refrigerators, freezers, dehumidifiers, and window air-conditioning units at no cost to the customer. During a scheduled visit to recycle a refrigerator and/or freezer, customers may also recycle a window air-conditioner and/or dehumidifier. In 2024, we continued to offer eight LED bulbs in addition to the recycling incentive for participants. This additional benefit has helped retain customer interest in the program and is reflected in steady program participation. We will continue to provide the additional LED bulb incentive in 2025.

The Home Appliance program also offered customers rebates for purchasing new standard-sized Energy Star® rated home appliances, including:

- Refrigerators
- Freezers
- Dishwashers
- Clothes washers
- Clothes dryers, including heat pump clothes dryers
- Induction cooktops
- Dehumidifiers
- Air purifiers
- Heat pump water heater

Otter Tail Power promoted the Home Appliance program using various resources including:

- Bill inserts targeting residential customers.
- Print advertising.
- Webpage content including hero ads placed on the Company's home page.
- Program, rate, and rebate pages within the Company's Ways to Save section of the website.
- Digital billboards.
- Bill messages.
- Inclusion, as appropriate, on Home Energy Reports mailed and emailed to customers through the Energy Feedback and Low-Income Energy Feedback programs.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Home Appliance Program	**Actual**	**Proposed**	**% of Goal**
Participation	1,118	829	135%
Budget $	$170,601	$183,000	93%

Evaluation Methodology

Energy savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Appliance Program	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	315,180
Demand Savings – kW	40.61

HOME DIRECT INSTALL

The Company's Home Direct Install program consisted of the previously approved residential Home Transformer and School Kit programs. The Home Direct Install program aimed to identify and assist customers in reducing energy loss and waste in their home and to save energy and money through installation of low-cost efficiency improvement measures. The Company reached the market for these improvement measures through the following distribution strategies:

1. Direct install kits distributed to customers at the time a free audit is provided through Home Transformer residential energy audits.
2. Multifamily housing outreach efforts to target this segment with free assessments and low-cost efficiency measures free to residents.
3. Home direct install kits distributed to students in conjunction with an energy efficiency lesson plan targeting 5th grade students in participating schools.

Home Transformer

Through Home Transformer, the Company offered customers with electric space and water-heating homes an energy audit and installation of select energy-efficiency measures at no cost to the customer. Products and services offered include:

- An energy audit including a blower door test and thermal imaging analysis.
- A detailed report on audit findings, including recommendations for energy saving measures with estimated costs, annual savings, and simple payback for each measure.
- Efficiency products, installation demonstration, and education.
    - Electric measures – LED bulbs and a Tier 2 power strip.
    - Heating and cooling measures – exterior door sweep, outlet gaskets, caulking, weather-stripping, and plastic film insulating kits for windows.
    - Water heating measures – pipe insulation, low-flow showerhead, faucet aerators, and temperature assessment of the water heater.

Otter Tail Power relied on a local community action agency for the technical expertise needed to provide professional home energy audits, reports, and direct installs of energy efficiency measures.

Additionally, Otter Tail Power partners with Minnesota Energy Resources Corporation (MERC) to provide audits and direct-install of energy saving measures for customers in single-family homes with natural gas as their primary heat source. The partnership allows

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both utilities to more cost effectively offer audits and direct install measures for our mutual customers.

Through contracted service providers, the Company completed outreach targeting multifamily housing complexes in 2024, successfully reaching one income-qualified unit in Bemidji, MN and provided audit and direct install services. The Company completed outreach targeting multifamily housing late in 2024, with efforts resulting in future assessment and direct install measure installations being scheduled in four properties totaling 112 individual housing units in 2025.

School Kit Distribution

The Home Direct Install program offered home energy efficiency products and educational materials to fifth grade students throughout Otter Tail Power's service area. Otter Tail Power implemented lesson plans and kit distributions using AM Conservation Group, a contracted third-party.

AM Conservation Group representatives successfully completed outreach by contacting schools throughout our service territory that teach school age children of Otter Tail Power customers. AM Conservation Group ordered school kits, assembled in reusable tote bags, and shipped the required inventory to participating schools. Kits included: a Tier 2 power strip, six 9-Watt LED Energy Star® bulbs, two faucet aerators, a high efficiency showerhead, weatherization measures, and a digital thermometer for a refrigerator. The kits also included information about the products and installation instructions.

Through the Home Direct Install program, teachers at participating schools received lesson plans and an instruction guide to integrate into their curriculum. Participating students received a workbook and study guide that supported the teacher's lesson plans and instruction guide. All teachers participating in the program reported they would recommend participation in the program to their peers.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Home Direct Install	**Actual**	**Proposed**	**% of Goal**
Participation	16,831	16,850	100%
Budget $	$150,963	$137,000	110%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Direct Install	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	1,389,044
Demand Savings – kW	121.37

HOME ENERGY FEEDBACK

The Energy Feedback program consisted of two components: an online energy feedback tool and the Opower Home Energy Report (HER) component. These behavior-based programs are designed to maximize energy savings achieved through behavior changes as a result of providing customers personalized and comparative energy use information.

The online energy feedback tool is an opt-in program option that is accessed with a secure sign-in to our web portal on the Otter Tail Power website. The HER component of the program is designed as an opt-out program and provides direct mail delivery of up to four comparative energy usage reports to participating Minnesota residential customers each year. Customers who have provided Otter Tail Power with an email address are also eligible to receive a monthly email home energy report (eHER).

Online Energy Feedback Tool

In 2024 and early 2025, Otter Tail Power and Accelerated Innovations developed and are currently executing the following scope of work to maximize verified behavioral energy efficiency savings from engagement with the My Account experience. The scope of work covers three primary areas that coincide with Otter Tail Power's rollout of AMI metering and optional Otter Tail Power-branded native mobile app to maximize participation and end customer engagement:

1. Actions Content Development and Implementation
   By enabling and configuring content through the MyMeter Actions module, Accelerated Innovation will support Otter Tail Power in engaging My Account users with recommendations and guidance on targeted no/low-cost actions that can lead to energy and cost savings. Accelerated Innovation will develop and implement a plan to manage Actions content, track user engagement and coordinate with the Company to promote additional Otter Tail Power offerings via the Actions user interface and related in-portal content areas including Dashboard widgets, notifications, and content overlays.

2. Enhanced New Bill Notification and Weekly Summary Communications Content
   As a core outbound communications engagement approach, Accelerated Innovation will develop and deliver enhancements to the New Bill Notification and Weekly Summary email templates to promote targeted energy-saving action recommendations, provide feedback on energy usage trends, and (if made available) incorporate usage disaggregation insights.

3. Third-Party Impact Evaluation
   In coordination with Otter Tail Power, Accelerated Innovation will engage a leading behavioral program evaluation services provider to complete annual impact evaluations to meet Minnesota Department of Commerce Division of Energy Resources (Department) requirements for claimed savings as part of the Company's ECO plan.

Home Energy Reports

The HER program component delivered comparative energy use information to selected Minnesota residential customers. HERs contain various personalized components, including:

- Comparisons of recent energy use to comparable nearby homes.
- Comparison of past energy use to current use over time.
- Energy efficiency tips based on the home's energy use pattern, season, and household heating type.
- Spanish-translated reports were made available upon request in 2024.

Participation in the HER component is defined as any Minnesota residential customer that received one or more personalized HERs during 2024. Participation in the HER program in 2024 was 29,860 with additional Minnesota residential customers participating through the Low-Income HER (LI HER) program. The LI HER program is described in more detail in the Low-Income Energy Feedback program section of this report.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Energy Feedback	**Actual**	**Proposed**	**% of Goal**
Online Energy Analysis[1]	0	4,500	0%
Opower HER Participation	29,860	29,000	103%
Budget $	$220,387	$340,000	65%

Evaluation Methodology – HER

The 2024 evaluation of energy savings for the HER program was completed by Opower using integrated data from a variety of sources that allow for detailed analysis of energy

[1] Participation and savings not claimed in 2024. Online tool in development.

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savings. The evaluation report is included in Appendix B – Third Party Evaluations. The data utilized by Opower included:

1. Consumption Data
   Otter Tail Power provided weekly updates of monthly consumption data for all households in the program, including historical consumption information.

2. Parcel Data
   Opower received, to the extent available from a third-party vendor, data about household parcels, including home size, age and value, heating and cooling type, as well as pool and hot tub data. These data elements are static with the exception of square footage, heating and cooling type, and pool and hot tub data, which may be updated at the customer's request.

3. Demographic Data
   Opower received, to the extent available from a third-party vendor, demographic data about participants, including household income, number of occupants, age of occupant(s), and an owner/renter indicator. These fields were used to recommend customized energy efficiency tips to customers by using relevant demographic targeting. Household size may be updated at the customer's request.

Opower's analysis of the HER program relies upon a fixed-effects regression model. This statistical methodology is standard procedure for the analysis of controlled experiments and is a well-accepted practice within the energy efficiency program measurement and verification (M&V) community. This methodology and analysis closely resemble the "Large Scale Data Analysis" techniques described in the Model Energy Efficiency Program Impact Evaluation Guide from the National Action Plan on Energy Efficiency.

In 2016, updates were made to the Modeled Savings Methodology to improve the accuracy of the reporting. These changes included:

- Establishing the relationship between the monthly savings rate and the cumulative number of print reports received per person in the wave up to that month.
- Applying the forecasted savings rate in each month to the usage of the modeled wave.
- Adapting the algorithm to apply to rolling enrollment waves.

Otter Tail Power received approval from the Department on October 7, 2016, to apply a revised Modeled Savings Methodology to calculate energy savings.

Overall adjusted energy savings associated with the HER and LI HER programs in 2024 totaled 13,019.01 MWh, equal to an average 330.43 kWh per participant household. Otter Tail Power has reduced its claimed savings to reflect the standard HER program savings below.

Energy Savings and Adjustments

In accordance with the Decision of the Department, these full savings are used in calculating the net benefits and cost effectiveness of the Energy Feedback program. For 2024, the energy savings associated with behavioral change has been reduced by two-thirds, based on the Decision by the Deputy Commissioner of the DER.[2]

ENERGY AND DEMAND RESULTS – 2024	
Online Energy Analysis[3]	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	0
Demand Savings – kW	0

ENERGY AND DEMAND RESULTS – 2024	
Opower Home Energy Reports	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	3,673,982
Demand Savings – kW	1,526.37

ENERGY AND DEMAND RESULTS – 2024	
Energy Feedback Combined Results	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	3,673,982
Demand Savings – kW	1,526.37

[2]April 26, 2012, Docket Nos. E,G999/CI-08-133 and E017/CIP-10-356.
[3] Participation and savings not claimed in 2024. Online tool in development.

HOME ENERGY MANAGEMENT

The Company's Home Energy Management program consisted of the residential Air Conditioning Control program (CoolSavings) that includes cycled control of central air-conditioning systems and heat pumps, and the Water Heater Program that promotes control of water heaters.

Through CoolSavings the Company targets residential customers with central air conditioning. Customers are encouraged to enroll in the program and receive a $8.25/month credit for each of the four summer months (June-September). During a control event, cooling systems are cycled 15 minutes on and 15 minutes off for the duration of the control period, which can occur during the summer season, June through September.

Controlled water heating storage is one of Otter Tail Power's largest residential direct load management programs. Controlled water heating gives participating customers a discounted rate or bill credit in exchange for allowing the Company to curtail their water heater operation during peak and high energy price periods. During a control event, water heaters are interrupted for the entire duration of the control period, which can occur at any time of the year.

Otter Tail Power promotes Home Energy Management using various resources including:

- Radio advertising campaigns.
- Digital and social media advertising campaigns.
- Digital billboards.
- Bill inserts.
- Bill messages.
- Bill return envelopes.
- Training sessions with community action agencies contracted to implement House Therapy.
- Customer care booklet provided to all new customers.
- *Programs and Services Guide* provided to contractors and employees.
- Program, rate, and rebate pages within the Company's Ways to Save section of the website.

In 2024, Otter Tail Power called controlled air conditioning events on 13 days totaling 22 hours and 12 minutes. This control time is within the 300-hour control limit in the air

conditioning rate tariff. Water heaters were controlled approximately 139 hours and 35 minutes in 2024 over 220 days. Water heater control events are based on price signals and aim to maximize savings for all customers.

Participation and Budget

Otter Tail Power initially filed the Water Heating program in its 2014 to 2016 CIP triennial plan with 100 percent residential participation. The program now has a ratio of 95 percent residential and 5 percent commercial. Otter Tail Power has included participation data for both classes in this section of the Status Report. Coolsavings remains at 100 percent residential participation.

PARTICIPATION AND BUDGET – 2024			
Home Energy Management	**Actual**	**Proposed**	**% of Goal**
Participation	18,691	18,906	99%
Budget $	$87,658	$116,000	76%

Evaluation Methodology

Energy savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Energy Management	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	403,646
Demand Savings – kW	10,188.57

HOME HEATING AND COOLING

The Company's Home Heating and Cooling (HHC) program provided incentives for efficient air-source and geothermal heat pumps, Energy Star® air conditioners, envelope insulation and air sealing, Energy Star® windows, and smart thermostat installations.

Heat Pumps and Energy Star® Air Conditioners

The heat pump component targeted residential customers currently using or considering the installation of less efficient electric resistance heating and cooling systems by offering rebates for high-efficiency air source or geothermal heat pumps. The Company applies Energy Star® qualifications and federal 25C tax credits as reference guides for setting equipment efficiency requirements for air-to-air and geothermal heat pumps. The Company utilizes the criteria set by Efficiency Vermont for the air to water heat pump as this emerging technology does not currently have an Energy Star® qualification standard reference.

In 2024, air source heat pumps and Energy Star® air conditioners met the following minimum rating requirements. As presented in the Company's September 2024 modification filing, higher tier cold climate heat pump efficiency requirements will continue to increase to remain consistent with requirements for 25C tax credits to ensure simplicity for customers and contractors.

	SEER2	HSPF2	COP*
Energy Star AC	> or = 15.2	-	-
Standard heat pump	> or = 14.3	> or = 7.5	-
CCHP - Ductless	> or = 16.0	> or = 9.5	-
CCHP – Ducted	> or = 15.2	> or = 8.1	-
Air to Water (AWHP)	-	-	> or =1.7

*COP rating at A5W110 (At an outdoor ambient temperature of 5°F, the unit must deliver 110°F supply water.)

In 2024, geothermal heat pumps met the following minimum rating requirements.

Geothermal Heat Pumps			
Type	**Loop Type**	**COP**	**EER**
Water to air	Open loop	4.1	21.1
Water to air	Closed loop	3.6	17.1
Water to water	Open loop	3.5	20.1
Water to water	Closed loop	3.1	16.1
Direct exchange	-	3.6	16.0
GHP single unit ≥ 6 tons	-	3.1	13.0

The Company provided an additional rebate for customers electing to add a buffer tank with a heating coil or a desuperheater option to their heat pump to provide preheating of domestic hot water. This rebate is limited to a maximum of 20 tons per customer.

Quality Installation

New for 2024, the Company developed a program to recruit contractors for the Quality Installation rebate program. This program's focus is to identify contractors who have gone above standard licensing requirements and have taken additional classes or have certifications focused on heat pump technology best practices. Eligible certifications and trainings include North American Technician Excellence (NATE), Minnesota Air Source Heat Pump Collaborative Preferred Contractor Network, Manufacturer or distributor sponsored training, or other pre-approved training. The Company approved 94 contractors with 389 total staff technicians in 2024. Engagement outreach for this program has included promotion in the annual program and service guide, contractor workshops, and follow up with non-participating contractors as applications are submitted by customers. This program allowed Otter Tail Power to gain valuable insight into the number of contractors serving within the Company's service territory and has led to improved dialogue and outreach initiatives with contractors.

Equipment Tune-Ups

New for 2024, the Company offered rebates for equipment tune-ups that included coil cleaning, refrigeration charge check, air filter cleaning, and air flow measurement and correction if not done by homeowner or contractor at equipment installation. This program offered a great opportunity and reminder for customers who often forget or neglect their heating and cooling systems until it stops working. The program also offered a great opportunity for contractors to have some discussions on possible future options if it was identified equipment is reaching end of life and repair parts might no longer be available if failure were to occur. These conversations are valuable in getting customers to start thinking about what system they might want to install in the future, begin budgeting, and seeing what rebates might be available. This is in contrast to waiting for equipment failure and then having rushed decision making without reviewing all options on the market. The Company rebated 41 heat pump customers and 70 A/C customers whose equipment had an average age of 16 years.

Home Insulation

Recognizing the importance of an efficient building envelope, the Home Heating and Cooling program targets residential customers with primary electric heat by offering rebates for contractor-installed weatherization and insulation measures and new in 2024, Energy Star® Northern Climate Zone windows.

Smart Thermostats

The smart thermostat component offers rebates to customers who buy and install a qualified Tier II or Tier III thermostat. Tier II thermostats are communicating thermostats that give users access to setpoints and the ability to schedule changes from anywhere using a smart device including a mobile phone, tablet, or computer. Tier III thermostats are analytics-capable thermostats that offer energy saving features in addition to those of the Tier II thermostats, including coaching, heating, ventilation, and air conditioning (HVAC) diagnostics, comparative information, and geofencing. The tier level and the type of heating system determined the level of rebate a customer received. A customer without primary electric heating but with a central cooling system is eligible for a lesser rebate.

Otter Tail Power promotes Home Heating and Cooling using various resources including:

- *Programs and Services Guide* provided to contractors and employees.
- Media campaigns including television, radio, and social media.
- Bill messages.
- Bill inserts.
- Digital billboard.
- Program, rate, technology, and rebate pages within the Company's Ways to Save section of the website.
- Hero spots on the home page of the website.
- Modules on HERs mailed to customers through the Energy Feedback program.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Home Heating and Cooling	**Actual**	**Proposed**	**% of Goal**
Participation	1,013	1,176	86%
Budget $	$1,166,518	$915,600	127%

Evaluation Methodology

Energy savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Heating and Cooling	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	5,973,867
Demand Savings – kW	655.05

HOME LIGHTING

The Company's Home Lighting program is designed to help transform the residential lighting market through three strategies:

1. Funding for upstream incentives to reduce prices of Energy Star® LED lamps at the point of purchase for consumers at participating retail stores.
2. Rebates for retrofits of inefficient, hard-wired light fixtures to LED technology.
3. Rebates during new home construction for installation of hard-wired LED light fixtures.

Upstream Incentives

Through the services of a third-party service provider, Otter Tail Power offers upstream incentives for Energy Star® lighting products with the following objectives:

- Leverage manufacturer dollars for instant consumer rebate incentives averaging approximately $1.84 per LED bulb.
- Leverage advertising dollars for retailers.
- Highlight Otter Tail Power's sponsorship of the promotions through press releases, in-store displays, special public relations events, and LED bulb sales.
- Implement the program with seamless coordination with other Energy Star® Lighting promotions throughout Minnesota and the Midwest.

There were 40 retailers in our service territory that participated in the 2024 campaign, contributing to distribution of approximately 119,329 bulbs.

Otter Tail Power promotes the Home Lighting program using various resources including:

- Bill inserts.
- *Programs and Services Guide* provided to contractors and employees.
- Program, rate, and rebate pages within the Company's Ways to Save section of the website.
- Modules on Home Energy Reports mailed and emailed to customers through the Energy Feedback program.
- Media campaigns including television, radio, and social media.
- LED lighting factsheets available upon request.
- Special promotional events with three participating retail stores, including live radio remotes highlighting the benefits of LEDs and special pricing on LED

lamps available through Otter Tail Power's program. The events paired nicely with the retail stores' customer appreciation events and were well attended by local customers.

Other promotions included the following:

- The Company provided eight LED bulbs to each participant who recycled an appliance through the Home Appliance program. This extended customer education about LED bulbs and increased total bulb distribution.
- The Company collaborated with local nonprofit organizations to distribute 1,872 LED holiday light strings through the fall of 2024. LED holiday strings were distributed to customers in exchange for nonperishable food items, toys or cash donations to the nonprofit organizations. The Company organized and staffed these events in Bemidji and Fergus Falls. Results included approximately 606 pounds of food donated, $511 in cash donations to benefit local food shelves along with 165 toy donations for the United Way Holiday Toy Program.
- In a separate collaboration with community food shelves, Otter Tail distributed 3,200 LED night lights and 7,176 four-packs of LED bulbs to local food shelves, who then included these in orders for food shelf clients through normal business operations.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Home Lighting	**Actual**	**Proposed**	**% of Goal**
Participation	127,780	187,765	68%
Budget $	$511,854	$657,000	78%

Evaluation Methodology

Energy savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Lighting	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	2,694,184
Demand Savings – kW	204.86

RESIDENTIAL CODE SUPPORT

In collaboration with four other Minnesota electric and gas utilities, Otter Tail Power contributed resources to the Minnesota Energy Code Support Program's codes and standards compliance initiative.[4] This proactive effort supports communities across Minnesota in improving commercial building energy code compliance. By providing resources and guidance, the utilities help communities throughout Minnesota understand and adhere to building codes in new construction projects, ultimately aiding them in achieving their energy performance and economic development goals.

Activities completed by the Minnesota Energy Code Support Program consultant included training, circuit rider outreach, development of technical documents and resources, and other general activities and meetings to support the program. Specific achievements in these four residential and commercial program areas in 2024 included:

Training

- In-Person – 14 Commercial
- Onsite Best Practices – 2 Residential and 10 Commercial
- Webinars – 2 Residential and 15 Commercial

Circuit Rider Outreach

- Jurisdiction and Organization Visits – 212
- Friendly Visit – 42
- Questions Answered – 13
- Helpline Responses – 8
- Requests Submitted – 1

Technical Documents and Resource Development

- Technical Documents – 7 Residential and 15 Commercial
- Videos – 1 Residential and 1 Combined Residential/Commercial
- Code Books – 67 Commercial
- Newsletters – 1 Combined Residential/Commercial

[4] Otter Tail Power is working with Xcel Energy, Centerpoint Energy, MN Power, and MN Energy Resource Group.

Meetings/Activities to Support Program

- Events – 4
- Meetings – 12
- Collaborative Meetings – 6
- Technical Advisory Group – 4
- CEE Meetings – 20
- Conferences – 1
- Articles Published – 1

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Code Compliance Support	**Actual**	**Proposed**	**% of Goal**
Participation	0	0	N/A
Budget $	$17,768	$30,000	59%

Evaluation Methodology

In the interest of minimizing any possible market confusion or duplication of tasks, the utilities waited to commence evaluation activities until the end of 2024. This allowed time to understand any immediate effects from legislation passed in 2024 as well as the opportunity for enhanced coordination with the Emerging Technology Accelerator (ETA) team. In 2025 the utilities expect the selected evaluation team to:

- Review inputs to the savings method and either confirm the inputs or suggest modifications (including Energy Use Intensity (EUI) improvement assumptions, compliance rates, and attribution rates).

- Review timelines and any other assumptions related to code adoption cycles and specify where updates are needed as a result of changes in legislation or administrative processes.

- Review forecasts of building volume, including distribution of building types and align with ETA methodology for calculating construction activity and resulting savings.

- Identify need and/or timing for a compliance study, enhanced program theory logic model development, and gross savings technical assumption updates to accommodate the next code cycle.

DIRECT IMPACT – LOW-INCOME

HOUSE THERAPY

The House Therapy program's primary focus is audit, direct-install, and weatherization services for low-income residential customers. The program and measures are available to both renters and homeowners. The following table provides details on measures installed and participant status as owners or renters.

House Therapy -- Owner / Renter Detail 2024			
Installed measures	**Owners**	**Renters**	**Total**
Audit	56	14	70
Custom Measure*	2		2
Energy Star Clothes Dryer	26	1	27
Energy Star Washer	24	1	25
Energy Star Dishwasher	6	1	7
Heat Pump	9		9
Faucet Aerator	24		24
Freezer	13	1	14
LED	311	232	543
Low-flow Showerhead	14		14
Pipe Insulation	1		1
Refrigerator	33	12	45
Power Strip Tier II	38	1	39
Water Heater	10	1	11
Water Heater - Reduce Temperature	28	2	30
Water Heater--Controlled Ser. Rate	4	1	5
Weatherization			
Attic Insulation Materials	5		5
Ceiling Fan Materials	1		1
Blower Door Test	2		2
Exterior Wall Insulation Materials	1		1
Other Weatherization Materials	9		9
Thermal Analysis	2		2

*Custom measures include electrical repairs and electrical panel upgrades.

House Therapy -- Owner / Renter Detail – 2024				
	CAP Spending	**Percent**	**Participation**	**Percent**
Owners	$191,880	90%	78	84%
Renters	$21,927	10%	15	16%
Total	$213,807	100%	93	100%

Otter Tail Power relies on local Community Action Program (CAP) Agencies to provide valuable technical expertise and implementation services for the House Therapy program. The Company commends the agencies' commitment to providing weatherization expertise and excellence in implementation services for this program.

Otter Tail Power promotes House Therapy using various resources including:

- Residential bill inserts.
- Within the environment disclosure insert posted on our website annually.
- Through the Company's website where contact information is listed for each of the agencies that implement the program.
- Through the CAP Agencies contracted with Otter Tail Power to implement the program.
- Through the Company's Low-Income Home Energy Feedback HERs targeting low-income households.
- Spanish-translated bill inserts were made available upon request in 2024.
- Outreach from contracted third parties to multifamily building owners and managers.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
House Therapy	**Actual**	**Proposed**	**% of Goal**
Participation	798	1,651	123%
Budget $	$255,085	$317,000	80%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
House Therapy	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	107,122
Demand Savings – kW	5.94

LOW-INCOME HOME ENERGY FEEDBACK

The Low-Income Home Energy Feedback program consists of a specialized Low-Income Home Energy Report (LI HER) experience to help the low-income segment of our customers to achieve energy savings, gain greater control over their home energy costs, and learn about resources available to them through Company programs and the greater community.

The LI HER program is designed as an opt-out program and provides direct mail delivery of up to four comparative energy usage reports and a monthly emailed LI HER that is sent to those participating customers who provide Otter Tail Power and email address.

Low-income customers were identified through segmentation within the Opower platform. Segmentation filters were based on the following attributes during 2024:

- The low-income home energy assistance program (LIHEAP) qualified indicator Otter Tail Power receives from state data; or
- Identified by Opower as meeting the Minnesota low-income definition, based on 80% of area median incomes, using third-party customer-level demographic data.

Participation in the program is defined as any low-income sector Minnesota residential customer that received one or more personalized LIHERs during 2024. Total participation in 2024 was 9,540 customers.

Low-Income Home Energy Reports

The LI HERs feature:

- Comparisons of recent energy use to comparable nearby homes.
- Comparison of past energy use to current use over time.
- Low-cost and no-cost energy saving ideas with an emphasis on those tips offering the highest impact on energy savings and the home's energy use pattern.
- Promotion of other low-income qualified programs available through Otter Tail Power.
- Promotion of other low-income qualified programs and services available in the region (such as LIHEAP).
- Spanish-translated reports upon request made available in 2024.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Low-Income Home Energy Feedback	**Actual**	**Proposed**	**% of Goal**
LI HER Participation	9,540	10,000	95%
Budget $	$72,617	$85,000	85%

Evaluation Methodology – LI HER

The 2024 evaluation of energy savings for the HER program was completed by Opower using integrated data from a variety of sources that allow for detailed analysis of energy savings results. The evaluation is included in Appendix B – Third Party Evaluations. The data included:

1. Consumption data
   Otter Tail Power provided weekly updates of monthly consumption data for all households in the program, including historical consumption information.

2. Parcel data
   Opower received, to the extent available from a third-party vendor, data about household parcels, including home size, age and value, heating and cooling type, as well as pool and hot tub data. These data elements are static with the exception of square footage, heating and cooling type, and pool and hot tub data, which may be updated at the customer's request.

3. Demographic data
   Opower received participant demographic data, to the extent available from a third-party vendor, including household income, age of occupant(s), number of occupants, and an owner/renter indicator. These fields were used to recommend customized energy efficiency tips to customers by using relevant demographic targeting. Household size may be updated at the customer's request.

Opower's analysis of the LI HER program relies upon a fixed-effects regression model. This statistical methodology is standard procedure for the analysis of controlled experiments, is a well-accepted practice within the energy efficiency program M&V community. This methodology and analysis closely resemble the "Large Scale Data Analysis" techniques described in the Model Energy Efficiency Program Impact Evaluation Guide from the National Action Plan on Energy Efficiency.

In 2016, updates were made to the Modeled Savings Methodology to improve the accuracy of the reporting. These changes include:

- Establishing the relationship between the monthly savings rate and the cumulative number of print reports received per person in the wave up to that month.
- Applying the forecasted savings rate in each month to the usage of the modeled wave.
- Adapting the algorithm to apply to rolling enrollment waves.

Otter Tail Power received approval from the Department on October 7, 2016, to apply a revised Modeled Savings Methodology to calculate energy savings to the HER program offered through the Energy Feedback program. The same approach is used for the Low-Income Energy Feedback LI HER program.

Overall adjusted energy savings associated with the HER and LI HER programs in 2024 totaled 13,019.01 MWh, equal to an average 330.43 kWh per participant household.

Energy Savings and Adjustments

In accordance with the Decision of the Department, these full savings are used in calculating the net benefits and cost effectiveness of the Energy Feedback program. For 2024, the energy savings associated with behavioral change has been reduced by two-thirds, based on the Decision by the Deputy Commissioner of the Department.[5]

ENERGY AND DEMAND RESULTS – 2024	
Low-Income Home Energy Feedback	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	1,173,804
Demand Savings – kW	487.66

[5]April 26, 2012, Docket Nos. E,G999/CI-08-133 and E017/CIP-10-356.

LOW-INCOME AND RENTER DETAILS

Pursuant to the Department's Decision in the matter of Otter Tail Power's 2021-2023 Electric Conservation Improvement Program Triennial Plan (Docket No. E017/CIP-20-475) issued November 24, 2020, utilities are required to clearly report the following metrics in their annual status reports:

a) the estimate of anticipated and actual low-income residential customer participation levels for each program as required in Minnesota Rules 7690.0550,
b) the estimate of anticipated and actual residential rental customer participation levels for each program as required in Minnesota Rules 7690.0550,
c) the planned and actual low-income spending and energy savings for each program, including dedicated low-income programs, as required in Minnesota Rules 7690.0550,
d) for programs that make use of the low-income multifamily policy guidance, the anticipated and actual spending and energy savings achieved for the program, and from market-rate versus affordable housing participants, through the program,
e) for programs that make use of the low-income multifamily policy guidance, the number of buildings and units served by market-rate versus affordable housing through the program, and
f) for programs that make use of the low-income multifamily policy guidance, the cumulative number and amount of incentives by measure type for market-rate versus affordable housing delivered through the program (e.g. total number and total value of incentives for boilers installed in market-rate and in affordable housing buildings through a multifamily program).

Tables A, B, and C below provide more detailed information pertaining to the Low-Income and Renter Details reporting requirements. Otter Tail Power does not offer any hybrid programs that make use of the low-income multifamily policy guidance to allocate expenses and savings. The company accounts for expenses and savings from multifamily projects taking place in buildings meeting low-income guidelines through its House Therapy program.

Table A: Budgeted total, actual total, anticipated low-income, and actual low-income participants.

	Budgeted Total Participants	Actual Total Participants	Anticipated Low-Income Participants*	Actual Low-Income Participants**
Residential				
Home Appliance	829	1,118	199	52
Home Direct Install	16,850	16,831	4,044	2
Home Energy Feedback***	33,500	29,860	-	748
Home Energy Management	18,906	18,691	4,537	1,477
Home Heating & Cooling	1,176	1,013	282	42
Home Lighting	187,765	127,780	45,064	38
EFS Electric Equipment and Too	303	178	73	23
Total - Residential	259,329	216,076	57,353	2,382
Low-Income				
House Therapy	1,651	798	1,651	368
Low-Income Energy Feedback	10,000	9,540	10,000	2,184
Total - Low-Income	11,651	10,338	11,651	2,552

* Based on 24 percent which was derived from 2020 and 2021 Census data.

**Cross referenced with OTP customers who received or were approved for an Energy Assistance Payments in 2024.

*** Low-Income participants are counted under the Low-Income Energy Feedback Program.

Table B: Budgeted total participants, actual total participants, anticipated rental participants and actual rental participants.

	TOTAL		RENTAL	
	Budgeted Participants	Actual Participants	Anticipated Participants *	Actual Participants **
Residential				
Home Appliance	829	1,118	232	19
Home Direct Install	16,850	16,831	4,718	3
Home Energy Feedback	33,500	29,860	9,380	3,633
Home Energy Management	18,906	18,691	5,294	1,688
Home Heating & Cooling	1,176	1,013	329	22
Home Lighting	187,765	127,780	52,574	20
EFS Electric Equipment and Tools	303	178	85	7
Total - Residential	259,329	195,471	72,612	5,392
Low-Income				
House Therapy	1,651	798	462	50
Low-Income Home Energy Feedback	10,000	9,540	2,800	1,781
Total - Low-Income	11,651	10,338	3,262	1,831

*Based on 28 percent which was derived from 2020 and 2021 Census data.

**Cross referenced with OTP customers who were identified as renter of landlord in our CIS system.

Table C: Proposed total kWh savings and expenditures, actual total kWh and expenditures, estimated low-income kWh and expenditures, and actual low-income kWh and expenditures.

	Budgeted Total		Actual Total		Anticipated Low-Income*		Actual Low-Income**	
	kWh Savings	Expenditures	kWh Savings	Expenditures	kWh Savings	Expenditures	kWh Savings	Expenditures
Residential								
Home Appliance	371,535	$183,000	315,180	$170,601	89,168	$43,920	832	2,500
Home Direct Install	1,414,236	$137,000	1,389,044	$150,963	339,417	$32,880	19,818	-
Home Energy Feedback***	3,755,119	$340,000	3,673,982	$220,387	901,228	$81,600	16,433	5,521
Home Energy Management	406,181	$116,000	403,646	$87,658	97,484	$27,840	83,402	6,927
Home Heating & Cooling	3,726,936	$915,600	5,973,867	$1,166,518	894,465	$219,744	134,080	19,876
Home Lighting	3,168,913	$657,000	2,694,184	$511,854	760,539	$157,680	856	2,237
EFS Electric Equipment and Tools	1,282,746	$194,000	563,703	$111,304	307,859	$46,560	4,165	3,498
Total - Residential	12,842,920	$2,542,600	14,449,903	2,307,982	3,082,301	$563,664	$255,421	$37,061
Low-Income								
House Therapy	107,122	$317,000	107,122	$255,085	107,122	$317,000	22,297	$135,364
Low-Income Energy Feedback	1,173,804	$85,000	1,173,804	$72,617	1,173,804	$85,000	1,338,451	$16,624
Total - Low-Income	1,280,926	402,000	1,280,926	327,701	1,280,926	402,000	1,360,748	151,988

* Based on 24 percent which was derived from 2020 and 2021 Census data.
**Cross referenced with OTP customers who received or were approved for an Energy Assistance Payments in 2024.
*** Low-Income participants are counted under the Low-Income Energy Feedback Program.

The Company does not require customers participating in its residential ECO programs to provide detailed information related to household income. For the purposes of the tables above, the Company instead has cross-referenced information on residential program participation with information on customers eligible for energy assistance. Not all customers who happen to be eligible for energy assistance will necessarily apply for and receive energy assistance, so it is likely that the above numbers understate actual low-income customer participation.

Further, actual participation attributed to low-income customers in larger programs, specifically in Home Lighting, is likely higher than reported estimates in the above tables. The majority of participation, kWh savings, and expenses for this program are the result of providing upstream incentives to provide participants with a more seamless experience. However, delivering programs through an upstream program model does not provide the Company with an accurate method of allocating participation, kWh savings, and expenses exclusively to customers meeting low-income program thresholds and/or those classified as renters. Therefore, Otter Tail Power only reports low-income Home Lighting participants as only those customers who the Company could cross reference between its hard-wired and new construction participants and those eligible for energy assistance. This results in the actual participation, savings, and incentive numbers being higher than reported in the above tables.

DIRECT IMPACT – COMMERCIAL

COMMERCIAL AUDITS AND STUDIES

Otter Tail Power's Audits and Studies program provided options for customers interested in assessing their facilities and operations to learn more about opportunities available in increasing energy efficiency. Key components of this program include:

- Building recommissioning/retrocommissioning (RCx).
- Compressed air system audits.
- Compressed air system leak studies.
- Compressed air RCx.
- Small to midsize business assessments.

Building recommissioning/retrocommissioning (RCx)

The *Energy Star® Building Manual* defines commissioning as the process of ensuring that systems are designed, installed, functionally tested, and capable of being operated and maintained to the owner's operational needs.

- Recommissioning is the term used for applying the process to a building that has been commissioned previously (either during construction or as an existing building).
- Retrocommissioning is the systematic process applied to existing buildings that have never been commissioned to ensure that their systems can be operated and maintained according to the owners' needs.

Building tune-ups, RCx Lite, and building optimization all refer to an evolution of the traditional RCx process. The approach starts by targeting the most common RCx measures with the highest chances of returning payback on operations and maintenance improvements. Often, these operation and maintenance improvements are associated with advanced control strategies. Engineering firms completing RCx Lite studies are often capable of identifying these measures through spot inspections of direct digital control systems without the added costs of seasonal monitoring and functional performance testing completed through formal RCx studies. Consequently, the RCx Lite process can identify up to 75 percent of the savings of a more formal RCx study at approximately 25 percent of the cost.

Otter Tail Power's RCx program provided incentives to qualifying commercial customers to complete RCx studies and implement cost effective, energy savings measures. The RCx program delivers a tiered approach to delivering RCx services. The RCx Lite tier provided

incentives for building tune-ups, where the RCx tier incentivized customers to implement formal RCx studies with more expansive measures. Potential participants must complete a pre-approval application form prior to initiating any RCx projects to insure eventual study funding from Otter Tail Power. Not all buildings and building types are ideal candidates for achieving energy savings through traditional RCx efficiency measures. The pre-approval process increased the likelihood that customers with buildings and building types with the best RCx opportunities capitalized on the RCx process.

Compressed Air Audits/RCx/Leak Studies

The Compressed Air Audit component paid up to 50 percent of compressed audit costs, with a maximum of $10,000 per participant. The project relied on industry consultants to provide professional audit services with an unbiased report on saving energy with compressed air system improvements.

Otter Tail Power provided incentives for customers completing studies to identify and repair leaks in compressed air distribution systems. Participants must have repaired all accessible leaks to qualify for study incentives.

Compressed air RCx studies focused on savings potential related to compressed air system setpoints, misapplications of compressed air, and other compressed air operating practices. Customers agreed to completing all identified measures with a combined payback of two years or less as part of receiving incentives through the program.

Small- to Mid-Sized Business Assessments

Customers who participated in Otter Tail Power's Commercial Direct Install program were eligible for a free assessment identifying the top three to five efficiency opportunities in their small- to mid-sized business. Working in tandem, one auditor focused on installation of low-cost efficiency measures while another auditor toured the business to identify efficiency opportunities. The Company followed up with a two-page report emailed to participants identifying efficiency investment opportunities along with cost estimates, energy cost savings, and payback information. Customers expressed appreciation for the efficiency measures and reports, with approximately ten percent of customers historically moving forward with implementing measures identified in their free assessments.

Otter Tail Power promoted the Commercial Audits and Studies program through a variety of resources including:

- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Bill inserts.
- Targeted campaigns featuring direct customer contact based on business type, energy use intensity, and geographic location.
- Brochures and literature.
- Personal consultations between program implementation staff and customers.
- Program, technology, and rebate information available on the Company's website.

Participation and Budget[6]

PARTICIPATION AND BUDGET – 2024			
Commercial Audits and Studies	**Actual**	**Proposed**	**% of Goal**
Participation	107	86	124%
Budget $	$143,706	$319,000	45%

Evaluation Methodology

Traditional RCx

Otter Tail Power, together with a third-party engineering consulting firm, reviewed the RCx study for accuracy of calculations, assumptions, and completion of all required RCx study requirements. Otter Tail Power works with the customer and the customer's engineering firm as needed to assure engineering calculations, assumptions, and the study all meet the Company's RCx program requirements.

Turn-Key RCx

Otter Tail Power used savings calculations developed by the Company's program implementation consultant using engineering fundamentals, site data, and energy modeling. To evaluate those savings, Otter Tail Power and its third-party program implementation consultant performed post-installation functional testing at each facility. This on-site M&V confirms each measure's implementation in accordance with the

[6] Reported participation in 2024 includes Commercial Direct Install Assessments which were originally included under the Advertising and Education program.

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engineering recommendations. The savings calculations were revised based on observed conditions post-implementation and reflect any alteration to the measure that results from customer implementation.

Compressed Air

Otter Tail Power used the MN Technical Reference Manual (TRM), when available, and the Wisconsin and Vermont TRMs in its absence. All savings algorithms include actual data from historical Otter Tail Power compressed air assessments performed by independent third-party engineers or vendors.

Energy Savings

ENERGY AND DEMAND RESULTS – 2024	
Commercial Audits and Studies	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	687,003
Demand Savings – kW	302.89

COMMERCIAL DIRECT INSTALL

The Commercial Direct Install (CDI) program offered free energy assessments and installation of low-cost energy efficiency measures for participating small- to mid-sized commercial customers. The program capitalizes on personal interactions to educate customers in this often-overlooked market segment on:

- Benefits of energy efficiency.
- Energy efficiency opportunities in the customer's business operations.
- Quick, easy, and affordable measures that have a direct, immediate impact on reducing energy bills.

The free energy assessment offered through the Commercial Audits and Studies program provides the customer with a simple two-page report identifying opportunities for investing in energy efficiency measures and further educates customers on the subject. At the same time, direct-installation of easily installed energy efficiency measures, at no cost to the participant, provides real world examples of technologies readily available for reducing energy expenses in small- to mid-size businesses. Otter Tail Power promoted the CDI program through a targeted strategy based on community size and geographic location. The Company relied on personal contacts with local administration and government, Chamber of Commerce personnel, and other business organizations to determine overall interest in implementing the program.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Direct Install	**Actual**	**Proposed**	**% of Goal**
Participation	702	2,465	29%
Budget $	$30,924	$67,000	46%

Evaluation Methodology

The Company uses TRM savings algorithms and assumptions and customer-specific operational data where applicable.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Direct Install	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	44,843
Demand Savings – kW	5.58

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COMMERCIAL ENERGY MANAGEMENT

The Commercial Energy Management program includes the previously approved commercial air conditioning control (CoolSavings) program. CoolSavings air conditioning control program targeted small commercial customers in Minnesota with central air conditioning systems. Customers were encouraged to enroll in the program and receive a bill credit of $6.00 per ton of connected load for each summer month (June-September).

Otter Tail Power promoted the program through various resources including:

- Personal business contacts.
- Bill inserts.
- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Program, technology, and rebate information available on the Company's website.

In 2024, Otter Tail Power controlled air conditioning 13 days, totaling 22 hours and 12 minutes. This control time is within the 300-hour control limit in the air conditioning rider.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Energy Management	**Actual**	**Proposed**	**% of Goal**
Participation	334	512	65%
Budget $	$4,533	$24,000	19%

Evaluation Methodology

Current energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Energy Management	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	7,234
Demand Savings – kW	76.18

COMMERCIAL HEAT PUMPS

The Commercial Heat Pump program targets commercial customers currently using or considering the installation of less efficient resistance electric heating and cooling systems by offering rebates for Energy Star® air conditioners and high-efficiency air source and geothermal heat pumps. During 2024 Otter Tail Power relied on Energy Star® qualifications and federal 25C tax credits as the reference for minimum equipment efficiency requirements. For air-to-water heat pumps, the Company utilized the criteria set by Efficiency Vermont, as this emerging technology does not currently have an Energy Star® qualification standard reference.

As discussed in the Home Heating and Cooling section, the higher tier cold climate heat pumps will continue to reference the 25C tax credit as presented in the Company's modification filing and will be reflected in the 2025 status report. The quality installation rebate program is also utilized by approved contractors for commercial customers and is discussed in more detail in the Home Heating and Cooling residential section.

Air source heat pumps met the following minimum rating requirements.

	SEER2	HSPF2	COP*
Energy Star A/C	> or = 15.2	-	-
Standard heat pump	> or = 14.3	> or = 7.5	-
CCHP - Ductless	> or =16.0	> or =9.5	-
CCHP – Ducted	> or = 15.2	> or = 8.1	-
Air to water (AWHP)	-	-	> or = 1.7

*COP rating at A5W110 (At an outdoor ambient temperature of 5°F, the unit must deliver 110°F supply water.)

Geothermal heat pumps met the following rating requirements:

Geothermal Heat Pumps			
Type	**Loop Type**	**COP**	**EER**
Water to air	Open loop	4.1	21.1
Water to air	Closed loop	3.6	17.1
Water to water	Open loop	3.5	20.1
Water to water	Closed loop	3.1	16.1
Direct exchange		3.6	16.0
GHP single unit ≥ 6 tons		3.1	13.0

The Company continued a minimum requirement for single units equal to or larger than six tons. This change was made in 2023 following contractor feedback and the limitation of Energy Star® testing that does not account for these larger units which are more

prevalent in these commercial buildings. At these larger sizes, when compared to other heating/cooling options, geothermal heat pumps remain the highest efficiency technology available for customers.

The Company also continued an additional rebate for customers electing to add a buffer tank with a heating coil or a desuperheater option to their heat pump to provide preheating of domestic hot water. This rebate is limited to a maximum of 20 tons per customer.

Otter Tail Power promotes energy efficient heat pumps using various resources including:

- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Media campaigns including television, radio, and social and digital media campaigns.
- Bill messages.
- Bill inserts.
- Digital billboards.
- Hero spots on the home page of the website.
- Program, technology, and rebate information available on the Company's website.
- Participation in the Company's Integrated Building Design Plus program.

To increase participation, the Company offered rebates and financing at 1.9 percent in 2024.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Heat Pumps	**Actual**	***Proposed***	**% of Goal**
Participation	227	311	73%
Budget $	$520,078	$675,000	77%

Evaluation Methodology

Energy savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Heat Pumps	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	2,486,061
Demand Savings – kW	308.77

COMMERCIAL LIGHTING

The Commercial Lighting program provides incentives to commercial and industrial customers installing qualifying energy-efficient lighting technologies in new construction and for retrofitting to energy-efficient lighting technologies such as LED lamps and fixtures and lighting controls.

Otter Tail Power actively promotes the Commercial Lighting program through a variety of strategies including:

- *Taking Care of Business* commercial and industrial ECO brochure.
- Bill inserts.
- Digital and social media campaign.
- Personal interactions between customers and Company program implementation staff.
- *Programs and Services Guide* provided to contractors and employees.
- Program, technology, and rebate information available on the Company's website.
- Assessments completed for small- to mid-sized commercial businesses through the Company's Commercial Audits and Studies and Commercial Direct Install programs.
- Participation in the Company's Integrated Building Design Plus program.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Lighting	**Actual**	**Proposed**	**% of Goal**
Participation	781	1,015	77%
Budget $	$981,325	$1,546,000	63%

Evaluation Methodology

Otter Tail Power uses the TRM to calculate impact savings for the Commercial Lighting program. For retrofit installation, the Company documents all existing lighting wattage removed at each site and compares it to the actual energy efficient lighting wattage being installed to calculate energy savings. While for newly installed lighting systems, qualifying installed measures are compared to TRM baseline efficiency systems to determine kilowatt-hour savings. The TRM also establishes hours of operation. In accordance with the TRM protocols, energy and demand savings adjustments of 9.5 and 25.4 percent

respectively were allocated to those businesses having electric mechanical cooling. This is consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Lighting	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	11,418,027
Demand Savings – kW	1,756.54

COMMERCIAL and INDUSTRIAL FOCUSED EFFICIENCY

Otter Tail Power's largest industrial customers collectively make up less than one percent of all Minnesota customers but account for approximately 65 percent of total retail energy sales. As significant consumers of electricity, the industrial sector often provides abundant opportunities for improvements in energy management practices and implementation of energy efficiency upgrades.

The Commercial and Industrial Focused Efficiency program targeted customers in Otter Tail Power's commercial and industrial segment with potential for improvements in production processes, end-use efficiency, and energy management practices. The program used a proactive approach to benchmarking energy management practices and identified specific opportunities for efficiency improvements in large commercial and industrial facilities.

Implementation of the Commercial and Industrial Focused Efficiency program consisted of the following strategies:

1. Proactive Participant Identification

   Otter Tail Power considered anticipated customer engagement and energy savings potential while screening potential participants. The program focused on customers with annual savings potential of 250,000 kWh or greater, typically requiring annual consumption of at least 5,000,000 kWh. Potential participants who bring engaged enthusiastic management and employee teams to the table are more likely to pursue the most cost-effective energy saving behaviors and opportunities.

2. Energy Management Benchmarking

   For qualified customers, Otter Tail Power funded the Envinta Energy Roadmap energy management benchmarking analysis early in the process. The benchmarking session focuses on management practices related to energy efficiency by incorporating participation from across the customer's organization.

3. Project Identification

   Forming an engaged and knowledgeable energy management team is imperative to identifying efficiency opportunities on the customer site. To further facilitate identification of efficiency measures, Otter Tail Power funds the cost of engineering studies needed to identify and evaluate energy savings opportunities above a $500 copay from the participant. Possible efficiency measures include

lighting, drive-power systems, process efficiency improvements, refrigeration systems, compressed air systems, and custom efficiency projects.

4. Project Implementation
   Working in tandem with the customer's representation on the energy management team, Otter Tail Power developed a schedule of efficiency projects with potential bonus incentives. Bonus incentives are provided in exchange for the participant's completion of all measures before established deadlines. Efficiency measures might include projects traditionally accounted for under Otter Tail Power's prescriptive rebate programs, but Otter Tail Power attributes energy savings for each efficiency measure to the Commercial and Industrial Focused Efficiency program.

5. Measurement and Verification
   Otter Tail Power followed the M&V Protocols for end-use efficiency projects meeting the formal M&V requirements established by the Department.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Industrial Focused Efficiency	**Actual**	**Proposed**	**% of Goal**
Participation	18	26	69%
Budget $	$473,955	$657,000	72%

Evaluation Methodology

Otter Tail Power developed energy savings estimates through both established methodologies for prescriptive measures and through engineering calculations for custom measures implemented by the customer.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Industrial Focused Efficiency	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	2,331,848
Demand Savings – kW	520.76

COMPRESSED AIR EFFICIENCY

The Compressed Air Efficiency program provided incentives to commercial and industrial customers for implementing efficiency improvements in compressed air systems.

Compressed air systems afford users relatively easy distribution of and access to a robust power source present in nearly all industrial facilities, often referred to as the fourth utility in industrial plants. At the same time, compressed air generation is one of the most energy-intensive utilities in industrial facilities, with efficiency of compressed air systems typically at only ten to fifteen percent. Consequently, any improvements in compressed air system efficiency can lead to reduction of facility energy consumption in the order of 20 to 50 percent.

Otter Tail Power promoted Compressed Air Efficiency using various resources including:

- Personal interactions between Otter Tail Power representatives and customers with large, compressed-air systems.
- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Program, technology, and rebate information available on the Company's website.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Compressed Air Efficiency	**Actual**	**Proposed**	**% of Goal**
Participation	10	16	63%
Budget $	$18,522	$71,000	26%

Evaluation Methodology

Otter Tail Power uses the MN TRM, when available, and the Wisconsin and Vermont TRMs in its absence. All savings algorithms include actual data from historical Otter Tail Power compressed air assessments performed by independent third-party engineers or vendors.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Compressed Air Efficiency	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	113,546
Demand Savings – kW	37.62

CUSTOM EFFICIENCY GRANTS (CUSTOM PROJECTS)

The Grants program offered customized incentives to commercial and industrial customers for conservation and efficiency improvements. In 2024, Otter Tail Power analyzed a variety of customer-submitted grant projects that were approved for incentives.

Custom Projects Type of System Installation	Quantity
Building Envelope Improvements	3
Chiller System	1
Cooking Equipment	7
Cooling System	5
Integrated Building Design Plus	2
Motors	2
Production Equipment	6
Pumps	1
Variable Speed Drive	1
Total	**28**

Otter Tail Power promotes the Grant program through a variety of resources including:

- Personal interaction between Otter Tail Power representatives and customers.
- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Bill inserts.
- Program, technology, and rebate information available on the Company's website.
- Participation in the Company's Integrated Building Design Plus program.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Custom Efficiency Grants	**Actual**	**Proposed**	**% of Goal**
Participation	28	18	156%
Budget $	$335,499	$334,000	100%

Evaluation Methodology

Each custom grant measure is evaluated on an individual basis and estimated energy savings are calculated by Otter Tail Power and are specific to each individual measure.

The Company also considers and will verify estimated energy savings when submitted by a qualified and independent third-party energy services provider. Otter Tail Power provided expertise as needed, helped commercial and industrial customers determine the energy and demand savings needed to develop a grant proposal, and often worked with internal or third-party engineers to determine and verify savings.

The Large Custom Grant M&V protocols affect any large project with estimated savings exceeding one million kilowatts hours. The protocols include several options for M&V of large grant projects that meet the protocol criteria. In 2023, Otter Tail Power had two custom projects under the Custom Efficiency Grant program estimated to save greater than one GWh. Otter Tail Power submitted Pre-M&V reports with the DER for approval in late December 2023. Otter Tail Power submitted Post M&V results for one project in October 2024. The savings result of the project fell within 10 percent of the original estimate and does not require a true-up. The second project was granted an extension to file a final M&V report. The equipment is a part of a larger expansion project that has not yet been completed. A Post-M&V report will be submitted to the Department in 2025.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Custom Efficiency Grants	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	1,847,925
Demand Savings – kW	380.28

DRIVE POWER

The Company's Drive Power program encouraged commercial and industrial customers to improve the efficiency of systems through incentives for efficient electric motors and adjustable speed drives to maximize operational efficiency of motor systems.

Motors

The goal of the motors measures within the Drive Power program is to reduce system peak demand and energy use by offering customers incentives to purchase and install motors that meet or exceed NEMA Premium® efficiency ratings for various applications. Otter Tail Power offers incentives for high-efficiency totally-enclosed fan-cooled and open drip-proof motors sized from one horsepower to five-hundred horsepower. Incentives were also available for customers upgrading to efficient motors with explosion-proof enclosures sized between one and three-hundred horsepower. Additionally, the Company provided incentives for select electronically commutated motors installed in exhaust and HVAC fan applications.

Adjustable Speed Drives (ASDs)

Induction motors are the workhorses of industry, used in virtually every manufacturing plant and office building. However, the single most significant source of energy savings in induction motor systems lies not in the motor itself but rather in the controls that govern the motor's operation. ASDs are one method of modifying or controlling motor operation that is a proven option for improving performance and efficiency in drive systems. Through the Drive Power program, Otter Tail Power offered incentives based on horsepower for seasonal and nonseasonal ASDs.

Otter Tail Power promoted the Drive Power program using various resources including:

- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Bill inserts.
- Program, technology, and rebate information available on the Company's website.
- Participation in the Company's Integrated Building Design Plus program.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Drive Power	**Actual**	**Proposed**	**% of Goal**
Participation	597	388	154%
Budget $	$606,834	$374,000	162%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Drive Power	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	11,875,304
Demand Savings – kW	1,274.47

REFRIGERATION

The Refrigeration program is designed to promote high-efficiency commercial refrigeration technologies by offering rebates for new and retrofit installation of equipment such as parallel racks, condenser systems, sub-cooling systems, electrically commutated motors, and high evaporator temperature cases.

Otter Tail Power promoted the Refrigeration program using a variety of resources including:

- *Taking Care of Business* commercial ECO brochure.
- *Programs and Services Guide* provided to contractors and employees.
- Program, technology, and rebate information available on the Company's website.
- Quarterly phone conversations with contractors specializing in service and installations of commercial refrigeration systems.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Refrigeration	**Actual**	**Proposed**	**% of Goal**
Participation	41	113	36%
Budget $	$40,828	$181,000	23%

Evaluation Methodology

The Company used the TRM and engineering estimates for each refrigeration measure. Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Refrigeration	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	341,091
Demand Savings – kW	59.25

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COMMERCIAL CODE COMPLIANCE SUPPORT

In collaboration with four other Minnesota electric and gas utilities[7], Otter Tail Power contributed resources to the Minnesota Energy Code Support Program's codes and standards compliance initiative. This proactive effort supports communities across Minnesota in improving commercial building energy code compliance. By providing resources and guidance, the utilities help communities throughout Minnesota understand and adhere to building codes in new construction projects, ultimately aiding them in achieving their energy performance and economic development goals.

Activities completed by the Minnesota Energy Code Support Program consultant included training, circuit rider outreach, development of technical documents and resources, and other general activities and meetings to support the program. Specific achievements in these four residential and commercial program areas in 2024 included:

Training

- In-Person – 14 Commercial
- Onsite Best Practices – 2 Residential and 10 Commercial
- Webinars – 2 Residential and 15 Commercial

Circuit Rider Outreach

- Jurisdiction and Organization Visits – 212
- Friendly Visit – 42
- Questions Answered – 13
- Helpline Responses – 8
- Requests Submitted – 1

Technical Documents and Resource Development

- Technical Documents – 7 Residential and 15 Commercial
- Videos – 1 Residential and 1 Combined Residential/Commercial
- Code Books – 67 Commercial
- Newsletters – 1 Combined Residential/Commercial

[7] Xcel Energy, MN Power, Centerpoint, and Minnesota Energy Resources.

Meetings/Activities to Support Program

- Events – 4
- Meetings – 12
- Collaborative Meetings – 6
- Technical Advisory Group – 4
- CEE Meetings – 20
- Conferences – 1
- Articles Published – 1

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Code Compliance Support	**Actual**	**Proposed**	**% of Goal**
Participation	N/A	N/A	N/A
Budget $	$18,380	$25,000	74%

Evaluation Methodology

In the interest of minimizing any possible market confusion or duplication of tasks, the utilities waited to commence evaluation activities until the end of 2024. This allowed time to understand any immediate effects from legislation passed in 2024 as well as the opportunity for enhanced coordination with the ETA team. In 2025 the utilities expect the selected evaluation team to:

- Review inputs to the savings method and either confirm the inputs or suggest modifications (including EUI improvement assumptions, compliance rates, and attribution rates).

- Review timelines and any other assumptions related to code adoption cycles and specify where updates are needed as a result of changes in legislation or administrative processes.

- Review forecasts of building volume, including distribution of building types and align with ETA methodology for calculating construction activity and resulting savings.

- Identify need and/or timing for a compliance study, enhanced program theory logic model development, and gross savings technical assumption updates to accommodate the next code cycle.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Code Compliance Support	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	532,990
Demand Savings – kW	60.84

DIRECT IMPACT – OTHER

PUBLICLY OWNED PROPERTY (POP) SOLAR

The objective of the POP Solar program is to demonstrate the benefits of solar PV generation by offering incentives for universal solar projects to rural Minnesota communities, local and tribal governments, and educational facilities. The program provides incentives for the installation of non-residential solar PV systems in public sector facilities. The POP Solar program is an example of universal solar, which shares the benefits of solar with all members of the community, university, public school, tribal property, or other publicly owned properties.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Publicly Owned Property Solar	**Actual**	**Proposed**	**% of Goal**
Participation	9	16	56%
Budget $	$423,763	$1,000,000	43%

Overall, the Company focus is providing information and support on technology, installation/interconnection processes, support letters and financial analysis on grants, tax credits, financing options and POP Solar rebates. Company engagement also included traveling to multiple schools and, in some cases, participating in contractor proposal reviews to provide additional guidance to school administrators. Additional participation included engagement at annual school leadership conferences and discussions with local action agencies and city councils. The program rebated nine installations with a solar capacity of 359 kW.

Evaluation Methodology

Otter Tail Power utilized National Solar Radiation Data to build hourly profiles for a typical solar installation in the company's service area. It uses these profiles to determine energy savings that can be expected of rebated systems based on kW size.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Publicly Owned Property Solar	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	516,684
Demand Savings – kW	222.55

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EFFICIENT TECHNOLOGY ACCELERATOR

The Efficient Technology Accelerator (ETA) is a new market transformation program managed by the Center for Energy and Environment and administered by the Department of Commerce, in coordination with investor-owned utilities. The goal of this partnership is to:

- Drive a strategic process to accelerate market deployment of key technologies,
- Employ effective strategies to leverage market forces,
- Become a hub for collaboration among stakeholders, and
- Achieve cost-effective energy savings and other benefits for utilities and Minnesotans.

In 2024, ETA laid the foundation for its market transformation efforts, working to accelerate the deployment of emerging energy-efficient technologies throughout the state. Key activities included:

- Engaging with key supply chain market actors,
- Developing and delivering training to support Minnesota installers and companies,
- Refining and improving technology value propositions,
- Enhancing customer tools and resources,
- Facilitating collaboration and alignment across utility programs,
- Forming partnerships with manufacturers, and
- Engaging nationally to raise visibility and focus on emerging technologies.

These strategic outreach and collaborative efforts have established a strong foundation for continued success in driving market transformation and generating energy savings across Minnesota.

By the end of 2024, ETA had advanced five initiatives to the Market Deployment Stage. These include Residential Air-Source Heat Pumps (ASHP), High-Performance Windows (HPW), Luminaire Level Lighting Controls (LLLC), Next Generation Rooftop Units (Next Gen RTU) and Energy Codes and Standards Advancement. Early projections for these technologies suggest they could significantly reduce customer bills while providing measurable societal benefits. While 2024 focused on launching new initiatives into the market, in 2025 the ETA plans to start claiming savings from the market effects of its activities.

Participation and Budget

The majority of 2024 ETA efforts were on Program development making it premature for participation numbers to be reported. Otter Tail Power did incur costs in 2024, receiving invoices from CEE in the amount of $116,167 and dedicating several hours of labor to the Program for a total annual 2024 spend of $117,832.

Energy Savings and Adjustments

The ETA program is still under development and has not produced savings to date. Otter Tail Power is hopeful these programs will deliver significant energy savings in the future.

INDIRECT IMPACT PROGRAMS / REGULATORY REQUIREMENTS

ADVERTISING AND EDUCATION – Residential and Commercial

Advertising and Education – Residential

The Advertising and Education program for 2024 targeted Minnesota service area residents of all ages with reinforcing messages to understand energy options for efficiency and to make conserving energy a lifestyle. The program was designed to include three approaches to achieve its goals:

- *Advertising* that increases awareness of and educates customers about energy-efficient technologies and motivates individuals to act to conserve energy.
- *Internet-based resources* including efficiency program content, technology descriptions, rebate information, and seasonal energy saving tips on the Company website.
- *Learning environment presentations* targeting students across all economic groups with educational messages and activities related to energy production, energy use, and conservation.

Advertising

In 2024, media campaigns supported through the Advertising and Education program focused on delivering messages about energy-efficient technologies. These included:

- Energy efficient technologies as a lifestyle campaign. Television, radio, and social media campaign spots showed customers the many applications where they can choose efficiency when putting energy to use. Advertisements highlighted Energy Star® home appliances, smart thermostats, and LED bulbs.
- Digital billboard space shared at various times of the year by all ECO projects.
- Comprehensive bill inserts offering seasonal energy-efficiency tips applicable to all efficiency programs.

Additional advertising support during 2024 for residential programs included a catalog of ECO offerings available to Minnesota residential and small commercial customers, and contractor education pieces.

Internet-Based Resources

This portion of the program supports development of ECO program-focused promotional and educational materials for the Company website. Web-based materials encourage participation in direct impact energy-efficiency programs in the ECO portfolio, featured

on the Company's "Ways to Save" section of its website. The website is continuously updated to feature the latest information on Otter Tail Power's energy efficiency and conservation programs.

Site visit data is collected from web analytic tools used to track unique visitors to the site. The data reported for 2024 reflects activity only on the web pages related to advertising spots supported through this program and are adjusted to reflect the Minnesota specific customer web participation, which is calculated as 45 percent of the unique visitors to the website pages. This represents the portion of Company customers located in Minnesota.

Learning Environment Presentations

Otter Tail Power continued its partnership with Otter Cove Children's Museum, a unique Fergus Falls resource that serves children in the region up to age 10, offering indoor play space with both educational exhibits and a playground structure under the same roof. In 2021, through Otter Tail Power's Advertising and Education program a set of interactive energy- and conservation-focused exhibits were developed. The exhibits continue to be accessed in 2024, and there were 20,625 children visits logged to the Otter Cove facility with the opportunity to interact with the installations. Additionally, Discover Energy!, a set of interchangeable engagements that are remixed to create unique experiences, was developed and introduced as staff-led experiences for children and their caretakers. Monthly Discover Energy! sessions provided during 2024 covered hydroelectric generation, solar energy, and wind energy generation topics and related activities with up to 22 children participating per session.

In 2024, Otter Tail Power provided support for the Headwaters Science Center in Bemidji to develop educational exhibits focused on the science and mechanics behind heat pumps. Heat pump technology is used, at the science center, to transfer energy between two habitats. Three tanks are on display on the exhibit floor. Tank 1 uses heat pump mechanisms and houses one axolotl. Tank 2 has hot climate lizards and cool water axolotls. Lizards live in >80 degrees while axolotls live in 60-64 degree water. Tank 3 is a modified and improved version of tank 2 and is home to 2 axolotls, male and female. Unintentionally, the female's eggs are fertilized. The Science Center is anticipating young soon.

Participation and Budget

2024 A&E Residential Detailed Participation	
Otter Cove Children's Museum	20,625
Headwaters Science Center	26,865
Web visits related to advertising	66,635
Total	114,125

PARTICIPATION AND BUDGET – 2024			
Residential Advertising & Education	**Actual**	**Proposed**	**% of Goal**
Participation	114,125	15,000	761%
Budget $	$166,297	$193,500	86%

Advertising and Education – Commercial

Otter Tail Power's Advertising and Education program is also used to support promotion of energy-efficiency technologies and conservation benefits to small and midsize commercial customers. One of the methods used is the development and distribution of a catalog of programs and rebate opportunities aimed at commercial business operations. Additionally, this program supports advertisement about energy efficient upgrades and rebates available to business customers through chamber of commerce newsletters.

Ongoing efforts include updates to the company web pages related to ECO programs for our Minnesota commercial and industrial customers. This work was included as part of the web update project for residential customers. The upgrades were designed to make the content mobile-friendly, easier to navigate, engaging and meaningful for commercial and industrial customers, and effective in helping the company reach its ECO program goals. Navigation directs customers to specific sections for businesses and contractors that target the most beneficial programs for visitors in those groups.

Participation and Budget

ACTUAL / BUDGET – 2024			
Commercial Advertising & Education	**Actual**	**Proposed**	**% of Goal**
Participation	0	0	N/A
Budget $	$29,877	$28,500	105%

Program participation of zero is the result of the Company now tracking efficiency assessments completed as part of the Commercial Direct Install program in Commercial Audits and Studies instead of its Advertising and Education program.

FINANCING – Commercial

The Financing program is designed to provide low-interest loans for installation of air source and geothermal heat pump systems. The difference between the interest expense at the Company's after-tax cost of capital and the expense at the customer's interest rate is the cost charged to the ECO Tracker Account. The interest rate was 5.9 percent for 2024.

Otter Tail Power promotes the low-interest Financing program in various resources including:

- *Taking Care of Business* commercial ECO booklet.
- *Programs and Services Guide* provided to contractors and employees.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Financing	**Actual**	**Proposed**	**% of Goal**
Participation	1	5	20%
Commercial Budget $	$7,766	$15,000	52%

IMPLEMENTATION AND TRAINING – Residential and Commercial

The Implementation and Training program provides instruction about energy efficient technologies and Demand Side Management trends for the Company's design, implementation, and customer service staff. This program also provides training opportunities for customers, electricians, insulation installers, other contractors, and Company representatives.

In January and February 2024, Otter Tail Power co-sponsored electrician code credit events with Minnkota Electric Cooperative. Workshops were promoted on our website, in newsletters, and through direct mail pieces.

The second key initiative in the Implementation and Training program consisted of training workshops held at Shooting Star Casino and Event Center in Mahnomen, Minnesota and Dakota Magic Casino near Hankinson, North Dakota along the Minnesota/North Dakota border. A total of 12 Otter Tail staff and 188 contractors, equipment vendors, and other interested parties attended the workshops with an agenda covering:

- Introductions of Otter Tail Power Energy Management Representatives,
- Energy Conservation and Optimization background,
- Current ECO programs and rebates,
- Introduction to www.otpco.com website, including Ways to Save pages featuring details on ECO programs; the Company's online "Find A Contractor" tool and details on the new Quality Installation incentive and certification process for contractors,
- Demand Response programs and incentives,
- Inflation Reduction Act update, and
- Vendor showcase with networking opportunities

The contractor workshops, in both locations, were successful in educating contractors about new incentives and opportunities brought forth with the transition from the former CIP to the new ECO programs through specific agenda items. The additional vendor show provided opportunities for program design and implementation staff, DSM equipment vendors and suppliers, along with installation contractors to network and learn about new technologies, programs, challenges, and opportunities that exist in the field. The Company is proud of the effort, with attendees rating the event with an average score of 4.5 out of 5 and numerous positive comments from attendees. The Company looks forward to similar training opportunities in 2025.

Internal Otter Tail Power training and testing for the Association of Energy Engineer's (AEE) Certified Energy Manager program was the third substantial strategy behind the Implementation and Training program. The Company experienced staffing changes and additions through 2024, specifically adding a commercial and industrial energy auditor, a residential energy auditor and new staff in industrial and commercial representative positions. After analyzing expenses required to send individuals to various AEE training sites, the Company determined it was more cost effective to contract with AEE for training onsite at Otter Tail Power's headquarters in Fergus Falls, MN. Sixteen staff members registered for the four-day course and exam. Staff who registered for the course reported challenging, but very useful content applicable to their careers in energy efficiency.

Participation and Budget

ACTUAL / BUDGET – 2024			
Implementation & Training	**Actual**	**Proposed**	**% of Goal**
Residential Participation	51	175	29%
Residential Budget $	$132,491	$38,000	349%
Commercial Participation	415	250	166%
Commercial Budget $	$160,466	$200,000	80%

INTEGRATED BUILDING DESIGN PLUS (IBD+) – Commercial

In the integrated building design process, architects, engineers, and energy experts team up early in the design process to coordinate and optimize the design of all components and systems. This team functions and works according to clearly defined goals:

- Design a building with operating costs as low as possible without sacrifices to occupant comfort.
- Design a building with as little environmental impact as possible.
- Design a building that will boost worker productivity.
- Incorporate all features with minimal increases in first costs.

The greatest opportunities to reduce the future energy use of a new building occur during the design development phase. However, the decisions made during commercial building design are often driven by aesthetics, capital costs, and designer familiarity. Information on how these decisions will impact energy consumption and operating costs is often not readily available to building design teams. Obtaining data on energy impacts is the primary barrier to analyzing effects of various design decisions on building energy efficiency, as accurate projections require complex, detailed analysis and energy modeling. Most design firms do not have the time or budget to perform the required analyses, and without the need to regularly exercise such skills, the firms also lack the critical staffing needed to perform specialized energy analysis and modeling.

The objective of Otter Tail Power's IBD+ program is to optimize the energy efficiency of new construction projects by encouraging greater design team cooperation in an integrated building design process. Otter Tail Power encourages participation in the IBD+ program by providing:

- Design assistance consulting services for participating customers and design teams.
- Reimbursements to design team members for added time required to participate in the integrated building design process.
- Identification of energy savings for various design packages compared to the baseline design efficiency of Minnesota State Energy Code.
- Identification of incentives available through Otter Tail Power's prescriptive Lighting, Motors, Adjustable Speed Drives, Heat Pumps, and Custom Grants programs.
- Training for design team professionals in proper design of geothermal and other high efficiency HVAC systems.

Otter Tail Power promotes the IBD+ program through a variety of resources including:

- *Taking Care of Business* commercial ECO brochure mailed to targeted commercial and industrial customers annually.
- Annual *Program and Services Guide* sent to contractors and dealers.
- The Company's website. The website also features a link to an electronic program application form.
- Through the design assistance consultant's network, membership, and participation as professionals in architectural and engineering organizations, including the American Society of Heating, Refrigeration, and Air Conditioning, Engineers (ASHRAE); the American Institute of Architects; and the Illuminating Engineering Society (IES).

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Integrated Building Design Plus	**Actual**	**Proposed**	**% of Goal**
Participation	4*	6	67%
Budget $	$145,661	$252,000	58%

*The four IBD+ participants are included here, however their energy efficiency measures are evaluated and included as participants within their corresponding direct impact programs.

EFFICIENT FUEL SWITCHING PROGRAMS

The 2024 Efficient Fuel Switching (EFS) Status Report has been combined with the 2024 ECO Status Report, and 2024 Financial Incentive Filing, produced annually on April 1. The EFS Status Report covers all 2024 programs. Participation, program costs, and energy and demand savings for all programs are outlined in Appendix A, Table 5. The programs described in this Status Report were approved alongside the 2024 ECO Plan unless stated otherwise.

The objective of Otter Tail Power's EFS programs is to promote technologies that provide customers benefits over the alternative fuel sources, reduce emissions, and meet all Minnesota statutory requirements.

HOME HEATING AND COOLING – FUEL SWITCHING

Otter Tail Power offers residential customers an incentive for the successful installation of a heat pump when the customer has an existing operational alternative fuel source (fuel oil, propane, or natural gas) heating system paired with an electric air conditioning system. The electric heat pump system reduces the usage of the alternative fuel system reducing emissions and provides the customer with the opportunity to reduce annual cooling and heating costs. The minimum performance requirements of the heat pump equipment are equal to the standard Home Heating and Cooling program and federal 25C tax credit requirements. This alignment streamlines marketing and communication processes for overall administration efficiency. The Company considers the first year of this program as a success, even with the delayed role out of the federal and state incentive programs.

Incentive Levels

- $300/ton for Standard Heat Pump– ductless and ducted
- $600/ton for Cold Climate Heat Pump – ductless
- $800/ton for Cold Climate Heat Pump – ducted
- $800/ton for Air to Water Heat Pump
- $1,200/ton for Geothermal Heat Pump

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Home Heating and Cooling	**Actual**	**Proposed**	**% of Goal**
Participation	74	85	87%
Budget $	$110,395	$150,000	74%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Home Heating and Cooling	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings - kWh	1,251,917
Demand Savings – kW	0

ELECTRIC VEHICLE AND OUTDOOR EQUIPMENT – RESIDENTIAL

The Company offers residential customers incentives for the purchasing of new or used battery electric vehicles (BEVs) or plug in hybrid (PHEVs). The customer must purchase the vehicle from an approved dealer and private to private sales do not qualify. The Company also offers incentives for outdoor electric equipment including push mowers, riding mowers, snow blowers, and lawn tools (weed trimmers and leaf blowers). These technologies currently come with a premium price and customer incentives are needed to move the market to adopt them, this is especially true in the rural areas Otter Tail Power serves. The Company saw significant interest and participation in the lawn equipment section. Electric lawn equipment and tools is a great introduction to the benefits of electric powered technologies and provides a steppingstone in the conversation with customers for taking the next step in switching out their vehicle transportation to electric.

Incentive Levels

- $3,000/unit for New Battery Electric Vehicle
- $1,500/unit for New Plug in Hybrid Electric Vehicle
- $750/unit for Used Plug in Hybrid Electric Vehicle
- $250/unit for New Electric Push Mower
- $750/unit for New Electric Riding Mower
- $150/unit for New Electric Snow Blower
- $25/unit for New Lawn Tools (Weed Trimmers, Leaf Blowers)

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Electric Vehicle - Residential	**Actual**	**Proposed**	**% of Goal**
Participation – Electric Vehicles	27	63	43%
Participation- Lawn Equipment	276	115	240%
Budget $	$111,304	$194,000	57%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Electric Vehicle - Residential	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings - kWh	563,703
Demand Savings – kW	0

Otter Tail Power offers commercial customers an incentive for the successful installation of a heat pump when the customer has an existing operational alternative fuel source (fuel oil, propane, or natural gas) heating system paired with an electric air conditioning system. The electric heat pump system reduces the usage of the alternative fuel system reducing emissions and provides the customer with the opportunity to reduce annual cooling and heating costs. The minimum performance requirements of the heat pump equipment are equal to the standard Commercial Heat Pump Program and federal 25C tax credit requirements. This alignment streamlines marketing and communication processes for overall administration efficiency. The Company looks to build on program success in future years and continue to increase awareness of fuel switching to customers who in prior years were ineligible for Otter Tail Power rebates.

Incentive Levels

- $300/ton for Standard Heat Pump– ductless and ducted
- $600/ton for Cold Climate Heat Pump – ductless
- $800/ton for Cold Climate Heat Pump – ducted
- $800/ton for Air to Water Heat Pump
- $1,200/ton for Geothermal Heat Pump

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Commercial Heat Pumps	**Actual**	**Proposed**	**% of Goal**
Participation	40	62	65%
Budget $	$69,069	$104,000	66%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Commercial Heat Pumps	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings - kWh	665,768
Demand Savings – kW	0

ELECTRIC EQUIPMENT – COMMERCIAL

The Company offered commercial customers incentives for the purchase of new electric equipment. The equipment options included electric school buses, push/riding mowers, and forklifts. The program is a great tool for customer engagement and leads to discussions with customers about the benefits going electric can have on larger purchases.

Incentive Levels

- $5,000/unit for New Electric School Bus
- $3,000/unit for New Electric Forklift: Over 6,000-pound lifting capacity
- $2,500/unit for New Electric Forklift: Under 6,000-pound lifting capacity
- $500/unit for New Electric Riding Mower
- $100/unit for New Electric Push Mower

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Electric Equipment – Commercial	**Actual**	**Proposed**	**% of Goal**
Participation	6	7	86%
Budget $	$17,692	$14,000	126%

Evaluation Methodology

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Electric Vehicle – Commercial	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	439,542
Demand Savings – kW	0

LOAD MANAGEMENT

In 2024, the Load Management program was newly incorporated into the Company's ECO portfolio as permitted by the 2021 Minnesota ECO legislation. The Load Management program specifically includes winter season loads on the Minnesota Small and Large Dual Fuel, Deferred Load, Residential Demand Control (RDC), Fixed Time of Service, and Electric Vehicle (EV) Charging Rates. This program's focus is peak demand reduction only and does not report any energy savings.

Otter Tail Power has a long history of offering load management programs. They are core to the Company's service offerings with nearly one-third of customers participating in some form of load management. This strong customer participation has made the program one of the largest in the country by customer adoption percentage. Load management has been and remains an effective tool to reduce total winter peak load, and with it, reducing system capacity needs. Through the load management programs customers partner with the Company to help manage the electrical grid as well as customer costs.

As Otter Tail Power Load Management tariffs are currently available to both residential and non-residential service, for approved permanently connected loads, this program is a combined program for residential and commercial customers. Savings are based on winter season demand reductions.

Specific tariffs included in the Load Management program are:

- **Small Interruptible Heating Customers**
  These are customers with self-contained metering on the Controlled Service – Interruptible Load Self-Contained and Current Transformer (CT) Metering Rider (commonly called Dual Fuel Riders). This rate is for permanently connected interruptible heating loads with alternate fuel backup systems served with self-contained (typical) metering. In 2024, Otter Tail Power controlled small interruptible heating customers 41 days, totaling 48 hours and 39 minutes.

- **Large Interruptible Heating Customers**
  These are larger load customers with CT metering on the Controlled Service – Interruptible Load Self-Contained and CT Metering Rider. This tariff is for permanently connected interruptible heating loads with alternate fuel backup systems serviced by current transformer CT metering. In 2024, Otter Tail Power

controlled large interruptible heating customers 41 days, totaling 70 hours and 27 minutes.

- **Residential Demand Control Customers**
  These are customers taking service on the Residential Demand Control (RDC) Service Rate. This rate is available to residential customers with approved demand-control systems and applies to lighting, heating, water heating, cooking, refrigeration, air conditioning, and other general uses of electricity. In 2024, Otter Tail Power controlled residential demand control customers 23 days, totaling 31 hours and 18 minutes.

- **Thermal Storage Customers**
  These are customers taking service on the Controlled Service – Deferred Load Rider which is applicable to both residential and non-residential service for any approved permanently connected thermal storage deferred loads. In 2024, Otter Tail Power controlled thermal storage customers 40 days, totaling 75 hours and 8 minutes.

- **Fixed Time of Service**
  These are customers taking service on the Fixed time of Service Rider in which energy is delivered only between the hours of 10 p.m. and 6 a.m. Eligible systems will be electric thermal storage central or room heating, underfloor electric cable or panel, and boilers associated with underfloor hydronic heat storage.

- **Electric Vehicle Charging**
  These are customers taking service on a qualified off-peak rate including the Electric Vehicle Charging Rate in which energy is delivered only between the hours of 10 p.m. and 6 a.m.

MARKETING

The target market of the Load Management program is both residential and commercial customers including those with end of life or inadequate systems.

Otter Tail Power reached the potential market for the Load Management program through bill inserts, bill messaging, website information, and traditional and digital media campaigns. Messaging focused on the benefits of demand response as a method of managing the electrical system and avoiding the purchase of higher priced energy, as well as the financial incentives available to customers through equipment rebates and discounted rates.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
Load Management	**Actual**	**Proposed**	**% of Goal**
Participation	1,679	10,241	16%
Budget $	$198,826	$311,500	64%

Evaluation Methodology

Otter Tail Power had initially assumed that all Load Management customers would be eligible for inclusion in the ECO Load Management program. However, following the MPUC Order on Utility Performance Incentives for Energy Conservation, Otter Tail Power has since revised its eligible participants which dramatically decreases the level of demand savings reported for 2024.[8] The Company used its billing system to review all new customers Load Management customers that were new to a qualified Load Management tariff since May 21, 2021, and are still a qualified customer as of the end of 2024. Savings assumptions per type of Load Management customer remained consistent from the 2024-2026 Triennial ECO filing. Otter Tail Power did not have the resources to individually monitor, track, and report the load reduction for qualified customers in 2024.

Energy and demand savings for this program are consistent with Attachment B: Electric Product Assumptions, approved in the Company's Triennial Plan.

Energy Savings and Adjustments

ENERGY AND DEMAND RESULTS – 2024	
Load Management	**At the Generator (DSMore Summer Coincident Peak kW)**
Energy Savings – kWh	0
Demand Savings – kW	10,369.23

[8] Docket E,G999/CI-08-133.

PROGRAM DEVELOPMENT

Program Development includes ECO strategic market planning analysis, ECO-related resource planning work, and ECO-related regulatory coordination. It includes program development time for research and studying new energy efficient and DSM technologies. Otter Tail Power also used development funding for appropriate development research and information from internal and external sources, including Chartwell.

Otter Tail Power's Sales, Marketing, and Reporting Tool (SMRT) has been in use since 2011, with continued improvements over that time. The SMRT system provides the data necessary for reporting, forecasting, tracking, and processing ECO rebates. Over the years, work improvements included adding new programs, development of management dashboards, reporting tools for program management, and ongoing enhancements of an online customer portal for submitting rebate applications or checking the status of rebates. The 2024-2026 ECO plan included the migration of SMRT from an on-premises system to the cloud which will provide several benefits to Otter Tail Power Staff. The cloud environment will allow for mobile accessibility, additional reporting capabilities, and integration with other Microsoft products used by Otter Tail Power staff, such as Outlook, SharePoint, and Teams. It will also provide opportunities to integrate with other systems at Otter Tail Power to create a comprehensive information system and will deliver a more efficient and user-friendly experience overall due to enhanced search functionality, intuitive navigation, and an improved document storage solution. The cloud migration project officially began in the fall of 2024, with just over one-third of the contracted hours of development completed by year-end. The project was completed in early 2025, and the system went live in the cloud at the end of February with great results.

ACTUAL / BUDGET – 2024			
Program Development	**Actual**	**Proposed**	**% of Goal**
Planning – Regulatory Affairs	$217,516	$280,000	78%
Research & Development	$69,302	$180,000	39%

REGULATORY REQUIREMENTS

PUC ASSESSMENTS / REGULATORY (NGEA) ASSESSMENTS

PUC ASSESSMENTS / REGULATORY (NGEA) ASSESSMENTS			
	Actual	**Proposed**	**% of Goal**
PUC Assessments	$2,010	$15,000	13%
Regulatory Assessments (NGEA)	$78,524	$125,000	63%
Transmission & Distribution Cost Study	$0	$0	0%

ASSESSMENTS	
NGEA Assessment – Technical Assistance	$13,141
NGEA Assessment – R&D Grant	$57,410
NGEA Assessment – Facilities Efficiency	$7,974
Total NGEA Assessments	**$78,524**
Direct PUC Assessments	$2,010
Transmission & Distribution Cost Study	$0
Total	**$80,535**

MISCELLANEOUS / INACTIVE PROGRAM COSTS

This section is a summary of costs corresponding to miscellaneous and inactive programs. The associated costs, including closing costs for these programs, were charged to the 2024 ECO tracker account. Each is detailed separately below.

ACCOUNTING ADJUSTMENTS

In 2024, one accounting adjustment was required in the Commercial Direct Install program to record a 2023 service provider billing true-up, decreasing costs by $49.70.

Since 1993, Otter Tail Power has implemented an internal process to handle moving incorrect charges between project work orders. A line item has been added to the ECO Tracker Account to reflect those charges in transition. The Company believes this method allows us to report current year program costs more accurately.

OTTER TAIL POWER ECO PROJECTS

Otter Tail Power didn't complete any facility efficiency projects rebated through ECO in 2024.

Participation and Budget

PARTICIPATION AND BUDGET – 2024			
OTP ECO Projects	**Actual**	***Proposed***	**% of Goal**
Participation	0	0	N/A
Budget $	0	0	N/A

CARRYING COSTS

Carrying Charges on the balance of the ECO Tracker totaled ($59,979), as shown in Appendix A, Table 1.

Otter Tail Power receives or pays a carrying charge on the outstanding ECO tracker account balance based on its short-term cost of debt rate. The ECO tracker currently reflects an overcollection for the majority of 2024, resulting in a carrying charge amount which will benefit ratepayers. As approved in the MPUC's September 26, 2015, Order, Docket No. E017/M-14-201, the monthly carrying charge on the ECO tracker-account balance has been set to the short-term cost of debt rate approved in the Company's last rate case. The MPUC's February 1, 2022, Order, Docket No. E017/GR-20-719, set the short-term cost of debt at 1.77 percent, effective January 1, 2021. Otter Tail Power applied this rate to the ECO tracker-account balance per the MPUC's order.

Otter Tail Power does not account for carrying cost charges when calculating the spending requirement (see Appendix A, Table 5 Status Report Recap) but does include the amount in the ECO Tracker for recovery.

4.8 DSM and Conservation Requirements

Demand Side Management

Otter Tail contracted with Brattle in 2020 to perform a Demand Response (DR) Potential Study for Otter Tail's system. This study is included as Appendix H. To perform the study, Brattle used its LoadFlex model which was also used in Brattle's 2019 load flexibility potential study prepared for Xcel Energy. Brattle studied the potential to increase Otter Tail's existing DR portfolio along with adding new DR products to its portfolio. Brattle evaluated each DR measure dispatched against an hourly forecast of marginal costs to determine value.

At a high-level Brattle found Otter Tail to have a large existing demand response portfolio which is actively utilized. Brattle states, "OTP's existing DR capability is in the top 10 percent of U.S. IOUs." Based on 2019 EIA-861 data Brattle found Otter Tail to be ranked at the 90th percentile in Peak Reduction Capability, 95th percentile in Residential Customer Enrolled in a DR program, and 90th percentile in Non-Residential Customers enrolled in a DR program.

Technical Potential

Page 17 of Brattle's study describes Incremental Technical Potential by 2036. Brattle defines Technical Potential as, "the maximum achievable potential irrespective of cost-effectiveness. It is incremental to OTP's existing DR portfolio." Brattle identified incremental technical potential for both summer and winter seasons. Most technical potential identified was by expanding Otter Tail's existing direct load control for Commercial and Industrial (C&I) customers. Other areas of large technical potential included offering more dynamic pricing to all classes of customers. These areas include, adding critical peak pricing rates (CPP) for residential, increasing C&I customer participation in the Company's existing CPP rate, and also increasing C&I participation in Otter Tail Time of Use (TOU) rates. As a reminder, Technical Potential does not take cost-effectiveness into account.

Economic Potential

Brattle's modeling used for the "Base Case" assumes current Otter Tail resources and a 2020 forecast of MISO energy and capacity values. For evaluation of economic potential, Brattle set incentive levels at maximum cost-effective levels. The Base Case modeling found that system conditions do not appear to support the cost-effective addition of new DR programs. Avoided generation capacity investments are the primary DR value proposition but based on current resources Otter Tail does not forecast a need for new capacity until 2033.[51] Regarding Economic Potential, the Brattle study concludes:

- Generation capacity avoidance is the key driver of DR value, and it is not currently an opportunity for Otter Tail
- There may be isolated opportunities for geo-targeted distribution deferral; requires detailed analysis of distribution plan
- Time-varying rates may be desirable as an option regardless, as they provide other benefits beyond avoided costs (e.g., equity, fairness, facilitating electrification).

Brattle also modeled a "High Value Sensitivity Case." The High Value Sensitivity Case assumes a need for capacity on the Otter Tail system and assumes higher capacity prices. This scenario was not based on any Otter Tail forecast, but instead an analysis to what strategies Otter Tail would target if there was a capacity need and if capacity prices were higher. Based on these assumptions the analysis did identify several cost-effective new DR opportunities. The opportunities identified mostly consisted of Otter Tail utilizing its CPP and TOU rate offerings to enroll a greater number of large and medium C&I customers. Lesser opportunities identified included expansion of its large C&I interruptible program and CPP for residential customers. While the Brattle study did not identify any cost-effective DR opportunities, the Company continues to have a strong commitment to DR. The Company understands its existing and robust DR portfolio is important to system planning and providing low-cost energy and capacity to its

[51] See Table 2-2, Line 9.

customers. Otter Tail continues to actively market its DR programs to its customers to recruit new customers, and to also maintain the existing customers' controllable loads.

Otter Tail is excited about the future possibilities of DR. The Company's ongoing multi-year Automated Metering Infrastructure project combined with its plan to update its aging load management system will prepare the Company for the future when it will better equipped to strategically control DR loads and thoroughly evaluate and offer additional dynamic pricing plans.

Conservation

The Minnesota Next Generation Energy Act of 2007 established a goal for all Minnesota electric and natural gas utilities of achieving energy savings equal to one percent of retail energy sales. In 2013, the energy savings goal was modified to an annual goal of 1.5 percent of retail energy sales. The goal is based on a rolling three-year average of weather normalized historical retail sales.[52] On July 1, 2019, the Company made its 2021-2023 Minnesota CIP Triennial filing with the Minnesota Department of Commerce's Division of Energy Resources. The CIP plan as filed complied with all regulatory requirements, including annual energy savings goals at or above 2.4 percent. This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in the Minnesota Energy Conservation and Optimization Act of 2021. In November 2020, the SD PUC approved the Company's 2021-2023 Energy Efficiency Partnership Triennial Plan (EEP). The EEP set forth a number of conservation projects with an estimated 4.6 million kWh in annual savings. As noted above the programs benefit customers in all three states served by Otter Tail by reducing our energy needs and reducing the costs of providing service to our customers.

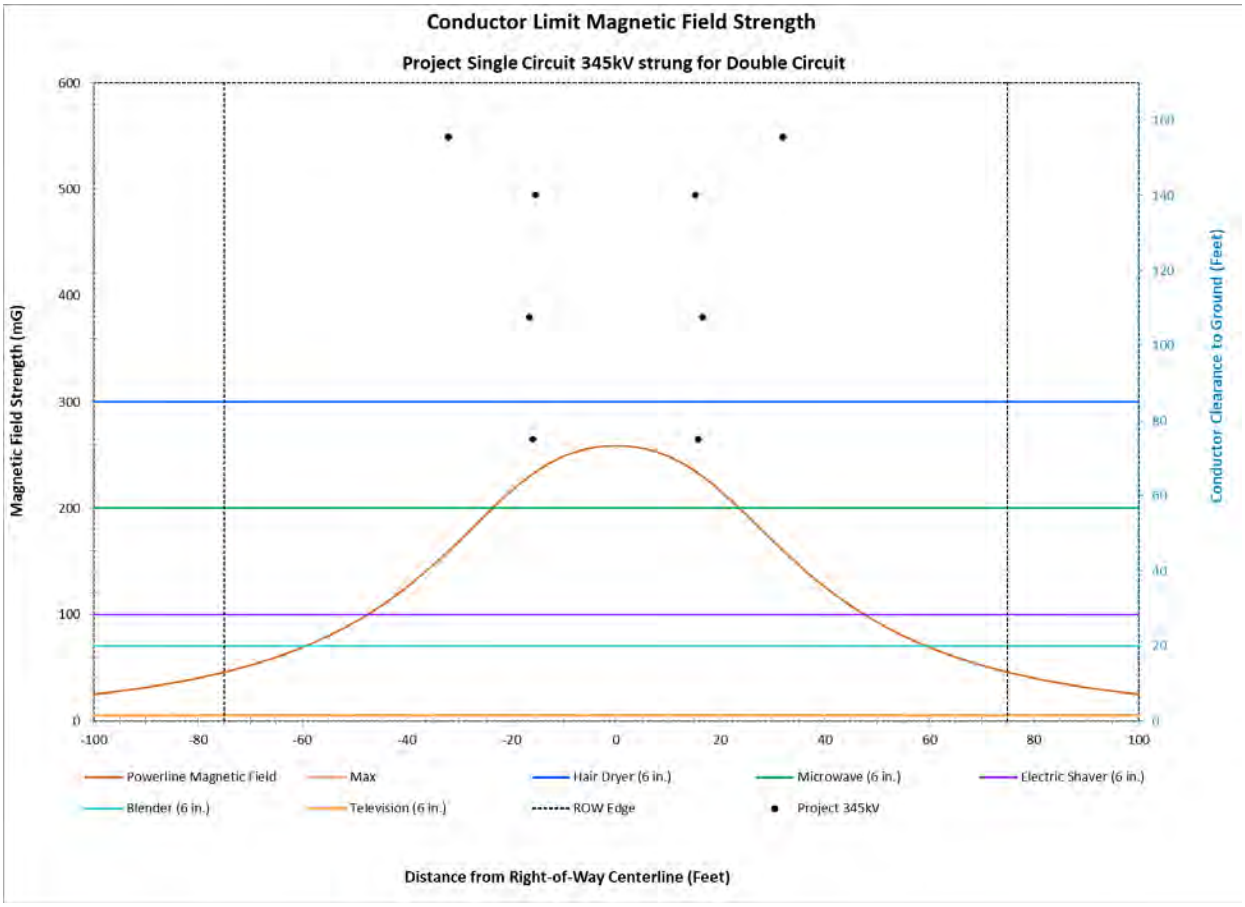
[52] On May 25, 2021, Minnesota Governor Tim Walz signed the Energy Conservation and Optimization (ECO) Act of 2021. This legislation modernized Minnesota conservation policy by adding new opportunities and setting higher conservation goals. The ECO Act increased the annual energy savings goal for public electric utilities, from 1.5 percent of retail sales, to 1.75 percent of retail sales, based on a rolling three year average of weather normalized sales.

APPENDIX J

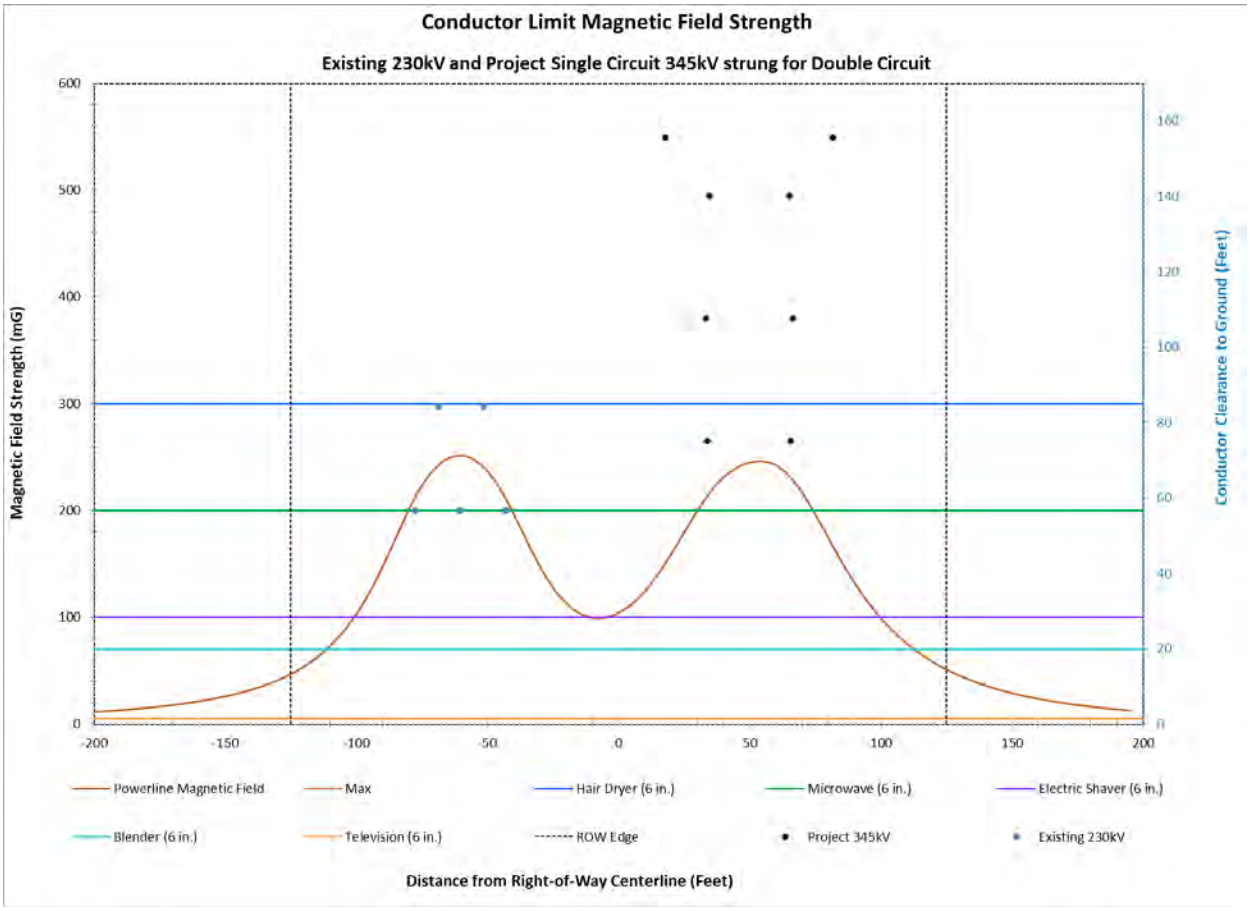
MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

EMF AND NOISE CALCULATIONS

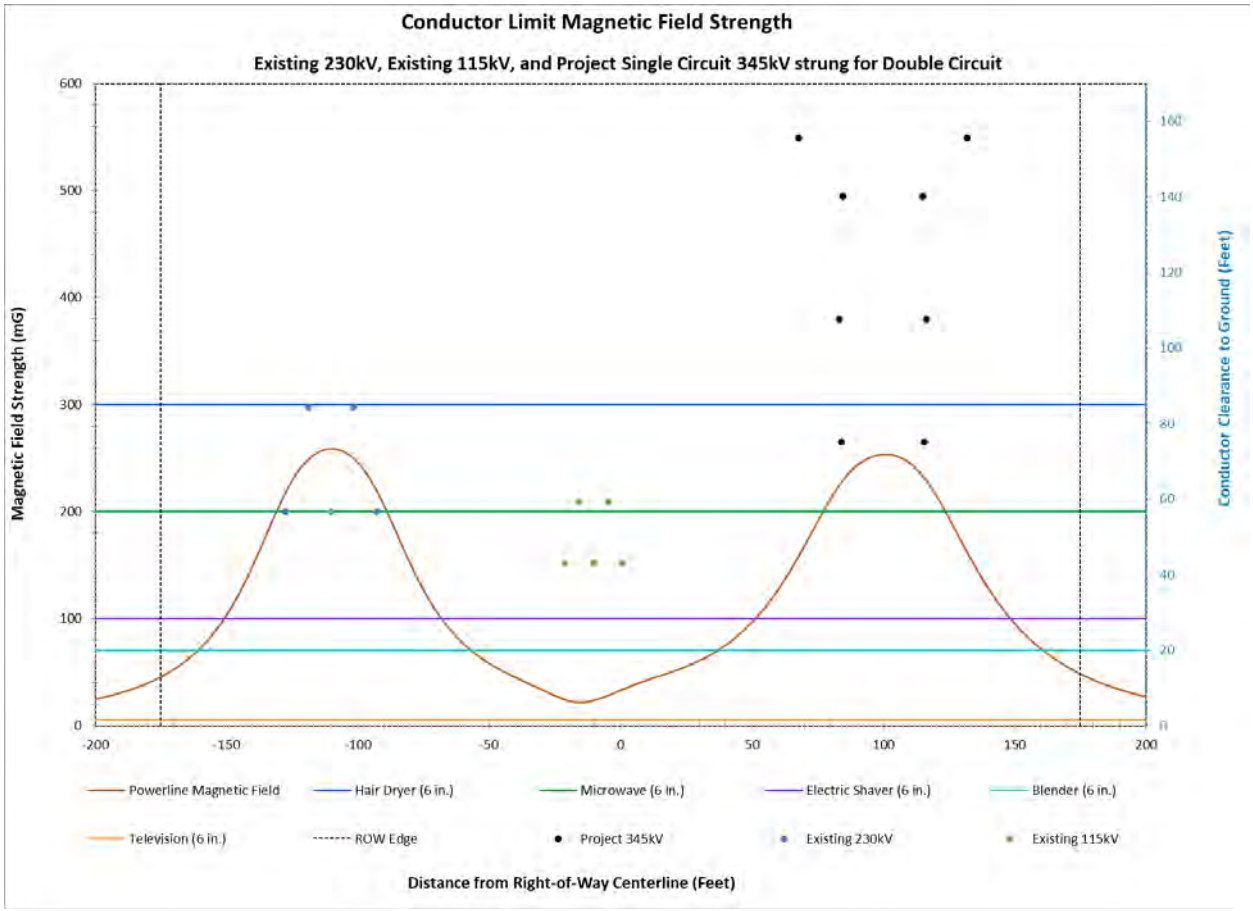
Case 1: Magnetic Field Strength for Project Single Circuit 345kV



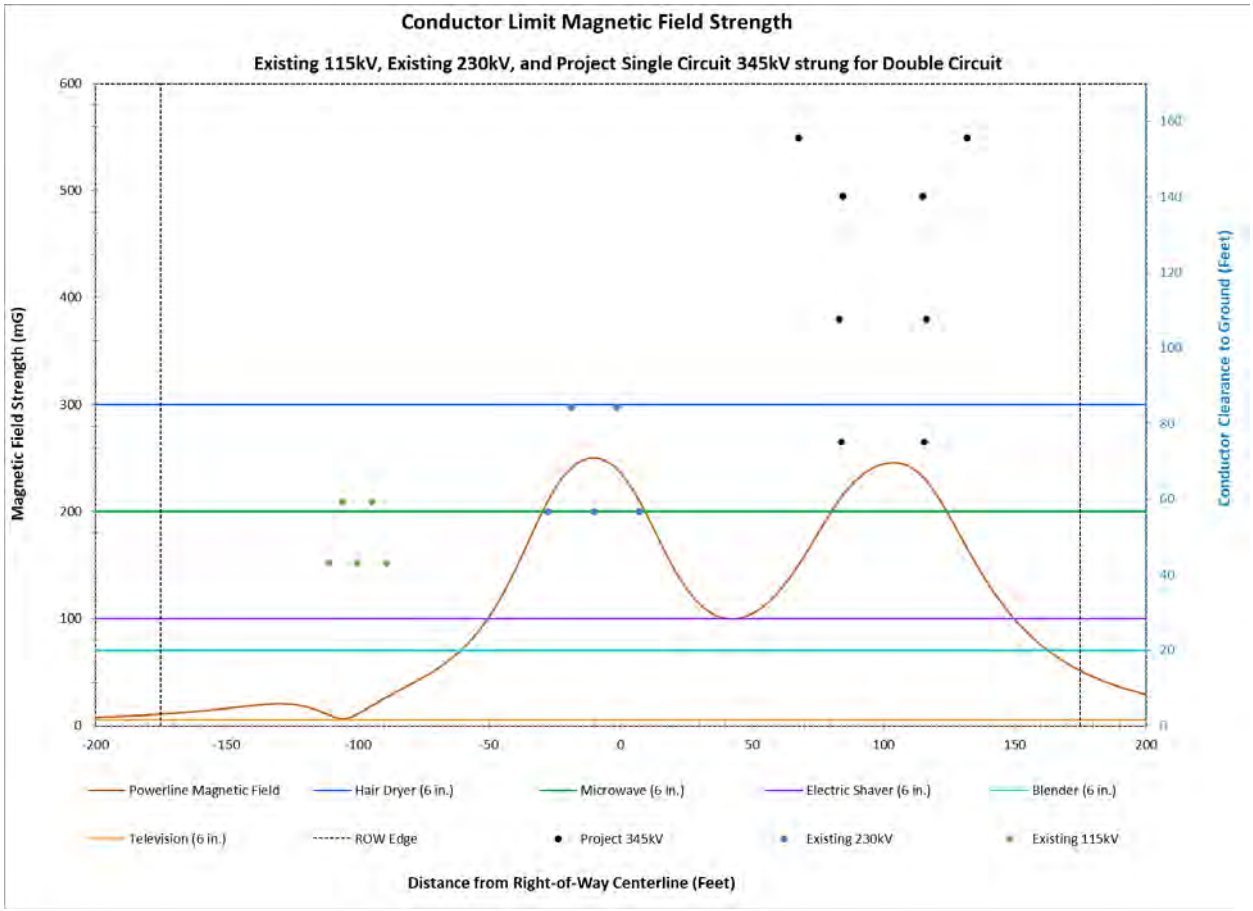
Case 2: Magnetic Field Strength for Existing 230kV H-Frame parallel to Project Single Circuit 345kV



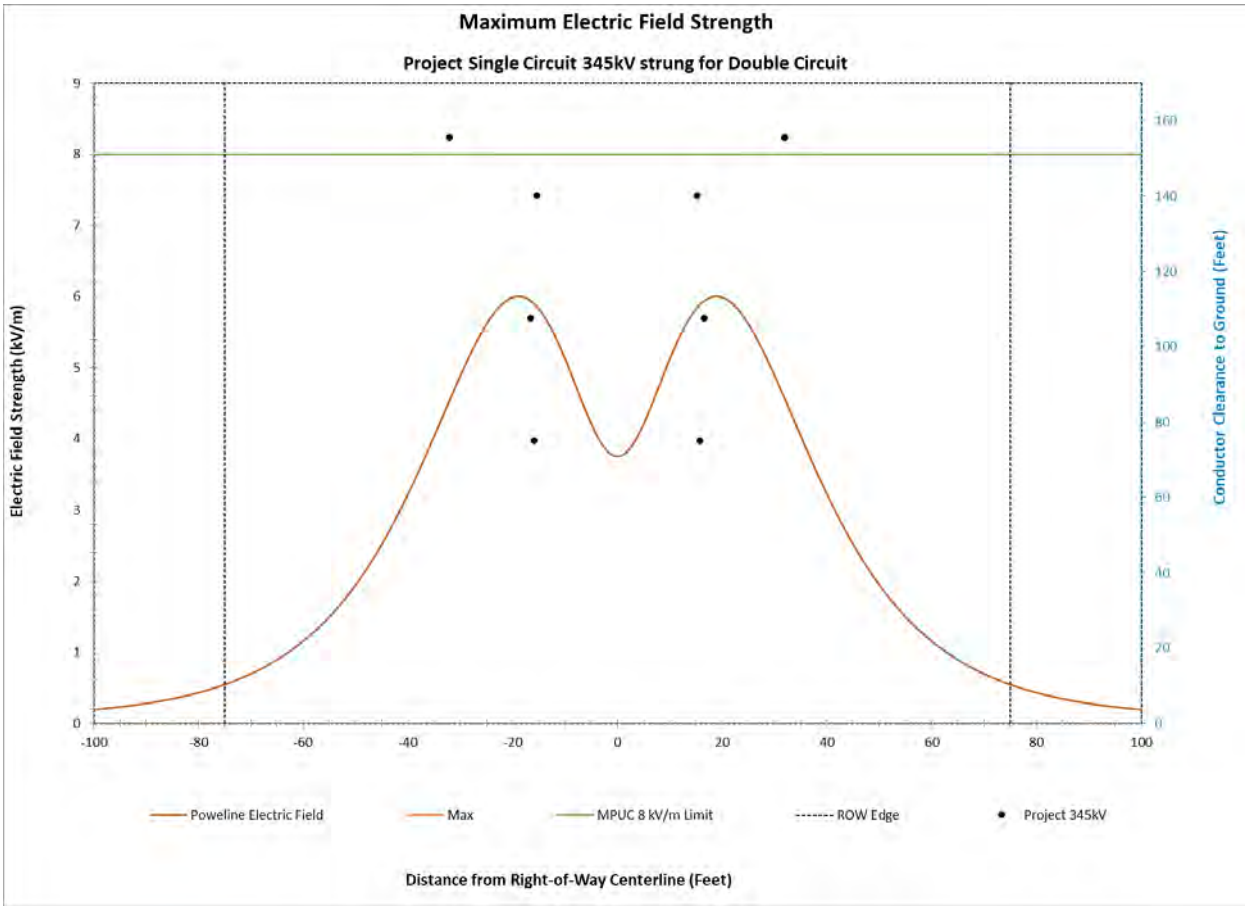
Case 3: Magnetic Field Strength for Existing 230kV H-Frame parallel to Existing 115kV H-Frame parallel to Project Single Circuit 345kV



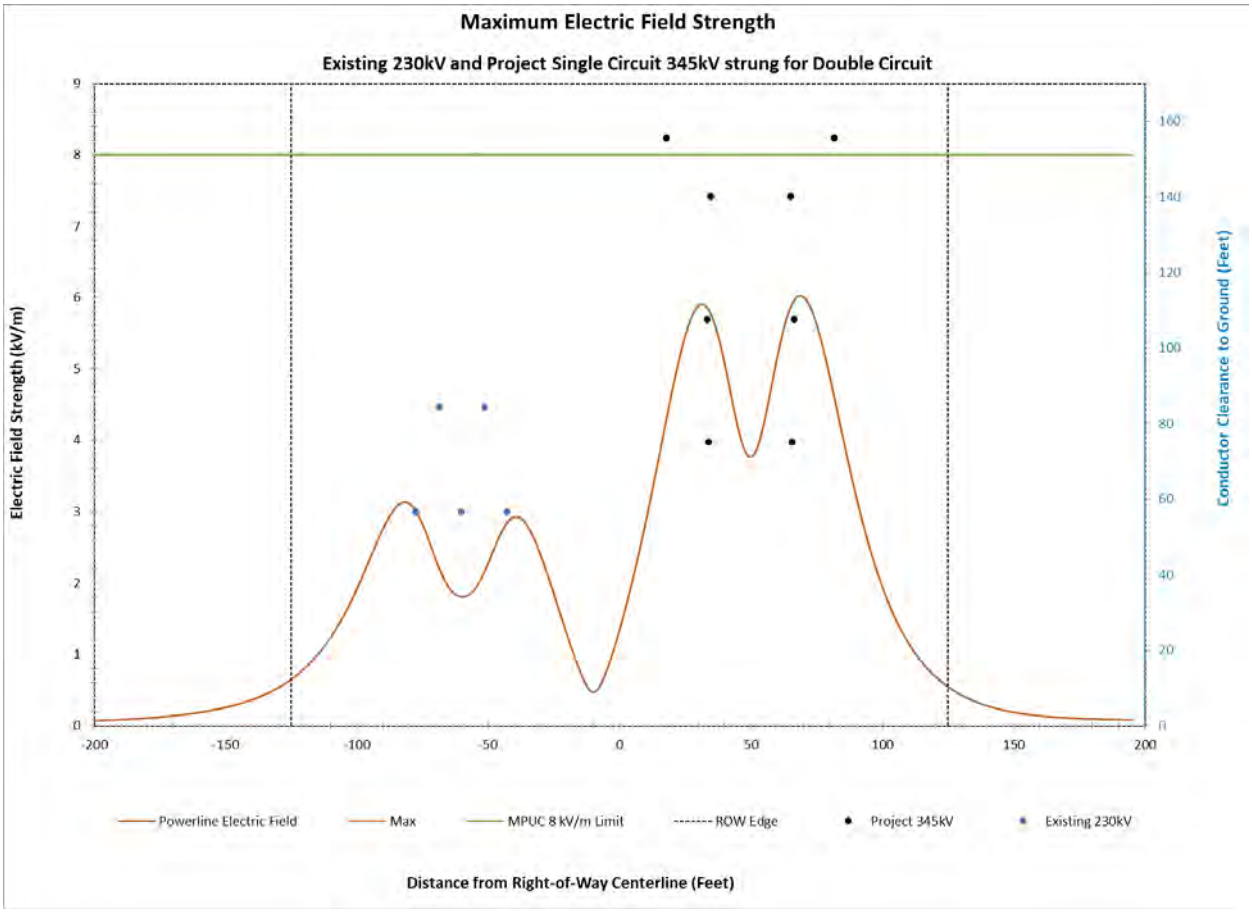
Case 4: Magnetic Field Strength for Existing 115kV H-Frame parallel to Existing 230kV H-Frame parallel to Project Single Circuit 345kV



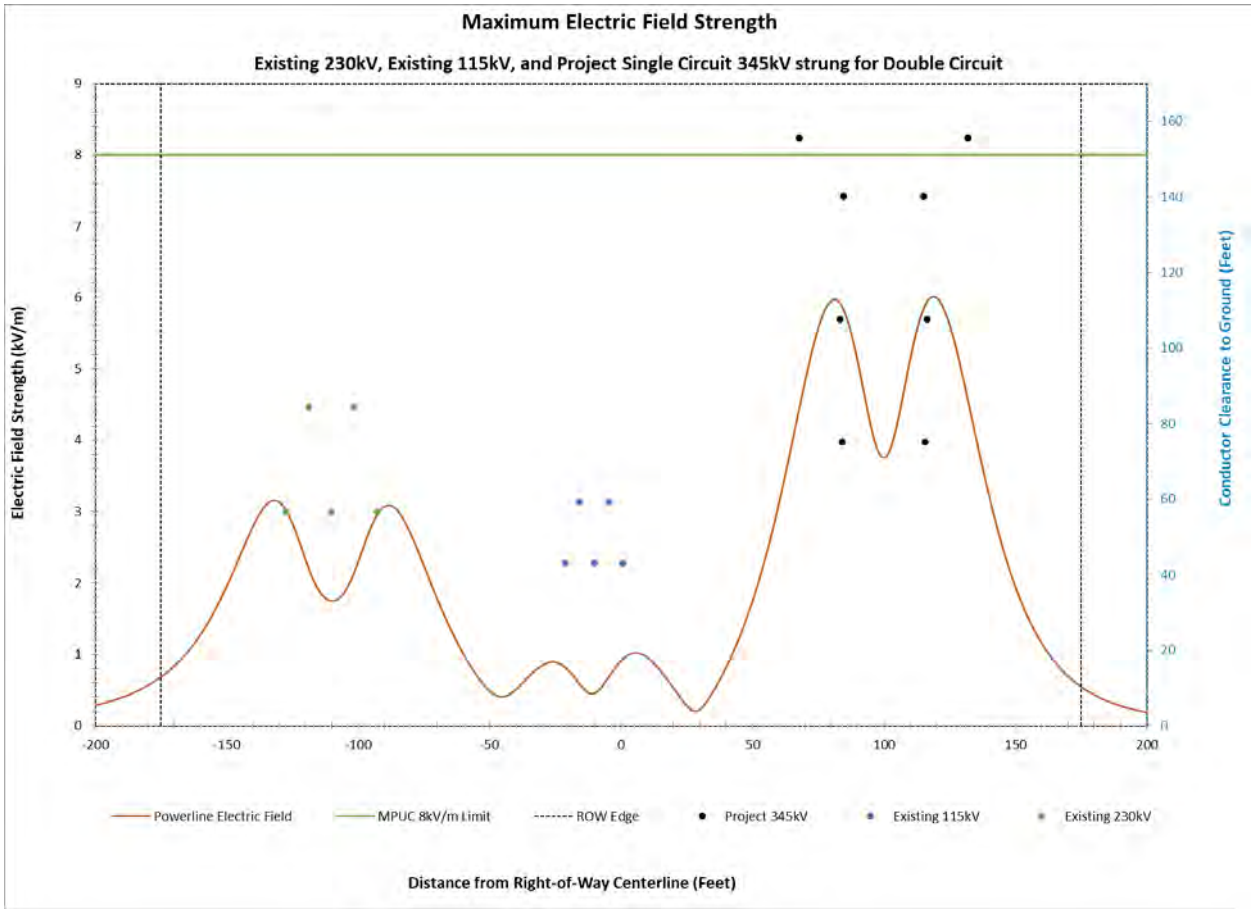
Case 1: Electric Field Strength for Project Single Circuit 345kV



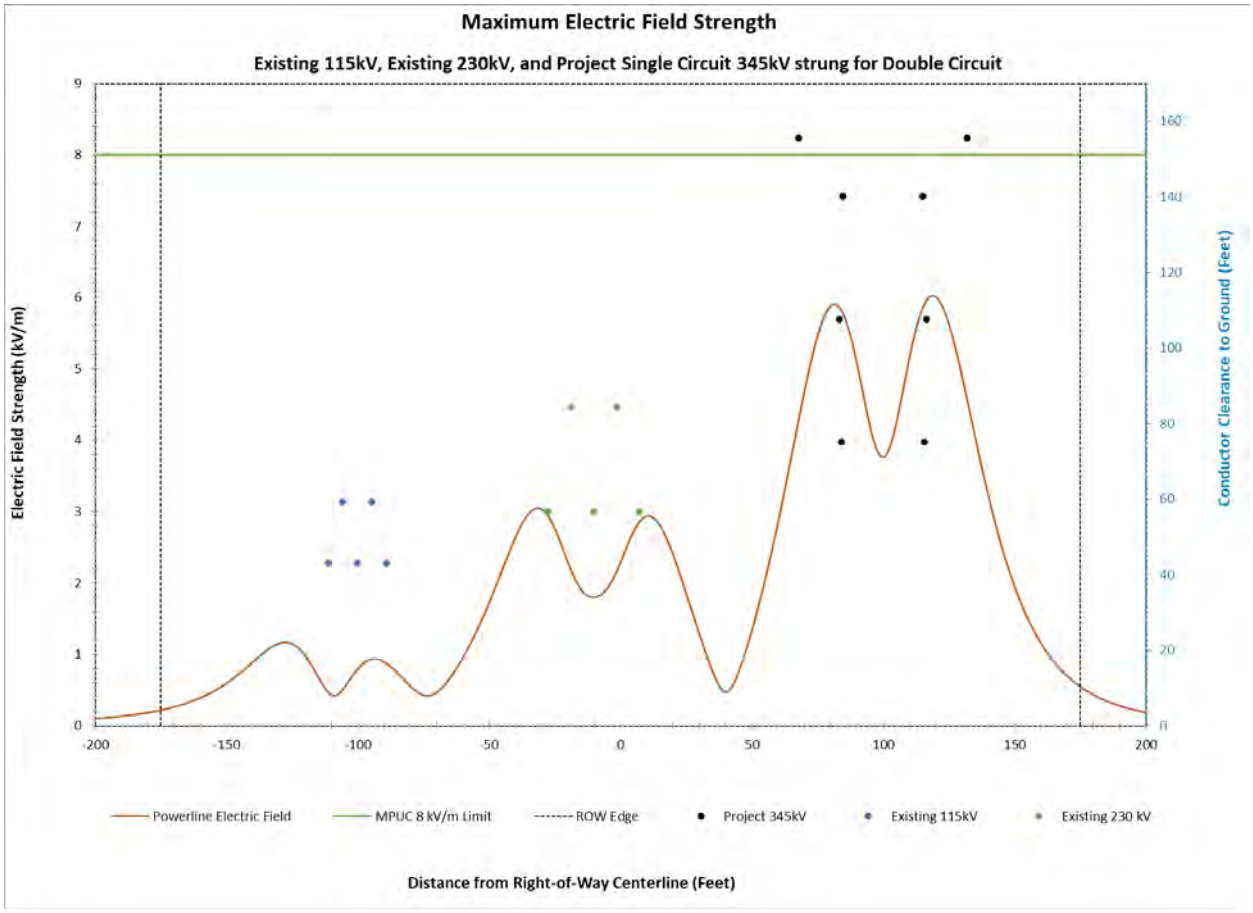
Case 2: Electric Field Strength for Existing 230kV H-Frame parallel to Project Single Circuit 345kV



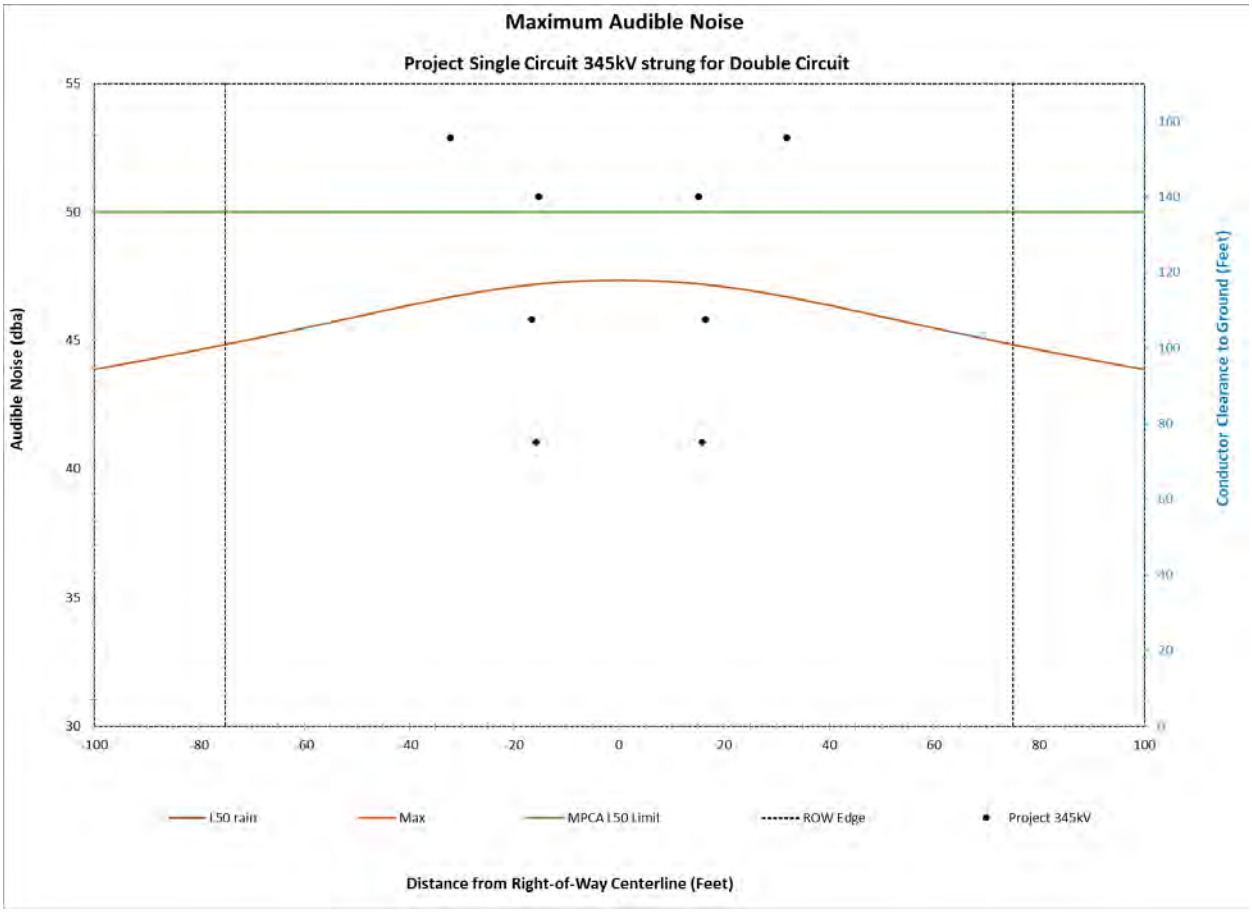
Case 3: Electric Field Strength for Existing 230kV H-Frame parallel to Existing 115kV H-Frame parallel to Project Single Circuit 345kV



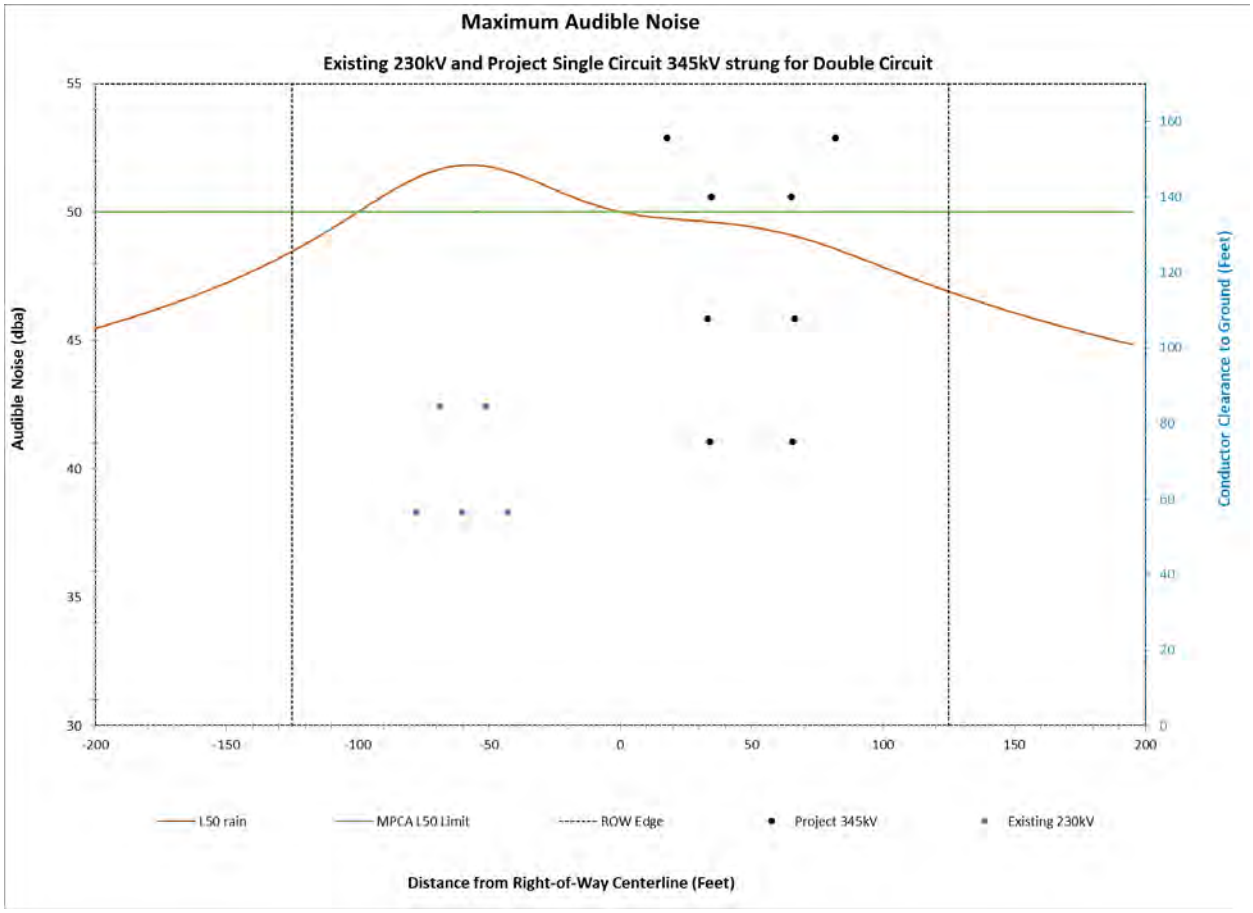
Case 4: Electric Field Strength for Existing 115kV H-Frame parallel to Existing 230kV H-Frame parallel to Project Single Circuit 345kV



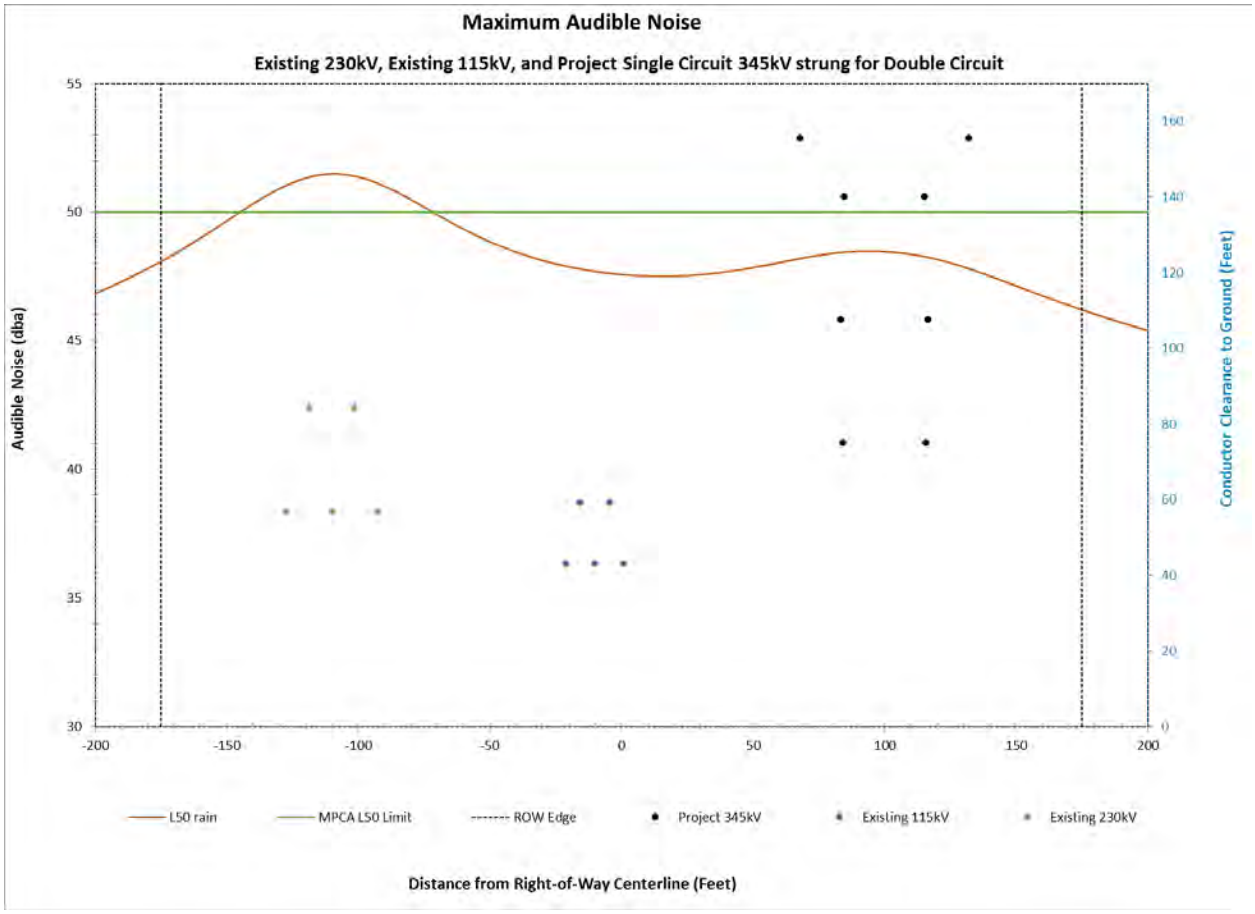
Case 1: Audible Noise Levels for Project Single Circuit 345kV



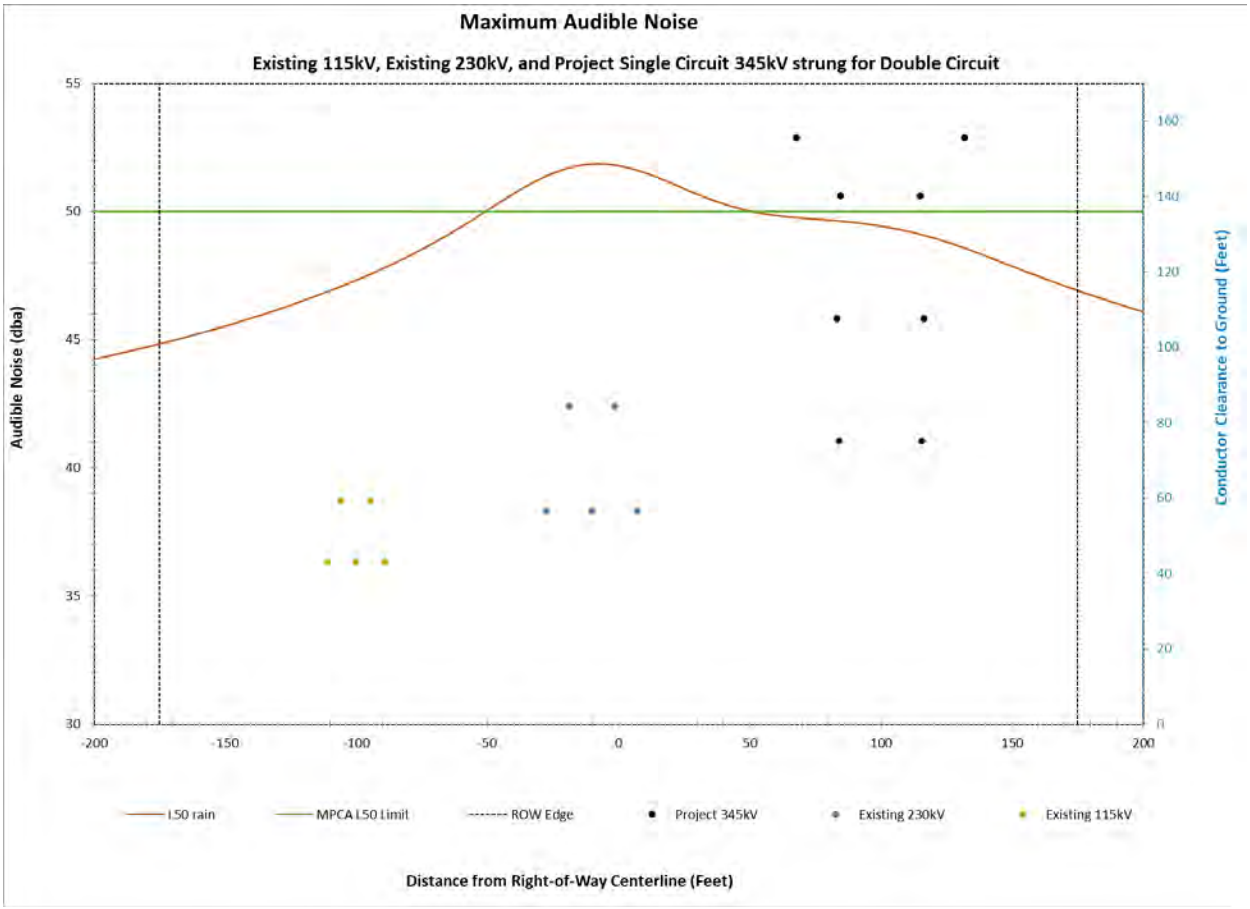
Case 2: Audible Noise Levels for Existing 230kV H-Frame parallel to Project Single Circuit 345kV



Case 3: Audible Noise Levels for Existing 230kV H-Frame parallel to Existing 115kV H-Frame parallel to Project Single Circuit 345kV



Case 4: Audible Noise Levels for Existing 115kV H-Frame parallel to Existing 230kV H-Frame parallel to Project Single Circuit 345kV



APPENDIX K

MAPLE RIVER – CUYUNA 345 KV TRANSMISSION LINE PROJECT

TRIBAL NATION COORDINATION AND COMMENTS

INDEX

Project Introduction Letter to Tribal Nations

Tribal Nation Responses to Introduction Letter

- 6/9/2025 Email, B. Savage, Fond du Lac Band of Lake Superior Chippewa
- 6/9/2025 Email, C. Lippert, Mille Lacs Band of Ojibwe
- 6/9/2025 Email, L. Wabasha, Shakopee Mdewakanton Sioux Community

Email Correspondence with Tribal Nations

- 10/7/2025 Email, B. Rudnicki, Shakopee Mdewakanton Sioux Community
- 10/7/2025 Email, L. Wabasha, Shakopee Mdewakanton Sioux Community

Formal Comment Letters from Tribal Nations

- 7/2/2025 Letter, Leech Lake Tribal Historic Preservation Office

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minnesota power
AN ALLETE COMPANY

OTTER TAIL POWER COMPANY

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12300 Elm Creek Boulevard
Maple Grove, MN 55369
763.445.5000
www.greatriverenergy.com

June 9, 2025

VIA Email

Name
Tribal Nation
Email Address

Re: Maple River – Cuyuna 345 kV Transmission Project
MPUC Docket No. E015, ET2, E017/CN-25-109

Dear Name:

On February 7, 2025, Minnesota Power, Otter Tail Power Company, and Great River Energy (collectively, the "Applicants") submitted a Notice of Intent to the Minnesota Public Utilities Commission ("Commission") to construct the Maple River - Cuyuna 345 kilovolt (kV) Transmission Project (also the "Project" or "MR-C Project").

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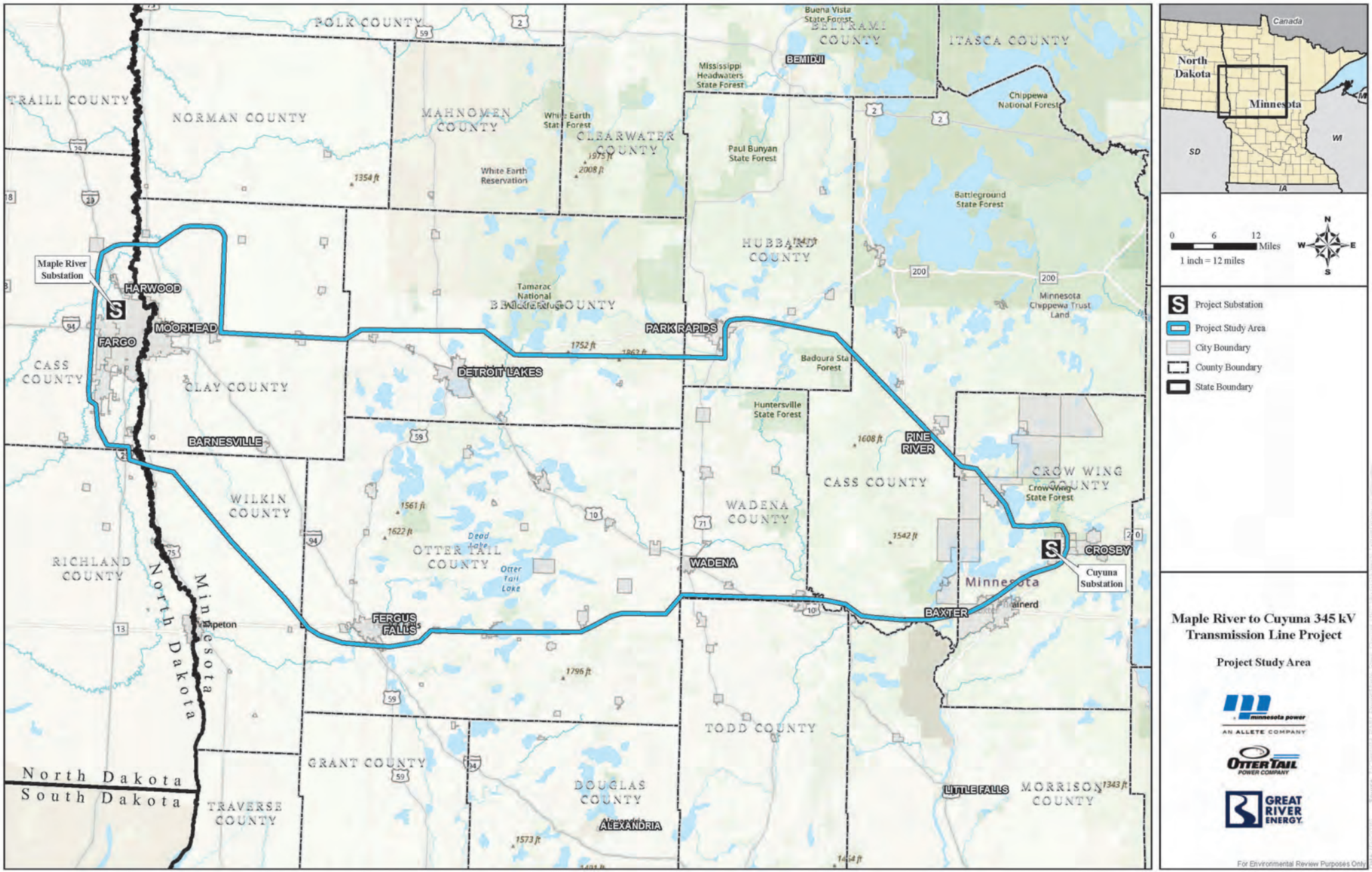
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Sincerely,

Drew Janke
Project Manager – Environmental
Minnesota Power

Enclosure: Project Study Area Map


Maple River Substation
HARWOOD
FARGO
MOORHEAD
CASS COUNTY
CLAY COUNTY
BARNESVILLE
WILKIN COUNTY
RICHLAND COUNTY
North Dakota
Minnesota
North Dakota
South Dakota
TRAVERSE COUNTY
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ALEXANDRIA
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FERGUS FALLS
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CLEARWATER COUNTY
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CROSBY
Cuyuna Substation
BAXTER
LITTLE FALLS
MORRISON COUNTY
OTTER TAIL COUNTY
Dead Lake
Otter Tail Lake
1354 ft
1975 ft
2008 ft
1752 ft
1863 ft
1608 ft
1542 ft
1561 ft
1622 ft
1796 ft
1573 ft
1343 ft
Project Substation
Project Study Area
City Boundary
County Boundary
State Boundary
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1 inch = 12 miles
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Canada
North Dakota
Minnesota
SD
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IA
Maple River to Cuyuna 345 kV Transmission Line Project
Project Study Area
minnesota power
AN ALLETE COMPANY
OTTER TAIL POWER COMPANY
GREAT RIVER ENERGY
For Environmental Review Purposes Only

From:	Bruce M Savage
To:	Dan Flo
Subject:	EXTERNAL: Re: Maple River - Cuyuna 345 kV Transmission Project
Date:	Monday, June 9, 2025 3:48:16 PM
Attachments:	image001.png

CAUTION: This email originated from outside of Merjent.

Robert is no longer here

Miigwech,

Fond du Lac Band of Lake Superior Chippewa
Bruce Savage, Chairman
www.FDLBand.org
BruceSavage@fdlband.org
1720 Big Lake Road
Cloquet, MN 55720

From: Dan Flo <dan.flo@merjent.com>
Date: Monday, June 9, 2025 at 2:21 PM
To: Robert A Abramowski <RobertAbramowski@FDLBand.org>, robabramowski5@gmail.com <robabramowski5@gmail.com>
Cc: Drew Janke (MP) <djanke@mnpower.com>, Tristen Joens <tristen.joens@galileoaz.com>
Subject: Maple River - Cuyuna 345 kV Transmission Project

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Robert Abramowski:

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Regards,

Dan Flo on behalf of
Drew Janke
Project Manager – Environmental
Minnesota Power

Dan Flo
Minneapolis
612.812.0069 mobile
dan.flo@merjent.com



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www.mnpower.com

215 S. Cascade Street
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218.739.8200
www.otpco.com

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June 9, 2025

VIA Email

Robert Abramowski
Fond du Lac Band of Lake Superior Chippewa
robertabramowski@fdlband.org; robabramowski5@gmail.com

Re: Maple River – Cuyuna 345 kV Transmission Project
MPUC Docket No. E015, ET2, E017/CN-25-109

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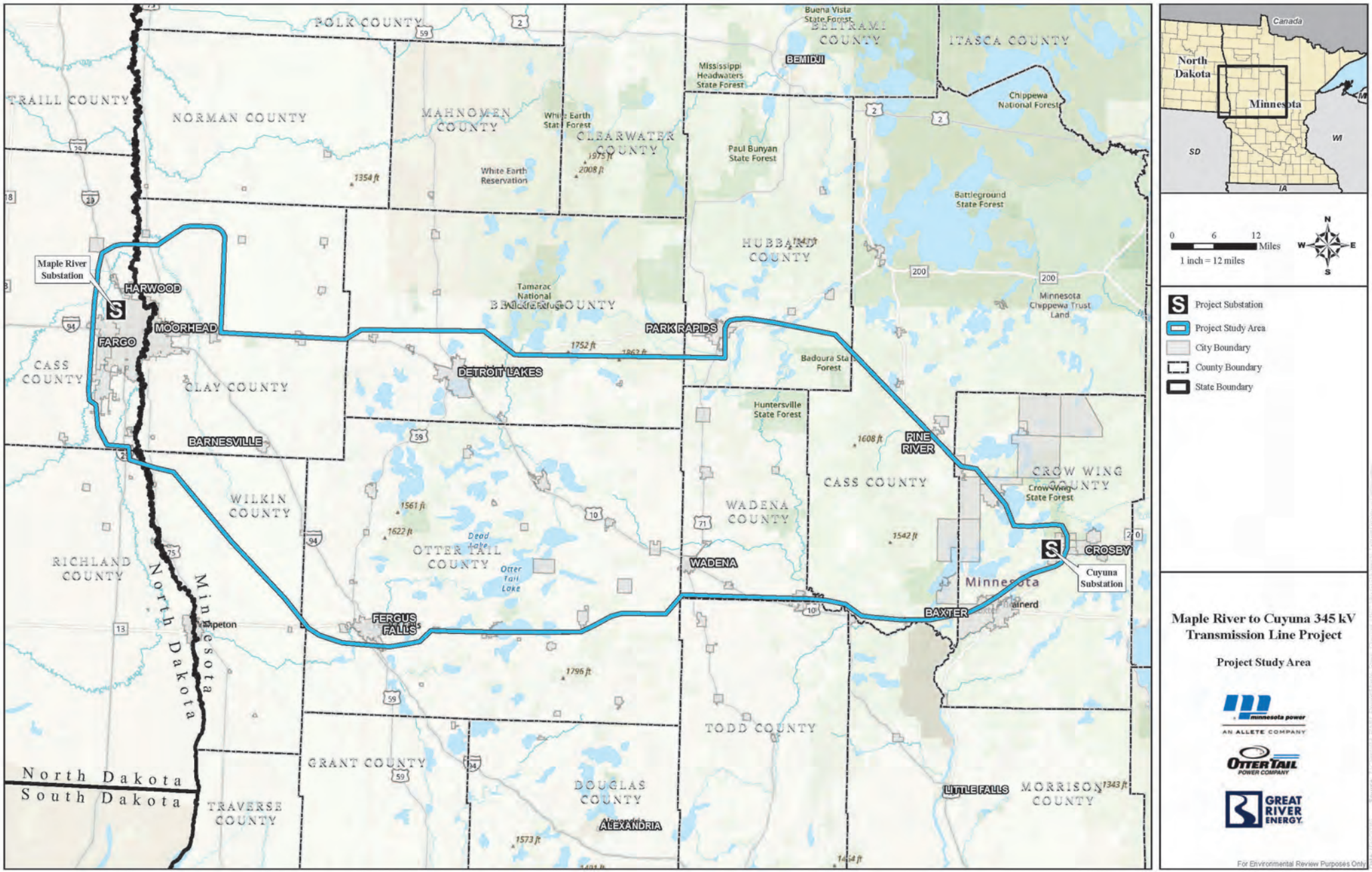
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Minnesota Power

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Maple River to Cuyuna 345 kV Transmission Line Project
Project Study Area
minnesota power
AN ALLETE COMPANY
OTTER TAIL POWER COMPANY
GREAT RIVER ENERGY
For Environmental Review Purposes Only

From:	Charlie Lippert
To:	Dan Flo
Cc:	Drew Janke (MP); Tristen Joens; Mike Wilson; Susan Klapel; Kelly Applegate; Perry Bunting
Subject:	RE: Maple River - Cuyuna 345 kV Transmission Project
Date:	Monday, June 9, 2025 10:58:52 AM
Attachments:	image002.jpg image003.png

Miigwech Dan for the notice on the Maple River – Cuyuna 345 kV Transmission Project.
For consultation and project coordination, my colleagues here at the Mille Lacs Band of Ojibwe would be interested in the portion of the project in Crow Wing and Cass Counties, while I would be additionally interested in the portion of the project in Hubbard and Wadena Counties. We would defer to Tribes to the west of us for the portion of the project in Becker, Clay, and Wilkin Counties, though we would appreciate a status update for those areas from time to time, as they would be in our 1855 Treaty of Washington (10 Stat. 1165) Ceded Territory.
Niin
Charlie L.



From: Dan Flo <dan.flo@merjent.com>
Sent: June 9, 2025 12:27 PM
To: Charlie Lippert <Charlie.Lippert@millelacsband.com>
Cc: Drew Janke (MP) <djanke@mnpower.com>; Tristen Joens <tristen.joens@galileoaz.com>
Subject: Maple River - Cuyuna 345 kV Transmission Project

Charles Lippert:

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Regards,

Dan Flo on behalf of
Drew Janke
Project Manager – Environmental
Minnesota Power

Dan Flo
Minneapolis
612.812.0069 mobile
dan.flo@merjent.com



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June 9, 2025

VIA Email

Charles Lippert
Mille Lacs Band of Ojibwe
charlie.lippert@millelacsband.com

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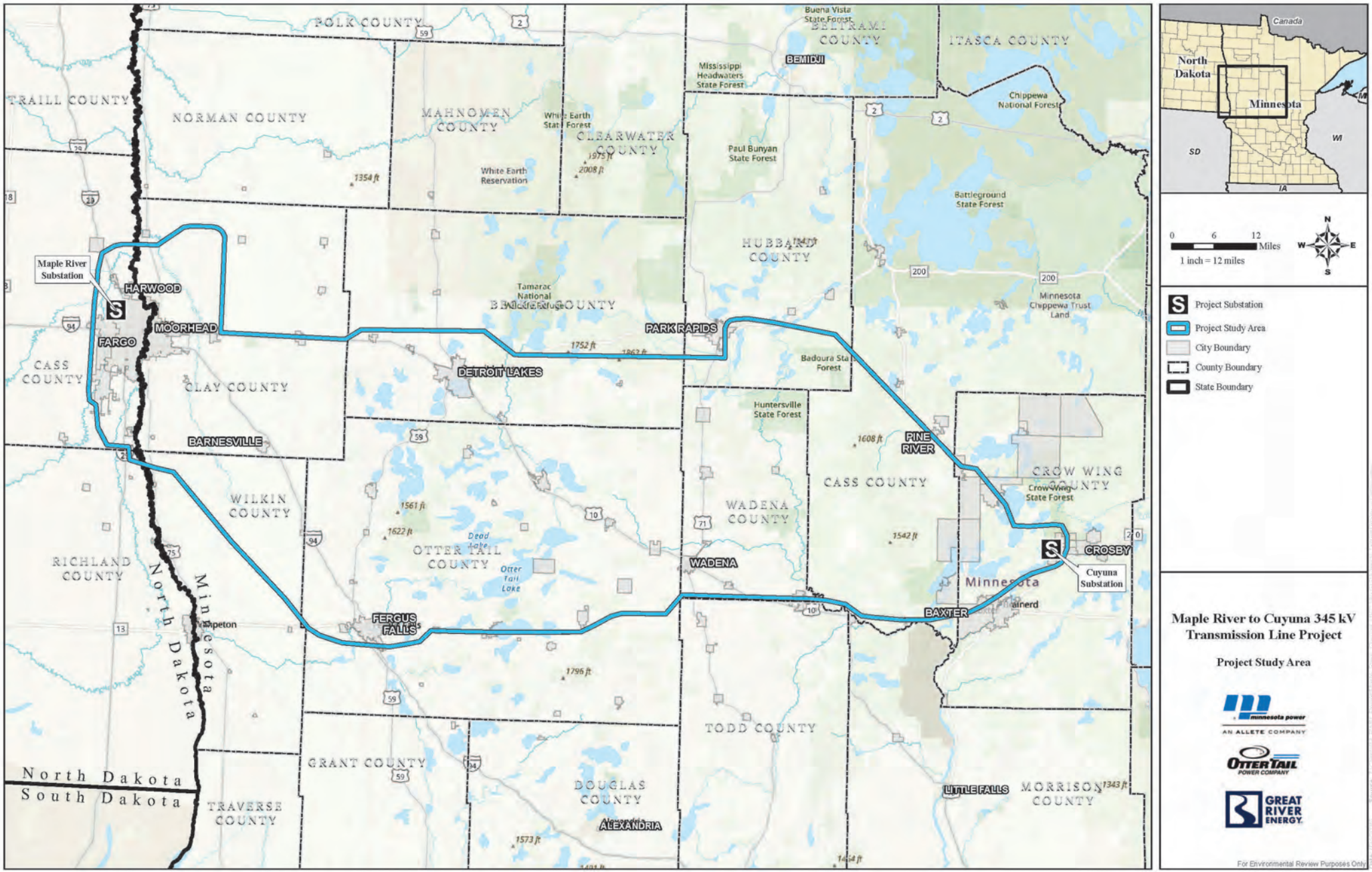
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Project Study Area
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For Environmental Review Purposes Only

From:	Leonard Wabasha (TO)
To:	Dan Flo
Cc:	Drew Janke (MP); Tristen Joens
Subject:	RE: Maple River - Cuyuna 345 kV Transmission Project
Date:	Monday, June 9, 2025 3:37:00 PM
Attachments:	image002.png image003.png

Thank you for the notice, please keep us informed and send the arch. studies when available…

LEONARD WABASHA
Tribal Historic Preservation Officer • Hocokata Ti
Shakopee Mdewakanton Sioux Community
d: 952.496.6120
shakopeedakota.org
Leonard.Wabasha@shakopeedakota.org

The Shakopee Mdewakanton Sioux Community is a federally recognized, sovereign Indian tribe located southwest of Minneapolis/St. Paul. With a focus on being a good neighbor, good steward of the earth, and good employer, the SMSC is committed to charitable donations, community partnerships, a healthy environment, and a strong economy.

From: Dan Flo <dan.flo@merjent.com>
Sent: Monday, June 9, 2025 2:15 PM
To: Leonard Wabasha (TO) <leonard.wabasha@shakopeedakota.org>
Cc: Drew Janke (MP) <djanke@mnpower.com>; Tristen Joens <tristen.joens@galileoaz.com>
Subject: Maple River - Cuyuna 345 kV Transmission Project

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Regards,

Dan Flo on behalf of

Drew Janke
Project Manager – Environmental
Minnesota Power

Dan Flo
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June 9, 2025

VIA Email

Charles Lippert
Mille Lacs Band of Ojibwe
charlie.lippert@millelacsband.com

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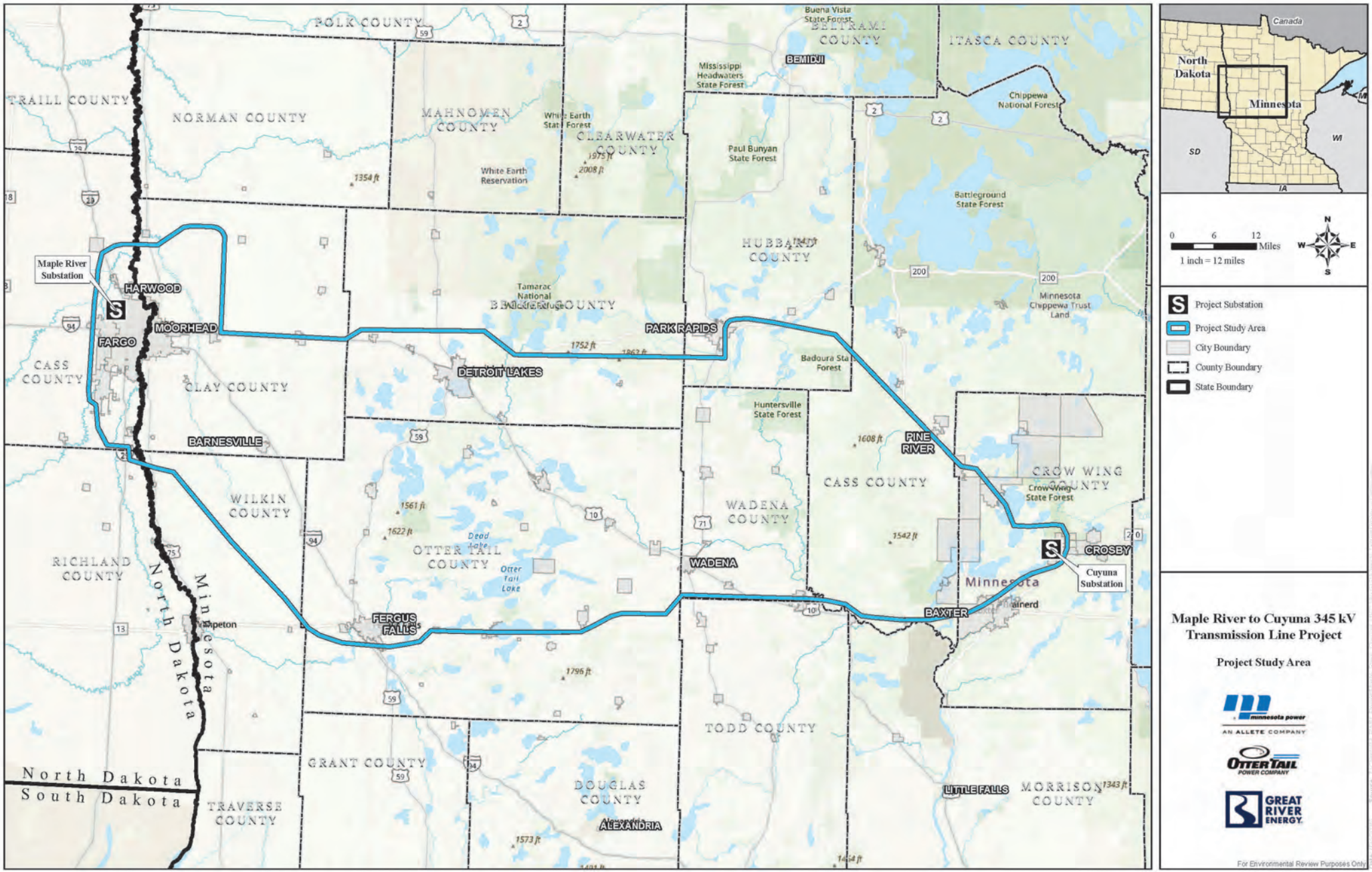
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For Environmental Review Purposes Only

From:	Bill Rudnicki (TO)
To:	Dan Flo; Leonard Wabasha (TO); Debra Flute (TO); Phil Brodeen
Cc:	Drew Janke (MP); Tristen Joens
Subject:	EXTERNAL: Re: Maple River – Cuyuna (MR-C) Transmission Project - October Open Houses
Date:	Tuesday, October 7, 2025 9:14:54 AM
Attachments:	image001.png image002.png image003.png MR-C_Preliminary Routes_October 2025.pdf

CAUTION: This email originated from outside of Merjent.

Thanks, I added Leonard as he will review and respond.

BILL RUDNICKI
Tribal Administrator • Tribal Administration
Shakopee Mdewakanton Sioux Community
d: 952.496.6145
ShakopeeDakota.org
bill.rudnicki@shakopeedakota.org

The Shakopee Mdewakanton Sioux Community is a federally recognized, sovereign Indian tribe located southwest of Minneapolis/St. Paul. With a focus on being a good neighbor, good steward of the earth, and good employer, the SMSC is committed to charitable donations, community partnerships, a healthy environment, and a strong economy.

From: Dan Flo <dan.flo@merjent.com>
Date: Tuesday, October 7, 2025 at 11:09 AM
Cc: "Drew Janke (MP)" <djanke@mnpower.com>, Tristen Joens <tristen.joens@merjent.com>
Subject: Maple River – Cuyuna (MR-C) Transmission Project - October Open Houses

Some people who received this message don't often get email from dan.flo@merjent.com. Learn why this is important

This message came from **outside the organization**. Do Not click on links, open attachments or respond unless you know the content is safe.

Good morning,

Minnesota Power, Otter Tail Power Company, and Great River Energy are hosting a second round of open houses to seek input on the Maple River – Cuyuna (MR-C) Transmission Project's preliminary routes. The proposed MR-C Transmission Project is an approximately 160-mile-long, single-circuit 345 kV transmission line on double-circuit-capable structures from Minnesota Power's Cuyuna Substation near Riverton, Minnesota to Otter Tail Power Company's Maple River Substation near Fargo, North Dakota.

Based on community input gathered during the first round of public open houses in June 2025

and through coordination with federal, state, local, and Tribal governments, Minnesota Power refined the initial study area by identifying routing opportunities based on existing transmission lines and developed several preliminary routes. Stakeholder comments included feedback on routing and impacts to aesthetics, groundwater, landowner's property interests, cultural resources, and environmental resources. Please find a map of the preliminary routes attached to this email.

We invite you to attend any of the open houses; the schedule is as follows:

MONDAY, OCTOBER 20, 2025 12:00-2:00PM Harwood Community Center 210 Freedland Dr Harwood, ND 58042	MONDAY, OCTOBER 20, 2025 5:30-7:30PM TAK Music Venue 1710 Center Ave W Dilworth, MN 56529
TUESDAY, OCTOBER 21, 2025 12:00-2:00PM Barnesville Event Center 101 Second St. SE Barnesville, MN 56514	TUESDAY, OCTOBER 21, 2025 5:30-7:30PM Historic Holmes Theatre 806 Summit Ave Detroit Lakes, MN 56501
WEDNESDAY, OCTOBER 22, 2025 12:00-2:00PM MN State Central Lakes College, Staples Location C168 1830 Airport Road Staples, MN 56479	WEDNESDAY, OCTOBER 22, 2025 5:30-7:30PM Hubbard Community Center 12141 County 6 Park Rapids, MN 56470
THURSDAY, OCTOBER 23, 2025 12:00-2:00PM The Lodge at Brainerd Lakes 6967 Lake Forest Rd Baxter, MN 56425	THURSDAY, OCTOBER 23, 2025 5:30-7:30PM Pelican Lakes Conservation Club and Community Center 8922 Thrane Dr Breezy Point, MN 56472

These meetings are open to the public and will give local community members and landowners an opportunity to learn about the project, ask questions, and provide input.

If you have questions about the Project or the Open Houses, please contact Drew Janke at (218) 576-9213 or djanke@mnpower.com.

Regards,

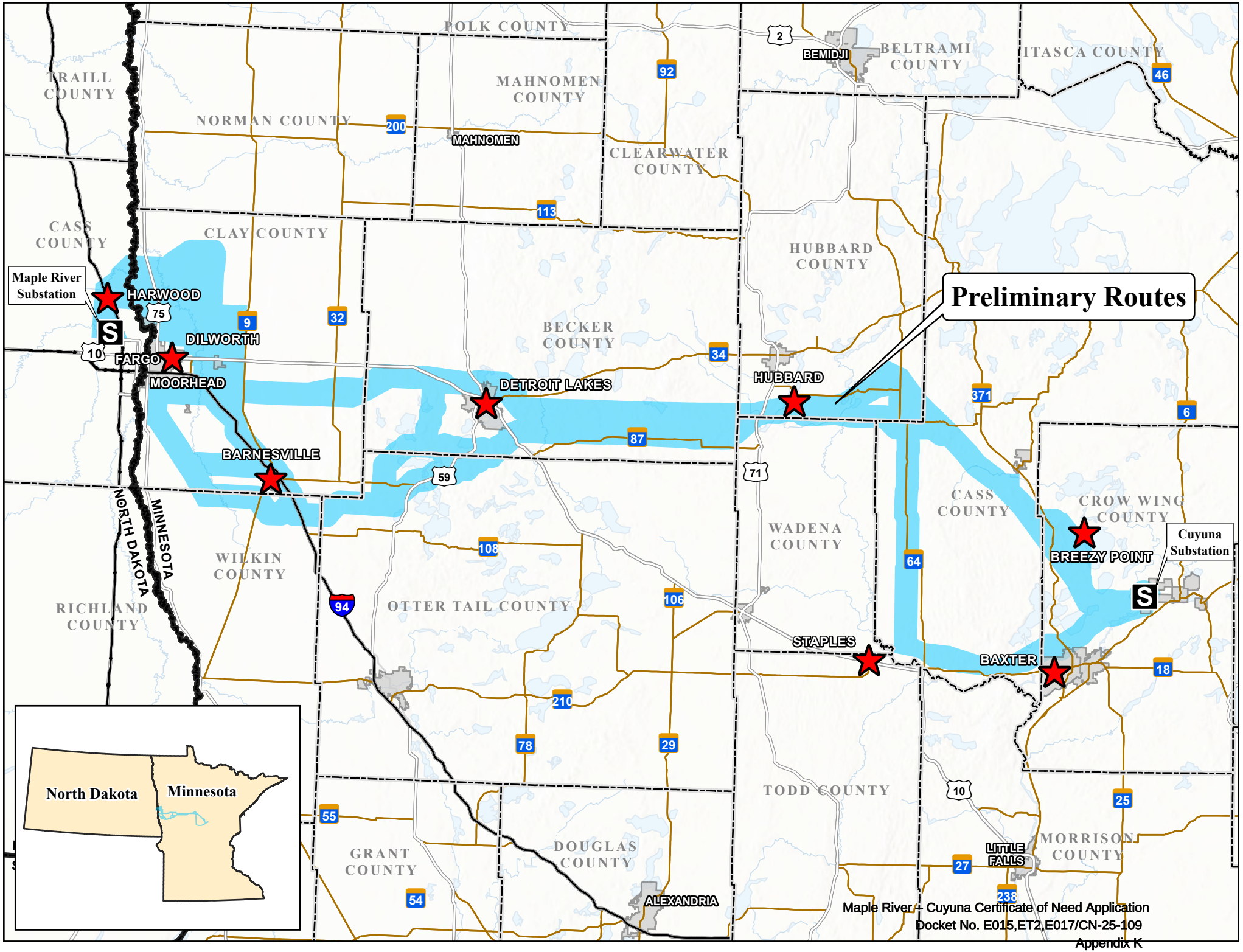
Dan Flo on behalf of
Drew Janke

Dan Flo
Senior Project Manager
612.924.3982 direct
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dan.flo@merjent.com

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Preliminary Routes
Maple River Substation
Cuyuna Substation
HARWOOD
FARGO
MOORHEAD
DILWORTH
DETROIT LAKES
HUBBARD
BARNESVILLE
BREEZY POINT
STAPLES
BAXTER
LITTLE FALLS
ALEXANDRIA
BEMIDJI
MAHNOMEN
POLK COUNTY
NORMAN COUNTY
MAHNOMEN COUNTY
CLEARWATER COUNTY
BELTRAMI COUNTY
ITASCA COUNTY
TRAILL COUNTY
CASS COUNTY
CLAY COUNTY
HUBBARD COUNTY
BECKER COUNTY
WADENA COUNTY
CROW WING COUNTY
WILKIN COUNTY
OTTER TAIL COUNTY
RICHLAND COUNTY
TODD COUNTY
GRANT COUNTY
DOUGLAS COUNTY
MORRISON COUNTY
NORTH DAKOTA
MINNESOTA
North Dakota
Minnesota

From:	Dan Flo
To:	Leonard Wabasha (TO)
Cc:	Bill Rudnicki (TO); Joe Bathel; Drew Janke (MP); Tristen Joens; Mandy Bohnenblust
Subject:	RE: EXTERNAL: RE: Maple River – Cuyuna (MR-C) Transmission Project - October Open Houses
Date:	Tuesday, October 7, 2025 9:38:40 AM
Attachments:	image001.png image002.png image003.png

Hello Mr. Leonard,

Thank you for the prompt response. We will be happy to continue providing you with updates as the MR-C Project continues through the routing and state permitting process.

Best regards,

Dan

Dan Flo
Minneapolis
612.812.0069 mobile
dan.flo@merjent.com

From: Leonard Wabasha (TO) <leonard.wabasha@shakopeedakota.org>
Sent: Tuesday, October 7, 2025 11:21 AM
To: Dan Flo <dan.flo@merjent.com>
Cc: Bill Rudnicki (TO) <bill.rudnicki@shakopeedakota.org>; Joe Bathel <jrbathel7@yahoo.com>
Subject: EXTERNAL: RE: Maple River – Cuyuna (MR-C) Transmission Project - October Open Houses

CAUTION: This email originated from outside of Merjent.

Dear Dan Flo
Thank you for the opportunity to consult with you on this project. As the area(s) of concern are not in our immediate area we will leave direct consultation to those Tribal Nations and other concerned parties closer to the proposed APE, however we would like to be kept informed of the project as it progresses, Thank you and Have a Great Day!!

LEONARD WABASHA
Tribal Historic Preservation Officer • Hocokata Ti
Shakopee Mdewakanton Sioux Community
d: 952.496.6120
shakopeedakota.org
Leonard.Wabasha@shakopeedakota.org

The Shakopee Mdewakanton Sioux Community is a federally recognized, sovereign Indian tribe located southwest of Minneapolis/St. Paul. With a focus on being a good neighbor, good steward of the earth, and good employer, the SMSC is committed to charitable donations, community partnerships, a healthy environment, and a strong economy.

From: Dan Flo <dan.flo@merjent.com>
Sent: Tuesday, October 7, 2025 11:09 AM
Cc: Drew Janke (MP) <djanke@mnpower.com>; Tristen Joens <tristen.joens@merjent.com>
Subject: Maple River – Cuyuna (MR-C) Transmission Project - October Open Houses

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Regards,

Dan Flo on behalf of
Drew Janke

Dan Flo
Senior Project Manager
612.924.3982 direct
612.812.0069 mobile
dan.flo@merjent.com

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LEECH LAKE BAND OF OJIBWE

Tribal Historic Preservation Office

Gina M Lemon, Tribal Historic Preservation Officer
Anita M Cloud, Tribal Historic Preservation Assistant

July 2, 2025 Via Internet

Merjent
Attn: Dan Flo, Project Manager
1 Main Street SE – Suite 300
Minneapolis, MN 55414

RE: Maple River – Cuyuna 345 kV Transmission Project. MPUC Docket No. E015, ET2, E017/CN-25-109.
Minnesota Power, Otter Tail Power Company, and Great River Energy (collectively, the "Applicants") are proposing to construct approximately 160 miles of new single-circuit 345 kV transmission line on double-circuit capable structures from Minnesota Power's Cuyuna Substation near Riverton, Minnesota to Otter Tail Power Company's Maple River Substation near Fargo, North Dakota. Approximately 95% of the transmission line will be in Minnesota. This project is referred to as the Maple River – Cuyuna 345 kV Transmission Project. Becker, Cass, Clay, Crow Wing, Hubbard, Otter Tail, Wadena, Wilkin, Counties, MN. Cass County, ND.

LL THPO No. 25-295-NCRI

Dear Dan Flo,

Thank you for the opportunity to comment on the above referenced project. This has been reviewed pursuant to the responsibilities given to the Tribal Historic Preservation Officer (THPO) by the National Historic Preservation Act of 1966, as amended in 1992, and the Procedures of the Advisory Council on Historic Preservation (38CFR800).

I have reviewed the documentation. After careful consideration of our records, I have determined that the Leech Lake Band of Ojibwe does not have any recorded historic properties, within this area. ** This does not mean there are not any cultural resources present, at this time. **

Should any human remains or suspected human remains be encountered, all work shall cease and the following personnel should be notified immediately: County Sheriff's Office, Office of the State Archaeologist, and the Leech Lake Band of Ojibwe along with other interested parties.

Please note the above determination does not "exempt" future projects from Section 106 review. In the event of any other tribe notifying you of an issue or us (LLBO) of concerns for this specific project, we may reenter into the consultation process.

You may contact me at **(218) 335-2940** if you have questions regarding our review of this project. Please refer to the **LL-THPO Number** as stated above in all correspondence with this project.

Respectfully submitted,

Gina M Lemon
Tribal Historic Preservation Officer

Leech Lake Tribal Historic Preservation Office - Established in 1996
190 Sailstar Drive NE * Cass Lake, MN 56633
Gina.lemon@llojibwe.net