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Minnesota Municipal Power Agency

APPLICATION FOR INTEGRATED RESOURCE PLAN APPROVAL 2025 - 2039

SUBMITTED TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

Minnesota PUC Docket No. ET6133 / PR-25-302

July 31, 2025

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Section 1. Executive Summary

This section provides a non-technical summary of the Minnesota Municipal Power Agency's (MMPA) Integrated Resource Plan (IRP).

Energy Industry Faces High Uncertainty

The electric utility industry is experiencing significant economic, growth, regulatory, and technological uncertainty. At the same time, the industry is undergoing a major transition toward carbon-free energy resources. These uncertainties make long-term planning increasingly complex and underscore the importance of maintaining flexibility throughout the planning process.

MMPA Anticipates Growth from Data Centers

MMPA has a special tariff for very large customers whose load is greater than 10 MW, such as data centers. This tariff requires that the customer supply their own capacity and energy that meets the carbon-free standards. This approach ensures that very large customers are responsible for the cost to supply power and it does not get passed on to MMPA's general rate payer. This also means, that very large customers do not need to be included in MMPA's energy and capacity projections.

MMPA accounted for the large customers (<10 MW), such as small data centers, in its energy and demand projections. Data center development is expected to increase in the coming years and its growth differs from historical trends. For this reason, MMPA addresses it separately in its projections.

MMPA Anticipates Additional Growth from EVs

Electricity usage by electric vehicles (EVs) was incorporated into MMPA's energy and demand projections. EV adoption is anticipated to accelerate in the next fifteen years. The growth is anticipated to differ from historical trends, so MMPA addresses it separately in its projections.

Conservation Savings Anticipated to Be More Difficult to Achieve

MMPA anticipates that achieving future energy savings will become more challenging because of the slowing pace of technological improvements. Despite this, MMPA continues to pursue energy savings through the Energy Conservation and Optimization (ECO) program by evaluating current offerings, exploring new technologies, and engaging with customers with high savings potential.

No MMPA Resource Retirements	MMPA plans to continue operating its existing resources throughout the IRP planning period, including natural gas generators, wind farms, a solar farm, and a biogas generator. The gas generators offer reliable, cost-effective, dispatchable power, while the renewable resources contribute carbon-free energy.
Preferred Plan Includes Battery Storage and Solar	MMPA's preferred plan includes 50 MW of short-duration battery storage and 435 MW of solar generation. The battery storage would be developed in multiple smaller projects projected to come online between 2030 and 2035. The 435 MW of solar is needed over the next ten years to meet Minnesota's carbon-free energy standard. The solar projects would be a combination of large, transmission-interconnected projects and small, distribution-connected projects.
Preferred Plan Is Flexible	The preferred plan creates flexibility for MMPA to adapt to future uncertainties, including shifts in technology, electricity demand, and energy policy. This flexibility is achieved through the continued operation of its existing resources, the use of scalable, modular resources such as storage and solar, and the use of renewable natural gas (RNG) or hydrogen in 2040.
Plan Meets the Carbon-Free Requirements	MMPA's plan aligns with Minnesota's carbon-free energy standard by steadily expanding MMPA's renewable portfolio. The plan calls for the addition of 435 MW of solar capacity over the next decade. To fulfill the remaining 8% of carbon-free energy by 2040, the plan anticipates using RNG or hydrogen.
Plan Is in the Public Interest	MMPA's plan is in the public interest. It draws on a diverse portfolio of resources to meet energy needs while maintaining grid reliability and adequacy. The preferred strategy emphasizes carbon-free options to help limit potential environmental and socioeconomic impacts. Flexibility is central to the plan, enabling MMPA to navigate changing financial, social, and technological landscapes. Throughout, the Agency remains committed to keeping customer bills and utility rates affordable.

Section 2. About MMPA

This section provides overview information about the Minnesota Municipal Power Agency.

MMPA Is a Municipal Power Agency

Minnesota Municipal Power Agency (MMPA) is a political subdivision of the state of Minnesota formed under Minnesota Statutes Chapter 453.

MMPA was formed in 1992 and began supplying power to its members in 1995. MMPA supplies wholesale electricity to its municipal utility members and they in turn sell that electricity to residential and business customers.

MMPA's mission is to provide reliable, competitively-priced power to its members and to create value for both the Agency and its members. MMPA is committed to supporting its member communities and demonstrates this commitment by offering an Energy Education Program, developing local power generation in member communities, and providing conservation and renewable energy programs to members' customers.

MMPA is governed by a board of directors with representatives from each member community.

Has 12 Members

MMPA is comprised of the following 12 Minnesota communities:

- Anoka
- Arlington
- Brownton
- Buffalo
- Chaska
- East Grand Forks
- Elk River
- Le Sueur
- North St. Paul
- Olivia
- Shakopee
- Winthrop

MMPA's member municipal utilities have approximately 83,000 retail customers in Minnesota with a combined population of approximately 170,000.

Sold 1.9 million MWh of Electricity in 2024	In 2024, MMPA sold a total of 1.9 million MWh of electricity to its 12 member communities.
2024 Peak Load: 422 MW	MMPA's peak summer load was 422 MW in 2024, occurring on August 26, 2024.
Project 47% Carbon-Free in 2025	MMPA projects that in 2025, 47% of its electricity will be from carbon-free resources. In 2025, 99% of MMPA's carbon-free energy is from wind resources and the remaining 1% is from a solar resource.
Produces RNG	MMPA is a producer of renewable natural gas (RNG) at its Hometown BioEnergy facility located in Le Sueur, Minnesota. Hometown BioEnergy uses anaerobic digestion to produce biogas from agricultural and food processing waste. In 2023, the plant began producing RNG that is injected into the interstate natural gas pipeline. MMPA currently sells the renewable attributes from RNG production.
MISO Member and Transmission Owner	MMPA is a registered transmission owner, with approximately 6.5 miles of transmission facilities located in Anoka and Chaska, Minnesota. MMPA is a member of the Midcontinent Independent System Operator (MISO), a federally regulated, non-profit regional transmission organization that manages the electric grid and ensures open access to the transmission system. MMPA is a registered generation owner and load-serving entity within MISO.
Two Members Receive Power from Western Area Power Administration	Two of MMPA's members, Olivia and East Grand Forks, receive allocations of power, approximately 95,000 MWh per year, from the Western Area Power Administration (WAPA). Both members have long-term contracts for the allocations. In this IRP, MMPA's energy and demand projections were reduced to account for the WAPA allocations. The WAPA allocations were assumed to remain at current levels through the IRP planning period. However, if this changes, MMPA's energy and capacity requirements would change accordingly because the Agency provides all power that is not supplied by WAPA.
Avant Energy Manages MMPA	MMPA contracts with Avant Energy, Inc. on a long-term basis to provide all management services. These services include:

- Overall long-term strategic planning and management
- Day-to-day energy market operations including purchasing and selling of electricity
- Project development for power generation
- Accounting and financial management

Section 3. Business Environment

This section discusses the business environment in which MMPA operates. MMPA's IRP recognizes electric market uncertainties that influence planning decisions.

Economic Environment Uncertain

Long-term planning is challenging for electric utilities because of economic uncertainty around electric growth, tariffs, and federal policy.

Electric Demand Growth

The growth of electric demand for data centers and electric vehicles (EVs) creates uncertainty for projecting future electricity needs. The number of new data centers has accelerated in recent years, driven by rising demand for cloud computing, AI applications, and digital infrastructure. Data centers represent large, concentrated loads that can significantly impact the local utility and electric system. However, the timing, location, and magnitude of these developments are largely driven by private companies and remain difficult to predict. Similarly, EV adoption is poised for growth, influenced by federal and state incentives, vehicle availability, infrastructure rollout, and consumer behavior. While EV adoption is expected to increase, their impact on electric load will depend heavily on when and where charging occurs, introducing further uncertainty into peak demand projections.

Tariffs

The U.S. has imposed tariffs on imports from multiple countries such as China, Mexico, and Canada. These tariffs are anticipated to affect the price of raw materials such as steel and aluminum and electrical equipment such as transformers and solar panels. Higher prices for materials and equipment are expected to increase costs for new power generation development. The uncertainty of how long the tariffs will last and how other countries will respond introduces additional volatility into long-term capital planning.

Federal Tax Credits

Federal clean energy policy has also undergone significant change. The Inflation Reduction Act (IRA), enacted in 2023, included significant tax credits for the development of clean energy projects such as solar, wind, and batteries. However, a new federal law enacted in July 2025 substantially scaled back this funding.

Under the 2025 policy, for solar and wind projects to qualify for tax incentives, they must be in service by the end of 2027 or start construction by July 4, 2026 and be operational by the end of 2030.

These conditions largely limit the tax credits to projects already in development.

Battery storage projects must start construction by the end of 2033 to be eligible for the full tax credit under the 2025 policy. In addition to the timing requirements, projects must comply with sourcing and labor provisions related to Foreign Entities of Concern. Since China is a large supplier of clean energy equipment, these restrictions may limit access to tax credits and pose additional procurement challenges.

Carbon-Free by 2040

In February 2023, Minnesota enacted a carbon-free electricity standard that is codified in Minnesota Statute §216B.1691. The standard requires electric utilities to generate or procure electricity from carbon-free sources for 100% of retail sales by 2040. Intermediate milestones for municipal utilities require carbon-free electricity at a threshold of 60% by 2030 and at 90% by 2035.

The Minnesota Public Utilities Commission (PUC) is responsible for issuing orders detailing the criteria and standards for utility compliance with the State's Carbon-Free Standard (CFS). These orders must protect against undesirable reliability and economic impacts affecting ratepayers. Further, these orders must allow for partial compliance for facilities utilizing carbon-free technologies.

As a part of this effort, the PUC opened Dockets No. E999/CI-23-151 and E999/CI-24-352 that are being used to engage with utilities and the public.

Transmission System Constrained

Across Minnesota and the broader MISO region, interconnecting new resources to the transmission system can be time-consuming and expensive. These constraints pose significant challenges for utilities striving to meet decarbonization goals..

<u>Transmission Availability</u>
Much of Minnesota's existing high-voltage transmission infrastructure is operating near or at capacity. The lack of transmission capacity significantly impacts the cost-effectiveness of new projects. When upgrades to the transmission system are required, overall project costs increase and in some cases, the project becomes financially unviable and must be abandoned.

<u>MISO Transmission Interconnection Process</u>
Projects greater than 5 MW that connect to the transmission system are required to participate in MISO's generation interconnection study process. This process is supposed to be completed within 18

months, but in recent years has experienced multi-year delays. These delays are the result of the large volume of interconnection requests and high number of late-stage project withdrawals.

To address these delays, in 2024 MISO's interconnection procedures were revised to include higher milestone payments, earlier site control requirements, and financial penalties for withdrawal. The new requirements are intended to reduce speculative interconnection requests that never get built. Additionally, in 2025, MISO imposed a cap on the total generation capacity allowed per study cycle. Beginning with the DPP-2025 cycle, each MISO study region is limited to a volume equal to 50% of its non-coincident peak load. The intent of the cap is to reduce the complexity of the MISO model, resulting in more accurate results and faster study cycles. In the interim, projects already in the queue continue to face delays.

<u>Transmission System Upgrades</u>
Even when a project receives an interconnection agreement, it often must wait for transmission system upgrades that can involve substation expansions, reconductoring existing lines, or building new transmission lines. Depending on the scope, location, and complexity, these projects can delay new resources coming online.

MISO Requirements Changing

In an attempt to improve reliability, MISO transitioned from annual to seasonal resource accreditation in planning year (PY) 2023. It also made an additional change to accreditation for thermal resources.

Recently, MISO filed and received Federal Energy Regulatory Commission (FERC) approval for another change to resource accreditation, called Direct Loss of Load (DLOL). This change will take effect in PY 2028 and is expected to impact the Planning Reserve Margin Requirement (PRMR). MISO indicated that the changes would lead to a lower total accreditation of the thermal generation fleet. MISO released indicative planning reserve margin (PRM) percentages under the DLOL methodology. DLOL accreditation will apply for all resource classes except emergency resources and behind the meter generation. MISO is currently designing changes to accreditation for emergency resources and behind the meter generation.

Starting in PY 2028, this IRP uses these indicative PRM percentages that MISO communicated to market participants.

Development Costs and Schedules Uncertain

New generation projects face a variety of risks that can significantly affect both development costs and construction timelines. One of the primary challenges is the increasing lead time for critical equipment, such as high-voltage transformers and circuit breakers. Lead times for these components can be upwards of three years because of a surge in global demand and limited manufacturing capacity. Compounding the issue, equipment costs have risen, with transformers prices increasing by as much as 60%.

Section 4. Emerging Technology Environment

This section discusses emerging technology that influences MMPA's planning decisions.

Short-Duration Battery Storage Implementable

Short-duration battery storage, typically ranging from two to four hours, is commercially available and increasingly used to provide capacity during peak demand, support grid reliability, and shift solar output. These systems offer considerable operational flexibility, including quick response times, the ability to charge and discharge rapidly, and the capacity to deliver ancillary services such as frequency regulation and voltage support. Lithium-ion technology remains the dominant form, with widespread deployment across U.S. markets because of its high energy density, scalability, and declining costs.

Battery systems are modular and available in various sizes, from small behind-the-meter setups to large utility-scale facilities. They are simpler to install and permit than traditional generators and can be expanded as needs change. Often paired with renewables, short-duration storage helps stabilize the grid and optimize the use of variable energy sources.

Costs have declined significantly in recent years and are becoming competitive with conventional resources under certain conditions. Section 13 has a detailed cost analysis of capacity resources. Existing federal incentives could further improve the economics.

Long-Duration Battery Storage Still Evolving

Long-duration energy storage, typically defined as lasting eight hours or more, has the potential to enhance grid reliability and improve the integration of renewable energy sources by storing energy over longer time periods. Unlike short-duration batteries, which manage hourly fluctuations and daily peaks, long-duration storage can address multi-day variability, extend renewable energy output during prolonged outages or periods of low generation, and provide firm capacity during seasonal demand shifts.

Long-duration battery storage technologies such as flow batteries, gravity-based systems, and advanced chemistries are under development, but few are commercially available.

Hydrogen-Fueled Energy Generation Limited

Hydrogen can be used as a fuel for combustion in gas turbines, offering a potential zero-carbon alternative to natural gas. While turbine manufacturers have made progress in adapting combustion systems to handle hydrogen, current commercial models are generally limited to blending hydrogen with natural gas. Full hydrogen capability remains limited to a small number of advanced or custom-designed turbines that are not widely deployed.

Hydrogen used in energy systems is categorized based on its production method, which determines its environmental impact. “Brown” or “black” hydrogen is produced from coal or lignite through gasification, resulting in high carbon emissions. “Grey hydrogen” is the most common form today and is made from natural gas via steam methane reforming without capturing the resulting CO_2 emissions. “Blue hydrogen” also uses steam methane reforming but incorporates carbon capture and storage (CCS) to reduce emissions. “Green hydrogen” is generated through electrolysis powered by renewable electricity and is considered the most sustainable option, producing no direct carbon emissions. Green hydrogen is not commercially available.

The use of hydrogen in utility-scale gas turbines faces several challenges. One barrier is inadequate infrastructure for hydrogen production, storage, and distribution. Existing natural gas pipelines and fueling systems are not designed to handle hydrogen’s unique properties, such as its low energy density and high diffusivity, which can cause leaks and safety concerns. Hydrogen combustion produces higher flame temperatures compared to natural gas, which increases the formation of nitrogen oxides, pollutants that require advanced control technologies to reduce.

Most existing turbines are only compatible with hydrogen blend ratios less than 30 percent. Upgrading turbines to handle higher blends or 100 percent hydrogen involves extensive modifications or full turbine replacement. Hydrogen-fired turbines tend to be less efficient than natural gas turbines because of differences in combustion characteristics and energy content, which affects the cost-effectiveness of power generation.

There is also limited long-term operational data for hydrogen-fired turbines, especially for high blend ratios or pure hydrogen. This limits confidence in their reliability, maintenance needs, and lifespan. Some turbine manufacturers, such as GE, have developed commercially viable solutions for low to moderate hydrogen blending, but fully commercial 100 percent hydrogen turbines are still in early demonstration stages.

Carbon Capture Not Widely Deployed

Carbon capture and storage (CCS) is a process that captures carbon dioxide emissions from fossil fuel combustion, compresses the gas, and transports it to a storage site, often deep underground, for long-term containment. It is one of the few technologies available to reduce emissions from gas- or coal-fired power plants while maintaining their generating capacity.

Despite its technical feasibility, CCS has not seen wide deployment in the power sector. Most projects have remained at the demonstration or early commercial stage. High capital and operational costs, including the energy required to capture and compress carbon dioxide, continue to limit broader use.

In addition to cost, widespread adoption of CCS for electric generation faces regulatory and logistical hurdles. These include permitting challenges, lack of established carbon pipelines, and limited access to secure geological storage sites. These barriers are especially pronounced in regions without existing carbon capture infrastructure.

RNG Can Be Used in Gas-Fired Plants

Renewable natural gas (RNG) is an alternative to fossil natural gas and can be utilized in existing gas-fired power plants with no modifications. It is produced from organic waste sources, including landfills, agricultural waste, livestock operations, and wastewater treatment facilities. During processing, bigas is cleaned and upgraded to RNG that meets natural gas pipeline quality standards, allowing it to be transported and used interchangeably with conventional natural gas.

The carbon intensity of RNG depends on the type of feedstock used and the method of processing. In most cases, RNG facilities can achieve very low or negative carbon intensity scores. Carbon intensity, calculated by a life cycle analysis, helps quantify total emissions reductions, or net environmental benefits, when RNG is used as a renewable fuel.

Nuclear Not an Option in Minnesota

Minnesota has had a statewide moratorium on the construction of new nuclear power plants since 1994. MMPA would consider using them as a carbon-free capacity resource if the moratorium were lifted.

Nuclear Not Commercially Available

New nuclear technologies are under development, including small modular reactors (50-300 MW), non-light-water reactor designs, and microreactors. These systems are designed to enhance safety, reduce costs, and increase dispatchability compared to traditional nuclear plants. Most of these designs are still in the early stages of development and are not commercially available.

Section 5. Energy Conservation

This section discusses MMPA's energy conservation and demand side management efforts. The Agency's energy conservation programs delay the need for new generation and reduce energy consumption.

ECO Act Signed into Law in 2021

In 2021, the Energy Conservation and Optimization (ECO) Act was signed into law. The ECO Act was an update to the Conservation Improvement Program (CIP) that:

- Added opportunities for load management and efficient fuel switching programs
- Established an Energy Savings from Conservation Improvements Goal that is in addition to the Energy Savings Goal
- Eliminated the Total Spending Goal (but if a utility fails to meet its Energy Savings from Conservation Improvements Goal three years in a row the Total Spending Goal may be reassigned)
- Allowed Consumer-Owned Utilities to file single or multi-year plans.

The changes from the ECO Act went into effect in 2023.

ECO Program Sets Three Goals for Utilities

The ECO Act evaluates utilities against the following three goals:

- Low-Income Spending – 0.2%
- Energy Savings from Conservation Improvements – 1.5%
- Total Energy Savings – 0.95% for years 2020-2024 and 0.90% for 2025 and beyond

MMPA Manages Program for 7 Members

MMPA manages the conservation improvement program group for seven of its member communities. The other five member communities manage their own ECO programs. Electric utilities with fewer than 1,000 customers are not required to participate in the program. Two of MMPA's member communities qualify for this exemption. However, both utilities chose to participate in the program and are both a part of the MMPA-managed program.

Variety of Rebates Offered to Customers

MMPA's conservation improvement program primarily focuses on customer rebates to achieve its energy savings goals. The program offers a variety of rebates to customers that include:

Residential:

- ENERGY STAR Appliance Rebate
- Secondary Refrigerator or Freezer Recycling Rebate
- LED Lighting Rebate
- Quality Installed Central Air Conditioning (AC) and Air Source Heat Pump Rebate
- AC Tune Up Rebate
- Custom Rebates

Commercial and Industrial:

- LED Lighting Retrofit Rebate
- LED Lighting New Construction Rebate
- Variable Frequency Drives (VFD) Rebates
- Custom Rebates

Focus on Rebates with High Energy Savings Potential

MMPA focuses on rebates that yield high energy savings relative to the rebate. The following rebates have historically demonstrated high energy savings:

- Recycling inefficient secondary refrigerators and freezers
- Retrofitting commercial lighting with LEDs
- Custom commercial and industrial rebates

Examples of custom rebates in 2024 include an ammonia condenser towers upgrade, compressed air leak detection and repair, delay timers, packaged terminal air conditioner upgrade, rooftop unit upgrade, and ENERGY STAR appliances in a new multi-family structure. Custom rebates made up 7% of MMPA's Agency-managed rebate spending in 2024.

Community Outreach Increased Since Last IRP

MMPA has increased its community outreach efforts to promote the program. Examples include reaching out to income qualified, multi-family housing owners to suggest LED lighting upgrades and sponsoring customer events to raise awareness about energy conservation and rebate options. MMPA also offers fillable electronic pdf forms to make it easier for customers to file for rebates.

Met ECO Goal for Low Income Spending

The ECO Act revised the low-income spending goal so that it applies to the MMPA-managed portfolio as a whole and not to each community individually. The following table shows that MMPA has consistently met Minnesota's low-income spending goal of 0.2% of residential gross operating revenues (GOR) for the portfolio as a whole.

Low-Income Spending for MMPA-Managed Program

	Low-Income Spending ($)	% of Residential GOR
2018	47,000	0.32
2019	51,000	0.33
2020	57,000	0.36
2021	103,000	0.63
2022	134,000	0.80
2023	130,000	0.75
2024	160,000	0.93

Met ECO Goal for Total Energy Savings from Conservation Improvements

The ECO Act implemented a new goal for total energy savings from conservation improvements. The MMPA-managed program has met the goal of 0.95%. The table below shows performance for the years the goal was in effect.

Total Energy Savings from Conservation Improvements for MMPA-Managed Program

	Energy Savings (kWh)	% of Sales
2023	3,906,000	1.16
2024	4,213,000	1.25

Did Not Meet Goal for Total Energy Savings

From 2019-2024, the MMPA-managed program's total energy savings have been slightly below Minnesota's goal of 1.5%. The members participating in the MMPA-managed programs are all smaller utilities with primarily residential and small commercial customers. This makes hitting the 1.5% goal challenging.

The table below shows performance for the years 2018-2024. For the MMPA-managed program, the total energy savings were the same as energy savings from conservation improvements.

Total Energy Savings for MMPA-Managed Program

	Energy Savings (kWh)	% of Sales
2018	5,943,000	1.75
2019	4,545,000	1.34
2020	4,399,000	1.30
2021	4,363,000	1.31
2022	4,204,000	1.26
2023	3,906,000	1.16
2024	4,213,000	1.25

Program Aims to Spend 1.5% of Gross Operating Revenue

The ECO Act eliminated the 1.5% total spending goal; however, the MMPA-managed program still aims to meet this goal. The table below shows that the MMPA-managed program has spent at least 1.5% of its gross operating revenue (GOR) on conservation improvements for the years 2018 to2024, with the exception of 2020.

Total Spending for MMPA-Managed Program

	Total Spending ($)	% of GOR
2018	567,000	1.51
2019	586,000	1.53
2020	565,000	1.40
2021	624,000	1.60
2022	591,000	1.50
2023	652,000	1.50
2024	682,000	1.56

Program Cost: $0.16/kWh of Energy Saved

In 2024, the MMPA-managed ECO program spent $0.16 for every kWh of energy saved.

Lighting Rebates Are Core to Program

In 2024, 67% of the MMPA-managed ECO program rebate spending went toward lighting projects. Lighting rebates are a cost-effective means of achieving energy savings. The table below highlights the return on investment from MMPA's 2024 ECO cycle.

2024 Lighting Rebate Effectiveness – MMPA-Managed Program

Rebate	Energy Saved (kWh)	Cost Effectiveness ($/kWh)
Commercial Lighting – New	358,000	0.19
Commercial Lighting - Retrofit	935, 000	0.08
Residential LED	1,000	0.22
Lighting Giveaway	697, 000	0.18
LED Street Lighting	138, 000	0.36
Direct Low-Income Lighting	182,000	0.11
All Lighting Combined	2,310,000	0.15

Energy Savings Goal Will Continue to Be Challenging to Achieve in the Future

It is anticipated that energy savings will continue to be challenging to achieve in the future. Retrofit lighting rebates are integral to the program, returning substantial energy savings at a low cost. Achieving the total energy savings goal is largely determined by the number of large commercial lighting and custom rebates paid. LED lighting upgrades have long useful lives, and the energy-saving technological advancements are likely to slow down. Despite this, MMPA believes it can continue to achieve the goal for total energy savings from conservation improvements.

MMPA continues to evaluate its existing program offerings and consider new energy-efficient technologies. It also works to engage with customers, especially industrial and commercial customers that are larger energy users and therefore have greater energy savings potential.

This IRP Assumes 1.3% for Future Energy Savings

This IRP assumes an ECO savings rate of 1.3%, although a low case of 1.0% and a high case of 1.5% are also analyzed. The Agency strives for a 1.5% total savings rate; however, planning processes need to take into consideration the uncertainties associated with longer-term effectiveness of ECO programs and the possibility of diminishing returns.

MMPA Does Not Have Demand-side Management Programs

MMPA currently has no demand-side management programs. As a wholesale electricity provider with no retail customers, it is not practical to implement these programs. However, the electricity price structure incentivizes large energy users to curtail in times of high demand. Further, some of MMPA's member communities have demand-side management programs.

Section 6. Projected Energy – 2025 to 2039

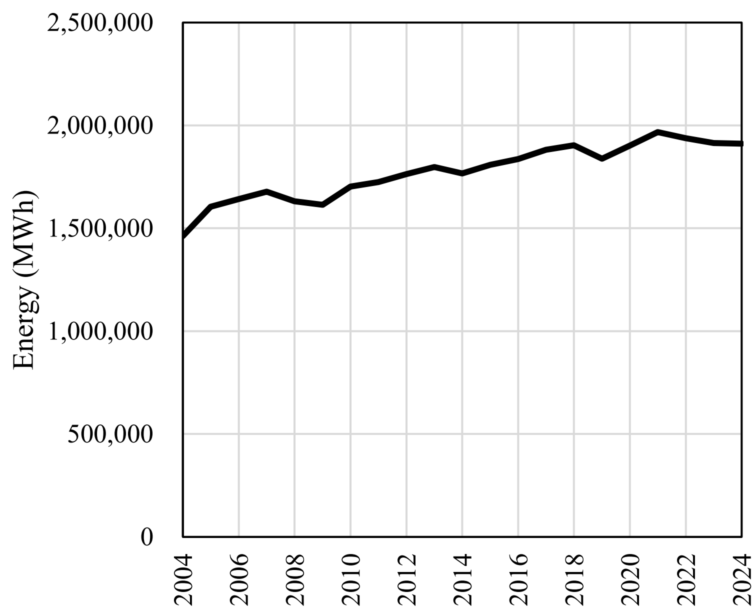
This section discusses MMPA's projected energy requirements.

Energy Consumption Grew 1.3% from 2004-2024

The energy needs of MMPA's twelve members grew at a compound annual growth rate of 1.3% between planning years 2004 and 2024. A planning year begins on June 1 of the given planning year and extends to May 31 of the following calendar year.

The graph below shows MMPA's historical energy requirements. Data is available for all twelve members beginning in 2004, even though MMPA did not supply power to Elk River until 2018 and the portion of Shakopee served by MMPA was expanded in 2009.

MMPA Historical Energy Requirements
Planning Years 2004-2024



Energy Consumption Slowed to 0.8% from 2014-2024

MMPA's energy requirements slowed to a compound annual growth rate of 0.8% between planning years 2014 and 2024. The graph above shows this growth.

Linear Regression Model Used to Project Energy

For this IRP, a linear regression model was used to project future energy requirements. The model used the following variables:

- Weather (heating degree days and cooling degree days)
- Population

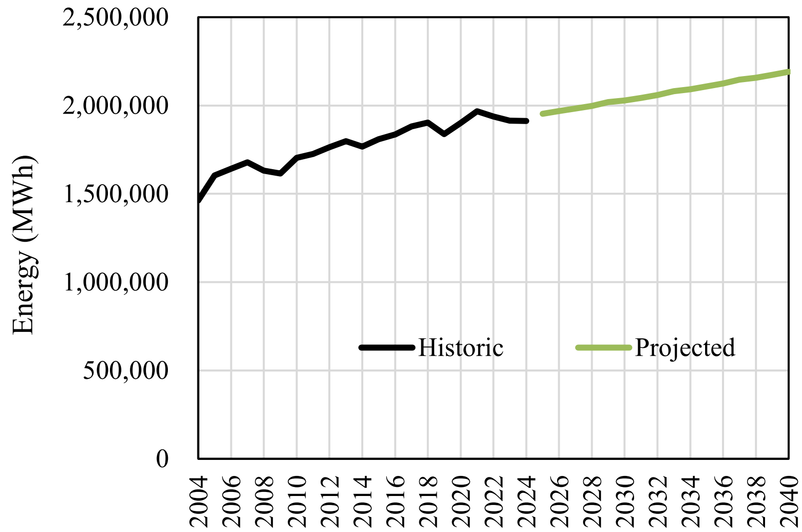
- Income per capita

More details on the inputs and assumptions of the methodology can be found in Appendix A.

Projected Energy Growth Rate: 0.8%

Using the linear regression model, MMPA's projected growth rate is 0.8% for planning years 2025 through 2039. The following graph shows historical and projected energy requirements. The data was adjusted for the energy suppled by WAPA.

MMPA Historical & Projected Base Energy Requirements
Planning Years 2004 to 2039



Assumed Additional Growth for Future Large Customers

The base energy projection was adjusted to account for future new large customers (<10 MW), such as data centers. A total of 30 MW of large load additions were estimated and added in 2 MW increments across the 15-year planning period. The additional energy was calculated using an 80% capacity factor.

Very large customers (>10 MW) have a separate tariff, and their energy requirements do not impact MMPA projections as discussed in Section 1.

Additional details of the methodology are available in Appendix A.

Assumed Additional Growth for Future EV Adoption

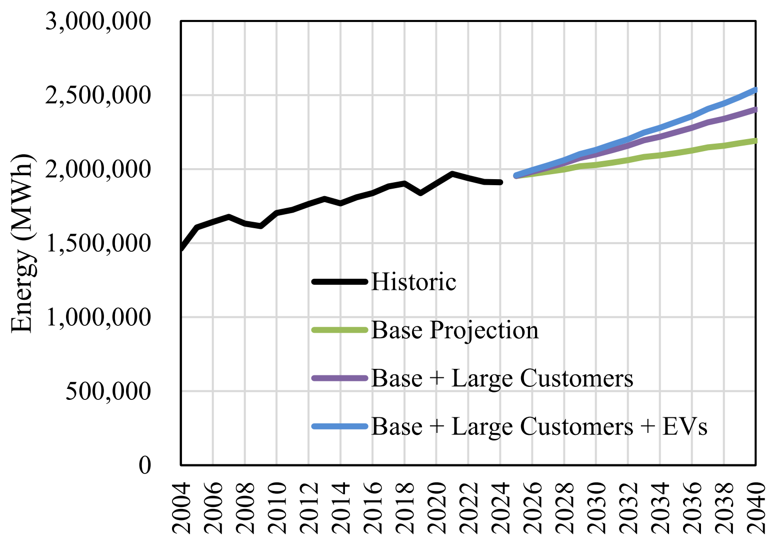
The base energy projection was also adjusted to account for the anticipated increase in EVs. The annual EV penetration was projected over the planning period. These estimates were used to calculate EV energy use. The additional energy was added to the base energy projection.

Additional details of the methodology are available in Appendix A.

Energy Growth Rate Including Large Customers and EV Additions: 1.7%

MMPA's adjusted growth rate is 1.7% after adding energy from future large customers and EVs to the base energy projection. The following graph shows the projected energy requirements with these adjustments.

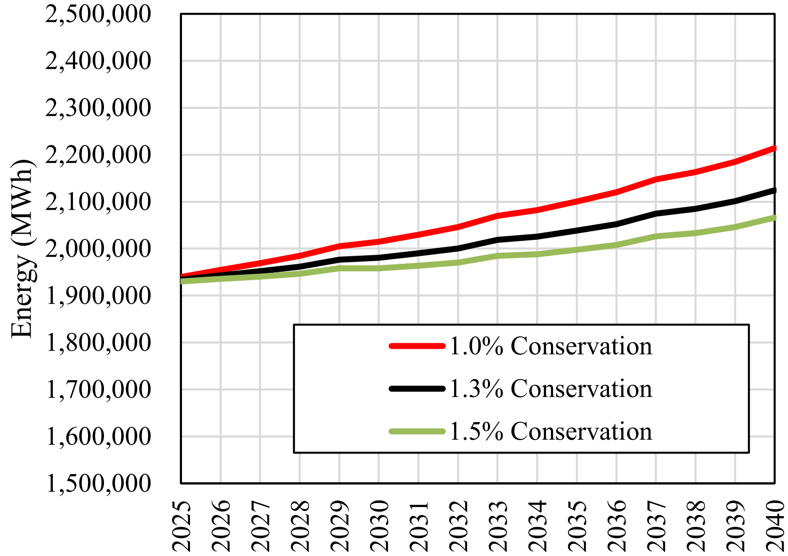
MMPA Historical & Projected Adjusted Energy Requirements Planning Years 2004 to 2039



Conservation Decreases Growth Rate by 1.1%

MMPA strives to meet Minnesota's energy conservation goal of 1.5%. However, in the future, this goal is going to become more difficult to achieve, as discussed in Section 5. For this reason, the IRP assumes 1.3% energy conservation savings. The energy savings are calculated using a lagging three-year rolling average of retail energy sales. Therefore, the percentage of conservation savings in a year relative to that year's projected wholesale energy is less than 1.3%. The following graph shows the variability in projected energy when using 1.0%, 1.3%, and 1.5% energy conservation savings assumptions.

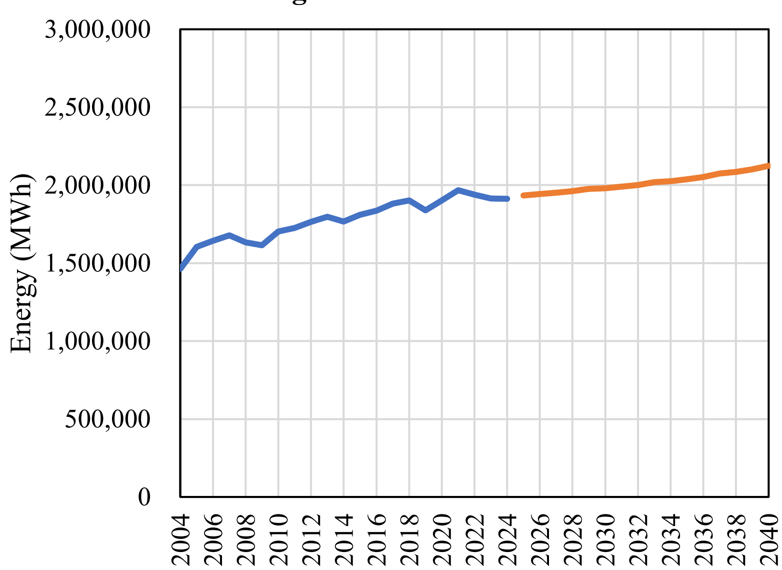
MMPA Projected Energy by Conservation Savings Adjustment
Planning Years 2025 to 2039



MMPA Energy Growth Rate for IRP: 0.6%

For this IRP, MMPA's projected energy growth rate is 0.6%. This includes the adjustments for future large customers, EVs, and conservation.

MMPA Historical & Projected
Adjusted Energy Requirements with Conservation
Planning Years 2004 to 2039



Projected MMPA Energy Requirements

The following table shows MMPA's energy projections for the planning period.

MMPA Energy Projections (MWh)

Planning Year	MMPA Energy	WAPA Adjustment	Large Customer Adjustment	EV Adjustment	Conservation Adjustment	Adjusted MMPA Energy
2025	2,048,668	(95,358)	0	5,023	(24,532)	1,933,801
2026	2,063,404	(95,358)	14,016	10,146	(49,257)	1,942,952
2027	2,078,292	(95,685)	28,032	15,371	(74,123)	1,951,888
2028	2,093,333	(95,358)	42,163	20,700	(99,224)	1,961,614
2029	2,114,354	(95,358)	56,064	26,135	(124,481)	1,976,713
2030	2,123,951	(95,358)	70,080	31,677	(149,859)	1,980,491
2031	2,139,490	(95,685)	84,096	37,330	(175,383)	1,989,847
2032	2,155,195	(95,358)	98,381	43,094	(201,032)	2,000,280
2033	2,176,979	(95,358)	112,128	51,642	(226,802)	2,018,589
2034	2,187,041	(95,358)	126,144	60,360	(252,675)	2,025,513
2035	2,203,227	(95,685)	140,160	69,252	(278,713)	2,038,242
2036	2,219,594	(95,358)	154,598	78,321	(304,905)	2,052,251
2037	2,242,248	(95,358)	168,192	90,352	(331,262)	2,074,172
2038	2,252,789	(95,358)	182,208	102,623	(357,764)	2,084,498
2039	2,269,583	(95,685)	196,224	115,140	(384,478)	2,100,784
2040	2,286,482	(95,358)	210,816	133,642	(411,392)	2,124,190
					Growth Rate:	0.6%

Section 7. Projected Demand – 2025 to 2039

This section discusses MMPA's projected demand requirements.

Summer Non-Coincident Peak (NCP) Grew 0.7% from 2019-2024

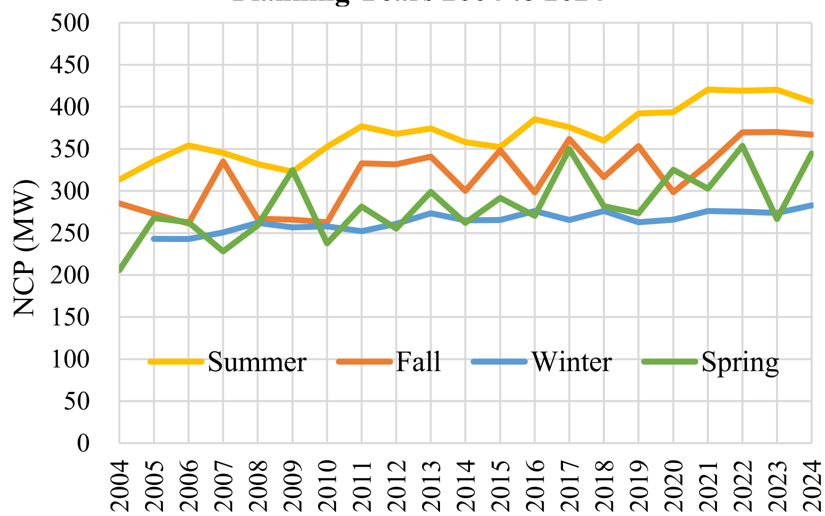
MMPA's summer non-coincident peak (NCP), or MMPA's peak load without regard to MISO's peak, grew at a compound annual growth rate of 1.3% between planning years 2004 and 2024. In recent years, between 2019 and 2024, the growth rate slowed to 0.7%.

The following graph shows historical MMPA member NCP demand requirements by season for the years 2004 to 2024. The seasons are defined as follows:

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

The historical data is based on MMPA's current power supply obligations.

MMPA Historical NCP Demand
Planning Years 2004 to 2024



NCP Volatile in Spring and Fall

The fall and spring NCP fluctuate significantly from year to year. The magnitude of the NCP can vary between the summer and winter peaks. This variability is closely linked to year-to-year changes in seasonal temperatures.

NCP Projected Using Weather Normalized Load Factor Approach

MMPA's NCP demand was projected seasonally. The seasonal NCP demand was calculated by multiplying MMPA's projected annual energy by a seasonal load factor and the number of hours in a year. The seasonal load factor used for the projections was the average of the most recent five years of weather normalized historical load factors. The seasonal NCP demand load factors are shown in the table below:

MMPA Seasonal Load Factors for NCP Demand

Summer	Fall	Winter	Spring
54.0%	64.8%	78.0%	70.4%

Details on the inputs and methodology can be found in Appendix A.

New Conservation Embedded in Projections

The projected annual energy used in the base NCP demand calculation included future conservation savings. Therefore, the assumption used for conservation savings in the energy projections is the same for the demand projections. Additionally, this is why the demand projections do not require further adjustment for conservation savings. This IRP assumed future conservation energy savings of 1.3%.

Details on the inputs and methodology can be found in Appendix A.

Projected NCP Summer Growth with Conservation: -0.5%

MMPA's projected summer NCP demand growth from 2025 to 2039 is -0.5%.

WAPA Allocation Decreases NCP

MMPA's NCP demand is adjusted to account for the power supplied by WAPA. The WAPA allocations were assumed to remain at current levels through the IRP planning period. If WAPA decreases the power available to its customers, MMPA's NCP demand would increase.

Future Large Customers Increase NCP

The impact of future large customers (<10 MW) is anticipated to increase MMPA's peak demand, and they were accounted for separately in the projections.

Large customers, such as data centers, have a different load factor than the rest of MMPA's system. This is because these customers operate at capacity most of the year. An 80% load factor was used for all seasons. The peak demand from future large customers was then added to MMPA's base demand projection.

Very large customers (>10 MW) have a separate tariff, and their energy requirements do not impact MMPA projections as discussed in Section 1.

Details on the inputs and methodology can be found in Appendix A.

Future EV Adoption Increases NCP

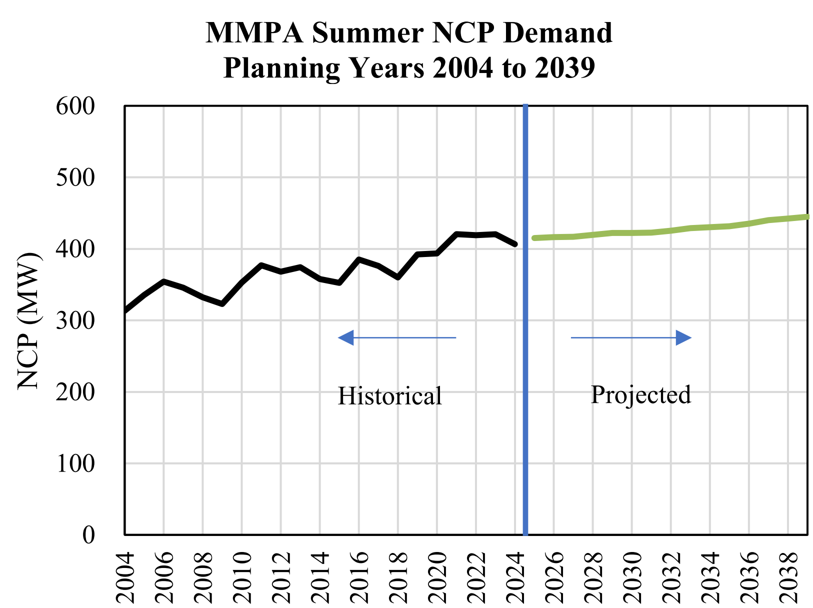
EVs are anticipated to increase MMPA's peak demand. The impact of EVs on MMPA's NCP was accounted for separately because the peak demand from EVs was assumed to not align with MMPA's base system. A 39% load factor was used for all seasons. The EV demand was then added to MMPA's base demand projections.

Details on the inputs and methodology can be found in Appendix A.

NCP Summer Growth Rate With EVs and Large Customers: 0.5%

MMPA's peak summer NCP demand is projected to grow at a rate of 0.5%. The projection accounts for conservation savings, future large customer additions, EVs and WAPA allocations.

The following graph shows historical and projected NCP for planning years 2004-2039.



NCP Projected by Season

The following tables show MMPA's seasonal NCP projections and include adjustments for conservation, large customers, EVs, and WAPA allocations. The projections do not include transmission losses or planning reserve margins which are accounted for in Section 8.

MMPA Projected Non-Coincident Peak – Summer (MW)

Planning Year	MMPA NCP with Conservation	WAPA Adjustment	Large Customer Addition	EV Addition	MMPA Adjusted NCP
2025	428.1	(14.5)	0.0	1.5	415.1
2026	426.0	(14.5)	2.0	3.0	416.5
2027	422.8	(14.5)	4.0	4.5	416.8
2028	421.8	(14.5)	6.0	6.0	419.3
2029	420.9	(14.5)	8.0	7.6	422.0
2030	417.6	(14.5)	10.0	9.3	422.3
2031	414.3	(14.5)	12.0	10.9	422.7
2032	413.3	(14.5)	14.0	12.6	425.4
2033	412.5	(14.5)	16.0	15.1	429.1
2034	409.2	(14.5)	18.0	17.7	430.3
2035	406.0	(14.5)	20.0	20.3	431.7
2036	405.0	(14.5)	22.0	22.9	435.4
2037	404.2	(14.5)	24.0	26.4	440.2
2038	400.8	(14.5)	26.0	30.0	442.4
2039	397.6	(14.5)	28.0	33.7	444.8
				Growth Rate:	0.5%

MMPA Projected Non-Coincident Peak – Fall (MW)

Planning Year	MMPA NCP with Conservation	WAPA Adjustment	Large Customer Addition	EV Addition	MMPA Adjusted NCP
2025	356.6	(15.6)	0.0	1.5	342.5
2026	354.8	(15.6)	2.0	3.0	344.2
2027	352.1	(15.6)	4.0	4.5	345.0
2028	351.3	(15.6)	6.0	6.0	347.7
2029	350.5	(15.6)	8.0	7.6	350.6
2030	347.8	(15.6)	10.0	9.3	351.4
2031	345.1	(15.6)	12.0	10.9	352.4
2032	344.3	(15.6)	14.0	12.6	355.2
2033	343.6	(15.6)	16.0	15.1	359.1
2034	340.8	(15.6)	18.0	17.7	360.8
2035	338.1	(15.6)	20.0	20.3	362.8
2036	337.3	(15.6)	22.0	22.9	366.6
2037	336.7	(15.6)	24.0	26.4	371.5
2038	333.8	(15.6)	26.0	30.0	374.3
2039	331.2	(15.6)	28.0	33.7	377.3
				Growth Rate:	0.7%

MMPA Projected Non-Coincident Peak – Winter (MW)

Planning Year	MMPA NCP with Conservation	WAPA Adjustment	Large Customer Addition	EV Addition	MMPA Adjusted NCP
2025	298.2	(17.3)	0.0	1.5	282.4
2026	296.8	(17.3)	2.0	3.0	284.4
2027	294.5	(17.3)	4.0	4.5	285.7
2028	294.7	(17.3)	6.0	6.0	289.5
2029	292.5	(17.3)	8.0	7.6	290.8
2030	291.0	(17.3)	10.0	9.3	293.0
2031	288.8	(17.3)	12.0	10.9	294.4
2032	289.0	(17.3)	14.0	12.6	298.3
2033	286.7	(17.3)	16.0	15.1	300.5
2034	285.3	(17.3)	18.0	17.7	303.6
2035	283.1	(17.3)	20.0	20.3	306.1
2036	283.4	(17.3)	22.0	22.9	310.9
2037	281.1	(17.3)	24.0	26.4	314.2
2038	279.6	(17.3)	26.0	30.0	318.4
2039	277.4	(17.3)	28.0	33.7	321.8
				Growth Rate:	0.9%

MMPA Projected Non-Coincident Peak – Spring (MW)

Planning Year	MMPA NCP with Conservation	WAPA Adjustment	Large Customer Addition	EV Addition	MMPA Adjusted NCP
2025	330.6	(14.8)	0.0	1.5	317.2
2026	329.0	(14.8)	2.0	3.0	319.1
2027	326.5	(14.8)	4.0	4.5	320.2
2028	326.7	(14.8)	6.0	6.0	324.0
2029	324.2	(14.8)	8.0	7.6	325.0
2030	322.6	(14.8)	10.0	9.3	327.1
2031	320.1	(14.8)	12.0	10.9	328.2
2032	320.4	(14.8)	14.0	12.6	332.1
2033	317.8	(14.8)	16.0	15.1	334.1
2034	316.2	(14.8)	18.0	17.7	337.1
2035	313.8	(14.8)	20.0	20.3	339.3
2036	314.1	(14.8)	22.0	22.9	344.2
2037	311.5	(14.8)	24.0	26.4	347.2
2038	310.0	(14.8)	26.0	30.0	351.2
2039	307.5	(14.8)	28.0	33.7	354.4
				Growth Rate:	0.8%

Section 8. Capacity Requirements – 2025 to 2039

This section discusses MMPA's projected capacity requirements.

Coincidence Factor Used to Project Demand Coincident with MISO Peak

MMPA's NCP demand projections were multiplied by a coincidence factor to project MMPA's demand at the time of MISO's peak demand, or coincident peak (CP) demand. The coincidence factor was the average of the seasonal historical coincidence factor from 2005-2024. The following are the seasonal coincidence factors used for CP demand projections:

MMPA Coincidence Factors for CP Demand

Summer	Fall	Winter	Spring
93.5%	92.0%	95.4%	95.2%

Details on the methodology can be found in Appendix A.

Coincident Peak (CP) Demand Projections Include Adjustments

MMPA's NCP demand projections included adjustments for future large customers, EVs, conservation, and WAPA allocations. Since the NCP projections are used to calculate the CP demand projections, the same assumptions are embedded in the CP demand projections. Therefore, the coincidence factor is the same for the base demand, large customers, conservation, and the WAPA allocation.

CP Summer Growth Rate: 0.5%

MMPA's summer CP demand is projected to grow at an annual rate of 0.5% between planning years 2025 and 2039.

Capacity Requirement Sum of CP Demand, Transmission Losses and Planning Reserve Margin

MMPA's capacity requirement is the sum of MMPA's CP demand, transmission losses, and MISO planning reserve margin requirements (PRMR).

The transmission losses are calculated as a percentage of the CP demand. Transmission losses increase the capacity requirement. The following table gives the seasonal transmission losses used in the capacity calculations.

Transmission Losses by Season (%)

Summer	**Fall**	**Winter**	**Spring**
2.4%	3.5%	3.1%	4.2%

The PRMR is calculated as a percentage of the sum of CP demand and transmission losses. The PRMR increases MMPA's capacity requirement. Beginning in planning year 2028, MISO expects the PRMR to decrease, coinciding with a change in MISO's capacity accreditation methodology. The following table gives the seasonal PRMR used in the capacity calculations.

PRMR by Season (%)

Planning Year	Summer	Fall	Winter	Spring
2025-2027	11.0%	17.0%	22.6%	26.8%
2028-2039	5.4%	8.1%	9.8%	2.5%

Summer Capacity Growth Rate: 0.1%

MMPA's summer capacity requirement is projected to grown at a rate of 0.1% between planning years 2025 and 2039.

The capacity requirement is growing at a slower rate than the CP demand because the PRMR decreases significantly beginning in 2028. The change to PRMR is so large in spring that the projected capacity growth is -0.7%.

Capacity Requirements Projected by Season

The following tables show MMPA's projected capacity requirements by season.

MMPA Capacity Requirements – Summer (MW)

Planning Year	MMPA CP Demand	Trans. Losses	Planning Reserve Margin	Capacity Req' t
2025	387.9	9.4	43.7	441.1
2026	389.2	9.5	43.9	442.5
2027	389.5	9.5	43.9	442.8
2028	391.9	9.5	21.7	423.1
2029	394.4	9.6	21.8	425.8
2030	394.7	9.6	21.8	426.1
2031	395.1	9.6	21.9	426.5
2032	397.6	9.7	22.0	429.2
2033	401.0	9.7	22.2	432.9
2034	402.1	9.8	22.2	434.2
2035	403.5	9.8	22.3	435.6
2036	406.8	9.9	22.5	439.2
2037	411.3	10.0	22.8	444.1
2038	413.4	10.0	22.9	446.3
2039	415.7	10.1	23.0	448.8
Growth Rate:	0.5%	--	--	0.1%

MMPA Capacity Requirements – Fall (MW)

Planning Year	MMPA CP Demand	Trans. Losses	Planning Reserve Margin	Capacity Req' t
2025	314.9	11.0	55.4	381.3
2026	316.5	11.0	55.7	383.2
2027	317.2	11.1	55.8	384.1
2028	319.7	11.2	26.8	357.7
2029	322.4	11.3	27.0	360.7
2030	323.1	11.3	27.1	361.5
2031	324.0	11.3	27.2	362.5
2032	326.6	11.4	27.4	365.4
2033	330.2	11.5	27.7	369.4
2034	331.8	11.6	27.8	371.2
2035	333.6	11.6	28.0	373.2
2036	337.1	11.8	28.3	377.1
2037	341.6	11.9	28.6	382.2
2038	344.1	12.0	28.8	385.0
2039	346.9	12.1	29.1	388.1
Growth Rate:	0.7%	--	--	0.1%

MMPA Capacity Requirements – Winter (MW)

Planning Year	MMPA CP Demand	Trans. Losses	Planning Reserve Margin	Capacity Req' t
2025	269.5	8.2	62.8	340.5
2026	271.4	8.3	63.2	343.0
2027	272.7	8.3	63.5	344.5
2028	276.2	8.4	27.9	312.6
2029	277.5	8.5	28.0	314.0
2030	279.6	8.6	28.2	316.4
2031	280.9	8.6	28.4	317.9
2032	284.6	8.7	28.7	322.1
2033	286.8	8.8	29.0	324.5
2034	289.8	8.9	29.3	327.9
2035	292.1	8.9	29.5	330.5
2036	296.7	9.1	30.0	335.7
2037	299.8	9.2	30.3	339.3
2038	303.8	9.3	30.7	343.8
2039	307.1	9.4	31.0	347.5
Growth Rate:	0.9%	--	--	0.1%

MMPA Capacity Requirements – Spring (MW)

Planning Year	MMPA CP Demand	Trans. Losses	Planning Reserve Margin	Capacity Req' t
2025	302.1	12.8	84.4	399.3
2026	303.9	12.8	84.9	401.7
2027	304.9	12.9	85.2	403.0
2028	308.5	13.0	8.0	329.6
2029	309.5	13.1	8.1	330.7
2030	311.5	13.2	8.1	332.8
2031	312.6	13.2	8.1	334.0
2032	316.3	13.4	8.2	337.9
2033	318.2	13.5	8.3	340.0
2034	321.1	13.6	8.4	343.0
2035	323.1	13.7	8.4	345.2
2036	327.8	13.9	8.5	350.2
2037	330.7	14.0	8.6	353.2
2038	334.5	14.1	8.7	357.3
2039	337.6	14.3	8.8	360.6
Growth Rate:	0.8%	--	--	-0.7%

Section 9. Existing Resources

MMPA has a diverse portfolio of existing resources that are discussed in this section.

Existing Resources Include: Gas, Wind, Solar, and Contracts

MMPA has a diverse set of resources to meet energy and capacity needs. The resources include natural gas generators, wind farms, a solar farm, a biogas generator, and capacity contracts.

No Retirements Planned

MMPA plans to continue operating all of its existing resources through the IRP planning horizon.

Gas and Contracted Resources Satisfy Majority of Capacity Requirements

MMPA's natural gas-fired resources and capacity contracts satisfy the majority of MMPA's capacity requirements. In summer 2025, these resources are projected to satisfy 98% of MMPA's total capacity obligation with the remainder covered by renewable resources.

MMPA Gas Resources Can Operate on RNG

All of MMPA's natural gas-fired resources can be fueled by RNG. No modifications are required for existing resources to use RNG.

MISO Capacity Accreditation Methodology Changes In 2028

MISO resource accreditation is a means of measuring how much capacity a resource can be relied on for meeting seasonal capacity requirements. A resource's accredited capacity can be calculated as a percentage of its installed capacity. Beginning in planning year 2028, MISO is changing the methodology for determining resource accreditation (see Section 3).

The new methodology results in substantial decreases to resource accreditation in the following cases:

- Combined-cycle generators in winter and spring
- Simple-cycle generators in winter and spring
- Solar facilities in all seasons
- Wind facilities in summer, fall, and spring

These changes are to some extent offset by the decrease in the MISO PRMR discussed in Section 8. However, if not fully offset, it would decrease MMPA's capacity position.

MISO Capacity Accreditation by Resource Type

In the new MISO methodology, the capacity accreditation for a transmission-interconnected resource can be determined by multiplying the installed capacity by the seasonal accredited capacity (SAC) percentage for the resource type. The SAC percentage is not a fixed number. It is dependent on the mix of resources on MISO's system and expected to change in future years, thus introducing greater uncertainty into future resource accreditation projections. In this IRP, future resource accreditation is based on the following:

- PY 2025-2027: MMPA's 2025 resource accreditation
- PY 2028-2029: MISO's projected SAC percentage for PY 2025 [1]
- PY 2030-2039: MISO's projected SAC percentage for PY 2030 [1]

The following SAC percentages are used for determining the accredited capacity of transmission-interconnected, gas resources under MISO's new methodology.

MISO SAC % for Combined-Cycle Facilities

Planning Year	Summer	Fall	Winter	Spring
2028-29	95	92	77	78
2030-39	95	91	77	78

MISO SAC % for Simple-Cycle Facilities

Planning Year	Summer	Fall	Winter	Spring
2028-29	88	85	64	68
2030-39	88	85	66	68

MISO's new methodology does not apply to gas resources that are connected to the distribution system. These resources are accredited based on their Equivalent Forced Outage Rate Demand (XEFORd) which is a measure of the probability that the generator will not be available when there is a need. In this IRP, the accredited capacity for these resources is the same for all years.

The following SAC percentages are used for determining the accredited capacity of wind resources under MISO's new methodology.

[1] MISO Presentation to Resource Adequacy Subcommittee, April 9, 2025, https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

MISO SAC % for Wind Resources

Planning Year	Summer	Fall	Winter	Spring
2028-29	8	15	23	15
2030-39	9	14	23	15

The following SAC percentages are used for determining the accredited capacity of solar resources under MISO's new methodology.

MISO SAC % for Solar Resources

Planning Year	Summer	Fall	Winter	Spring
2028-29	45	28	19	28
2030-39	10	4	2	5

Gas-Fired Resources

MMPA has three existing natural gas resources: Faribault Energy Park, Shakopee Energy Park, and Minnesota River Station.

Faribault Energy Park (FEP) is a combined-cycle gas plant that was completed in 2007. The plant is located in Faribault, Minnesota and has a summer installed capacity of 263 MW and a winter installed capacity of 293 MW. The plant is capable of operating on fuel oil during peak natural gas demand, thus enhancing its reliability. FEP uses a selective catalytic reduction system to reduce nitrogen oxide emissions.

FEP is an innovative power plant that uses a series of created wetlands for water management at the plant. Rainwater is collected and filtered before being used for steam production and equipment cooling. The wetland area is open to the public as a park with several short trails. The plant is also designed to be a "working classroom," with an observation room where visitors can view both the steam turbine and the plant's control room.

Minnesota River Station (MRS) is a simple-cycle gas plant located in Chaska, Minnesota. The 44 MW plant became operational in 2001 and operates during times of peak energy demand. The City of Chaska, one of MMPA's members, owns the plant and sells the entire output to MMPA under a long-term contract.

Shakopee Energy Park (SEP) is a 46 MW distributed energy resource located in the MMPA member community of Shakopee, Minnesota. SEP uses reciprocating engines to provide power during times of peak energy use and increases its reliability by storing LNG onsite so it can operate during peak natural gas demand. SEP generates local, reliable power for the City of Shakopee, as well as contributing to MMPA's overall power supply.

The following tables give the seasonal accredited capacity for FEP, MRS, and SEP which are determined using MISO's forecast of SAC percentages.

Faribault Energy Park Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-27	253.7	258.0	304.8	292.1
2028-29	250.2	248.2	225.9	210.1
2030-39	250.2	245.5	225.9	210.1

Minnesota River Station Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-27	39.4	41.5	41.4	38.2
2028-29	38.5	37.3	28.3	29.9
2030-39	38.5	37.3	29.2	29.9

SEP is connected to the distribution system and MISO uses a different methodology to calculate capacity accreditation for these resources. Since the methodology is not changing, MMPA projects the same capacity accreditation for all years of the IRP as was received in 2025.

Shakopee Energy Park Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-39	47.5	47.4	47.3	48.4

Biogas-Fired Resource and RNG Producer

Hometown BioEnergy (HTBE) is located in the MMPA member community of Le Sueur, Minnesota. The plant uses anaerobic digestion to produce biogas from agricultural and food processing wastes. The plant began operation in 2013 with 8 MW of dispatchable, renewable electricity. In 2023, the plant began making RNG. HTBE cleans the biogas so that it is equivalent to natural gas and injects it into the natural gas pipeline. HTBE supports the local community by collecting and processing local waste that might otherwise end up in the landfill and turning it into a renewable resource.

HTBE is connected to the distribution system and MISO uses a different methodology to calculate capacity accreditation for these resources. Since the methodology is not changing, MMPA projects the same capacity accreditation for all years of the IRP.

Hometown BioEnergy Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-39	5.9	5.0	5.5	5.6

Wind Resources

MMPA has three wind resources: Walleye Wind Farm (WWF), Black Oak Getty Wind Farm (BOGWF), and Oak Glen Wind Farm (OGWF).

WWF is a 112 MW facility located in Rock County, Minnesota. This is a new resource since MMPA's last IRP. MMPA has a 30-year contract with NextEra to purchase all the output from the facility. WWF began commercial operation in 2022.

OGWF is a 44 MW facility located near Blooming Prairie, Minnesota. The MMPA-owned facility began commercial operation in 2011.

BOGWF is a 78 MW facility located in Stearns County, Minnesota. MMPA has a 30-year Power Purchase Agreement (PPA) for the entire electric output from BOGWF. The wind farm, composed of 39 wind turbines, began commercial operation in December 2016.

The following tables give the seasonal accredited capacity for WWF and OGWF which are determined using MISO's SAC percentage estimates. BOGWF is not an accredited capacity resource and only serves energy needs.

Walleye Wind Farm Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-27	25.3	62	32.4	42.3
2028-29	9.0	16.8	25.8	16.8
2030-39	10.1	15.7	25.8	16.8

Oak Glen Wind Farm Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-27	9.7	13.0	11.5	11.4
2028-29	3.5	6.6	10.1	6.6
2030-39	4.0	6.2	10.1	6.6

Solar Resources

The Buffalo Solar Facility (BSF) is a 7.1 MW AC utility-scale solar facility located in MMPA's member community of Buffalo. MMPA signed a 22.5-year contract with HQC Tatanka Wi Solar Power Generation LLC, for the entire output of the solar facility. BSF entered commercial operation at the end of 2017.

The following table gives the seasonal accredited capacity for BSF which is determined using MISO's forecast of SAC percentages.

Buffalo Solar Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025-27	4.0	3.1	0	4.0
2028-29	3.2	2.0	1.3	2.0
2030-39	0.7	0.3	0.1	0.4

Manitoba Hydro Capacity Contracts

MMPA and the Manitoba Hydro-Electric Board (MHEB) have a long-standing relationship MMPA has a summer capacity need and MHEB has a winter capacity need and the two have been able to work together to execute mutually beneficial contracts.

MMPA contracted with MHEB for the purchase of between 90 and 105 MW of capacity for planning years 2026 through 2029.

MMPA and MHEB have segued the first contract into a 100 MW capacity exchange contract for planning years 2030 through 2035. In the winter, MMPA gives MHEB 100 MW of capacity and in the summer MMPA receives 100 MW of capacity.

Capacity Contracts Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2025	90	90	90	90
2026	90	90	90	90
2027	95	95	95	95
2028	100	100	100	100
2029	105	105	105	105
2030-35	100	--	(100)	--

Section 10. Committed Resources

MMPA is actively pursuing additional resources to meet its future carbon-free energy and capacity needs. This section describes resources that, while not yet constructed, have been committed to and are expected to come online. As such, these resources are considered part of MMPA's portfolio in subsequent sections when determining future resource needs.

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FEP Upgrade Provides Needed Capacity

MMPA is working with the original equipment manufacturer, General Electric, to replace the combustion turbine at FEP. The upgrade is an important project for meeting MMPA's future capacity needs. The upgrade is anticipated to be complete in 2030. MMPA is seeking additional transmission rights above its existing 300 MW to obtain full accreditation for the upgrade. FEP is an important capacity resource for MMPA and maintaining FEP is central to MMPA's resource plan.

The following table shows the projected additional capacity accreditation for the upgrade. The capacity accreditation is based on MISO's SAC percentages found in Section 9.

Faribault Energy Park Upgrade Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2030-40	61.8	64.6	41.6	55.4

FEP Upgrade Hydrogen-Ready

The combustion turbine replacement is expected to be hydrogen-ready. The upgrade would provide MMPA additional flexibility for meeting carbon-free requirements.

This is in addition to FEP already being capable of operating on RNG.

4.5 MW Elk River Solar Projected Operational in 2027

Elk River Solar is a 4.5 MW solar project that will connect to the distribution system in the member community of Elk River. The project will be owned by MMPA and is project to in-service in 2027.

The projected seasonal accredited capacity for Elk River Solar is based on MISO's SAC percentages found in Section 9.

Elk River Solar Capacity Accreditation (MW)

Planning Year	Summer	Fall	Winter	Spring
2027	2.6	2.0	0	2.6
2028-29	2.0	1.3	0.9	1.3
2030-40	0.5	0.2	0.1	0.2

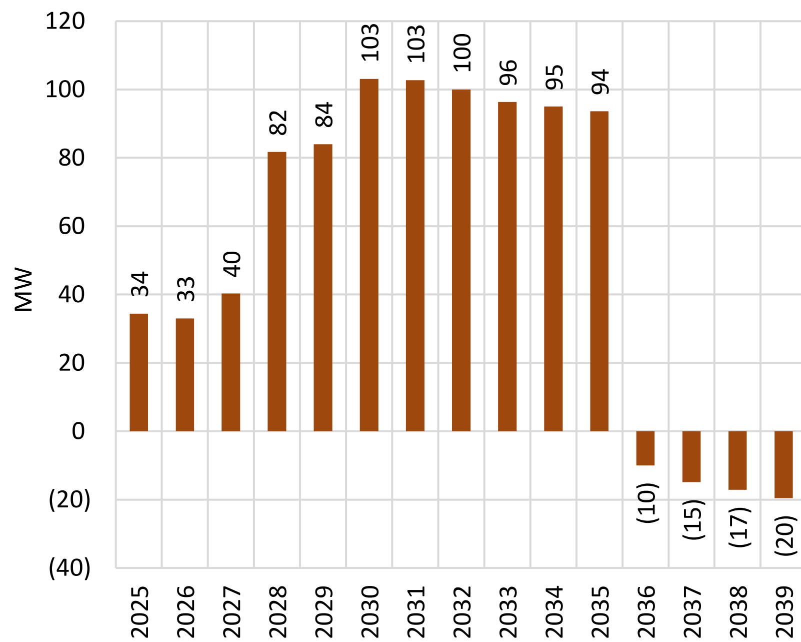
Section 11. Additional Capacity Requirements

This section describes MMPA's projected additional resource requirements over the IRP planning period. The capacity requirements discussed in Section 8 are used for IRP planning.

Need Summer Capacity in 2036

MMPA is projected to need summer capacity beginning in planning year 2036. The capacity need is 10 MW in 2036 and grows to 20 MW in 2039. The chart below shows the projected summer capacity position for the planning period. The significant drop in the capacity position in 2036 occurs because the MHEB capacity exchange ends.

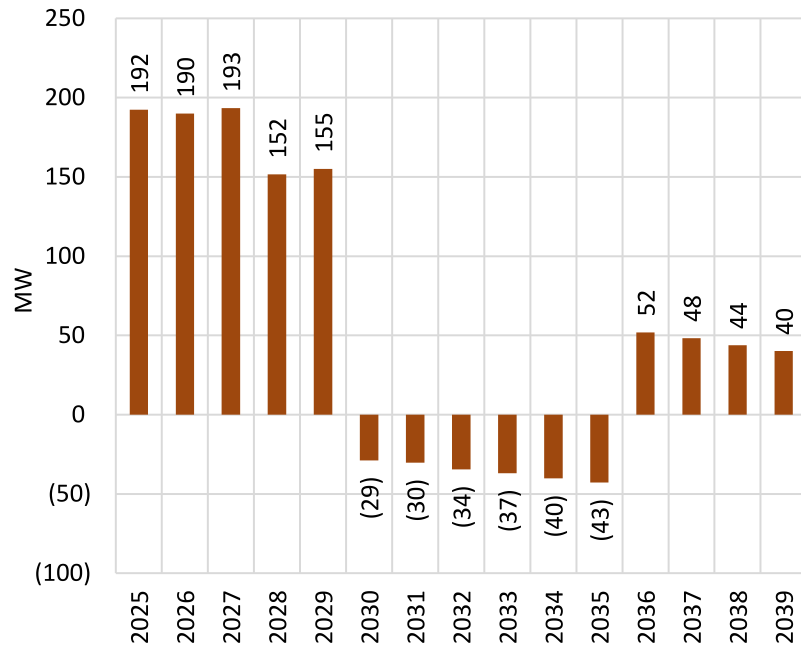
MMPA Summer Capacity Position - Excess (Deficit) Planning Years 2025 to 2039



Need Winter Capacity in 2030

MMPA is projected to need winter capacity beginning in planning year 2030. The capacity need is 29 MW in 2030 and grows to 43 MW in 2035. The chart below shows the projected winter capacity position for the planning period. The large change in the capacity position in 2030 is because the MHEB capacity purchase ended and the capacity exchange started, resulting in a decrease of 205 MW. The capacity position in 2030 also changes because the FEP upgrade comes online and the capacity accreditation for solar decreases.

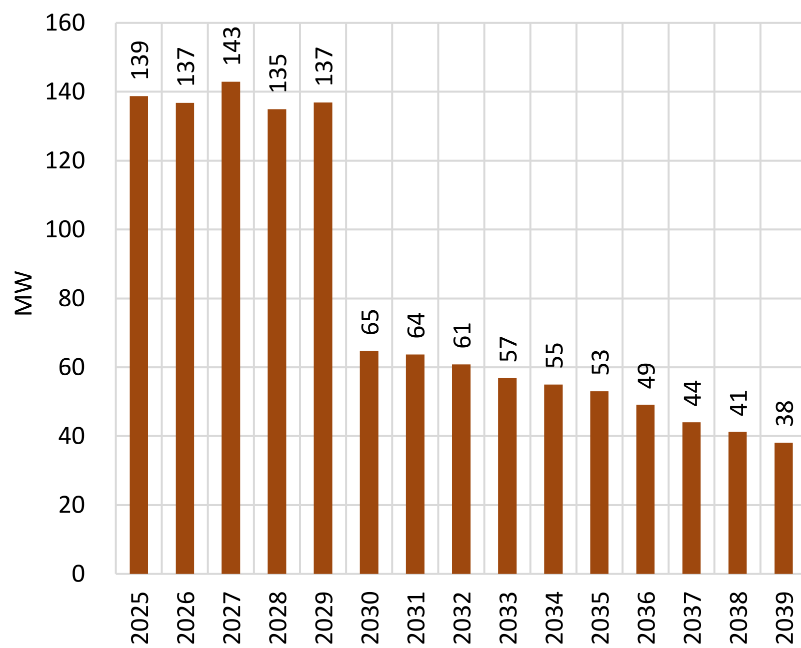
MMPA Winter Capacity Position - Excess (Deficit)
Planning Years 2025 to 2039



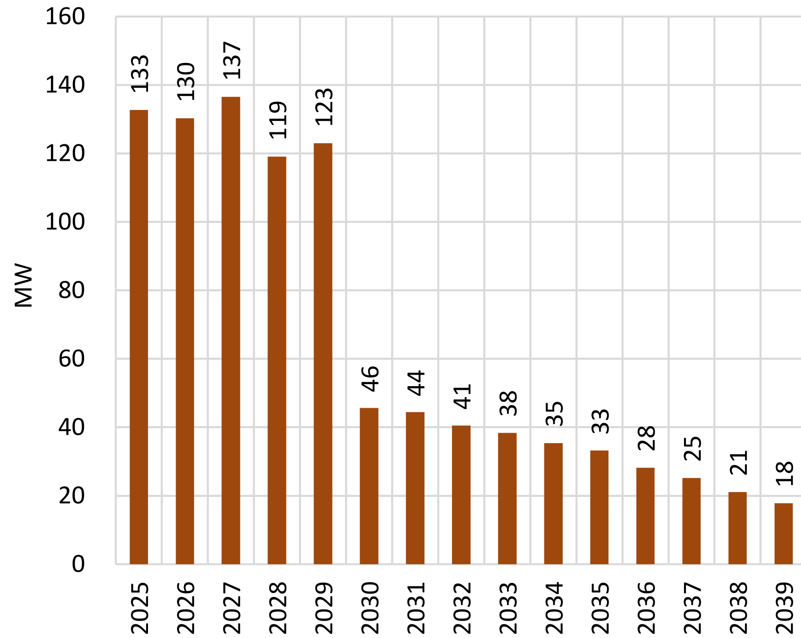
Fall and Spring Capacity Not Needed

MMPA is not projected to need capacity in fall or spring. The charts below show the projected fall and spring capacity position for the planning period. The large change in capacity position in 2030 is because the MHEB capacity purchase ends.

MMPA Fall Capacity Position - Excess (Deficit)
Planning Years 2025 to 2039



MMPA Spring Capacity Position - Excess (Deficit)
Planning Years 2025 to 2039



Capacity Need Increases If Planning Reserve Margin Increases

If the MISO PRMR increases, then MMPA's future capacity needs would also increase. The PRMR is a reliability safeguard used by MISO to ensure there are enough resources available at times of peak demand.

More Capacity Needed If Resource Accreditation Decreases

If MMPA's capacity resource accreditation decreases from its projections, then MMPA's future capacity requirements would increase.

Section 12. Planning Approach

This section outlines MMPA's planning approach.

Operate Existing Resources Through Planning Period

MMPA plans to operate its existing resources through the IRP planning period. This includes maintaining MMPA's natural gas resources, which provide reliable, cost-effective, dispatchable power. MMPA will continue to evaluate options to transition these resources to carbon-free.

Gas Resources Are RNG Ready

All of MMPA's gas resources are capable of operating on RNG. Depending on future technology, economics, and regulations, RNG could be an option for meeting carbon-free requirements.

While RNG has not yet been designated as a carbon-free resource by the Public Utilities Commission (PUC), MMPA recognizes the potential benefits of RNG and considers it a viable resource in its energy portfolio. MMPA is closely monitoring PUC dockets No. E999/CI-23-151 and E999/CI-24-352, where determinations on RNG's classification are expected. MMPA remains flexible and prepared to adapt its approach based on the outcome of these proceedings.

FEP Would Be Hydrogen-Ready

The FEP upgrade is an opportunity to make the plant hydrogen-ready. This would allow FEP to blend hydrogen with natural gas or RNG in the future. This option would provide a way of increasing MMPA's carbon-free energy while still maintaining FEP as a dispatchable capacity resource.

Add Renewable Resources to Meet Carbon-Free Standard

MMPA plans to bring new generation resources online when needed to meet Minnesota's carbon-free energy standards. Energy technologies continue to evolve as discussed in Section 4. By waiting, MMPA can maintain flexibility and benefit from economic and technological improvements.

Remain Flexible

MMPA prioritizes plans that are flexible and allow the Agency to respond to change. The electric industry faces high levels of uncertainty as discussed in sections 3 and 4. In addition, the extent of load growth from new large customers and EVs may vary from projections.

Section 13. Capacity Resource Analysis

This section outlines MMPA's analytical model and results for capacity resources.

Total Cost Model Used to Evaluate New Capacity Resource Alternatives

A total cost model was used to evaluate capacity resource alternatives. The model graphs the total cost of the resources, in dollars per kilowatt across different capacity factors. The model allows resource types to be compared under varying cost and operating conditions.

Evaluated Battery Storage and Gas Resources

For the cost model, the following resources were considered: short-duration battery storage, combined-cycle turbine, and combustion turbine (simple-cycle).

Short-duration battery storage was analyzed for capacity factors between 0 and 50%. Because batteries must charge for approximately the same amount of time as they discharge, a capacity factor greater than 50% is not possible.

Nuclear power plants were excluded from the resource analysis because of their ongoing moratorium in Minnesota.

Coal power plants were not considered because they have long lead times for development, the size of the resource does not align with MMPA's capacity needs, and gas plants offer a cheaper and cleaner alternative.

Solar and wind resources were excluded in the resource analysis because MISO projects the capacity accreditation for these technologies to be small.

Long-duration battery storage was not considered because it is still considered an emerging technology.

Included Capital, O&M, Fuel, and Regulatory Costs

The total cost model included operations and maintenance (O&M), capital, fuel, and regulatory costs. Regulatory costs are the likely costs an electric generation facility will incur to upgrade a facility to comply with future regulations to reduce emissions. A sensitivity analysis was done using a low, base, and high case for capital, fuel, and regulatory costs.

The following capital costs were used in the model:

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The National Renewable Energy Laboratory (NREL) Annual Technology Baseline, 2024 was the source for capital costs and adjusted to 2025 dollars.

The following fuel costs were used in the model:

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Battery storage equipment is modeled to charge using the grid. The cost of the "fuel" is based on the average, forward off-peak power price at MISO's MINN.HUB for May 2025 to April 2026. Natural gas fuel costs are based on the average fuel forward prices at Henry Hub for the same period.

Regulatory costs are the costs that future carbon dioxide regulation will likely impose on electricity generation. The regulatory costs were $5, $40, and $75 per ton of carbon dioxide emitted for the low, base, and high cases respectively. These values came from the December 19, 2023, PUC Order Addressing Environmental and Regulatory Costs in docket E-999/CI-07-199. The following regulatory costs were used in the model:

Regulatory Costs (2025 $/MWh)

Technology	Low Case	Base Case	High Case
Battery Storage	0	0	0
Combined-Cycle	1.67	13.33	24.99
Combustion Turbine	2.67	21.38	40.08

The Order further states that the environmental costs of emissions are evaluated separately. Unlike the regulatory costs that are a direct cost to an electric generation facility, the environmental costs are the costs that society will incur over time from a facility's emissions. See Section 14 for this evaluation.

Fixed and variable O&M costs were included in the model but were not included in the sensitivity analysis. Theses costs were sourced from the NREL 2024 Annual Technology Baseline and adjusted to reflect 2025 dollars.

Tax credits were not included in the model because the recent federal policy changes discussed in Section 3 significantly limit their applicability.

Cases Evaluated

The following seven cost cases were evaluated:

- Base Case: base capital, base fuel, base regulatory
- Case 1: base capital, base fuel, LOW regulatory
- Case 2: base capital, base fuel, HIGH regulatory
- Case 3: base capital, LOW fuel, base regulatory
- Case 4: base capital, HIGH fuel, base regulatory
- Case 5: LOW capital, base fuel, base regulatory
- Case 6: HIGH capital, base fuel, base regulatory

Battery Storage and Combined-Cyle Were Least-Cost Resources

In the seven cases evaluated:

- Battery storage was the least cost resource for three cases,
- Combined-cycle was the least cost resource for three cases, and
- Battery storage and combined-cycle costs were very similar in the base case so both were considered the low-cost resource.

The only time a combustion turbine was the least-cost resource was for low capacity factors.

The following table summarizes the findings of the total cost model where the green check mark represents the low-cost resource. In the base case, battery storage and combined-cycle were both marked the low-cost resource because they had comparable costs.

Summary of Low-Cost Resource Using Total Cost Model

	Base Case	Regulatory Cost		Fuel Cost		Capital Cost	
		Low	High	Low	High	Low	High
Battery Storage	✓		✓		✓	✓	
Combined-Cycle	✓	✓		✓			✓
Combustion Turbine							

Battery Storage and Combined-Cycle Are Preferred Resources in Base Case

In the base case, battery storage and combined-cycle have roughly the same cost and are the least-cost resource for capacity factors greater than approximately 18%. A combustion turbine is slightly lower cost at low capacity factors.

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Combined-Cycle Least-Cost for Low Regulatory Costs

In case 1, when regulatory costs are low, combined-cycle is the least-cost resource for capacity factors greater than approximately 20%. A combustion turbine is slightly lower cost at low capacity factors.

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Battery Storage Least-Cost for High Regulatory Costs

In case 2, when regulatory costs are high, battery storage is the least-cost resource for capacity factors greater than approximately 12%. A combustion turbine is slightly lower cost at low capacity factors.

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Combined-Cycle Least Cost for Low Fuel Costs

In case 3, when fuel costs are low, combined-cycle is the least-cost resource for capacity factors greater than approximately 20%. A combustion turbine is slightly lower cost at low capacity factors.

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Battery Storage Least-Cost for High Fuel Costs

In case 4, when fuel costs are high, battery storage is the least-cost resource for capacity factors greater than approximately 10%. A combustion turbine is slightly lower cost at low capacity factors.

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Battery Storage Least-Cost for Low Capital Costs

In case 5, when capital costs are low, battery storage is the least-cost resource for capacity factors greater than approximately 15%. A combustion turbine is slightly lower cost at low capacity factors.

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Combined-Cycle Least-Cost for High Capital Costs

In case 6, when capital costs are high, combined-cycle is the least-cost resource for capacity factors greater than approximately 18%. A combustion turbine is slightly lower cost at low capacity factors.

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Battery Storage Preferred Option for New Capacity Resources

Short-duration battery storage is MMPA's preferred technology for new capacity resources. The total cost of battery storage is essentially the same as a combined-cycle turbine in the base case of the total cost model and is the least-cost resource under high regulatory, high fuel, and low capital cost conditions. Beyond costs, battery storage projects better align with MMPA's capacity needs because they can be a few megawatts in size up to hundreds of megawatts and can be implemented in phases as need grows. When environmental costs are considered, as is done in Section 14, battery storage is the least cost resource for all cases, further reinforcing it as the preferred resource.

Section 14. Environmental Costs of Capacity Resources

This section outlines MMPA's evaluation of the environmental costs of capacity resources.

Total Cost Model Used to Evaluate Environmental Costs

The environmental cost of resource alternatives was evaluated using a total cost model. The model is the same as the model in Section 13, except environmental costs are also included. The intent was to understand the social cost of emissions for each resource type.

The following environmental costs were used:

Environmental Costs (2025 $/MWh)

Technology	Low Case	Base Case	High Case
Battery Storage	0	0	0
Combined-Cycle	99.80	140.08	216.70
Combustion Turbine	160.11	222.26	347.65

Approximately 99% of the environmental costs used in the model were from carbon dioxide emissions. The environmental cost of carbon dioxide was based on the PUC's December 19, 2023, Order Addressing Environmental and Regulatory Costs.

Environmental Cost Analysis Evaluated Three Cases

The following environmental cost models were evaluated:

- Environmental Base Case: base capital, fuel, and environmental costs
- Low-Cost Case: LOW capital, fuel, and environmental costs
- High-Cost Case: HIGH capital, fuel, and environmental costs

Battery Storage Least Cost for Base Case For the base case, battery storage is significantly lower cost than other resources for virtually all capacity factors.

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Battery Storage Least Cost for Low-Cost Case For the low-cost case, battery storage is significantly lower cost than other resources for virtually all capacity factors.

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Battery Storage Least Cost for High-Cost Case

For the high-cost case, battery storage is significantly lower cost than other resources for virtually all capacity factors.

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Battery Storage Preferred Option for New Capacity Resources

Battery storage is the preferred resource for new capacity resources. When including the environmental cost of emissions, battery storage is significantly lower cost than a combined-cycle turbine and a combustion turbine under all scenarios and across all capacity factors. Further, as discussed in Section 13, when environmental costs are not considered, battery storage is cost-competitive with combined-cycle.

Section 15. Carbon-Free Energy Resource Analysis

This section includes MMPA's analysis of carbon-free resources.

Carbon-Free Energy Resources Considered

Solar, wind, hydrogen, and RNG resources were considered as resource options for meeting carbon-free energy requirements. Nuclear was not evaluated because Minnesota has a moratorium on the technology. Battery storage was not evaluated because it is a capacity resource and not an energy resource.

Energy conservation programs are not addressed in this section. However, reducing how much electricity is needed is effectively a carbon-free resource. MMPA accounts for conservation in its energy and demand projections and continues to invest in conservation energy programs as discussed in Section 5.

Constrained Transmission for Wind Resources

In Minnesota, transmission constraints exist between areas with high wind energy potential and regions with high electricity demand. Many wind farms have already been developed in these high-resource areas, and the transmission system is now operating near or at capacity. As a result, adding new wind projects often requires expensive transmission upgrades, making many projects financially unviable.

This challenge was evident in 2019 when the PPA MMPA had for Dodge County Wind was canceled because of prohibitively expensive transmission system upgrades. The impact of these constraints is also reflected in the MISO Generation Interconnection queue, which shows relatively few new wind projects being proposed.

Solar Only Viable Carbon-Free Resource Currently

Solar energy is currently the only commercially viable carbon-free energy resource for new power generation. Solar has become one of the most affordable generation resources, with capital costs continuing to decline and minimal ongoing operating expenses. Utility-scale solar can be developed in most areas of the state; however, development can be challenged by transmission availability, land availability, and setback requirements. Since solar output is limited to daylight hours and affected by weather conditions, reliability remains a challenge. Solar development can create local jobs in construction and the environmental impact on air and water from solar energy is low compared to fossil resources.

RNG and Hydrogen Create Optionality

RNG and hydrogen offer valuable optionality for MMPA to decarbonize its portfolio while maintaining system reliability and resource diversity. These low-carbon fuels can be integrated into existing natural gas infrastructure and power generation assets, allowing MMPA to leverage current resources while transitioning toward cleaner energy. They can serve as flexible, dispatchable fuel for power generation, helping to balance intermittent renewable resources. RNG is already commercially available, whereas green hydrogen, the most sustainable type of hydrogen, is not yet commercially available.

Together, RNG and hydrogen give MMPA optionality to meet carbon-free energy requirements, manage operational risks, and adapt to changing market and policy conditions.

Section 16. Preferred Plan

This section outlines MMPA's preferred plan.

Add Solar for Carbon-Free Energy

MMPA's preferred plan includes 435 MW of solar to meet incremental energy requirements and carbon-free energy requirements. The projects would also supply approximately 44 MW of summer capacity. Solar is the preferred carbon-free resource because of its low cost, availability, and scalability. Solar projects can be scaled from a few megawatts to hundreds of megawatts depending on land availability, transmission system capacity, and utility needs.

The following solar projects are in MMPA's preferred plan:

MMPA's Preferred Plan – Solar Development

Size	Status	Projected In-service
100 MW	In MISO 2023 Interconnection Queue	2029
100 MW	In MISO 2023 Interconnection Queue	2029
100 MW	Seeking land or PPA	2033
100 MW	Seeking land or PPA	2034
4.5 MW	Planning Phase	2027
4 x 7.5 MW	Seeking land	2028-2031

Add Battery Storage for Capacity Needs

MMPA's preferred plan includes approximately 50 MW of short-duration battery storage to meet future capacity needs. Battery storage is the preferred resource because of its cost-competitiveness (Section 13), low environmental impact (Section 14), ease of execution, and scalability. Battery storage aligns well with the size of MMPA's capacity need and allows MMPA to install battery storage as multiple smaller projects. This allows MMPA to phase the projects in as needed and to remain flexible to respond to future conditions. Approximately 35 MW would need to be in service by planning year 2030 and the remaining 15 MWs would need to be phased in by planning year 2035.

RNG and Hydrogen for Remaining Carbon-Free Need

In 2040, 92% of MMPA's members' retail energy requirements are projected to be supplied by wind and solar resources (Section 17). In MMPA's preferred plan, beginning in 2040, RNG, hydrogen or a combination of the two are proposed to supply the remaining 8% of carbon-free energy. RNG and hydrogen could be used in MMPA's existing natural gas assets, such as Faribault Energy Park, without additional modifications beyond those already committed.

RNG and hydrogen provide MMPA a pathway to 100% carbon-free electricity by 2040, while also preserving flexibility to adapt to evolving future conditions and technology. Given the significant uncertainty facing the energy industry (Section 3 and Section 4) and with 2040 being the outer edge of this IRP's planning horizon, it is prudent for MMPA to incorporate optionality into its resource plan. Doing so enables MMPA to remain responsive to potential technological advancements, policy developments, and market changes that may emerge over time.

Continue to Evaluate Technology Options

MMPA will continue to reevaluate its options such as long-duration battery storage, hydrogen, and carbon capture and storage. Specifically, when a resource need becomes near term, MMPA will evaluate the availability, reliability, cost, socioeconomic effects, and environmental effects of the available alternatives and determine the preferred alternative.

Plan Supports Local Jobs

MMPA's plan creates employment opportunities for Minnesota workers. No impact is anticipated on existing workers because MMPA plans to continue operating its existing resources. The development of new solar and battery resources would create construction job opportunities. The following is an estimate of the number of workers that would be employed to construct the facilities described in the preferred resource plan:

Construction Jobs Estimate

Project	Size	Full-Time Equivalent Employees Per Project	Number of Projects
Solar	100 MW	170	4
Solar	4.5-7.5 MW	30	5
Battery Storage	12.5 MW	50	4

MMPA prefers to work with Minnesota-based contractors. A benefit of working with local contractors is that they are usually connected to the local workforce.

	MMPA does not have any direct employees and contracts all management services to Avant Energy, Inc. whose workforce is approximately 20% racially diverse.
Plan Minimizes Impact on Environmental Justice Areas	MMPA's preferred plan minimizes the impact on environmental justice areas. The solar and battery storage projects are unlikely to impact environmental justice areas because they would likely be located outside of cities and towns where in the southern half of the state most environmental justice areas are found.

Section 17. Carbon-Free Energy Compliance and Its Rate Impact

This section describes MMPA's efforts toward meeting the State of Minnesota's carbon free standard and renewable energy standard and the estimated rate impact of complying with these standards.

Added 112 MW of Wind in 2022

In 2022, MMPA added the 112 MW Walleye Wind Farm to its portfolio. The asset was an important step toward meeting Minnesota's carbon-free requirements.

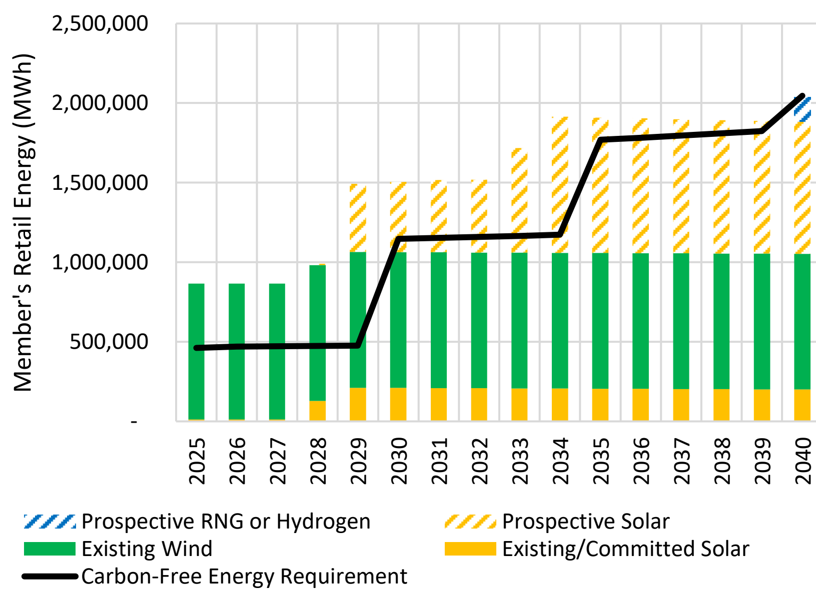
MMPA Will Exceed 2025 Renewable Energy Standard

MMPA is on track to meet the 2025 eligible energy technology standard of 25%. MMPA projects that 47% of its energy will be generated from carbon-free resources in 2025.

MMPA's Preferred Plan Meets Carbon-Free Standard

MMPA's preferred plan complies with the Minnesota carbon-free standard. The following graph projects MMPA's carbon-free energy as a percentage of MMPA members' retail sales:

MMPA Projected Carbon-Free Energy Planning Years 2025 to 2040



435 MW of Solar Needed to Meet Carbon-Free Standard

To meet the Minnesota carbon-free standard, MMPA projects it needs to add 435 MW of solar over the next ten years.

RNG in 2040 Provides Plan Optionality

In this plan, in 2040, the last increment of carbon-free energy is supplied by RNG. RNG offers MMPA a viable route to achieving carbon-free electricity by 2040 while giving the Agency flexibility to respond to future developments. Considering the high level of uncertainty in the energy sector and the fact that 2040 marks the furthest point of this IRP's outlook, incorporating flexibility into the resource strategy is prudent. This approach positions MMPA to effectively respond to emerging technologies, evolving policies, and shifting market dynamics.

Rate Impact of Renewable Energy Objectives 2018-2024: 0.73¢/kWh

The rate impact of the renewable energy objectives for 2018 to 2024 ranged from 0.40 cents per kWh to 0.94 cents per kWh with a levelized average rate impact of 0.73 cents per kWh.

Projected Rate Impact of Carbon-Free and Renewable Energy Objectives 2025-2040: (0.61)¢/kWh

The projected rate impact for complying with the carbon-free and renewable energy objectives for 2025 through 2040 ranges from a savings of 1.44 cents per kWh to a cost of 0.27 cents per kWh. The levelized average rate impact was a savings of 0.61 per kWh.

The rate impact included avoided regulatory costs of $40 per pound of carbon dioxide in years 2028-2040.

Additional details of the rate impact can be found in Appendix C.

All Incremental Energy Needs Met with Carbon-Free Resources

Minnesota Statutes § 216B.2422 subdivision 2 (c) states that a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources. By satisfying the carbon-free requirement, MMPA will meet all of its incremental energy needs through renewables. MMPA's conservation efforts are included in the projections.

On Track to Meet Greenhouse Gas Emission Reduction Goals

MMPA's generation assets and power purchase agreements that contribute to meeting the carbon-free standard also support meeting Minnesota's greenhouse gas emission reduction goals that were established in Minn. Stat. § 216H.02. Minnesota established a goal to reduce statewide greenhouse gas emissions, when compared to the level of emissions in 2005, by 30% in 2025, by 50% by 2030 and to net-zero by 2050.

MMPA's Projected Greenhouse Gas Reductions from 2005 Levels

	2025	2030
% Reduction in Total Emissions (lbs CO_2)	62%	76%
% Reduction in Emission Rate (lbs CO_2/MWh)	73%	83%

By meeting the requirement of 100% carbon-free energy by 2040, MMPA also meets the net-zero greenhouse gas requirement by 2050.

Pathway for Compliance with Recent EPA Regulations

MMPA has a pathway to meet the carbon dioxide regulations promulgated by the EPA under CAA 42 U.S.C. § 7411 (b) and (d). These rules have the potential to apply to FEP.

New requirements were issued in May 2024 under U.S.C. § 7411(b) that apply to new, modified, and reconstructed gas-fired combustion turbines. If the FEP upgrade triggers this rule, MMPA anticipates it will be able to meet the requirement. The new requirements would depend on the future capacity factor of the facility and require a plant with a capacity factor between 20% and 40% to meet emission standards equivalent to a highly efficient natural gas-fired simple-cycle turbine. As a combined-cycle plant with an efficiency better than simple-cycle, MMPA anticipates being able to meet this requirement.

U.S.C. § 7411(d) includes a proposed rule for existing, large (>300 MW), frequently operated (capacity factor >50%) gas-fired combustion turbines. As currently written, it would not apply to FEP. In addition, it is unclear if or when this rule will be passed.

Section 18. 5-Year Plan

This section describes MMPA's 5-year action plan with key activities, including construction and regulatory filings.

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Upgrade FEP

MMPA plans to upgrade the combustion turbine at FEP. MMPA will apply to the Minnesota Pollution Control Agency for a revised air permit prior to beginning construction. To get the full capacity from the upgrade, MMPA needs to increase its transmission interconnection capacity. MMPA intends to submit an application to MISO for additional interconnection capacity. The project is anticipated to be in service by 2030. It is expected that the upgrade will take approximately 4 months.

Develop Transmission-Connected Solar

MMPA has two solar projects in the 2023 MISO Generation Interconnection queue. Belle Solar is a 112 MW project located north of Hutchinson, Minnesota in McLeod and Meeker Counties. Livonia Solar is a 100 MW project located east of Zimmerman, Minnesota in Sherburne County. The size of these projects may decrease depending on the MISO interconnection study findings and the cost of transmission upgrades. For planning purposes, MMPA is assuming a total of 100 MW for each project.

These two projects would be owned by MMPA and developed to support compliance with Minnesota's 2040 carbon-free standard. As required by Minnesota Statutes § 216B.2422 subdivision 6 and § 216B.243 subdivision 9, this provides notice to the PUC of MMPA's intent to site and construct these projects.

MMPA will apply to the PUC for site and route permits for these projects using the standard review process. MMPA anticipates applying for these permits in 2026; however, the exact timing will depend on the progress of the MISO Generation Interconnection study. MISO's current estimate for executing the GIA for these projects is September 17, 2026. Based on this date, the earliest

	projected in-service date for these projects is 2029. Construction and commissioning are estimated to take a year and a half. The schedules for these projects are highly dependent on when they receive a GIA. If the GIA issuance is delayed, the in-service date is very likely to be delayed.
Battery Storage for Capacity Need	MMPA plans to develop 50 MW of battery storage. The battery storage will be multiple smaller projects located at MMPA resources. MMPA will apply for PUC site permits, as needed, based on project sizes. Construction is anticipated to start in 2029 with an in-service date of 2030.
Develop Distributed Solar	MMPA is developing a 4.5 MW, distribution-connected solar project. The project is located in Elk River, Minnesota. The projected in-service date for the facility is 2027. Construction is estimated to take one year.
Increase RNG Production	MMPA plans to increase its RNG production through the development of an RNG facility located at the Elk River Landfill in Elk River, Minnesota. The facility is anticipated to be in service in 2026. MMPA intends to sell the renewable attributes from RNG production until a later date when it could be used at MMPA gas facilities.

Section 19. MMPA's Plan Is in the Public Interest

This section discusses how MMPA's Integrated Resource Plan is in the public interest.

MMPA's Plan Has a Pathway to Carbon-Free by 2040

The preferred plan presents a clear and viable pathway to meet the 2040 carbon-free standard. MMPA's strategy leverages a diverse mix of resources, including wind, solar, and RNG or hydrogen, to achieve this goal.

MMPA's Plan Provides Flexibility

The preferred plan gives MMPA flexibility to accommodate future uncertainties such as technological changes, electric growth, and energy policy. MMPA created this flexibility by selecting scalable, modular resources and utilizing RNG or hydrogen in 2040.

MMPA's Plan Meets the Public Interest Criteria in Rule 7843

MMPA's plan meets the public interest criteria set out in Commission Rule 7843.0500 Subp. 3, which are:

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

MMPA's plan incorporates a diverse mix of resources to meet its energy and capacity needs while supporting grid adequacy and reliability. The preferred approach includes carbon-free resources that reduce potential socioeconomic and environmental impacts. Recognizing the current period of uncertainty, MMPA prioritized flexibility in its power supply strategy. This flexibility helps mitigate risk and enhance the Agency's ability to adapt to evolving financial, social, and technological conditions. Considering all of this, MMPA's plan still keeps customer bills and utility rates reasonable.

Appendix A. Load Projection Methodology

This appendix describes the methodology used to project MMPA's energy and demand requirements for this Integrated Resource Plan.

Members' Energy Usage Was Projected with A Linear Regression Model

MMPA member energy usage was projected using linear regression analysis. The energy usage for three of MMPA's member cities (East Grand Forks, Buffalo, and Elk River) was projected separately from that of the other nine members. Those four projections were then combined to obtain the entire Agency's projected energy. The MMPA9 projection includes the member cities of Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia, Shakopee and Winthrop. The historical monthly energy data sets for these four projections are from January 2005 to May 2025. Total MMPA energy requirements were projected by adding the results of these four regression models.

Throughout this appendix, all 12 MMPA member cities are referred to as MMPA12 and all 11 MMPA member cities, excluding Elk River, are referred to as MMPA11.

Explanatory Variables for Energy Projections Were Weather, Income, And Population

The explanatory variables used for the regression models were weather, income, and population.

<u>Weather</u>
Cooling degree days (CDD) and heating degree days (HDD) were both used as explanatory variables. All CDD and HDD data is supplied by the National Oceanic and Atmospheric Administration (NOAA). Historical CDD and HDD data for all member communities, except East Grand Forks, comes from the Minneapolis-St. Paul International Airport weather station. Historical CDD and HDD data for the East Grand Forks model comes from the Grand Forks International Airport weather station. CDD and HDD projections are historical "normal" data from 1991-2020 (the latest "normal" data set available published by NOAA).

<u>Income per Capita</u>
Both historical and projected income data come from Woods and Poole Economics' *Minnesota State Profile 2024 State and County Projections to 2060*. This data is provided at the county level. The MMPA9 model uses a weighted average income variable, created by weighting each of those nine member cities' income per capita by the city's annual energy usage.

Population

Historical population data from 1988 to 2023 comes from the Minnesota State Demographic Center and the Metropolitan Council *Historic Household and Population Estimates*. Data was unavailable for the year 1989, so linear smoothing of 1988 and 1990 data was used. Population projections from 2024 to 2041 are based on actual data for 2023, annually increased by long term county population growth rates calculated from Woods and Poole projections.

The four explanatory variables listed above were evaluated for inclusion in each of the four models using their t-stat results. If the t-stat showed that the variable was significant, it was included in the regression model. Population, HDD, and CDD were used in the MMPA9 model. All variables were used in the Buffalo model. Income, HDD, and CDD were used in the Elk River Model. For the East Grand Forks model, only HDD and Income were used. Minimal air conditioning load explains the low t-stats in the East Grand Forks model for CDD.

Each model used monthly data to project monthly energy, which was then aggregated to provide annual energy projections.

Agency Energy Requirements Were Reduced By WAPA Allocations

Projected energy requirements were reduced by the energy that WAPA supplies to two MMPA member cities (Olivia and East Grand Forks). These WAPA allocations were assumed to remain at current levels throughout the projection period.

Annual Energy Was Increased for Large Customers and Electric Vehicles

Following the reduction of the energy requirements for WAPA allocations, the annual energy was adjusted to account for a projected increase in usage by large customers and electric vehicles (EVs).

The large customers were assumed to add 2 MW of incremental demand in each year of the study period for a total of 30 MW. The annual energy was then calculated by using a capacity factor of 80%.

To determine the annual energy used by EVs, the number of EVs in MMPA’s service territory was projected. It was projected that the rate of EV adoption would increase over the study period and it is projected to reach 25% by 2040. The average annual energy usage per EV is set equal to the Minnesota Department of Commerce’s calculation of 4 MWh.

Annual Energy Was Reduced by Conservation

Following the adjustments for WAPA, large customers, and electric vehicles, annual energy projections were decreased by 1.3% of the Agency's three-year rolling average retail energy usage. This reduction represents MMPA's assumption regarding new conservation measures.

Conservation levels of 1.0% and 1.5% were also analyzed, but the 1.3% base case was used for the purposes of this IRP. Conservation reductions lowered the compounded annual growth rate by 1.1%, resulting in a net annual growth rate of 0.6% for the base case energy usage.

NCP Demand Was Projected Using a Weather Normalized Load Factor

MMPA's Non-Coincident Peak (NCP) demand requirements were projected by applying a weather normalized load factor to the Agency's energy projections. This weather normalized load factor was calculated for each season as the average of that season's weather normalized load factors from Planning Years (PYs) 2020 to 2024. These weather normalized load factors were 54.0% for summer, 64.8% for fall, 78.0% for winter, and 70.4% for spring. The average seasonal load factor was then applied to the conservation-adjusted energy projections to obtain MMPA's projected seasonal NCP demand.

NCP Demand Adjusted for Large Customers and Electric Vehicles

MMPA's NCP was adjusted for 2 MW of incremental demand from large customers in each year of the planning period.

MMPA's NCP was also adjusted for increased demand from EVs. To project EV demand, the projected EV annual energy usage was divided by the number of hours in the year and the Electric Power Research Institute's (EPRI) estimate of a 39% diversified load factor.

Demand at MISO's Seasonal Coincident Peak Was Projected Using A Coincidence Factor Approach

MMPA's demand at the time of MISO's seasonal peak (CP demand) was projected by applying a coincidence factor to the Agency's seasonal NCP projections. These coincidence factors were calculated as the average of the historical coincidence factors in the month of MISO's seasonal peak. The historical data begins in 2005 for summer and in 2007 for other seasons and extends through the end of PY 2024. The seasonal coincidence factors are 93.5% for summer, 92.0% for fall, 95.4% for winter, and 95.2% for spring. The average seasonal coincidence factors were then applied to the seasonal NCP demand projections to obtain MMPA's projected CP demand.

CP Demand Was Adjusted for WAPA-Supplied Capacity

Like the energy projections, CP demand projections were reduced by the capacity that WAPA supplies to two MMPA member cities. These WAPA allocations were assumed to remain at the current contract levels throughout the projection period.

Capacity Requirements Include Losses and Reserves

The Agency's total capacity requirements are calculated by adding transmission system losses and planning reserve margin requirements to the projected CP demand requirements.

MMPA's entire load is in MISO Zone 1 and currently serves load in three Local Balancing Authorities (LBAs). The majority of MMPA's load is in the NSP LBA. The remainder of MMPA's load is in the OTP and GRE LBAs. For the purposes of this IRP, the Agency assumes a weighted average of the PY 2024 transmission losses for the three LBAs. This weighted average is 2.4% for summer, 3.5% for fall, 3.1% for winter, and 4.3% for spring.

MISO's final planning reserve margin (PRM) includes two components: an initial PRM and an adjustment from the reliability-based demand curve (RBDC). Load serving entities can choose to opt out of the RBDC; in this case, their final PRM equals the initial PRM plus the RBDC opt out adder. If they choose not to opt out, the final PRM will equal the initial PRM adjusted by the clearing of the RBDC. These two approaches should yield similar results over time because the RBDC opt out adder is set equal to the three-year average of the final PRM less initial PRM.

For the purpose of this IRP, the final PRM requirement for PYs 2025 to 2027 is set equal to the sum of the initial PRM for PY 2024 and the RBDC opt out adder for PY 2024. This gives a projected PRM of 11.0% in summer, 17.0% in fall, 22.6% in winter, and 26.8% in spring.

The initial PRM is projected to be lower beginning in PY 2028 due to MISO's transition to a new methodology for resource accreditation. This change, known as Direct Loss of Load (DLOL) accreditation, has been approved by FERC. MISO has published indicative results for what the PRM would have been for PY 2025 if DLOL accreditation had been in effect. For PYs 2028-2039, the final PRM is set equal to the sum of the indicative PRM under DLOL and the actual RBDC opt out adder for PY 2025. This gives final PRMs of 5.4% for summer, 8.1% for fall, 9.8% for winter, and 2.5% for spring.

Appendix B. Advance Forecast

This appendix contains MMPA's filing to the Department of Commerce as outlined in Minnesota Administrative Rules Chapter 7610.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION
CY 2024
INSTRUCTIONS

These worksheet tabs correspond closely to the tables in the forecast instructions received by the utility.
The forecast instructions pertain to the data to be entered in each of the worksheet tabs.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS OR CHANGE THE NAME OF THIS WORKBOOK.

In general, the following color scheme is used on each worksheet:

- Cells shown with a dark blue background correspond to applicable Minnesota Rules section number/names on each worksheet tab.
- Cells shown with a light green background correspond to headings for sections, columns, row, or individual fields on each worksheet tab.
- **Cells shown with a light yellow background require data to be entered by the utility.**
- Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet tab contains a section labeled "Comments" below the main data entry area.
You may enter any comments in that section to provide an explaination or clarification on the data entered; OR
why data IS NOT being entered on the worksheet tab (for example: cells left blank).

Cells with automatic calculations (typically totals) are provided on some worksheets to assist with the accuracy of the data provided by the utility. It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

Please complete the required worksheet tabs and save the completed workbook to your local computer.
Then attach the completed workbook to an email message, include your contact information, and send it to the following email address:
rule7610.reports@state.mn.us

If you have any questions please contact:

Anne Sell
MN Department of Commerce, Division of Energy Resources
Email: rule7610.reports@state.mn.us (*preferred*)
Direct: 651-539-1851 (*leave a message*)
COMM Website: https://mn.gov/commerce/industries/energy/utilities/annual-reporting/

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - FORECAST SECTION
CY 2024
7610.0120 REGISTRATION

ENTITY ID#	[fill-in]
REPORT YEAR	2024

RILS ID#	[fill-in]

UTILITY DETAILS	
UTILITY NAME	Minnesota Municipal Power Agency
STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	

CONTACT INFORMATION	
CONTACT NAME	Oncu Er
CONTACT TITLE	Chief Operating Officer
CONTACT STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
CONTACT E-MAIL	Oncu.Er@AvantEnergy.com

COMMENTS

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Eric Smith
PREPARER'S TITLE	Manager of Quantitative Analysis
DATE	7/29/2025
PREPARER'S EMAIL ADDRESS	Eric.Smith@AvantEnergy.com

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. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.
Please remember that the number of customers *should reflect the* ***number of customers*** *at year's end,* ***not the number of meters***.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2024	No. of Customers									0
		MWH									0
Present Year	2025	No. of Customers									0
		MWH									0
1st Forecast Year	2026	No. of Customers									0
		MWH									0
2nd Forecast Year	2027	No. of Customers									0
		MWH									0
3rd Forecast Year	2028	No. of Customers									0
		MWH									0
4th Forecast Year	2029	No. of Customers									0
		MWH									0
5th Forecast Year	2030	No. of Customers									0
		MWH									0
6th Forecast Year	2031	No. of Customers									0
		MWH									0
7th Forecast Year	2032	No. of Customers									0
		MWH									0
8th Forecast Year	2033	No. of Customers									0
		MWH									0
9th Forecast Year	2034	No. of Customers									0
		MWH									0
10th Forecast Year	2035	No. of Customers									0
		MWH									0
11th Forecast Year	2036	No. of Customers									0
		MWH									0
12th Forecast Year	2037	No. of Customers									0
		MWH									0
13th Forecast Year	2038	No. of Customers									0
		MWH									0
14th Forecast Year	2039	No. of Customers									0
		MWH									0

* 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
MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

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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									0
		MWH									0
Present Year	2025	No. of Customers									0
		MWH									0
1st Forecast Year	2026	No. of Customers									0
		MWH									0
2nd Forecast Year	2027	No. of Customers									0
		MWH									0
3rd Forecast Year	2028	No. of Customers									0
		MWH									0
4th Forecast Year	2029	No. of Customers									0
		MWH									0
5th Forecast Year	2030	No. of Customers									0
		MWH									0
6th Forecast Year	2031	No. of Customers									0
		MWH									0
7th Forecast Year	2032	No. of Customers									0
		MWH									0
8th Forecast Year	2033	No. of Customers									0
		MWH									0
9th Forecast Year	2034	No. of Customers									0
		MWH									0
10th Forecast Year	2035	No. of Customers									0
		MWH									0
11th Forecast Year	2036	No. of Customers									0
		MWH									0
12th Forecast Year	2037	No. of Customers									0
		MWH									0
13th Forecast Year	2038	No. of Customers									0
		MWH									0
14th Forecast Year	2039	No. of Customers									0
		MWH									0

* 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
MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES MWH [7610.0310 B(3)]	DELIVERED FOR RESALE MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2024			1,899,678	3,946,865	2,047,187				0
Present Year	2025			1,907,848	3,654,764	1,746,916				0
1st Forecast Year	2026			1,939,089	3,685,948	1,746,859				0
2nd Forecast Year	2027			1,948,336	3,700,427	1,752,091				0
3rd Forecast Year	2028			1,957,308	3,842,183	1,884,875				0
4th Forecast Year	2029			1,967,020	4,353,439	2,386,419				0
5th Forecast Year	2030			1,976,479	4,371,756	2,395,277				0
6th Forecast Year	2031			1,986,088	4,393,142	2,407,054				0
7th Forecast Year	2032			1,995,718	4,409,912	2,414,194				0
8th Forecast Year	2033			2,007,448	4,617,878	2,610,430				0
9th Forecast Year	2034			2,020,107	4,825,285	2,805,178				0
10th Forecast Year	2035			2,033,084	4,832,911	2,799,827				0
11th Forecast Year	2036			2,046,180	4,845,972	2,799,792				0
12th Forecast Year	2037			2,061,430	4,853,001	2,791,571				0
13th Forecast Year	2038			2,077,608	4,861,543	2,783,935				0
14th Forecast Year	2039			2,094,163	4,872,852	2,778,689				0

COMMENTS

Under the Midcontinent Independent Transmission System Operator's (MISO) energy market, utilities purchase all of their load from MISO and sell all of the output from their generating resources to MISO. This table has been completed reflecting that structure of the industry. MMPA supplies its memeber cities with energy for resale. The energy values reported here correspond to a calendar year reporting period.

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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2024									0.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2024	287.0	249.4	247.8	239.1	277.6	350.4	404.8	424.1	377.0	276.4	248.7	283.5

COMMENTS
MMPA is requesting an exemption from Item C of this page, as it does not possess the information necessary to classify the system peak by class of service. The Agency sells all of its power and energy to its member utilities at wholesale. The peak demand presented in Item D includes transmission system losses.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MegaWatts)

NAME OF OTHER UTILITY =>										
Past Year	2024	Summer								
		Winter								
Present Year	2025	Summer								
		Winter								
1st Forecast Year	2026	Summer								
		Winter								
2nd Forecast Year	2027	Summer								
		Winter								
3rd Forecast Year	2028	Summer								
		Winter								
4th Forecast Year	2029	Summer								
		Winter								
5th Forecast Year	2030	Summer								
		Winter								
6th Forecast Year	2031	Summer								
		Winter								
7th Forecast Year	2032	Summer								
		Winter								
8th Forecast Year	2033	Summer								
		Winter								
9th Forecast Year	2034	Summer								
		Winter								
10th Forecast Year	2035	Summer								
		Winter								
11th Forecast Year	2036	Summer								
		Winter								
12th Forecast Year	2037	Summer								
		Winter								
13th Forecast Year	2038	Summer								
		Winter								
14th Forecast Year	2039	Summer								
		Winter								

COMMENTS
The Agency Does not Have any Firm Purchases from Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item E. PART 2: FIRM SALES (Express in MegaWatts)

NAME OF OTHER UTILITY =>										
Past Year	2024	Summer								
		Winter								
Present Year	2025	Summer								
		Winter								
1st Forecast Year	2026	Summer								
		Winter								
2nd Forecast Year	2027	Summer								
		Winter								
3rd Forecast Year	2028	Summer								
		Winter								
4th Forecast Year	2029	Summer								
		Winter								
5th Forecast Year	2030	Summer								
		Winter								
6th Forecast Year	2031	Summer								
		Winter								
7th Forecast Year	2032	Summer								
		Winter								
8th Forecast Year	2033	Summer								
		Winter								
9th Forecast Year	2034	Summer								
		Winter								
10th Forecast Year	2035	Summer								
		Winter								
11th Forecast Year	2036	Summer								
		Winter								
12th Forecast Year	2037	Summer								
		Winter								
13th Forecast Year	2038	Summer								
		Winter								
14th Forecast Year	2039	Summer								
		Winter								

COMMENTS
The Agency Does not Have any Firm Sales to Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MegaWatts)

NAME OF OTHER UTILITY =>			Short Term Capacity Purchases							
Past Year	2024	Summer	85							
		Winter	80							
Present Year	2025	Summer	90							
		Winter	85							
1st Forecast Year	2026	Summer	90							
		Winter	90							
2nd Forecast Year	2027	Summer	95							
		Winter	90							
3rd Forecast Year	2028	Summer	100							
		Winter	95							
4th Forecast Year	2029	Summer	105							
		Winter	100							
5th Forecast Year	2030	Summer	100							
		Winter	105							
6th Forecast Year	2031	Summer	100							
		Winter	0							
7th Forecast Year	2032	Summer	100							
		Winter	0							
8th Forecast Year	2033	Summer	100							
		Winter	0							
9th Forecast Year	2034	Summer	100							
		Winter	0							
10th Forecast Year	2035	Summer	100							
		Winter	0							
11th Forecast Year	2036	Summer	0							
		Winter	0							
12th Forecast Year	2037	Summer	0							
		Winter	0							
13th Forecast Year	2038	Summer	0							
		Winter	0							
14th Forecast Year	2039	Summer	0							
		Winter	0							

COMMENTS
This spreadsheet reflects transactions entered into as of 7/29/25. The winter purchases are for the period from December of the previous calendar year though February of the listed calendar year.

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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MegaWatts)

NAME OF OTHER UTILITY =>			Short Term Capacity Sales							
Past Year	2024	Summer	0							
		Winter	0							
Present Year	2025	Summer	0							
		Winter	0							
1st Forecast Year	2026	Summer	0							
		Winter	0							
2nd Forecast Year	2027	Summer	0							
		Winter	0							
3rd Forecast Year	2028	Summer	0							
		Winter	0							
4th Forecast Year	2029	Summer	0							
		Winter	0							
5th Forecast Year	2030	Summer	0							
		Winter	0							
6th Forecast Year	2031	Summer	0							
		Winter	100							
7th Forecast Year	2032	Summer	0							
		Winter	100							
8th Forecast Year	2033	Summer	0							
		Winter	100							
9th Forecast Year	2034	Summer	0							
		Winter	100							
10th Forecast Year	2035	Summer	0							
		Winter	100							
11th Forecast Year	2036	Summer	0							
		Winter	100							
12th Forecast Year	2037	Summer	0							
		Winter	0							
13th Forecast Year	2038	Summer	0							
		Winter	0							
14th Forecast Year	2039	Summer	0							
		Winter	0							

COMMENTS
This spreadsheet reflects transactions entered into as of 7/29/25. The winter sales are for the period from December of the previous calendar year through February of the listed calendar year.

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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MegaWatts)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (Column 3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (Column 4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (Column 9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (Column 7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (Column 12 - 14)
Past Year	2024	Summer	425		425	425			425	425	384	85	0	469	38	464	6
		Winter	287		287	425			287	425	429	80	0	509	73	360	149
Present Year	2025	Summer	425		425	425			425	425	386	90	0	476	34	459	17
		Winter	292		292	425			292	425	487	85	0	572	80	371	200
1st Forecast Year	2026	Summer	426		426	426			426	426	386	90	0	476	34	460	15
		Winter	291		291	426			291	426	443	90	0	533	54	345	188
2nd Forecast Year	2027	Summer	427		427	427			427	427	388	95	0	483	34	460	23
		Winter	293		293	427			293	427	443	90	0	533	54	347	186
3rd Forecast Year	2028	Summer	429		429	429			429	429	408	100	0	508	10	439	69
		Winter	295		295	429			295	429	443	95	0	538	54	349	189
4th Forecast Year	2029	Summer	432		432	432			432	432	502	105	0	607	10	442	164
		Winter	298		298	432			298	432	366	100	0	466	17	315	150
5th Forecast Year	2030	Summer	432		432	432			432	432	497	100	0	597	10	442	155
		Winter	300		300	432			300	432	405	105	0	510	17	317	193
6th Forecast Year	2031	Summer	433		433	433			433	433	498	100	0	598	10	443	155
		Winter	302		302	433			302	433	439	0	100	339	17	319	20
7th Forecast Year	2032	Summer	436		436	436			436	436	498	100	0	598	10	446	152
		Winter	304		304	436			304	436	439	0	100	339	17	321	18
8th Forecast Year	2033	Summer	439		439	439			439	439	508	100	0	608	10	450	158
		Winter	308		308	439			308	439	439	0	100	339	17	325	14
9th Forecast Year	2034	Summer	441		441	441			441	441	518	100	0	618	10	451	167
		Winter	310		310	441			310	441	441	0	100	341	17	327	14
10th Forecast Year	2035	Summer	442		442	442			442	442	518	100	0	618	10	452	166
		Winter	313		313	442			313	442	443	0	100	343	18	331	12
11th Forecast Year	2036	Summer	446		446	446			446	446	518	0	0	518	10	456	62
		Winter	316		316	446			316	446	443	0	100	343	18	333	10
12th Forecast Year	2037	Summer	451		451	451			451	451	518	0	0	518	10	461	57
		Winter	321		321	451			321	451	443	0	0	443	18	338	104
13th Forecast Year	2038	Summer	453		453	453			453	453	518	0	0	518	10	463	54
		Winter	324		324	453			324	453	443	0	0	443	18	342	101
14th Forecast Year	2039	Summer	456		456	456			456	456	518	0	0	518	10	466	52
		Winter	328		328	456			328	456	443	0	0	443	18	347	96

COMMENTS

Seasonal Demands as shown include Transmission System Losses.

Net Generating capability is projected Seasonal Accredited Capacity. Accreditation through winter 2026 is actual. Summer 2026 and 2027 accreditation are set equal to actual summer 2025 accreditation. Winter 2027 and 2028 accreditation are set equal to actual winter 2026 accreditation. Starting in summer 2028, accreditation uses 2025 Installed Capacity (ICAP) multiplied by MISO's projected Seasonal Accredited Capacity percentage of ICAP under Direct Loss of Load methodology. Source of MISO projection of SAC % of ICAP is MISO Presentation to Resource Adequacy Subcommittee, April 9, 2025. MISO projection includes 2025 and 2030. For summer 2028 to winter 2030, 2025 projection is used. Starting in summer 2030, 2030 projection is used.

Net Reserve Capacity Obligation is actual for through winter 2026. Summer 2025 and winter 2026 reserve margines are used for summer 2026 to winter 2028. MISO indicative Planning Reserve Margin under Direct Loss of Load accreditation methodolgoy is used starting in summer 2028.

The summer demand reported here for a given year corresponds to MMPA's summer peak demand of that year. The winter demand reported for a given year is MMPA's peak demand for the winter season beginning in December of the previous calendar year and extending through February of the listed year.

As requested in DOC instructions, we report MMPA's maximum seasonal demand here. In MMPA's IRP, in accordance with MISO requirements, we report MMPA's Coincident Peak (CP) with MISO at the time of MISO's annual peak. Per MISO requirements, MMPA's capacity requirements, as reported in the IRP, are based upon MMPA's CP with MISO. Therefore, the capacity obligation reported here (based upon MMPA's NCP) differs from that reported in MMPA's IRP.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MegaWatts)

		ADDITIONS	RETIREMENTS
Past Year	2024	0.0	
Present Year	2025	0.0	
1st Forecast Year	2026	0.0	
2nd Forecast Year	2027	2.6	
3rd Forecast Year	2028	48.4	
4th Forecast Year	2029	93.4	
5th Forecast Year	2030	108.1	
6th Forecast Year	2031	0.8	
7th Forecast Year	2032	0.0	
8th Forecast Year	2033	10.0	
9th Forecast Year	2034	10.0	
10th Forecast Year	2035	0.0	
11th Forecast Year	2036	0.0	
12th Forecast Year	2037	0.0	
13th Forecast Year	2038	0.0	
14th Forecast Year	2039	0.0	

COMMENTS

Generating capability is projected summer Seasonal Accredited Capacity. For additions in 2027, current accreditation percentage of ICAP is assumed. Starting in summer 2028, accreditation uses Installed Capacity (ICAP) multiplied by MISO's projected Seasonal Accredited Capacity percentage of ICAP under Direct Loss of Load methodology. Source of MISO projection of SAC % of ICAP is MISO Presentation to Resource Adequacy Subcommittee, April 9, 2025. MISO projection includes 2025 and 2030. For resource additions in 2028 and 2029, 2025 projection is used. For resource additions in 2030-2039, 2030 projection is used.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of this worksheet tab.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5	
		Name of Fuel	NG	Name of Fuel	FO2	Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	MMBtu	Unit of Measure	MMBtu	Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2024	7,961,618	1,136,003	6,340	95						
Present Year	2025	6,623,692	879,565	19,250	2,500						
1st Forecast Year	2026	6,623,692	879,565	19,250	2,500						
2nd Forecast Year	2027	6,623,692	879,565	19,250	2,500						
3rd Forecast Year	2028	6,641,839	881,982	19,250	2,500						
4th Forecast Year	2029	6,623,692	879,565	19,250	2,500						
5th Forecast Year	2030	6,623,692	879,565	19,250	2,500						
6th Forecast Year	2031	6,623,692	879,565	19,250	2,500						
7th Forecast Year	2032	6,641,839	881,982	19,250	2,500						
8th Forecast Year	2033	6,623,692	879,565	19,250	2,500						
9th Forecast Year	2034	6,623,692	879,565	19,250	2,500						
10th Forecast Year	2035	6,623,692	879,565	19,250	2,500						
11th Forecast Year	2036	6,641,839	881,982	19,250	2,500						
12th Forecast Year	2037	6,623,692	879,565	19,250	2,500						
13th Forecast Year	2038	6,623,692	879,565	19,250	2,500						
14th Forecast Year	2039	6,623,692	879,565	19,250	2,500						

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (Water)
COAL - Coal (General)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-Distillate)	REF - Refuse, Bagasse, Peat, Non-wood waste	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual Fuel Oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	**To Be Built** (enter X for selection)	**To Be Retired** (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)

COMMENTS
MMPA does not own, nor does it expect to own during the forecast period, any transmission lines above 200 kilovolts.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)
CY 2024

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest.

	DATE OF PEAK DAY DEMAND	DATE OF PEAK DAY DEMAND	
	8/26/24	1/15/24	**<= ENTER DATES**
TIME OF DAY	MW USED ON **SUMMER** PEAK DAY	MW USED ON **WINTER** PEAK DAY	
0100	257	217	
0200	244	213	
0300	237	212	
0400	235	213	
0500	236	218	
0600	250	228	
0700	273	244	
0800	297	260	
0900	317	267	
1000	340	270	
1100	363	272	
1200	384	273	
1300	399	274	
1400	412	273	
1500	422	272	
1600	425	272	
1700	424	277	
1800	416	287	
1900	398	286	
2000	336	280	
2100	316	272	
2200	300	259	
2300	279	245	
2400	258	231	

COMMENTS
MMPA's reported MW include transmission system losses.

Appendix C. Renewable Energy Standard Rate Impact Report

This appendix contains MMPA's rate impact report for complying with the Renewable Energy Objectives (REO) in Minnesota Statute §216B.1691.

Rate Impact Follows the PUC Established Methodology

MMPA's RES rate impact calculations in this appendix follow the PUC established methodology.

Minnesota Statute §216B.1691 establishes a Renewable Energy Standard and requires a utility to evaluate the rate impact of the standard and file the report as an appendix in its resource plan. On January 6, 2015, the Minnesota Public Utilities Commission (PUC) issued Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. §216B.1691 ("Order") under Docket No. E-999/CI-11-852.

Levelized Historic RES Rate Impact Was 0.73 cents/kWh

MMPA's historic RES rate impact was evaluated for the years 2018 to 2024. On an annualized basis, the RES rate impact ranged from 0.40 to 0.94 cents per kWh. The levelized RES rate impact for this time period was 0.73 cents per kWh. Full details are provided in the historic table below.

The years analyzed satisfies Order point 2A(1) directing an analysis for the period since the last filing.

Levelized RES Rate Impact Projected to be (0.61) cents/kWh

The RES rate impact was projected for the years 2025 to 2040. On an annualized basis, the RES rate impact is projected to range from 0.27 to (1.44) cents per kWh. The levelized RES rate impact for this time period is projected to be (0.61) cents per kWh. Full details are provided in the projection table below.

The years analyzed satisfies Order point 2A(2) directing an analysis of the 15 years following the last reported year.

Includes All Generation Assets that Comply with the Renewable Energy Standard

MMPA's rate impact analysis includes all its generation assets that meet the renewable energy standard regardless of when the asset was acquired.

The resources included in the evaluation satisfy the requirement of Order point 2B.

Rate Impact Includes Direct Costs

The RES rate impact calculations include direct costs incurred to meet the RES. These costs include power purchase agreements (PPAs) from renewable resources and the capital and operating costs of owned assets. There were no transmission costs to include in the rate impact.

The direct costs included satisfy Order points 2C and 2E.

Rate Impact Includes Avoided Costs

The RES rate impact calculations include avoided energy, capacity, and emissions costs. There were no avoided transmission costs included in the rate impact.

Historically, the avoided energy costs are those associated with MMPA's PPAs and owned assets. The projected avoided energy costs are based on locational marginal prices at the resource, escalated at inflation. The avoided capacity costs are based on the MISO Zone 1 Cost of New Entry (CONE), escalated at inflation.

The avoided regulatory cost of emissions is included and based on the December 19, 2023 PUC Order Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation. These costs start in 2028 and are the midpoint of the regulatory cost estimates in the Order. Based on the guidance in the Order, these costs are not increased at inflation.

The avoided costs accounted for in the RES rate impact are in compliance with Order points 2F and 2G(2).

Rate Impact Excludes Costs for Ancillary Services and Base Load Cycling

The RES rate impact does not include the indirect costs of ancillary services or base load cycling that are a result of the increase in intermittent generation resources on the system. Based on MISO's market construct, MMPA sells all generation output to, and procures all its load from, the MISO market. MISO charges for ancillary services and base load cycling cannot be attributed to the RES resources.

This analysis meets the requirements of Order point 2D.

RES Rate Impact Summary Tables

The tables below detail the historic and projected RES rate impact. They report annualized and levelized cost impacts, satisfying Order point 2H.

MMPA RES Rate Impact – Historical (2018-2024)

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

MMPA RES Rate Impact – Projected (2025-2039)

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Appendix D. Regulatory Requirements Cross Reference Index

The following table provides a cross reference index for the various regulatory requirements related to Integrated Resource Plan filings.

Statute or Rule	Description of Requirement	Location in IRP
7843.0400 Subp. 1	Include most recent Advance Forecast filed with DOC	Appendix B
7843.0400 Subp. 2	File a proposed plan for meeting the service needs of its customers	Section 16
7843.0400 Subp. 3A	Describe resource options considered, including information supporting selection of proposed resources	Section 13, Section 14, Section 15
7843.0400 Subp. 3B	Include descriptions of the overall process and of the analytical techniques used to create resource plan from available options	Section 12, Section 13, Section 15
7843.0400 Subp. 3C	Include a five-year action plan	Section 18
7843.0400 Subp. 3D	Explain why the plan is in the public interest	Section 19
7843.0400 Subp. 4	Include a non-technical summary	Section 1
216B.1691 Subd. 2a	Status of compliance with eligible energy technology standard	Section 17
216B.1691 Subd. 2e	Rate impact of compliance with Renewable Energy Objectives	Section 17
216B.1691 Subd. 2g	Status of compliance with carbon-free standard	Section 17
216B.1691 Subd. 3a	Description of efforts towards meeting Renewable Energy Objectives	Section 17
216B.2422 Subd. 2	Include a least cost plan for meeting 50% and 75% of all energy needs from new and refurbished generating facilities through a combination of conservation and renewable energy resources	Section 17
216B.2422 Subd. 2a	Historical data and advance forecast	Appendix B

216B.2422 Subd. 2c	Narrative on utility's progress towards achieving the state greenhouse gas emission reduction goals	Section 17
216B.2422 Subd. 3	Use Commission values and other external factors including socioeconomic costs when evaluating and selecting resource options	Section 14
216B.2422 Subd. 4a	Report on local job creation	Section 16
216B.2422 Subd. 6	Indicate intent to site or construct a large energy facility.	Section 18
216B.243 subd. 9	Notice of solar electric generation facility intended to meet obligations of REO	Section 18
216B.2426	Consideration of distributed generation	Section 18, Section 16
PUC 12/19/2023 Order Addressing Environmental and Regulatory Costs	Demonstrate how plan to comply with MN carbon-free standard and CO2 regulations promulgated by the EPA under CAA 42 U.S.C. § 7411 (b) and (d)	Section 17

Appendix E. Acronyms Index

The following index provides definitions of acronyms used in this IRP.

Acronym	Definition
AC	Alternating current
BOGWF	Black Oak Getty Wind Farm
BSF	Buffalo Solar Facility
CAGR	Compound annual growth rate
CCS	Carbon Capture and Storage
CDD	Cooling degree day
CFS	Carbon-free standard
CIP	Conservation Improvement Program
CP	Coincident peak
DIR	Dispatchable Intermittent Resource
DLOL	Direct Loss of Load
DOC	Department of Commerce
ECO	Energy Conservation and Optimization
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERMU	Elk River Municipal Utilities
EV	Electric Vehicle
FEP	Faribault Energy Park
FERC	Federal Energy Regulatory Commission
GIA	Generation Interconnection Agreement
GOR	Gross operating revenue
GW	Gigawatt
GWh	Gigawatt-hour
HDD	Heating degree day
HTBE	Hometown BioEnergy
ICAP	Installed capacity
IRP	Integrated resource plan
kW	Kilowatt
kWh	Kilowatt-hour

LBA	Local balancing area
LNG	Liquified natural gas
MATS	Mercury and Air Toxics Standards
MHEB	Manitoba Hydro Electric Board
MISO	Midcontinent Independent System Operator
MMPA	Minnesota Municipal Power Agency
MRS	Minnesota River Station
MW	Megawatt
MWh	Megawatt-hour
NCP	Non-coincident peak
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OGWF	Oak Glen Wind Farm
PPA	Power purchase agreement
ppb	Parts per billion
PRM	Planning reserve margin
PRMR	Planning resource margin requirements
PUC	Public Utilities Commission
PY	Planning year (June 1 through May 31)
RBDC	Reliability-based demand curve
REC	Renewable energy credit
RES	Renewable energy standard
RNG	Renewable natural gas
SAC	Seasonal Accredited Capacity
SEP	Shakopee Energy Park
UCAP	Unforced capacity
WAPA	Western Area Power Administration
WWF	Walleye Wind Farm
XEFORd	Equivalent forced outage rate demand
ZRC	Zonal resource credits