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Minnesota Municipal Power Agency

APPLICATION FOR INTEGRATED RESOURCE PLAN APPROVAL 2014 - 2028

SUBMITTED TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

December 20, 2013

AVANT
ENERGY

220 South Sixth Street
Suite 1300
Minneapolis, MN 55402

TEL 612.349.6868
FAX 612.349.6108
WEB AVANTENERGY.COM

December 20, 2013

VIA E-FILING
Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: 2013 Resource Plan
DOCKET NO: E____/RP-13-____

Dear Dr. Haar:

Minnesota Municipal Power Agency (MMPA or the Agency) is pleased to submit its 2013 Integrated Resource Plan (IRP or the Plan) to the Minnesota Public Utilities Commission (PUC) for consideration and approval. The planning period covered in MMPA's 2013 IRP is 2014-2028.

This is MMPA's third IRP. The Commission accepted MMPA's 2008 and 2011 IRPs and found MMPA to be in compliance with its Renewable Energy Standards obligations. MMPA has incorporated into the current IRP the recommendations made by the PUC in approving MMPA's 2011 IRP. The Commission recommended that:

1. MMPA provide an analysis in its next resource plan of what level of DSM appears achievable, taking into account historic results.

   MMPA studied its historical Conservation Improvement Program (CIP) performance and developed three cases (1.0%, 1.3% and 1.5%) for its CIP for the projection period. Although MMPA will continue to strive to achieve energy savings averaging 1.5% of the Agency's retail sales, MMPA decided to use 1.3% CIP savings in its projections realizing possible diminishing returns in the next 15 years. MMPA discussed this approach with the Division of Energy Resources (DOER) staff. DOER staff agreed that MMPA's new approach is reasonable. Section 6 of the IRP addresses Energy Conservation and Demand Side Management.

2. MMPA include an analysis of a range of possible fuel and capital costs, along with a range of environmental costs; an analysis of what capacity additions best meet its needs considering the resources currently in its portfolio and inclusion of Commission approved CO_2 and externality costs in its base case.

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In its 2013 IRP, MMPA used a range of fuel scenarios, capital scenarios and possible environmental cost scenarios to analyze the capacity additions that best meet its needs. As recommended, MMPA also included the commission approved CO_2 and externality costs in its base case.

MMPA's Plan contains a discussion of a wide variety of analytical, market and policy issues and presents a five-year action plan and a long range plan that MMPA believes is needed to continue to meet member needs for a low-cost, reliable and environmentally sound energy supply. Given the volatility in commodity markets, and especially in energy commodities, the Plan was designed to provide a high level of flexibility. Overall, MMPA believes the Plan reflects the key issues facing the Agency and its members and provides members with a clear understanding of the Agency's proposed path.

Pursuant to Commission Rule 7829.3200, MMPA respectfully requests a variance from the portions of Rule 7610.0310 that require a utility to provide customer count data by class. Compliance with this rule would impose an excessive burden upon MMPA because, as a wholesale supplier to its members, the Agency has no retail customers. Therefore, it does not keep this data. Moreover, granting the variance would neither adversely affect the public interest nor conflict with standards imposed by law.

Enclosed, please find the Public and Non-public versions of MMPA's 2013 Integrated Resource Plan. Please contact me at (612) 252-6542 if you have any questions.

Very truly yours,

Avant Energy, Inc.
Agent for MMPA

Oncu Er

Enc.
Cc: Service list

CERTIFICATE OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

Oncu Er of the City of Roseville, County of Ramsey, in the State of Minnesota, says that on the 20th day of December, 2013, he served or caused to be served the enclosed document on the attached list of persons by eFiling or by mailing to them copies thereof, enclosed in an envelope, postage prepaid, and by depositing same in the post office at Minneapolis, Minnesota.

Oncu Er

Christina L. Holtan
Notary Public
Minnesota
My Commission Expires January 31, 2015

Christina L. Holtan 12/20/13

In The Matter of
Minnesota Municipal Power Agency's
2013 Integrated Resource Plan

Initial Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
John	Stine	John.Stine@state.mn.us	Pollution Control Agency	520 Lafayette Road North, Saint Paul, MN 55155	Electronic Service	No
William	Seuffert	Will.Seuffert@state.mn.us	Environmental Quality Board	520 Lafayette Road North, Saint Paul, MN 55155	Electronic Service	
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul,MN 551012134	Electronic Service	No
Ed	Ehlinger	Ed.Ehlinger@state.mn.us	Minnesota Department of Health	P.O. Box 64975 St. Paul,MN 55164-0975	Electronic Service	No
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis,MN 55402	Electronic Service	No
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul,MN 551012198	Electronic Service	No
Dave	Frederickson	Dave.Frederickson@state.mn.us	MN Department of Agriculture	625 North Robert Street St. Paul,MN 551552538	Electronic Service	No
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul,MN 551012147	Electronic Service	Yes
Thomas	Landwehr	tom.landwehr@state.mn.us	Department of Natural Resources	Box 37, 500 Lafayette Rd St. Paul,Minnesota 55155	Electronic Service	No
Bethany	Pribila	bethany.pribila@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis,MN 55402	Electronic Service	No
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul,MN 551012130	Electronic Service	No
Brian	Napstad	bnapstad@yahoo.com	Board of Water and Soil Resources	51227 Long Point Place McGregor,MN 55780	Paper Service	No
Laurance R.	Waldoch	lwaldoch@lindquist.com	Lindquist & Vennum	4200 IDS Center 80 South 8th Street Minneapolis,MN 554022274	Paper Service	No
Charles	Zelle	charlie.zelle@state.mn.us	Department of Transportation	MN Dept of Transportation 395 John Ireland Blvd St. Paul,MN 55155	Electronic Service	No

Table of Contents

Section 1. Executive Summary

This section is intended to provide a brief overview of the Minnesota Municipal Power Agency's (MMPA) third Integrated Resource Plan (IRP).

Electric Utility Industry Facing High Uncertainty

The electric utility industry currently faces high levels of uncertainty.

Most energy-related commodity prices are volatile.

The transmission interconnection process adds significant planning uncertainty regarding both the schedule and cost of new generation projects.

Even though Congress has not passed carbon cap and trade legislation, President Obama announced his Climate Action Plan on June 25, 2013. Since that time, the EPA announced its first action under the President's Plan and issued carbon standards for new power plants. The EPA is also working to develop a separate set of carbon limits for existing power plants. These carbon regulations further increase uncertainty regarding future technology selection.

Elk River Municipal Utilities Joined MMPA in June 2013

Elk River Municipal Utilities (ERMU) became the twelfth member of MMPA in June 2013. ERMU serves 9,300 metered electric customers in a 44 square mile area and has a peak demand of approximately 60 MW. MMPA's electrical power load is projected to increase by approximately 20 percent with the addition of ERMU. The Agency will begin providing wholesale power to ERMU on October 1, 2018, under a Power Sales Agreement that runs through 2050.

MMPA Energy And Demand Growth Projected To Be Lower Than Historical Levels

MMPA's energy and demand growth are projected to be significantly lower than historical levels. Although the twenty-five year historical growth rates are approximately three percent per year, the projected annual growth rate for the 2014 to 2018 period is less than two percent and during the 2019 to 2028 period is around one percent. These slower growth rates are attributed to projected economic and population slowdowns and improved conservation efforts, among other factors.

The table below shows MMPA's projected annual energy growth before and after Elk River's addition.

	2014-2017 Pre-ERMU	**2019-2028 Post-ERMU**
Energy Growth	1.5%	1.1%

The following table shows the projected annual growth of MMPA's Non-Coincident Peak (NCP) and Coincident Peak (CP) with the Midcontinent Independent System Operator (MISO) before and after Elk River's addition.

	2014-2018 Pre-ERMU	**2019-2028 Post-ERMU**
NCP Growth	1.0%	1.1%
CP Growth	0.9%	1.0%

For further details on the projection methodology and the projection periods, see Sections 4 and 5 and Appendix A.

MMPA Is Striving To To Meet Its 2013 Conservation Goal

The Agency is striving to meet Minnesota's 2013 conservation goal. MMPA is refining its energy conservation portfolio to incorporate the most relevant and cost effective strategies for reducing electricity use of its customers. MMPA's conservation programs are discussed in Section 6 under Energy Conservation/Demand Side Management.

MMPA Needs More Capacity In The Future

MMPA needs additional capacity in the future. Prior to serving ERMU, MMPA's projected capacity needs in this IRP are comparable to those projected in MMPA's 2011 IRP. Capacity requirements in this IRP would have been greater, but for the new MISO resource adequacy construct that became effective June 1, 2013. This construct requires each market participant to acquire capacity resources to cover its coincident peak with MISO rather than its non-coincident peak. This new construct provides more diversity and reduces MMPA's projected capacity needs.

As previously noted, MMPA will begin serving ERMU on October 1, 2018. Therefore, starting with summer of 2019, MMPA's capacity requirements increase by 71 MW.

The Agency's need for additional capacity grows from 9 MW in 2016 to 156 MW in 2028. This need arises from the expiration of existing capacity contracts, the addition of ERMU and member demand growth.

MMPA Has Many Projects At Various Development Stages To Meet Its Electric Supply Needs

MMPA has many projects at various stages of development to meet its future electric supply needs. Planning flexibility is vital to success given the high level of uncertainty in the electric utility industry. A utility cannot be certain that any one project can be implemented. Therefore, the Agency is developing a large number of resource prospects to meet its future needs. Our planning approach and resource prospects are discussed in Section 9.

Preferred Plan Includes Distributed Generation

The Agency's preferred plan to satisfy its capacity requirements includes Agency owned distributed generation. MMPA will continue its renewable generation efforts. The short-range action plan is discussed in Section 11, and the long range plan is presented in Section 12.

MMPA Has Made A Good Faith Effort To Meet The REO And Is Positioned To Meet The RES

MMPA has made a good faith effort to meet Minnesota's Renewable Energy Objective and is positioned to meet the Renewable Energy Standard. The Agency constructed Hometown WindPower, a project that put a wind turbine in each member community (excluding Elk River who was not a member at the time) and at the Faribault Energy Park site. The Agency constructed and put in service the 44 MW Oak Glen Wind Farm (OGWF) and the 8 MW Hometown BioEnergy (HTBE) project. MMPA also recently signed wind Power Purchase Agreements (PPAs) that total 138 MW. Section 14 will address meeting the RES as well as the rate impact of complying with the RES.

MMPA's Plan Is In The Public Interest

MMPA's IRP is in the public interest. The Agency's plan allows MMPA to maintain flexibility during this period of unprecedented uncertainty, reducing risks to its customers while keeping rates as low as practical. MMPA's plan also minimizes negative environmental impacts through its emphasis on conservation and renewable energy. Section 15 further describes how MMPA's plan is in the public interest.

Section 2. About MMPA

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

MMPA Is A Municipal Power Agency

MMPA is a municipal power agency formed in 1992 under Chapter 453 of Minnesota Statutes. The Agency is a political subdivision of the state of Minnesota. MMPA began supplying power to its members in 1995.

MMPA Has 12 Members

The twelve members of MMPA are the following Minnesota cities:

- 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 69,000 retail customers in Minnesota with a combined population of approximately 152,000.

MMPA Is Projected to Sell 1,478,593 MWh In 2013

MMPA is projected to sell 1,478,593 MWh of energy to its eleven member municipal utilities in 2013. MMPA will begin serving Elk River in 2018; therefore MMPA will have no sales to Elk River in 2013.

The Agency's 2013 Peak Load Was 329 MW

MMPA's peak load during the summer of 2013 was 329 MW on August 26, 2013. (This load includes 2.5% transmission system losses, excludes the MISO planning reserve margin, and excludes WAPA allocations for two MMPA members.)

Avant Energy Manages MMPA

Avant Energy manages the Minnesota Municipal Power Agency. Avant is an innovator, bringing new technologies and new ways of doing business to the energy industry.

Avant's services to MMPA include:

- Day-to-day management of the Agency's operations
- Electricity purchasing and selling and relationship management with MISO
- Overall long-term strategic management of the Agency
- Project development for power generation, from planning through operations

MMPA's First Owned Plant Was Completed In 2007

Faribault Energy Park (FEP), the first power plant to be owned by the Agency, was completed in 2007. The plant was built in two phases. The 159 MW simple cycle phase became operational in April 2005. The combined cycle phase, which increased both the capacity and fuel efficiency of the plant, became operational in the summer of 2007. MMPA's ownership of FEP marks a transition from a resource portfolio based solely on contracts to one that also includes Agency-owned assets. FEP is described in more detail in Section 7.

MMPA's First Owned Wind Farm Was Completed in 2011

Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm. It is 44 MW and is located near Blooming Prairie, Minnesota. It was awarded a U.S. Department of Energy "2012 Public Power Wind Award" for leadership, innovation, project creativity and benefits to customers. OGWF's innovative ownership and financial structure also qualified the wind project to receive a $25.4 million federal grant. OGWF is described in more detail in Section 7.

Section 3. Business Environment

This section discusses the business environment in which MMPA operates. MMPA's IRP must recognize electricity market uncertainties that influence planning decisions for the future.

Electric Industry Faces High Levels Of Uncertainty

In our 2011 IRP, we stressed the unprecedented levels of uncertainty surrounding the electric industry. The past two years have demonstrated that high levels of uncertainty have become the new normal for many sectors of the business world.

The electric utility industry continues to have high levels of uncertainty. These uncertainties include commodity prices, transmission availability and cost, environmental legislation, MISO market changes and global economic conditions.

Most Commodity Prices Are Volatile

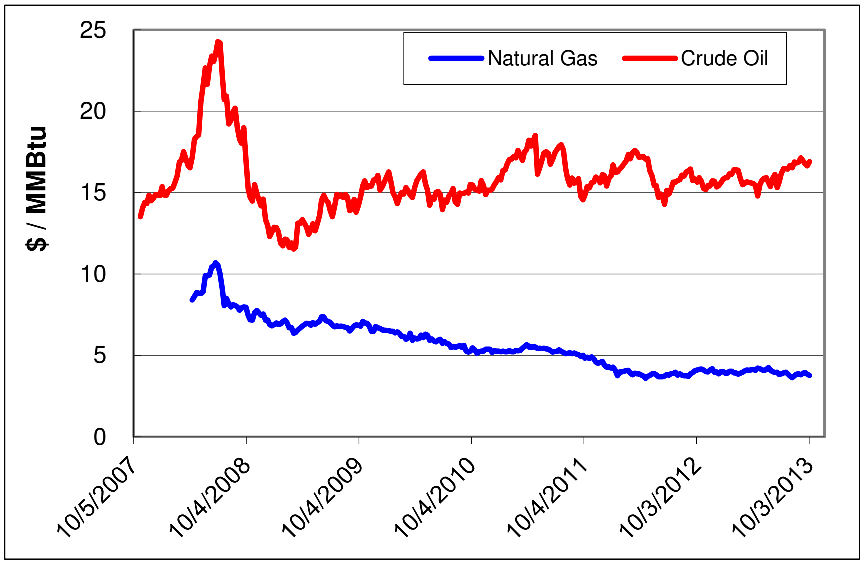
Prices for a large number of commodities, including grains, metals, and energy, are currently volatile.

Factors such as the shale gas revolution, proposed EPA regulations on fossil fuel generation and the most recent economic slowdown contributed significantly to the volatility in natural gas prices. The price of natural gas futures for June 2014 delivery increased 27% from April to June of 2008, before dropping 60% by the end of 2011. Prices have continued to fluctuate to a lesser extent since the beginning of 2012.

The price of crude oil futures for June 2014 delivery increased nearly 80% from the end of 2007 to the summer of 2008 before dropping 52% by March 2009. Unlike natural gas futures, oil futures increased another 60% by spring 2011 and since then have continued to fluctuate widely.

The following chart shows available data for weekly close of oil and gas futures for June 2014 delivery as expressed in $ per MMBtu.

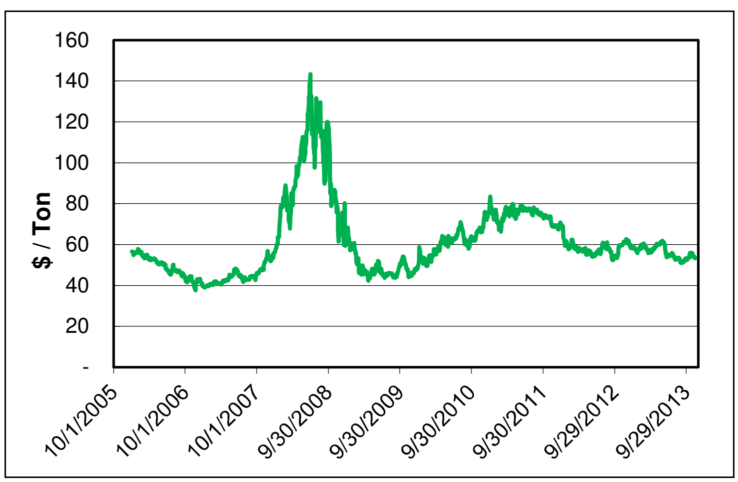
Oil and Natural Gas Futures Prices
June 2014 Delivery



The price of near-month contract coal futures settlements decreased by 34% from January to November 2006, before climbing 282% by the summer of 2008, then dropping 68% by March 2009. Volatility continued as prices again climbed 57% from March 2009 to the end of 2011. Since 2012, volatility has decreased.

The next chart shows Central Appalachian coal futures settlement prices, expressed in $ per ton.

Central Appalachian Coal Futures
Near-Month Contract Final Settlement Prices



These graphs illustrate the volatility of commodity prices. Volatile commodity prices increase uncertainty in the electric utility industry and pose a challenge to long range planning.

Timing and Cost Outcomes Of Transmission Interconnection Process Are Unpredictable

FERC approved a MISO interconnection queue process reform in August 2008. MISO was implementing the new process when FERC required a large number of projects to go through a restudy in 2010.

On November 1, 2011, MISO filed proposed revisions (Queue Reform III Filing) to its Generator Interconnection Procedures in its Tariff to address backlogs in the generator interconnection queue and late stage terminations of generation interconnection agreements. FERC conditionally accepted the 3rd round of queue reform revisions and directed MISO to make three informational filings in April of 2013, 2014 and 2015 to report on progress and effectiveness. The effectiveness of the 3rd queue reform is yet to be assessed. The unknown effectiveness of the 3rd queue reform and possible future process changes continue to make planning difficult. In particular, these uncertainties make it difficult to predict the timing and cost implications of interconnecting future generation projects.

Transmission Cost Allocation Changes Shift Transmission Costs Of MVPs To Load

In 2010, FERC issued an order conditionally accepting the MISO tariff revisions that outlined a new transmission cost allocation methodology where certain transmission upgrades are identified as Multi Value Projects (MVPs). On one hand, these tariff revisions transfer the financial burden of MVP transmission projects from generation to load and therefore, make it easier and less costly for new generation projects to interconnect to the system. On the other hand, this presents increased costs to load. A number of parties petitioned for review and these petitions were consolidated in the 7th Circuit Court of Appeals. In June 2013, the 7th Circuit affirmed FERC's decision shifting costs to load serving entities.

New EPA And State Emissions Standards And Carbon Legislation Could Increase Cost Of Fossil Fuel Based Generation

New EPA and state emissions standards and carbon legislation could increase the cost of fossil fuel based generation.

The EPA's Mercury and Air Toxics Standards (MATS) Final Rule, issued in April 2013, establishes emission limits for mercury, particulate matter, sulfur dioxide, acid gases and certain individual metals for new power plants. Comments were due in late August.

Although the EPA has taken no further action on the above mentioned comments at this time, the MATS Rule would particularly affect the cost of future coal and oil fired power plants when it fully goes into effect.

In addition to MATS, the EPA issued notice in late August 2013 announcing reconsideration of specific issues in the final Reciprocating Internal Combustion Engines (RICE) rule. The Final

RICE rule affects cost and operations of reciprocating internal combustion engines. As of the writing of this IRP, the comment period is still open.

In addition to the above, President Obama announced his Climate Action Plan on June 25, 2013. In September 2013, the EPA announced its first action under the President's Climate Action Plan, setting carbon limits for new power plants that burn fossil fuels. As of the writing of this IRP, the comment period is still open. The EPA said it has started work to develop a separate set of carbon limits for existing power plants.

Individual states are also taking initiative and setting rules and regulations to first cap and then decrease carbon emissions from certain sectors of their economies. The Minnesota legislature has a state CO_2 reduction goal of 15% by 2015, 30% by 2025, and 80% by 2050.

Uncertainty regarding the amount of a tax or the price of an allowance under a national cap and trade system complicates power supply planning. This IRP uses the low and high costs of $9 and $34 per ton of carbon dioxide as established by the Public Utilities Commission order issued on November 2, 2012.

MISO Market Changes Introduce Planning Uncertainties

MISO market changes introduce uncertainties and make planning difficult.

Increased penetration of wind resources over the past few years and the intermittent generation characteristic of wind create short and long term planning uncertainties. MISO introduced the concept of Dispatchable Intermittent Resource (DIR) to be able to overcome some of these uncertainties. MISO also fully integrated Load Modifying Resources (LMR) and Energy Efficiency Resources (EE) into the MISO energy and capacity markets.

In addition, MISO transmission markets are still assessing the effectiveness of the changes introduced by Multi Value Projects (MVPs) and their cost allocations.

Most recently, MISO introduced the concept of annual capacity auctions and administered its first annual capacity auction under its recently enhanced resource adequacy construct in April 2013. The system wide clearing price for the 2013-2014 planning year of $1.05 per megawatt-day reflected ample supply of generation and demand response resources in MISO as well as the robust transmission system. Although the year out MISO auction suggests the abundant availability of capacity in the immediate term, the absence of long term capacity markets and the associated price signals for the long term cost of capacity make long term planning challenging.

The Independent Market Monitor (IMM) that monitors market activity in MISO reported the below in its 2012 State of the Market Report (Page ii), published in the summer of 2013:

"Our net revenue analysis in this report shows that the MISO's economic signals would not support private investment in new resources, which is partly due to the modest capacity surplus that currently exists in MISO. However, we believe the economic signals would continue to be inadequate even under little or no surplus because of the shortcomings of MISO's current capacity market described in this report. This resource adequacy concern is likely to rise as environmental regulations, increasing wind output, and low natural gas prices accelerate the retirements of coal-fired resources in the medium term."

The unknown impacts of the above changes are a source of uncertainty in long range planning.

Weak Dollar Puts Upward Pressure on Domestic Fuel Prices

Central banks around the world have continued to implement their policies of quantitative easing in an effort to ignite growth and lower unemployment. Most notably, the aggressive quantitative easing policies of the Federal Reserve Bank contribute to the continuing weakness of US dollar. A weaker dollar puts upward pressure on the price of imported oil. However, this upward pressure is counteracted by the shale revolution, which decreases US dependence on expensive foreign oil and increases the supply of domestic oil and gas. This dual tension in fuel prices complicates power supply planning.

Weak Dollar Creates Higher Capital Costs

A weak dollar also increases capital costs for power generation equipment. The weaker dollar makes US-produced power generation equipment more affordable to foreign buyers, increasing demand and cost. At the same time, foreign-made power generation equipment is more costly because of the low value of the dollar relative to the foreign currency.

Shale Revolution Puts Downward Pressure On Near Term Gas And Oil Prices

The shale revolution is arguably the most important development in the energy landscape in the past 5 years. The share of shale in US natural gas production is projected to rise to 45% by 2035. In November 2012, the International Energy Agency (IEA) projected that shale would help the US become a net fuel exporter by 2030 and achieve energy independence by 2035.

Although a large amount of projected shale gas and oil supply put downward pressure on oil and natural gas prices in the near to intermediate term, factors such as coal to gas switching, increased consumption from industrial and commercial production, possible environmental regulations, and projected increase in LNG and oil exports make the long term price of these fossil fuels less certain.

World And US Economies Are Going Through Challenging Times

The past 5 years have been some of the most challenging economic times in the modern world's history.

Although there have been improvements in the US economy since our last IRP, the world and, to a lesser extent, the US economy are still struggling with high structural unemployment, increasing cost of living, debate over entitlement programs, high budget deficits, issues with regulation and increased challenges with climate changes. This IRP does not quantify effects of these economic challenges on the energy market, but planning decisions must be developed in this context of increased uncertainty.

Section 4. Projected Energy Requirements – 2014 to 2028

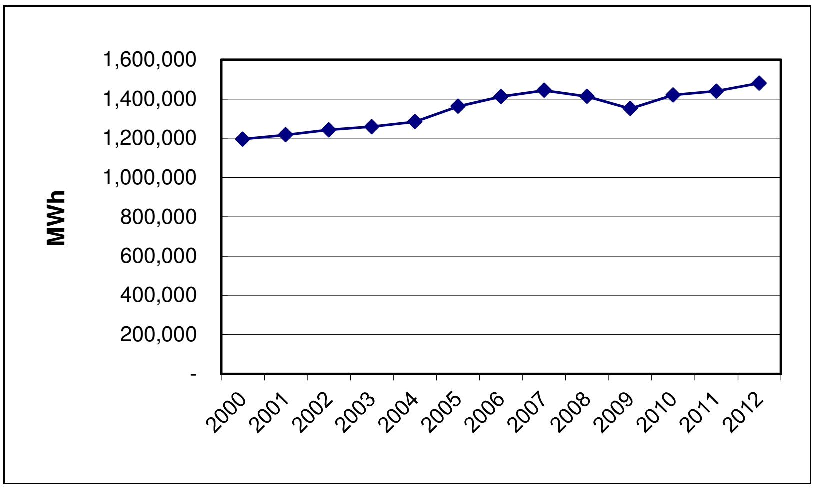
This section discusses the projected slowdown between MMPA's historical and future energy requirements.

MMPA's Historical Energy Growth Rate Is 3.4%

Over the period 1988 to 2012, MMPA's energy usage grew at a compound annual growth rate of approximately 3.4% for the 9 members for which data is available.

The following graph shows historical MMPA energy requirements for the years 2000 to 2012, the time period for which data is available for the eleven member cities historically served by MMPA. The data has been adjusted to include all of Shakopee's load.

Minnesota Municipal Power Agency
Historical Member Energy Requirements (MWh)



MMPA Will Begin Serving Elk River In October 2018

MMPA will start providing electric service to Elk River as a member in October 2018.

MMPA's Projected Energy Growth Rate Net Of Conservation: 1.5% (2014-2017), 1.1% (2019-2028)

Because of the significant Elk River load addition in the last quarter of 2018, we examine MMPA's projected energy requirements in two periods for this IRP:

- 2014-2017 or pre-Elk River energy growth
- 2019-2028 or post-Elk River energy growth

We exclude the year 2018 in these projection periods because the partial year of Elk River energy (October-December) in 2018 would skew the projected growth rate.

MMPA's projected annual energy growth rate net of conservation is 1.5% for the 2014-2017 projection period and 1.1% for the 2019-2028 projection period.

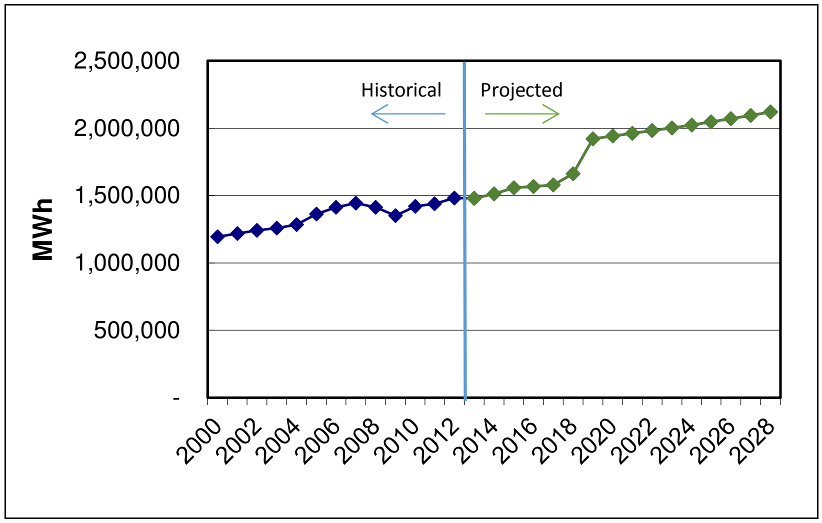
The projected growth rates in this IRP are higher than the projected growth rates in our previous IRPs. The main reasons for higher projected growth rates are:

- The addition of Elk River which has higher projected energy growth rates (2.6% for 2019-2028 net of conservation)
- Lower CIP projections in MMPA's base case energy projections. Although MMPA strives to meet its CIP spending requirements and energy savings targets, the Agency recognizes the increasing difficulty of sustaining the CIP energy savings targets over the projection period and therefore uses a 1.3% CIP energy savings in its base case. MMPA also analyzes 1.0% and 1.5% CIP energy savings scenarios.
- Higher load growth coming from commercial load additions

Pre-Elk River projected energy growth rate is higher than post-Elk River projected growth because in the next four years, two MMPA members are adding significant new commercial load in excess of historical energy growth. After these commercial load additions level off in 2018, projected MMPA growth decreases.

The following graph shows historical and projected MMPA energy requirements, including conservation adjustments, for the years 2000 to 2028.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted
Member Energy Requirements (MWh)

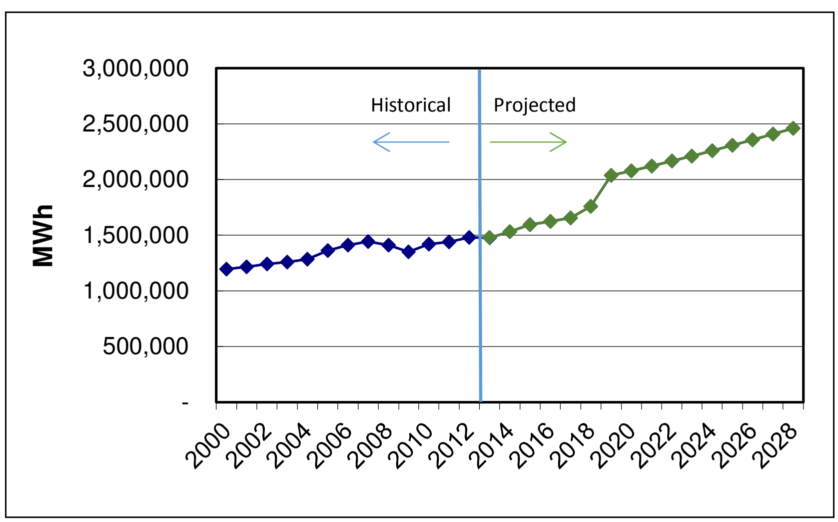


MMPA's Projected Energy Growth Rate Absent Conservation: 2.6% (2014-2017), 2.1% (2019-2028)

MMPA's projected energy growth rate absent conservation is 2.6% for the 2014-2017 projection period and 2.1% for the 2019-2028 projection period.

The following graph shows historical and projected MMPA base energy requirements, without conservation adjustments, for the period 2000 to 2028.

Minnesota Municipal Power Agency
Historical & Projected Base Member
Energy Requirements (MWh)



Slower Projected Income And Population Growth Limit Further Load Increases

Slower income and population growth limit load growth in MMPA energy projections.

The population of MMPA's member cities grew at a compound annual growth rate of 2.2% from 1988 to 2012. However, projections based upon Woods and Poole long term growth rates suggest that population will increase between 2013 and 2028 at a 1.8 % compound annual growth rate for MMPA cities excluding Elk River, which is projected to grow at 2.2%. Several of MMPA's member cities are now fully built out. As developable land in member cities declines, population growth is expected to slow.

According to the Woods and Poole State and County Projections, the source of MMPA's income data, the weighted average income per capita for 9 MMPA cities grew at a compound annual growth rate of 2.1% from 1988 to 2010. The income per capita for East Grand Forks, Buffalo and Elk River, the remaining MMPA cities, grew at respective rates of 2.1%, 1.5% and 1.2% over the same period. Woods and Poole projects significant slowdowns in all of these income growth rates from 2013 to 2028. Over this time period, compound annual growth rates for income per capita for MMPA9, East Grand Forks, Buffalo and Elk River are projected to decrease to 1.2%, 1.2%, 1.0%, and 1.0% respectively.

Linear Regression Model Used To Project Growth

A linear regression model was used to project energy usage for this IRP. The variables in the model are:

- Weather (heating degree days and cooling degree days)
- Population
- Income per capita

Details on the inputs and assumptions of this model can be found in Appendix A.

New Conservation Assumed To Reduce Annual Energy Growth Rate By: 1.1% (2014-2017), 1.0% (2019-2028)

New conservation measures are assumed to reduce the Agency's annual energy growth rate by approximately 1.0%. See table below:

	2014-2017 Pre-ERMU	**2019-2028 Post-ERMU**
Pre-Conservation Energy Growth Rate	2.6%	2.1%
Effect of Conservation	1.1%	1.0%
Post-Conservation Energy Growth Rate	1.5%	1.1%

MMPA's current level of energy conservation is built into the historical energy usage data that is an input to the linear regression model. For further clarification, the base case of 1.3% conservation does not translate into a 1.3% reduction in the energy growth rate because CIP savings calculations are based upon a lagging 3-year average of MMPA's energy consumption.

Section 6 discusses in detail MMPA's current and future conservation efforts.

Additional Customers Would Increase Energy Requirements

MMPA's projected energy requirements would increase if the Agency were to take on additional customers or members. The projections in this IRP account for anticipated new load associated with new retail customers in two member communities. This IRP assumes that the 12 member Agency does not take on any additional wholesale customers or members during the projection period.

Decreased Supply From WAPA Would Increase Energy Requirements

Two of MMPA's 12 members currently receive allocations of energy (approximately 95,000 MWh per year) from the Western Area Power Administration (WAPA). Both of these WAPA allocations run through 2020. WAPA could reduce the amount of energy and power available to its customers. This would represent a policy change from the past. If WAPA decreases the energy available to its customers, MMPA's energy requirements would increase, as the Agency provides all of the energy that is not supplied by WAPA to the two cities. This IRP assumes that WAPA supplies remain at 2010 to 2015 contract amounts throughout the projection period.

Increased Electric Use For Transportation Would Increase Energy Requirements

In our 2011 IRP, we noted that we expected electricity to gain greater traction as a fuel for transportation, as it holds the potential to reduce reliance on oil and reduce carbon emissions from transportation.

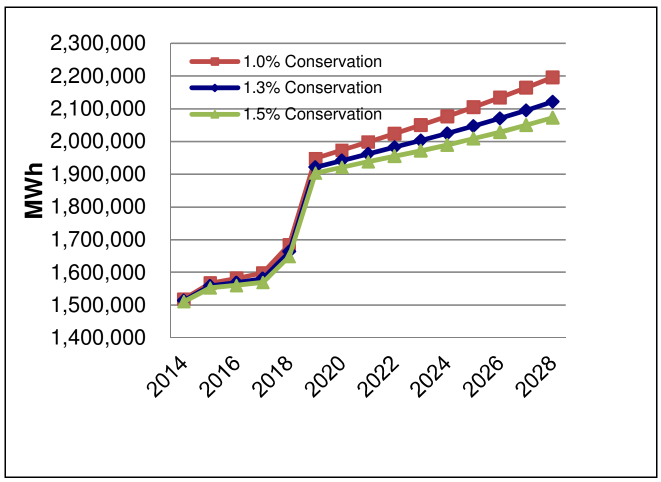
According to Minnesota Department of Public Safety, there were 269 electric or electric hybrid vehicles in Minnesota as of December 2012 and only a handful of these vehicles are registered in MMPA member cities. Furthermore, the majority of these vehicles in Minnesota (219 out of 269) have the capability to run on gasoline as well as electricity. The limited ability to run solely on electricity and the ability to run on gasoline could make electricity a secondary fuel source and have an insignificant effect on electric demand and energy use.

Although MMPA anticipates an increase in energy requirements over the long term as the development and commercialization of plug in electric and hybrid vehicles get underway, this IRP assumes no increase in MMPA's electric load since the penetration of this technology has been relatively slow.

Lower CIP Savings Would Increase Energy Requirements

As recognized by the Department of Commerce (DOC) staff, MMPA's CIP program has been very successful over the past few years. Although MMPA will strive to meet its CIP goals in the future, planning processes need to take into consideration the uncertainties associated with longer term effectiveness of CIP programs and the possibility of diminishing returns. This IRP assumes a 1.3% energy conservation rate for planning purposes, however, high and low cases of 1.0% and 1.5% conservation were also considered. The below chart shows MMPA's energy requirements for 3 CIP savings cases: 1.0%, 1.3% and 1.5%.

Minnesota Municipal Power Agency
Projected Conservation-Adjusted Member Energy (MWh)



We discuss MMPA's CIP efforts and corresponding results in Section 6.

MMPA's Pre- and Post-Conservation Energy Projections

The table below shows MMPA's base energy projections and pre- and post-conservation energy requirements. It also shows the adjustments made to the base energy projections to calculate these requirements. All units are in MWh.

Year	Base Energy	Plus Olivia WAPA Adjustment	Plus East Grand Forks WAPA Adjustment	Plus New Load Adjustment	Pre-Conservation Energy Requirements	Plus 1.3% Conservation	Post-Conservation Energy Requirements
2014	1,565,140	(22,307)	(73,051)	62,415	1,532,197	(18,495)	1,513,702
2015	1,586,164	(22,307)	(73,051)	104,835	1,595,641	(37,328)	1,558,314
2016	1,609,476	(22,381)	(73,304)	111,416	1,625,207	(56,603)	1,568,605
2017	1,634,507	(22,307)	(73,051)	117,682	1,656,831	(76,322)	1,580,509
2018	1,736,961	(22,307)	(73,051)	117,682	1,759,285	(96,431)	1,662,854
2019	2,015,643	(22,307)	(73,051)	117,682	2,037,967	(116,830)	1,921,137
2020	2,057,065	(22,381)	(73,304)	118,004	2,079,384	(137,682)	1,941,702
2021	2,099,805	(22,307)	(73,051)	117,682	2,122,129	(160,062)	1,962,067
2022	2,143,939	(22,307)	(73,051)	117,682	2,166,263	(184,006)	1,982,256
2023	2,189,466	(22,307)	(73,051)	117,682	2,211,790	(209,247)	2,002,543
2024	2,236,328	(22,381)	(73,304)	118,004	2,258,647	(234,754)	2,023,894
2025	2,284,639	(22,307)	(73,051)	117,682	2,306,963	(260,523)	2,046,439
2026	2,334,301	(22,307)	(73,051)	117,682	2,356,625	(286,561)	2,070,064
2027	2,385,367	(22,307)	(73,051)	117,682	2,407,691	(312,877)	2,094,814
2028	2,437,836	(22,381)	(73,304)	118,004	2,460,155	(339,485)	2,120,670
Growth Rate (2014-2017)					2.6%		1.5%
Growth Rate (2019-2028)					2.1%		1.1%

Section 5. Projected Demand Requirements – 2014 to 2028

This section discusses the projected slowdown between MMPA's historical and future demand requirements.

MMPA's first two IRPs examined projected demand requirements at the time of the Agency's own peak – or Non-Coincident Peak (NCP) with MISO. Under a new MISO capacity construct effective Planning Year (PY) 2013 that spans June 2013 through May 2014, MMPA must instead project its demand at the time of MISO's peak – i.e. the Agency must project MMPA's Coincident Peak (CP) with MISO.

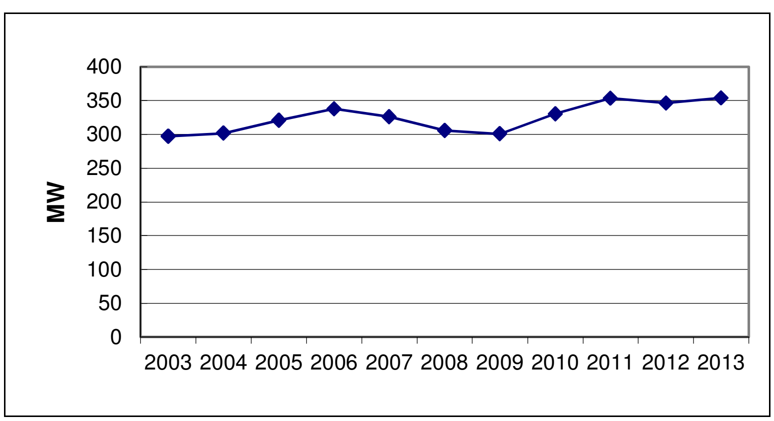
This IRP examines both MMPA's NCP demand requirements and MMPA's CP demand requirements. In accordance with DOC instruction and in compliance with MISO, MMPA uses its CP demand requirements for planning purposes in this IRP.

MMPA's Historical NCP Demand Growth Rate Is 2.9%

Over the period 1988 to 2013, the NCP demand for 9 MMPA cities grew at a compound annual growth rate of 2.9%. The following graph shows historical MMPA peak capacity requirements (including 2.5% losses and 7.5% reserves) for the years 2003 to 2013, the time period for which data is available for the eleven member cities historically served by MMPA. Years 2003 – 2008 have been adjusted to include full Shakopee load.

Actual reserve requirements have varied from 2003-2013 but for comparability reasons, this IRP assumed 7.5% for all periods of its calculations.

Minnesota Municipal Power Agency
Historical NCP Demand (MW)



Weather Normalized Load Factor Approach Used To Project MMPA NCP Demand

MMPA's Non-Coincident Peak (NCP) demand was projected using a weather normalized historical average load factor which was applied to MMPA's projected base energy requirements net of conservation. Details of the methodology can be found in Appendix A.

MMPA's Projected NCP Growth Rate Net Of Conservation: 1.0% (2014-2018), 1.1% (2019-2028)

MMPA will begin providing electric service to Elk River as a member in October 2018. Because of this significant load addition in the last quarter of 2018, we examine MMPA's projected NCP requirements in two periods for this IRP:

- 2014-2018 or pre-Elk River NCP growth
- 2018-2028 or post-Elk River NCP growth

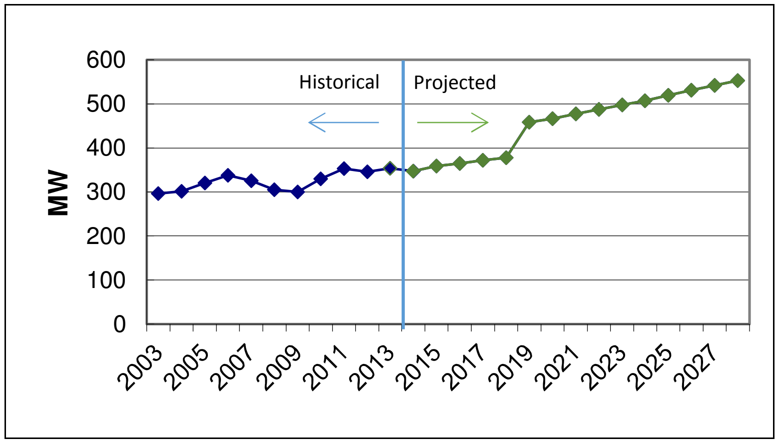
MMPA will have had its NCP before Elk River joins in 2018, and so the 2018 MMPA NCP is projected (via load factor) using only energy from MMPA's other 11 member cities (MMPA11). Therefore, the pre-Elk River NCP growth period goes through 2018. By contrast, the pre-Elk River Energy growth period only goes through 2017, as mentioned in Section 4, because 2017 is the last full year in which MMPA does not serve any Elk River load. Including 2018 in the pre-Elk River Energy projection period would skew growth rates, as MMPA begins serving Elk River's load in October 2018. Details of the methodology and data used can be found in Appendix A.

MMPA's projected NCP growth rate net of conservation is 1.0% for the 2014-2018 projection period and 1.1% for the 2019-2028 projection period.

MMPA's Projected NCP Demand Growth Rate Is Approximately 2.2% Absent Conservation

The base compound annual growth rate of member NCP demand (before conservation) is projected to be 2.2% for the 2014-2018 projection period and 2.1% for the 2019-2028 projection period. The following graph shows projected MMPA NCP capacity requirements, including 2.5% losses and 7.5% reserves.

Minnesota Municipal Power Agency
Historical & Projected Base NCP Demand (MW)

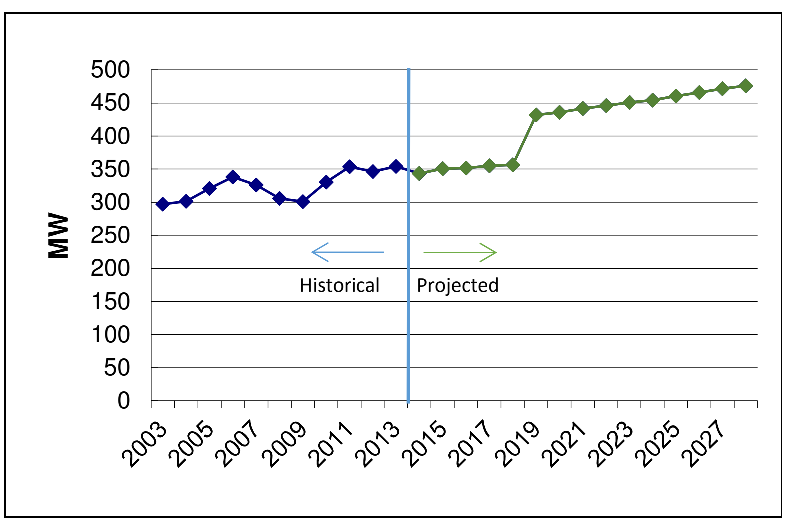


New Conservation Assumed To Reduce NCP Growth By: 1.2% (2014-2018), 1.0% (2019-2028)

The effect of new conservation measures is assumed to reduce the annual growth rate of MMPA's NCP requirements by approximately 1.0%:

	2014-2018 Pre-ERMU	2019-2028 Post-ERMU
Pre-Conservation NCP Growth Rate	2.2%	2.1%
Effect of Conservation	1.2%	1.0%
Post-Conservation NCP Growth Rate	1.0%	1.1%

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted
Member NCP Demand (MW)
Includes 2.5% Transmission Losses and 7.5% PRM



Linear Regression Used To Project MMPA CP Demand

MMPA's demand coincident with MISO's peak was projected using a linear regression model. This forecasting methodology is similar to that used by MMPA and accepted by MISO for compliance with MISO's Module E-1 requirements. The model uses the Agency's NCP demand and weather at the time of MMPA's CP with MISO as explanatory variables. Details of the methodology can be found in Appendix A.

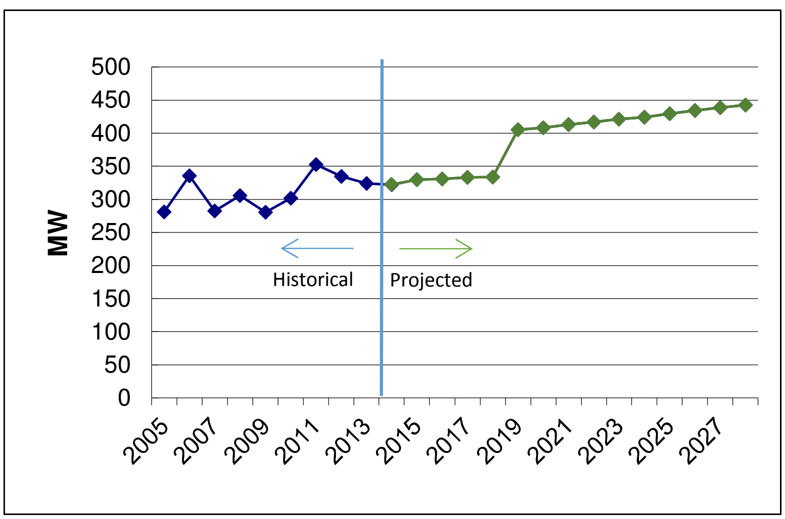
MMPA's Projected CP Growth Rate Is: 0.9% (2014-2018), 1.0% (2019-2028)

MMPA's projected CP (Coincident with MISO) growth rate is 0.9% for 2014-2018 and 1.0% for 2019-2028.

Unlike Energy and NCP projections, the CP growth in the post-Elk River period is higher than in the pre-Elk River period because we use different data sets to project MMPA's CP in the two projection periods. The pre-Elk River projection uses annual historical MMPA11 demand data. The post-Elk River projection uses historical data for what MMPA12's demand would have been, had MMPA historically served Elk River's load. See Appendix A for details.

The graph below shows historical and projected MMPA CP demand requirements adjusted for new conservation and including 2.5% losses and 7.5% reserves.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted
Member CP Demand (MW)



As noted earlier, in accordance with DOC instruction and compliance with MISO, MMPA uses CP demand requirements for planning purposes in this IRP.

MMPA's Energy, NCP Demand, And CP Demand Projections, Net Of Conservation

The table below summarizes MMPA's energy, NCP demand, and CP demand projections from 2014 to 2028. The energy projections have been adjusted for conservation, anticipated new load in two member communities, and WAPA allocations. The NCP and CP projections have been adjusted for these same factors, as well as transmission losses and the MISO planning reserve margin.

Year	Energy (MWh)	MMPA NCP (MW)	MMPA CP (MW)
2014	1,513,702	343.2	322.3
2015	1,558,314	350.8	329.7
2016	1,568,605	351.8	330.7
2017	1,580,509	355.0	333.1
2018	1,662,854	356.5	333.9
2019	1,921,137	432.1	405.3
2020	1,941,702	435.6	408.3
2021	1,962,067	441.4	413.2
2022	1,982,256	445.9	417.1
2023	2,002,543	450.5	421.0
2024	2,023,894	454.1	424.1
2025	2,046,439	460.5	429.5
2026	2,070,064	465.8	434.1
2027	2,094,814	471.4	438.9
2028	2,120,670	476.0	442.7

Slower Projected Income And Population Growth Limit Further Load Increases

Slower income and population growth limit load growth in MMPA energy projections.

The population of MMPA's member cities grew at a compound annual growth rate of 2.2% from 1988 to 2012. However, projections based upon Woods and Poole long term growth rates suggest that population will increase between 2013 and 2028 at a 1.8 % compound annual growth rate for MMPA cities excluding Elk River which is projected to grow at 2.2%. Several of MMPA's member cities are now fully built out. As developable land in member cities declines, population growth is expected to slow.

According to the Woods and Poole State and County Projections, the source of MMPA's income data, the weighted average income per capita for 9 MMPA cities grew at a compound annual growth rate of 2.1% from 1988 to 2010. The income per capita for East Grand Forks, Buffalo and Elk River, the remaining MMPA cities, grew at respective rates of 2.1%, 1.5% and 1.2% over the same period. Woods and Poole projects significant slowdowns in all of these income growth rates from 2013 to 2028. Over this time period, compound annual growth rates for income per capita for MMPA9, East Grand Forks, Buffalo and Elk River are projected to decrease to 1.2%, 1.2%, 1.0%, and 1.0% respectively.

Additional Customers Would Increase Demand Requirements

MMPA's projected coincident peak demand would increase if the Agency were to take on additional customers or members. The projections in this IRP account for anticipated new load associated with new customers in two member communities. This IRP assumes that the 12 member Agency does not take on any additional wholesale customers or members during the projection period.

Decreased Supply From WAPA Would Increase Demand Requirements

Two of MMPA's 12 members currently receive allocations of power (15.7 MW) from the Western Area Power Administration (WAPA). Both of these MMPA members have a contract with WAPA through 2020. WAPA could reduce the amount of energy and power available to its customers. This would represent a policy change from the past. If WAPA decreases the power available to its customers, MMPA's demand requirements would increase, as the Agency provides all of the power to the two cities that is not supplied by WAPA. This IRP assumes that WAPA supplies remain at 2010 to 2015 contract amounts throughout the projection period.

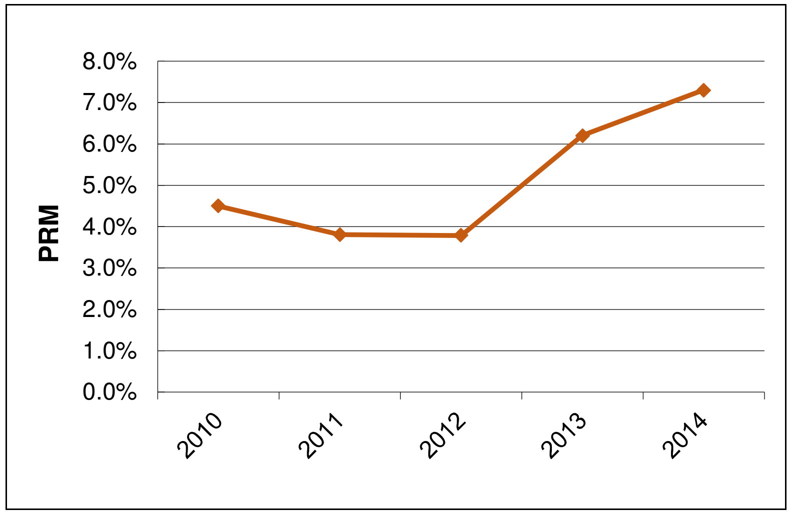
Effect Of Electric Vehicle Use On Demand Requirements Is Unclear

As discussed in Section 4, the commercialization and development of plug in electric and hybrid vehicles has been slower than anticipated. As this technology penetrates the markets, we would expect that charging of electric vehicles would primarily occur at night. It is possible that these vehicles could be connected to the grid in parking lots during the day and used as a power source during times of peak demand. However, a high level of penetration of electric vehicles would be necessary to affect MMPA's level of demand. This IRP assumes no increase in demand requirements during the projection period as the effect of electric vehicle use on demand requirements is unclear.

MISO Planning Reserve Margin (PRM) Increases Would Increase Capacity Requirements (PRMR)

MISO's Planning Reserve Margin (PRM) was reduced from 4.5% for PY 2010 to 3.81% for PY 2011. The PRM was further reduced to 3.79% for PY 2012 but then increased to 6.2% for PY 2013. The most recent MISO Loss of Load Expectation working group recommended a PRM of 7.3% for the upcoming planning year 2014 (see graph below for recent PRM percentages). This IRP uses a PRM of 7.5% to calculate MMPA's Planning Resource Margin Requirements, which is slightly more conservative than the MISO PY 2010 – 2014 PRM values.

MISO Planning Reserve Margin



A Change In Transmission Losses Would Change PRMR

MMPA's entire load is in MISO Zone 1. In 2012, approximately 95% of MMPA's load was in the NSP Load Balancing Area (LBA) while the remaining 5% was in the OTP LBA. NSP transmission losses in 2012 were 2.4% and OTP's were 4.6%. Starting with PY 2019, MMPA will also serve load in the GRE LBA, which had a 2012 transmission loss rate of 1.3%. This IRP uses 2.5% transmission losses for calculation of its MISO Planning Resources Margin Requirements (PRMR), or demand requirements. However, a change in these transmission losses would change MMPA's PRMR.

Increased Generation Forced Outage Rate Would Reduce Recognized Capacity

An increased generation forced outage rate, as measured by Equivalent Demand Forced Outage Rate (EFORd), would decrease the capacity market credits MMPA would receive. This would effectively increase MMPA's capacity requirements. Faribault Energy Park (FEP) historically had EFORds that are well under the MISO class average. Going forward, this IRP assumes that FEP EFORd will increase to match the current MISO class average in 2014.

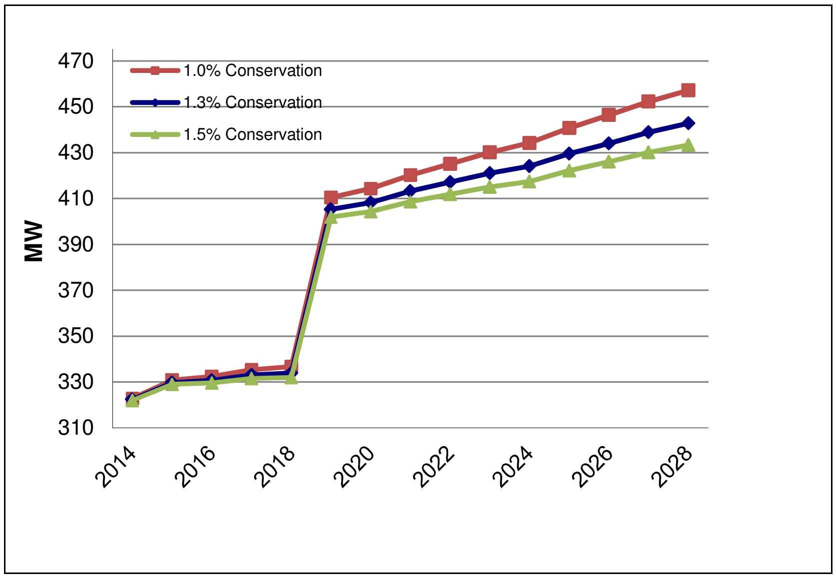
Minnesota River Station (MRS) EFORds have been improving and this IRP assumes that MRS EFORds will decrease to match the MISO class average in 2014.

Lower Conservation Rates Would Increase Capacity Requirements

Lower conservation rates would increase capacity requirements. Although this IRP assumes a 1.3% energy conservation rate for planning purposes, high and low cases of 1.5% and 1.0% conservation were also considered. See Section 6 and Appendix A for further details on conservation.

The graph below shows MMPA's CP demand projections based upon 1.0%, 1.3%, and 1.5% conservation levels. These demand projections include 2.5% transmission losses and a 7.5% planning reserve margin. Although MMPA strives to meet the 1.5% conservation goal, MMPA uses 1.3% conservation adjustments for the projection period.

Minnesota Municipal Power Agency
Projected Conservation-Adjusted Member CP Demand (MW)



Section 6. Energy Conservation/Demand Side Management

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

State Legislature Established A CIP Energy Savings Target

In 2007, the State Legislature revised the Conservation Improvement Program (CIP) statute to set an annual energy savings goal for each electric utility beginning in 2010.

Through 2013, eight of MMPA's 12 members participate in the MMPA CIP program managed by the Agency while the other three members manage their own energy efficiency programs at the municipal utility level. As discussed earlier, Elk River Municipal Utilities, the twelfth member that joined MMPA in June 2013, will not be buying its energy requirements from MMPA until October 2018.

Beginning in 2014, seven of MMPA's 12 members will participate, and beginning in 2019 Elk River is expected to join these seven to participate in the MMPA CIP program managed by the Agency, while the other four members will manage their own energy efficiency programs at the municipal utility level.

2012 CIP Figures Point To Steady Performance

MMPA's participating members met their 1.5% CIP Spending Requirement and achieved CIP savings of 1.4% for 2012.

MMPA CIP Spending 2009-2012

MMPA has consistently met its annual CIP spending goal of 1.5%. The table below shows historical annual CIP dollars spent and their percentage of Gross Operating Revenue (GOR) over the period 2009 through 2012.

	2009	2010	2011	2012
Spending	$911,609	$891,140	$753,955	$856,506
% of GOR	1.6%	1.5%	1.5%	1.5%

MMPA kWh Savings 2009-2012

MMPA has shown steady success in meeting its annual CIP kWh savings goal of 1.5%. The table below shows historical annual kWh saved over the period 2009 through 2012.

	2009	2010	2011	2012
kWh Savings	3,020,104	8,390,622	9,409,154	8,954,766
% of Sales	n/a	1.3%	1.5%	1.4%

Note: kWh savings reflect transmission & distribution losses of 7.5% to be consistent with figures calculated by the DOC.

MMPA Strives To Meet Its 2013 CIP Spending Requirement And Energy Savings Target

MMPA strives to meet its 2013 CIP spending requirement and energy savings target.

MMPA has undertaken significant efforts to develop a CIP portfolio that will meet its CIP energy savings target in 2013 and beyond.

This IRP Assumes 1.3% Savings for Projections

As described in Sections 4 and 5 and Appendix A, this IRP assumes a CIP savings rate of 1.3%, although a low case of 1.0% and a high case of 1.5% were also analyzed.

MMPA Focuses Its CIP Spending On End-User Conservation

Based upon data for 2012, MMPA met its internal goal of $0.10 per kWh saved for dollars spent on conservation improvement.

MMPA believes that it will have a continuing energy savings impact during the 2014-2028 projection period by focusing on developing CIP strategies with the lowest cost per kWh of electricity saved.

Lighting And Custom Rebates Are Best Performing Programs

MMPA's CIP portfolio includes lighting and custom projects. In 2012, 37% of MMPA's Agency-managed CIP rebate spending went toward lighting projects. The table below highlights the return on investment in MMPA's 2012 CIP cycle.

Project Type	kWh saved	2012 Cost/kWh saved
Commercial Lighting – New	1,607,992	$0.02
Commercial Lighting - Retrofit	3,073,879	$0.07
Residential CFL	28,999	$0.03

Custom rebates are unique in that they give MMPA flexibility to support its customers on projects with high energy savings potential. These projects also tend to achieve a good return on investment, an average rebate cost of $0.11 per kWh of electricity saved in 2012. Custom rebates made up 20% of MMPA's Agency-managed CIP rebate spending in 2012.

Other high performing rebates include the refrigerator recycling bonus ($0.05/kWh electricity saved), which creates customer incentives to unplug inefficient refrigerators, and variable frequency drives ($0.06/kWh electricity saved), which improve system operation.

Agency-Managed CIP Portfolio Centers On Rebate Effectiveness

Based upon data for 2012, MMPA's CIP program cost an average of $0.10/kWh of electricity saved.

In 2013 and beyond, MMPA's Agency-managed CIP portfolio will incorporate rebates and programs that help to maintain an average rebate cost-to-electricity savings ratio of $0.10/kWh or less.

Programs offered in the Agency-Managed 2013 CIP Portfolio include:

Residential: Clothes Washer, Dishwasher, Refrigerator, Refrigerator Recycling Bonus, Compact Fluorescent and LED Lighting, Central Air Conditioning (AC) and Air Source Heat Pump Quality Installation, AC Tune Up, Home Energy Audit

Commercial: Lighting Retrofit, Lighting New Construction, Motors, Variable Frequency Drives (VFD), Custom Rebates, Vending Machine Controller

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MMPA Members Enhance Low-Income CIP Strategies

In 2012, MMPA's participating members spent over $24,300 on low-income energy conservation.

Low-income conservation program spending is tracked at the city level; each city must meet the spending requirements when calculated individually. Tracking the actual low-income energy savings and participation rate remains an administrative and reporting challenge. MMPA is concentrating on developing programs that provide direct benefits to low-income customers.

MMPA Currently Has No Load Curtailment Program

Prior to 2010, MMPA's customers had the ability to curtail up to 16,513 kW of demand through various load curtailment programs. MMPA retired its load curtailment program in favor of focusing on CIP program when MMPA's curtailment program became a less competitive option to acquire capacity as market prices of capacity became less expensive. Below is a table showing MMPA's cost of operating and maintaining its curtailment program:

Year	Demand Curtailment Potential (kW)	Cost to Operate and Maintain ($)
2005	11,547	426,938
2006	15,703	522,096
2007	16,184	576,852
2008	16,337	586,296
2009	16,513	592,356

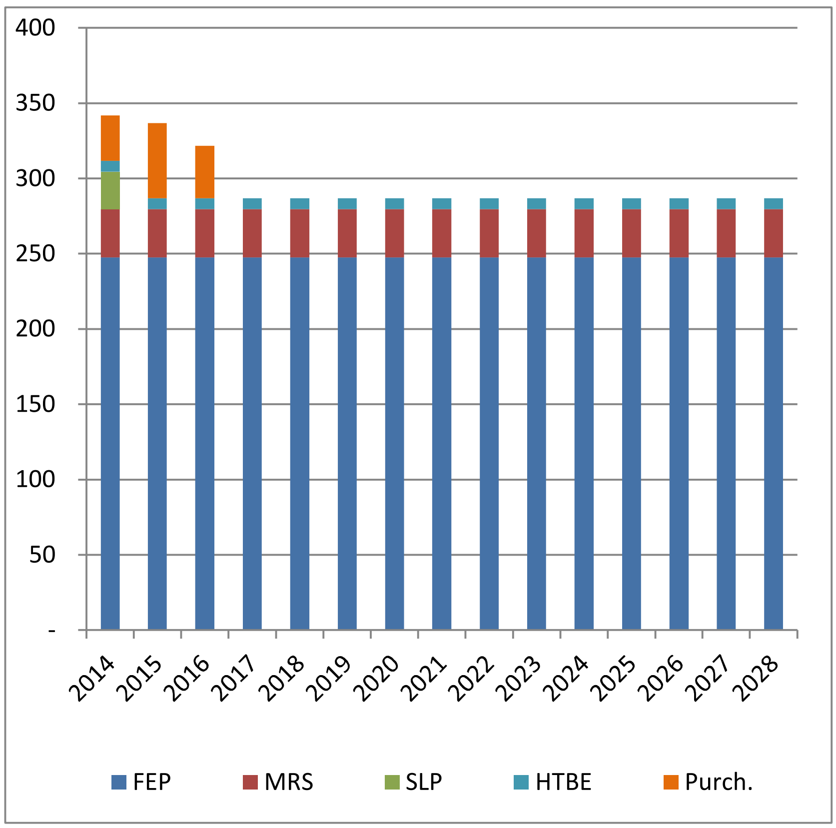
Section 7. Existing Resources

MMPA's existing resource portfolio is a mix of owned generation and power purchase agreements.

MMPA Has 342 MW Of Power Supply Resources

MMPA has a power supply portfolio that consists of 342 MW of both contractual resources and Agency-owned generation for Planning Year (PY) 2014. The graph below shows MMPA's existing resources over the period 2014 to 2028.

Minnesota Municipal Power Agency
Power Supply Resources – Summer Capacity In MW
2014 to 2028



Key:
FEP: Faribault Energy Park
MRS: Minnesota River Station
SLP: Rochester Public Utilities' Silver Lake Contract
HTBE: Hometown BioEnergy
Purch: Bilateral Purchases

MISO Capacity Measured By Unforced Capacity

MISO capacity is measured by Unforced Capacity (UCAP). UCAP is calculated by multiplying the Installed Capacity (ICAP) of a generating resource by 1 minus the Effective Forced outage Rate (EFORd). Once the UCAP of a resource is calculated, market participants can convert UCAP to Zonal Resource Credits (ZRCs) to get capacity.

Faribault Energy Park Is An Innovative 261 MW Combined Cycle Power Plant

Faribault Energy Park (FEP) is the first power supply resource financed and built by MMPA. The plant was built in two phases, with simple cycle operation beginning in April 2005. The combined cycle phase began operations in the summer of 2007, improving the fuel efficiency and increasing the maximum accredited summer output of the plant to 261 MW.

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 wetlands area is open to the public as a park with several small 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.

The plant uses natural gas as its primary fuel, with fuel oil as a backup.

FEP's ICAP for PY 2013 is 260.9 MW. The EFORd used to calculate FEP's 2013 UCAP is 1.79% which is much better than the class average for similar generators in MISO of 5.11%. This IRP conservatively assumes that FEP's EFORd will rise to match the 2013 MISO class average in 2014 and remain at this level for the projection period through 2028.

MMPA's UCAP from FEP is reduced by about 13 MW for 2013 because of capacity sales to other utilities.

	2013	2014-2028
FEP		
ICAP	260.9	260.9
EFORd	1.79%	5.11%
UCAP/ZRC	256.2	247.6
Capacity sales	13.4	-
UCAP/ZRC	242.8	247.6

Minnesota River Station Is A 41 MW Peaking Combustion Turbine

The Minnesota River Station (MRS) plant is MMPA's peaking resource. The City of Chaska, one of the Agency's members, owns the plant and sells the entire output to MMPA under a long-term contract. MRS became operational in the summer of 2001 and is accredited for approximately 41 MW in the summer. Like FEP, Minnesota River Station uses natural gas as its primary fuel.

MRS ICAP for PY 2013 is 40.6 MW. The EFORd used to calculate MRS's 2013 UCAP is 28.12% which is higher than the class average of 21.23% for similar generators in MISO. Taking into consideration the improvements in MRS EFORd over the past few years, this IRP assumes that MRS's EFORd will improve slightly to match the 2013 MISO class average in 2014 and remain at this level for the projection period through 2028.

		2013	2014-2028
MRS			
	ICAP	40.6	40.6
	EFORd	28.13%	21.23%
	UCAP/ZRC	29.2	32.0

Contract With Rochester Public Utilities Provides 25 MW Of Capacity And Energy

MMPA has a contract with Rochester Public Utilities (RPU) related to the output of RPU's Silver Lake Plant (SLP). MMPA purchases 25 MW of capacity and energy from SLP through May 31, 2015.

SLP is projected to provide 25MW of UCAP for PY 2014.

		2013	2014	2015-2028
SLP				
	ICAP	25	25	0
	EFORd	0	0	0
	UCAP/ZRC	25.0	25.0	-

Oak Glen Wind Farm Is A 44 MW Wind Farm

Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm. It is 44 MW and is located near Blooming Prairie, Minnesota.

It was awarded a U.S. Department of Energy "2012 Public Power Wind Award" for leadership, innovation, project creativity and benefits to customers. OGWF's innovative ownership and financial structure qualified the wind project to receive a $25.4 million federal grant.

OGWF ICAP for PY 2013 is 44 MW. For wind resources, MISO uses capacity credit instead of EFORd. The UCAP is simply calculated by multiplying the ICAP by the capacity credit. The capacity credit used to calculate OGWF's 2013 UCAP is 19.77%. Because of wind's variability, this IRP assumes that OGWF will not receive any capacity for 2014-2028.

	2013	2014-2028
OGWF		
ICAP	44	44
Capacity Credit	19.77%	0
UCAP/ZRC	8.7	-

Hometown BioEnergy Projected To Provide 8 MW

Hometown BioEnergy (HTBE) is projected to provide MMPA with 8 MW of installed capacity via anaerobic digestion to produce biogas that will fuel its reciprocating engines. The facility is projected to be in service by the end of December 2013.

HTBE is located in, and directly interconnected with, the City of Le Sueur, which is an MMPA member community.

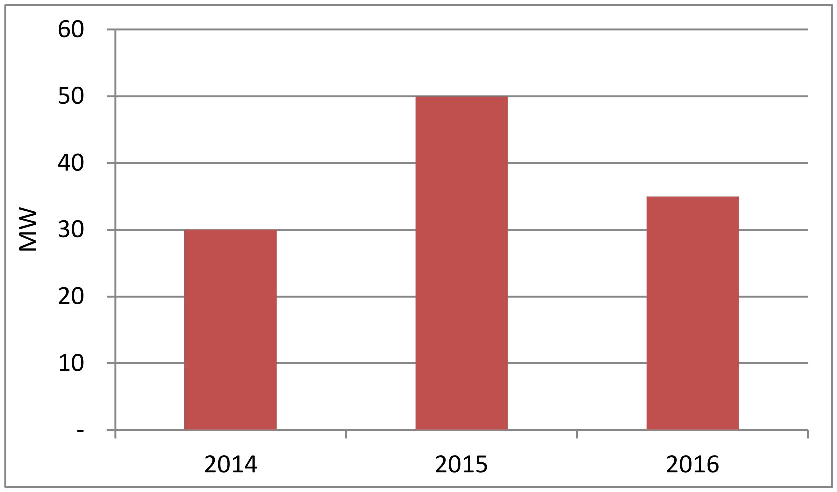
HTBE ICAP for PY 2014 is projected to be 8 MW. The EFORd used to calculate HTBE's 2014 UCAP is 9.75%, which is the class average for diesel generation in MISO in 2013. HTBE will be using reciprocating engines, and we expect it to have better EFORd than MISO class average for diesel generation. This IRP conservatively assumes that HTBE's EFORd will match the 2013 class average for diesel generation for the projection period through 2028.

	2013	2014-2028
HTBE		
ICAP	0	8
EFORd	0	9.75%
UCAP/ZRC	-	7.2

MMPA Purchased Capacity For 2014-2016

MMPA has purchased between 30 and 50 MW of MISO Aggregate Planning Resource Credits (APRCs) for 2014 through 2016:

Minnesota Municipal Power Agency
Capacity Purchases (ZRCs)
2014-2016



MMPA Buys Energy From MISO Under Current Market Structure

MMPA buys all energy for its load from the MISO energy market. Under the current market structure, MMPA also sells the output of all of its power supply resources to MISO, except for HTBE, which is directly interconnected with the distribution system.

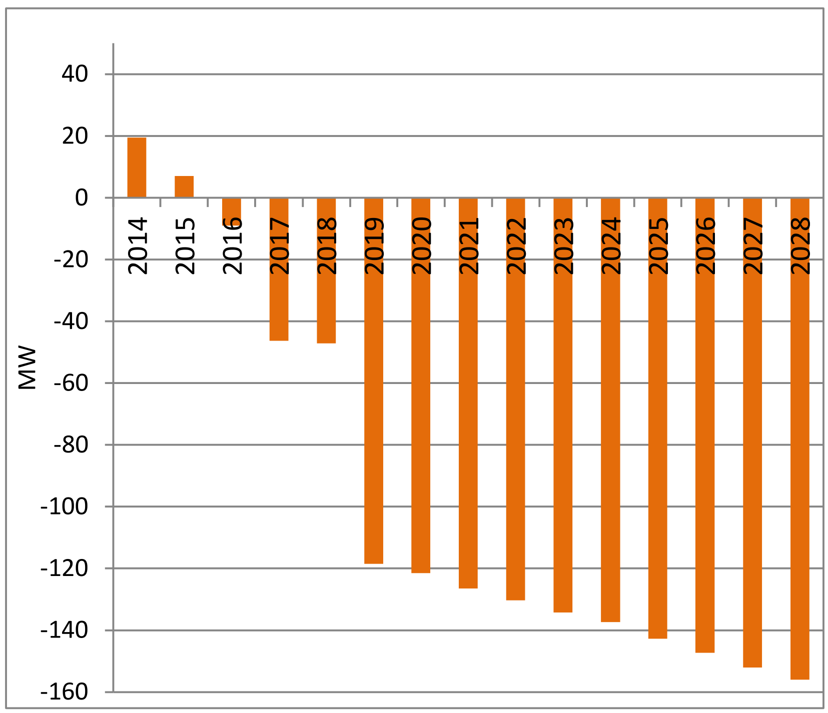
Section 8. Additional Generation Requirements

This section describes MMPA's projected additional generation requirements over the planning period.

MMPA Is Projected To Need New Capacity In PY 2016

MMPA is projected to need new capacity in Planning Year (PY) 2016. The chart below shows MMPA's projected capacity position by year during the projection period.

Minnesota Municipal Power Agency
Projected Capacity Position
2014-2028



MMPA's Projected Capacity Need Grows From 9 MW In 2016 To 156 MW In 2028

MMPA's projected capacity need grows from 9 MW in 2016 to 156 MW in 2028. The increasing need is the result of member growth, the expiration of existing supply contracts, and the addition of Elk River.

Planning Reserve Margin Requirement Of 7.5% Is Assumed

MMPA currently participates in the MISO Planning Reserve Margin (PRM) pool. This IRP assumes a PRM of 7.5% for the projection period. Any change in this PRM would change MMPA's capacity needs, as discussed in previous sections.

Transmission Losses Are 2.5% Transmission losses of 2.5% are assumed for this IRP, as discussed in previous sections.

Section 9. Planning Approach and Resource Prospects

This section outlines MMPA's planning approach and describes both the conventional and renewable resource prospects considered by the Agency in this IRP.

Maintain Flexibility In Power Supply Plan

MMPA seeks to maintain flexibility in its power supply plan. The uncertainty in the electric utility industry makes flexibility vital to any planning process.

Buy Capacity When Cost Effective

MMPA maintains long term relationships with many MISO market participants and looks for opportunities to buy capacity when cost effective.

Construct Facilities Of Economic Generation Size

The cost of adding new resources can vary greatly depending on the size and technology of the resources. MMPA will construct facilities of economic generation size and buy additional capacity to meet its members' requirements, as necessary. For instance, if building 50 MW of generation is more economical than building 60 MW of generation, then MMPA would purchase 10 MW to bridge the capacity shortage.

Agency Is Committed To Sustainable Energy

The Agency is committed to sustainable energy. MMPA plans to meet or exceed Minnesota's Renewable Energy Standard (RES). Section 14 further discusses MMPA's plan to meet this renewable requirement.

MMPA Is Developing 333 MW Of Resource Prospects

MMPA views potential future power supply alternatives as resource prospects. The high amount of uncertainty in the electric utility industry makes it impossible to rely completely on any particular resource being implementable in a given year. Transmission, permitting, environmental regulation, or other factors can change the feasibility or economics of any given resource prospect.

It is important to note that MMPA's planning approach from its 2008 and 2011 IRPs resulted in the construction of the Oak Glen Wind Farm and Hometown BioEnergy Facility.

In this IRP, MMPA is developing resource prospects with up to 333 MW of capacity. Because some of these prospects are wind projects, the total accredited capacity would be less than 333 MW. The resource prospects are as follows:

Renewable
- Wind PPAs – 138 MW
- Exploring additional wind PPAs
- Exploring hydro PPAs

Conventional
- Distributed Generation, Natural Gas – Up to 155 MW

These resource prospects are greater than MMPA's needs because of the uncertainty in the electric utility industry. By developing projects in excess of its needs, the Agency retains the planning flexibility that is vital to success in today's market.

MMPA Has Signed Three Wind PPAs Totaling 138 MW

MMPA has signed three wind PPAs that total 138 MW of generating capacity. The contract commercial operation dates (COD) and the capacity of these PPAs are as follows:

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TRADE SECRET DATA ENDS]

These PPAs will help MMPA achieve the Agency's Renewable Energy Standard obligations.

MMPA Is Exploring Additional PPAs With Wind Developers

MMPA is exploring purchased power agreements (PPAs) with other wind developers. The current environment in the wind industry is unstable because of uncertainty regarding extension of the Production Tax Credits (PTCs) and uncertainty regarding transmission availability. As discussed further in Section 11, the Agency would also consider C-BED projects to the extent that they are feasible and economic.

MMPA Is Exploring Hydro PPAs

MMPA is exploring hydro PPAs with other counterparties.

Agency Is Pursuing Distributed Generation Fired

MMPA's analysis indicates that distributed generation is one of the least cost ways for the Agency to meet its planning reserve margin requirements. Distributed generation also improves system

With Natural Gas

reliability in member communities and, by connecting with members' distribution systems, avoids the uncertainty and costs associated with the transmission interconnection process.

The Agency is pursuing distributed generation fired with natural gas in its member communities. Under this approach, MMPA would install small natural gas fired generators in 5 to 25 MW increments in larger member cities. The Agency estimates that it could install up to 155 MW of distributed generation fired with natural gas across its member communities by 2028.

Section 10. Analytical Model and Results

This section describes the analytical model used by MMPA to determine both its short-range action plan and its long-range plan.

Total Cost Model Used To Evaluate Traditional Resource Alternatives

A total cost per kilowatt model was used to evaluate resource alternatives. This model graphs a given resource's total cost on the vertical (y) axis in dollars per kilowatt. The resource's capacity factor is displayed on the horizontal (x) axis as a percentage of the time the resource is operating.

Various Technologies Were Evaluated

The Agency's total cost model was used to evaluate five technologies:

- Coal
- Nuclear
- Combined Cycle Combustion Turbine
- Simple Cycle Combustion Turbine
- Distributed Generation

MMPA's analysis assumes that renewable energy is pursued as needed to meet Minnesota's Renewable Energy Standard, and it is not evaluated in this section. A description of MMPA's efforts to meet the RES can be found in Section 14.

Cost Estimates And Other Assumptions Were Developed For Each Technology

Cost estimates, including capital costs, fixed and variable O&M, and fuel costs were developed for each technology. Other assumptions, such as the heat rate and emissions rates for various pollutants, were also developed.

The costs of transmission are not included in this analysis because transmission costs are project specific.

Low, Base, High And No Externality Cost Scenarios

Scenarios using both the low and high environmental externality costs as established by the Public Utilities Commission for various emissions (SO_x, NO_x, CO_2) were used in the analysis. The PUC-established low and high values of $9 and $34 per ton of CO_2 were also included in the analysis. The base case uses the midpoint externality costs.

Low, Base And High Capital Cost Scenarios

Low, base and high capital cost scenarios were used in the analysis. The following capital costs are in 2013 $/kW:

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Low, Base, High Fuel Cost Scenarios

Low, base and high fuel cost scenarios were used in the analysis. The following range of fuel costs are in 2013 $/kWh:

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Nine Scenarios Were Analyzed

Nine scenarios were constructed and analyzed. These scenarios are:

- Base case: base capital cost, base fuel costs, base externalities
- Case 1: low externalities
- Case 2: high externalities
- Case 3: low fuel cost
- Case 4: high fuel cost
- Case 5: low capital cost
- Case 6: high capital cost
- Case 7: high natural gas cost
- Case 8: no externalities

Model Indicates Most Cost-Effective Mix Of Resources

The results of MMPA's total cost model are shown below. The most cost-effective mix of dispatchable resources is represented by the line segments that run closest to the bottom of the graph.

The lowest fixed cost resource was assumed to be used to meet the Agency's reserve requirements.

Natural Gas Fired Generation Is The Least Cost Resource In The Base Case

Natural gas fired generation is the least cost resource under the base case. Distributed generation is the lowest cost for almost all capacity factors, followed by combined cycle and combustion turbine.

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Natural Gas Fired Generation Is The Least Cost Resource Under Low And High Externalities

Natural gas fired generation is the least cost mix in the low and high externalities cases.

Similar to the base case, in low and high externality cases, distributed generation is the lowest cost resource for most capacity factors (specifically between 10% and 70%), followed by combined cycle and combustion turbine. Nuclear becomes competitive with combustion turbine above a 90% capacity factor in the low and above a 70% capacity factor in the high externality case.

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Natural Gas Fired Generation Is The Least Cost Resource Under Low and High Fuel Cost Scenarios

Distributed generation is the least cost resource over a 5% capacity factor in the low fuel cost scenario. Combustion turbine is the next least cost generation until about a 35% capacity factor, after which combined cycle becomes the least cost resource behind distributed generation.

Distributed generation is the least cost resource between a 5% and 75% capacity factor in the high fuel cost scenario, after which nuclear becomes the least cost resource.

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Natural Gas Fired Generation Is The Least Cost Resource Under Low and High Capital Cost Scenarios

Distributed generation is the least cost resource between a 5% and 80% capacity factor in the low capital cost scenario after which nuclear becomes the cheapest resource. Under the high capital cost case however, distributed generation resources are the least cost at almost all capacity factors.

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Natural Gas Fired Generation Is Still The Least Cost Resource Under High Natural Gas Scenario

Case 7 was constructed by assuming high fuel costs for natural gas fired resources and base fuel costs for coal and nuclear resources. Under this scenario, up to a 75% capacity factor, distributed generation and combined cycle resources are still the least cost options, after which nuclear becomes the least cost resource.

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Under The No Externalities Case, Natural Gas Fired Generation Is The Least Cost Resource

Under the no externalities case using base capital and base fuel costs, distributed generation is the least cost resource addition followed by combined cycle and combustion turbine.

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Natural Gas Alternatives Present A Tradeoff Between Efficiency And Location

In all of the scenarios, natural gas alternatives present a tradeoff between efficiency and locational advantages. For instance, whereas combined cycle gas fired generation would have the best efficiency from a heat rate perspective, it might have to be located further away from load because of challenges with land, transmission, and gas supply availability. On the other hand, distributed generation could be located right at load because of its smaller size, but it is less efficient than combined cycle generation.

Addition Of Transmission Costs Would Make Generation Connected to the Transmission System More Expensive

As discussed earlier, the costs of transmission are not included in the above analysis because transmission costs are project specific. However, it is important to note that including transmission costs would further improve the economics of distributed generation. Generation connected to the transmission system would be required to pay for MISO interconnection costs, whereas generation directly connected to the distribution system would avoid these costs.

Section 11. Short Range Action Plan

This section outlines MMPA's short range action plan for the years 2014 to 2018.

Add Distributed Generation

The following table outlines MMPA's preferred short range action plan:

Minnesota Municipal Power Agency
Preferred Short Range Action Plan
2014 to 2018

Year	Resource Addition
2015	Add 10 MW of Distributed Generation
2016	Add 15 MW of Distributed Generation
2017	Add 15 MW of Distributed Generation
2017	Purchase 6 MW of Market Capacity
2018	Add 15 MW of Distributed Generation

MMPA's analysis from the previous section shows that distributed generation is the most effective resource to meet the Agency's needs. Two uncertainties particularly complicate MMPA's planning process: fuel prices and environmental legislation.

The fuel scenarios in this IRP are based on natural gas prices of \$3.18 to \$6.36 per MMBtu in 2013 dollars. EIA's 2013 Annual Energy Outlook projected natural gas prices to be about \$5.20/MMBtu by 2028 in 2011 dollars. If natural gas prices return to 2007-2008 levels, then other technologies such as coal or nuclear could be lower cost resources.

However, long lead times of 10 years or more, as well as uncertainty surrounding environmental legislation, make committing to baseload generation difficult. Baseload resources also diminish the Agency's ability to respond to changes in demand and market conditions. Therefore MMPA still believes that it would be wise not to commit to a baseload generation technology until some of the above mentioned uncertainty is resolved.

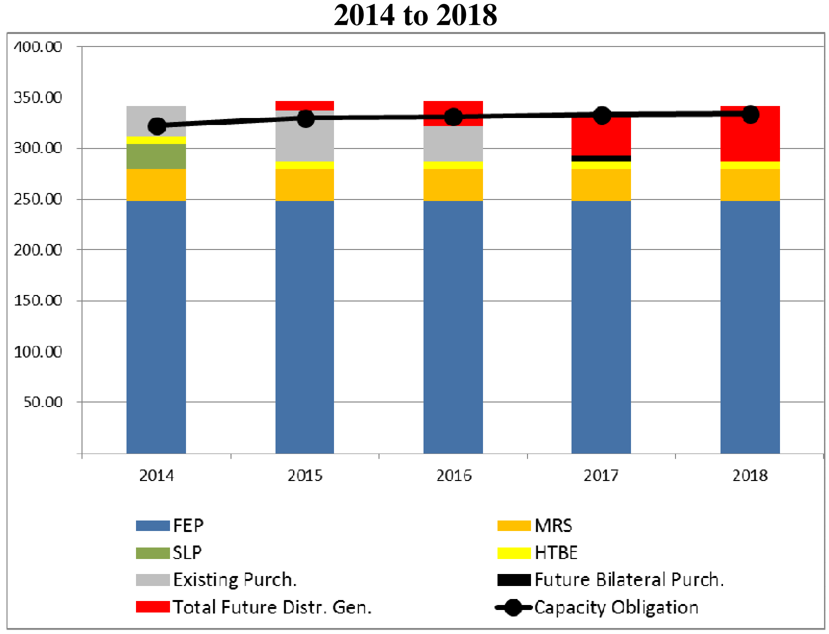
In addition, MMPA's required capacity additions are relatively small and as such, installing large generation in front of the meter does not address MMPA's capacity needs in the most effective and cost efficient way. MMPA plans to build new generation to match its needs and avoid the short-term excess capacity that often results from building a larger resource. The Agency also plans to maintain flexibility to respond to changes in projected demand growth.

Therefore, in this IRP, the Agency's preferred short range action plan still focuses primarily on distributed generation as it can be built more quickly and for a lower cost than baseload technology; it avoids lengthy and costly MISO transmission interconnection process; it provides better flexibility than baseload or large gas turbines to respond to changes in market and demand conditions and better addresses MMPA's incremental capacity needs.

MMPA is also pursuing a significant amount of renewable energy. As reported in previous sections of this IRP, MMPA has signed wind PPAs for 138 MW and is pursuing additional wind resources as well. Wind resources are the dominant renewable resource in most electric utilities' portfolios. However, because of wind's limited ability to contribute to MISO's generation stack at the time of MISO's peak, MISO capacity credits for wind resources range between a couple of percent to about thirty percent. The class average capacity credit for MISO wind resources for Planning Year 2014 is 14.1%. Given the wide range and the variability of wind capacity credits, MMPA does not account for capacity from its existing and planned wind resources. Furthermore, this section does not include MMPA's wind generation efforts. Section 14 further discusses MMPA's plans for renewable generation additions.

The following graph shows MMPA's power supply resources and projected capacity requirements under the preferred short range action plan.

Minnesota Municipal Power Agency
Power Supply Resources and Requirements (Summer MW)
Preferred Short Range Action Plan
2014 to 2018



MMPA's Preferred Plan Is Implementable

MMPA's preferred short range action plan is implementable even with the high level of uncertainty in the electric utility industry. The plan is also flexible, giving the Agency the opportunity to respond to changes in member demand, economic conditions, or relative fuel prices.

In addition to the plan outlined above, MMPA plans to take the following actions regarding its future power supply.

Continue To Develop And Market Cost-Effective Conservation Programs

MMPA will continue to develop and market cost-effective conservation programs for its member utilities to offer to their retail customers. The Agency's philosophy is to focus on programs that generate the most energy savings per dollar spent. MMPA also remains committed to providing energy efficiency programs that benefit Minnesota's low income households.

Continue Pursuing Renewable Resources

MMPA will continue to pursue renewable resources. MMPA's existing and planned renewable resources are expected to provide the renewable energy needed for MMPA's compliance with Minnesota's Renewable Energy Standard.

Pursue C-BED Projects Where Available And Economic

MMPA is also committed to Community Based Energy Development (C-BED). The Agency will pursue C-BED projects where they are available and economic. MMPA's website advertises the Agency's interest in C-BED projects and provides contact information for interested developers.

Section 12. Long Range Plan

This section outlines the Agency's long range plan for the years 2019 to 2028.

Add Distributed Generation

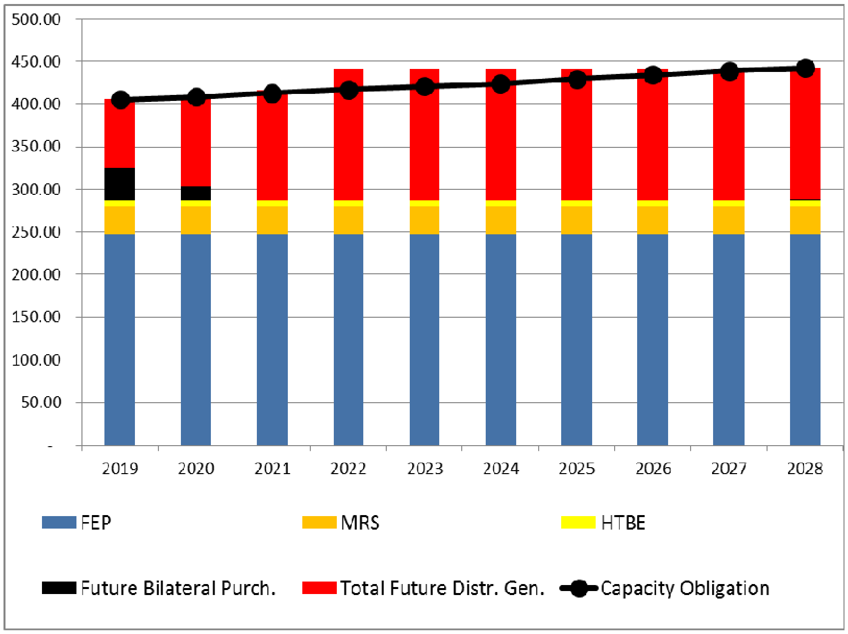
The Agency's long range plan involves the addition of distributed generation. The following table outlines MMPA's preferred long range plan:

Minnesota Municipal Power Agency
Preferred Long Range Plan
2019 to 2028

Year	Resource Addition
2019	25 MW of Natural Gas Fueled Distributed Generation
2019	39 MW of Market Purchased Capacity
2020	25 MW of Natural Gas Fueled Distributed Generation
2020	17 MW of Market Purchased Capacity
2021	25 MW of Natural Gas Fueled Distributed Generation
2022	25 MW of Natural Gas Fueled Distributed Generation
2028	1 MW of Market Purchased Capacity

The following graph shows MMPA's power supply resources and projected capacity needs under the preferred long range plan.

Minnesota Municipal Power Agency
Power Supply Resources and Requirements (Summer MW)
Preferred Long Range Plan
2019-2028



Largest Annual Increase In MMPA Capacity Needs Is 71 MW In 2019

The largest annual increase in MMPA's capacity needs (above its existing resources) between 2014 and 2028 is 71 MW in 2019, when the Agency starts serving Elk River. The following table shows MMPA's capacity position with its existing resources:

	Resources UCAP/PRCs	Capacity Needs	Capacity Surplus/(Deficit)	Yearly Change
2014	342	322	19	-
2015	337	330	7	(12)
2016	322	331	(9)	(16)
2017	287	333	(46)	(37)
2018	287	334	(47)	(1)
2019	287	405	(119)	(71)
2020	287	408	(122)	(3)
2021	287	413	(126)	(5)
2022	287	417	(130)	(4)
2023	287	421	(134)	(4)
2024	287	424	(137)	(3)
2025	287	430	(143)	(5)
2026	287	434	(147)	(5)
2027	287	439	(152)	(5)
2028	287	443	(156)	(4)

MMPA Continues to Develop Strategies To Reduce Environmental Footprint

MMPA continues to develop strategies to reduce its environmental footprint. MMPA has expanded its CIP offerings, focused its CIP spending on end-user conservation and enhanced its low income CIP strategies.

In addition, MMPA took significant action regarding renewables by constructing the Oak Glen Wind Farm, constructing Hometown BioEnergy and signing 138 MW of wind PPAs.

Distributed Generation Provides Implementation Flexibility

Having the ability to add more distributed generation provides implementation flexibility for MMPA. As discussed in the previous sections, distributed generation can be built more quickly and for a lower cost than most technologies. In addition, since distributed generation can be built in smaller increments than most other technologies, MMPA could build new generation to match its needs and avoid the short-term excess capacity that often results from building a larger resource.

Section 13. Transmission

This section describes the Agency's position on transmission.

MMPA Became a MISO Transmission Owner in 2013

MMPA became a transmission owning member of MISO in 2013.

MMPA Currently Owns Limited Transmission Assets

MMPA members own limited transmission assets throughout the state of Minnesota. The Agency is registered as a Transmission Owner for facilities in Chaska.

MMPA Purchases Transmission Service From Xcel And MISO

The Agency currently purchases most of its transmission service needs from Xcel Energy under a grandfathered contract that expires at the end of 2015. MMPA also purchases transmission service from MISO. After 2015 MMPA will purchase all of its transmission from MISO.

MMPA Plans To Invest In Transmission Facilities To Meet Load And Generation Requirements

MMPA plans to increase its investment in transmission resources. MMPA is in discussions with local utilities to purchase existing or future transmission assets. The Agency is specifically interested in investing in transmission projects that would enhance the delivery of electricity to MMPA's member communities. MMPA would partner with other entities to develop new facilities and upgrade existing facilities.

MMPA's Distributed Generation Approach Would Benefit Transmission System

The distributed generation approach proposed in this Integrated Resource Plan would benefit the transmission system. MMPA generation resources would be located close to load, and therefore use little to no bulk transmission system resources. Furthermore, the use of distributed generation (as opposed to larger plants) requires less MISO planning. MMPA would add reliable generation to the system quickly, without contributing to the congested MISO interconnection queue.

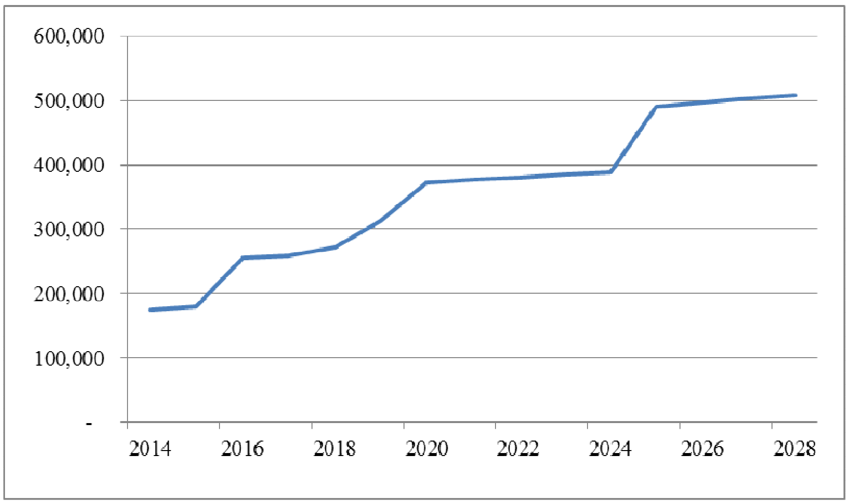
Section 14. RES Compliance and Its Rate Impact

This section describes MMPA's efforts toward meeting the State of Minnesota's Renewable Energy Standard (RES).

MMPA's REC Requirements Are Projected To Grow From 174,000 In 2014 To 509,000 In 2028

MMPA's annual Renewable Energy Credit (REC) requirements are projected to grow from 174,000 in 2014 to 509,000 in 2028. It is important to note that the steep increase in REC requirements in 2018 is mainly because MMPA begins to serve Elk River as a new member.

Projected MMPA REC Requirements 2014-2028



MMPA Has RECs In Its Inventory

The Agency currently has 756,191 RECs in its inventory. MMPA actively follows the REC markets and seeks opportunities to buy RECs to satisfy its future requirements. Below is the breakdown of MMPA's current REC inventory:

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MMPA Purchased Additional RECs

In addition to the RECs currently in its inventory, MMPA has purchased from counterparties RECs to be generated in the future:

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MMPA Completed Service 44 MW Oak Glen Wind Farm

MMPA placed the 44 MW Oak Glen Wind Farm (OGWF) in service in October 2011. OGWF is projected to generate approximately 150,000 MWh per year.

Hometown BioEnergy In Service by End of 2013

By the end of December 2013, MMPA plans to place the Hometown BioEnergy Project (HTBE) in service. This facility will generate 8 MW of electricity by converting agricultural processing residues to biogas. HTBE is projected to generate approximately 30,000 MWh per year.

MMPA's Hometown WindPower Is In Service

MMPA's Hometown WindPower project has been in service since March 2010. This effort made MMPA the first power agency with a wind turbine in each of its member communities except Elk River, as Elk River became a member in 2013. Hometown WindPower is expected to produce approximately 1,000 MWh of renewable energy annually for the Agency.

MMPA Signed Three Wind PPAs Totaling 138 MW

MMPA has signed three wind Power Purchase Agreements (PPAs) that total 138 MW of generating capacity. The PPA terms are 20 year or longer. The contract commercial operation deadlines (COD) and the capacity of these PPAs are as follows:

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These PPAs are expected to help MMPA meet the Agency's

Renewable Energy Standard obligations by producing approximately 480,000 MWh of renewable energy annually.

MMPA Is Seeking Other PPAs With Wind Developers

MMPA is still seeking PPAs with other wind developers. The current environment in the wind industry is unstable because of uncertainty regarding extension of the production tax credit (PTC) and uncertainty regarding transmission availability. As discussed further in Section 11, the Agency would also consider C-BED projects to the extent that they are feasible and economic. MMPA has no firm plans at this time regarding potential PPAs but continues to work with developers.

MMPA Expects To Meet Over 50% Of Its Incremental Energy Needs Through Combination Of Conservation And Renewables

Minn. Statute §216B.2422, subd.2 states, " As a part of its resource filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources".

In 2028, MMPA's energy requirements of 2,120,670 MWh will be 606,968 MWh over its projected 2014 requirements. MMPA's renewable energy requirement for 2028 of 508,961 MWhs is 84% of its incremental energy needs. By satisfying the RES, MMPA will meet 50 to 75 % of its incremental energy needs through renewables. The effects of MMPA's conservation efforts are included in the base calculations.

MMPA Is Positioned To Meet The RES

MMPA is positioned to meet the RES through its mix of purchases and resources.

The Agency's PPAs and owned resources are projected to produce over 662,000 MWh of renewable energy starting in 2016. This is over two and a half times the amount of energy required under the RES in 2016 and more than the amount of energy required under the RES in 2028.

Rate Impact Of Complying With REO/RES

Per the Minn. Stat. §216B.1691 Subdivision 2e, after filing the initial report within 150 days of May 28, 2011, each electric utility must submit, in its IRP, a report to the Commission containing an estimation of the rate impact of activities of the electric utility necessary to comply with the REO/RES.

The first report MMPA filed with the Commission in 2011 reported on the rate impact of the REO/RES for 2011 and 2012. In this IRP, we report on the projected rate impact of REO/RES for 2013 and 2014.

The table below shows MMPA's projected REC retirement requirements for 2013 and 2014:

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TRADE SECRET DATA ENDS]

Section 15. 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 Provides Flexibility In An Uncertain Environment

MMPA's IRP gives the Agency flexibility during this time of uncertainty regarding commodity prices, transmission availability, carbon legislation, and cost of new generation. The Agency creates this flexibility by developing multiple resource prospects in excess of its projected needs, giving it options for meeting its future capacity and renewable energy requirements. The use of distributed generation provides further flexibility for MMPA because of the ability to install facilities in smaller increments and on a quicker timetable than other resources.

MMPA's Plan Limits Environmental Effects

The Agency's plan limits negative environmental effects. MMPA is aggressively pursuing both increased energy conservation and a number of renewable energy projects.

MMPA's Facilities Ensure Compliance With Emissions Control Equipment And Report As Required

MMPA uses a Continuing Emissions Monitoring System (CEMS) at Faribault Energy Park (FEP) to measure NO_x and CO_2 emissions, and to measure or calculate SO_2 and CO_2. MMPA uses low emitting pipeline quality natural gas and low sulfur distillate fuel oil for its fuel sources. In addition, combustion of MMPA's fuels emit relatively low levels of particulate matter and mercury.

Emissions are controlled by the use of selective catalytic reduction (SCR), dry-low NO_x combustion, water injection and low sulfur fuels. MMPA also tests its emissions and emissions monitoring equipment annually.

MMPA's Minnesota River Station facility is operated as a peaking facility. MMPA tests its emissions at this facility per its permit requirements.

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
- 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 promotes adequate and reliable service, particularly through its use of distributed generation, which reduces the load on the transmission system. The Agency's plan also keeps rates as low as practical given uncertainties about future commodity prices and carbon regulation by adding peaking resources that move MMPA closer to its least cost resource portfolio.

MMPA balances socioeconomic and environmental considerations by both promoting energy conservation and developing a number of renewable resource prospects. As noted throughout this IRP, MMPA is adding significant amount of renewable generation to its portfolio which is projected to help MMPA meet its RES requirements. In addition, by mid-2015, MMPA's contract from RPU will expire. This will allow MMPA to take another step toward meeting the greenhouse gas emission reduction goals set by the State.

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 of three member cities was projected separately from that of the other nine members. Those projections were then added to obtain the entire Agency's projected energy. The projections can be summarized as follows:

- MMPA 9 – Includes the cities of Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia, Shakopee and Winthrop with monthly historical energy usage from 1988 through October 2013.
- East Grand Forks – Monthly historical energy usage from 1996 to October 2013.
- Buffalo – Monthly historical energy usage from 2000 to October 2013.
- Elk River – Monthly historical energy usage from 2003 to July 2013.

Data constraints for East Grand Forks and Buffalo prompted the separate projections for those cities. Elk River was projected separately because MMPA begins serving its load in 2018.

Total MMPA energy requirements were projected by adding the results of these four regression models.

Throughout this appendix, we refer to all 12 MMPA member cities as MMPA12 and all 11 member cities with the exception of Elk River 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.

Weather

Cooling Degree Days (CDD) and Heating Degree Days (HDD) were both used as explanatory variables. Historical weather data for all member communities except East Grand Forks comes from the Minneapolis-St. Paul International Airport weather station and is supplied by Telvent DTN. Weather data for the East Grand Forks model comes from the Fargo weather station (the closest available) and is supplied by degreedays.net. CDD and HDD projections are an average of historical CDD and HDD since 1981.

Income per Capita

Both historical and projected income data come from Woods and Poole Economics' *Minnesota State Profile 2013 State and County Projections to 2040*. This data is provided at the county level. The MMPA9 model uses a weighted average income variable, created by weighting each of those 9 member cities' income per capita by the city's annual energy usage.

Population

Historical population data from 1988 to 2012 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 2013 to 2028 are based on actual data for 2012, annually increased by long term county population growth rates calculated from Woods and Poole projections.

All explanatory variables listed above were used in the MMPA 9 model. For the East Grand Forks model, CDD and population were excluded because of low t-stat results. Minimal air conditioning load and a devastating 1997 flood likely explain the low t-stats for CDD and population, respectively. The Buffalo and Elk River models exclude income per capita, also because of low t-stat results.

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

Annual Energy Was Reduced By Conservation

Annual energy projections were decreased by about 1.3%, representing 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. In the period before MMPA begins serving Elk River's load (2014-2017), conservation reductions resulted in a compounded annual growth rate reduction of 1.1% and a net annual growth rate of 1.5% for energy. In the period after MMPA begins serving Elk River's load (2019-2028), conservation reductions reduced the compounded annual growth rate by 1.0%, resulting in a net annual energy growth rate of 1.1%.

Expected Future Load Additions Increased Energy Requirements

MMPA expects new load additions above and beyond its historical growth model. Two MMPA members have informed the Agency of load additions beginning in 2014. The additional energy and demand requirements resulting from this new load were added to the energy and demand projections.

Agency Energy Requirements Were Reduced By WAPA-Supplied Energy

Following adjustments for conservation and new load additions, projected energy requirements were reduced by the energy that WAPA supplies to two member cities. These WAPA allocations were assumed to remain at the 2010-2015 contract level throughout the projection period.

Agency 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 of 55.6% was calculated as the average of annual weather normalized load factors from 2006 to 2012. The average load factor was then applied to the conservation-adjusted energy projections to obtain MMPA's projected NCP demand.

Agency Demand At MISO's Annual Coincident Peak Was Projected Using Linear Regression

MMPA projects its demand at the time of MISO's annual coincident peak (CP), in compliance with a new MISO regulation effective planning year 2013. The projections are made using a linear regression methodology similar to that used for MISO compliance purposes.

Two regressions are developed: one to project MMPA11's coincident peak from 2014-2018 and one to project MMPA12's coincident peak from 2019-2028, once MMPA begins serving Elk River's load. The 2014-2018 regression uses annual historical MMPA11 demand data at the time of MISO's peak from 2005 to 2012: the years for which MISO has published its coincident peak dates and hours. The 2019-2028 regression uses historical data for what MMPA12's demand would have been from 2005 to 2012, had MMPA served Elk River's load during those years.

Explanatory Variables Used to project CP Demand Were Weather and NCP Demand

The explanatory variables used for the regression analysis to project MMPA's CP demand were weather and MMPA's NCP demand.

<u>Weather</u>
The first explanatory variable is Cooling Degree Days on the date of MISO's annual coincident peak. Historical CDD data comes from the Minneapolis-St. Paul International Airport weather station and is supplied by Telvent DTN and Weather Bank. CDD projections from 2014 to 2028 are an average of the CDD at the hour of MISO's annual coincident peak from 2005 to 2012.

The same historical weather data is used in both the 2014-2018 and the 2019-2028 regressions.

<u>MMPA's NCP Demand</u>

The second explanatory variable is MMPA's annual NCP with MISO. NCP demand for 2014 to 2028 was projected as described above, by applying a 55.6% load factor to the conservation-adjusted energy projections.

The 2014-2018 regression uses historical MMPA11 NCP demand data, and the 2019-2028 regression uses historical data for what MMPA12's NCP demand would have been if MMPA had historically served Elk River's load.

Agency CP Demand Was Adjusted By WAPA-Supplied Capacity and Future Load Additions

Like the energy projections, CP demand projections were also reduced by the capacity that WAPA supplies to two member cities. These WAPA allocations were assumed to remain at the 2010-2015 contract level throughout the projection period.

Also like the energy projections, CP demand projections were increased by expected future load additions in two member communities beginning in 2014.

Capacity Requirements Include Losses And Reserves

The Agency's total capacity requirements are calculated by adding 2.5% transmission system losses and 7.5% planning reserve margin requirements to the projected CP demand requirements.

MMPA currently serves load in two Load Balancing Authorities (LBAs). The vast majority of MMPA's load is in the NSP LBA, where transmission losses are 2.4%. The remainder of MMPA's load is in the OTP LBA, with transmission losses of 4.6%. In 2018, MMPA will begin serving Elk River load in the GRE LBA, which currently has transmission losses of 1.3%. For the purposes of this IRP, the Agency assumes aggregate 2.5% transmission losses.

MISO's planning reserve margin requirement is expected to be 7.3% in planning year 2014. For long term planning purposes, a planning reserve margin of 7.5% was used.

Appendix B. Advance Forecast

This appendix contains MMPA's filing to the Department of Commerce as outlined in Rule 7610.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

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

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
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 contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 296-8963

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	266
REPORT YEAR	2012

RILS ID#	U13724

UTILITY DETAILS	
UTILITY NAME	Minnesota Municipal Power Agency
STREET ADDRESS	200 South Sixth Street Suite 300
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	Vice President, Planning
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	
PERSON PREPARING FORMS	Benjamin Simmons
PREPARER'S TITLE	Associate
DATE	12/11/2013

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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	2012	No. of Cust.									0
		MWH									0
Present Year	2013	No. of Cust.									0
		MWH									0
1st Forecast Year	2014	No. of Cust.									0
		MWH									0
2nd Forecast Year	2015	No. of Cust.									0
		MWH									0
3rd Forecast Year	2016	No. of Cust.									0
		MWH									0
4th Forecast Year	2017	No. of Cust.									0
		MWH									0
5th Forecast Year	2018	No. of Cust.									0
		MWH									0
6th Forecast Year	2019	No. of Cust.									0
		MWH									0
7th Forecast Year	2020	No. of Cust.									0
		MWH									0
8th Forecast Year	2021	No. of Cust.									0
		MWH									0
9th Forecast Year	2022	No. of Cust.									0
		MWH									0
10th Forecast Year	2023	No. of Cust.									0
		MWH									0
11th Forecast Year	2024	No. of Cust.									0
		MWH									0
12th Forecast Year	2025	No. of Cust.									0
		MWH									0
13th Forecast Year	2026	No. of Cust.									0
		MWH									0
14th Forecast Year	2027	No. of Cust.									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.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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 number of customers 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	2012	No. of Cust.									0
		MWH									0
Present Year	2013	No. of Cust.									0
		MWH									0
1st Forecast Year	2014	No. of Cust.									0
		MWH									0
2nd Forecast Year	2015	No. of Cust.									0
		MWH									0
3rd Forecast Year	2016	No. of Cust.									0
		MWH									0
4th Forecast Year	2017	No. of Cust.									0
		MWH									0
5th Forecast Year	2018	No. of Cust.									0
		MWH									0
6th Forecast Year	2019	No. of Cust.									0
		MWH									0
7th Forecast Year	2020	No. of Cust.									0
		MWH									0
8th Forecast Year	2021	No. of Cust.									0
		MWH									0
9th Forecast Year	2022	No. of Cust.									0
		MWH									0
10th Forecast Year	2023	No. of Cust.									0
		MWH									0
11th Forecast Year	2024	No. of Cust.									0
		MWH									0
12th Forecast Year	2025	No. of Cust.									0
		MWH									0
13th Forecast Year	2026	No. of Cust.									0
		MWH									0
14th Forecast Year	2027	No. of Cust.									0
		MWH									0

* MINING needs to be reported as a separate category only if annual sales are greatere 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.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2012			2,419,998	3,307,397	887,399				0
Present Year	2013			2,585,441	3,279,654	694,214				0
1st Forecast Year	2014			2,258,512	2,890,359	631,847				0
2nd Forecast Year	2015			1,660,714	2,305,700	644,987				0
3rd Forecast Year	2016			1,568,605	2,234,534	665,930				0
4th Forecast Year	2017			1,580,509	2,264,916	684,407				0
5th Forecast Year	2018			1,662,854	2,366,971	704,117				0
6th Forecast Year	2019			1,921,137	2,658,104	736,967				0
7th Forecast Year	2020			1,941,702	2,712,752	771,050				0
8th Forecast Year	2021			1,962,067	2,764,734	802,667				0
9th Forecast Year	2022			1,982,256	2,817,773	835,517				0
10th Forecast Year	2023			2,002,543	2,838,060	835,517				0
11th Forecast Year	2024			2,023,894	2,860,643	836,750				0
12th Forecast Year	2025			2,046,439	2,881,956	835,517				0
13th Forecast Year	2026			2,070,064	2,905,581	835,517				0
14th Forecast Year	2027			2,094,814	2,930,331	835,517				0

COMMENTS

Under the Midwest 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.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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 2012									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 2012	213.7	196.0	191.6	182.8	235.1	291.9	314.4	299.4	280.8	193.1	210.4	220.8

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 2.5% transmission system losses.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>										
Past Year	2012	Summer								
		Winter								
Present Year	2013	Summer								
		Winter								
1st Forecast Year	2014	Summer								
		Winter								
2nd Forecast Year	2015	Summer								
		Winter								
3rd Forecast Year	2016	Summer								
		Winter								
4th Forecast Year	2017	Summer								
		Winter								
5th Forecast Year	2018	Summer								
		Winter								
6th Forecast Year	2019	Summer								
		Winter								
7th Forecast Year	2020	Summer								
		Winter								
8th Forecast Year	2021	Summer								
		Winter								
9th Forecast Year	2022	Summer								
		Winter								
10th Forecast Year	2023	Summer								
		Winter								
11th Forecast Year	2024	Summer								
		Winter								
12th Forecast Year	2025	Summer								
		Winter								
13th Forecast Year	2026	Summer								
		Winter								
14th Forecast Year	2027	Summer								
		Winter								

COMMENTS

The Agency Does not Have any Firm Purchases from Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>										
Past Year	2012	Summer								
		Winter								
Present Year	2013	Summer								
		Winter								
1st Forecast Year	2014	Summer								
		Winter								
2nd Forecast Year	2015	Summer								
		Winter								
3rd Forecast Year	2016	Summer								
		Winter								
4th Forecast Year	2017	Summer								
		Winter								
5th Forecast Year	2018	Summer								
		Winter								
6th Forecast Year	2019	Summer								
		Winter								
7th Forecast Year	2020	Summer								
		Winter								
8th Forecast Year	2021	Summer								
		Winter								
9th Forecast Year	2022	Summer								
		Winter								
10th Forecast Year	2023	Summer								
		Winter								
11th Forecast Year	2024	Summer								
		Winter								
12th Forecast Year	2025	Summer								
		Winter								
13th Forecast Year	2026	Summer								
		Winter								
14th Forecast Year	2027	Summer								
		Winter								

COMMENTS

The Agency Does not Have any Firm Sales to Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			Rochester Public Utilities	MISO Capacity Auction	Short Term Capacity Purchases					
Past Year	2012	Summer	25	5	30					
		Winter	25	5	20					
Present Year	2013	Summer	25	5	50					
		Winter	25	5	50					
1st Forecast Year	2014	Summer	25		30					
		Winter	25		30					
2nd Forecast Year	2015	Summer			50					
		Winter			50					
3rd Forecast Year	2016	Summer			35					
		Winter			35					
4th Forecast Year	2017	Summer								
		Winter								
5th Forecast Year	2018	Summer								
		Winter								
6th Forecast Year	2019	Summer								
		Winter								
7th Forecast Year	2020	Summer								
		Winter								
8th Forecast Year	2021	Summer								
		Winter								
9th Forecast Year	2022	Summer								
		Winter								
10th Forecast Year	2023	Summer								
		Winter								
11th Forecast Year	2024	Summer								
		Winter								
12th Forecast Year	2025	Summer								
		Winter								
13th Forecast Year	2026	Summer								
		Winter								
14th Forecast Year	2027	Summer								
		Winter								

COMMENTS

This spreadsheet reflects transactions entered into as of 12/18/13. Short term capacity purchases from several counterparties are aggregated for limited disclosure. The data reported for each season follows MISO's planning year construct because it is according to that construct that MMPA purchases capacity. Under that construct -- and as reported here -- summer of a given planning year corresponds to June-November of that year, and winter of a given planning year corresponds to December of that year through May of the next year.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			Sales to Coop 1	Sales to Coop 2						
Past Year	2012	Summer	5.4	7.1						
		Winter	5.2	6.5						
Present Year	2013	Summer	5.6	7.8						
		Winter	5.6	7.8						
1st Forecast Year	2014	Summer								
		Winter								
2nd Forecast Year	2015	Summer								
		Winter								
3rd Forecast Year	2016	Summer								
		Winter								
4th Forecast Year	2017	Summer								
		Winter								
5th Forecast Year	2018	Summer								
		Winter								
6th Forecast Year	2019	Summer								
		Winter								
7th Forecast Year	2020	Summer								
		Winter								
8th Forecast Year	2021	Summer								
		Winter								
9th Forecast Year	2022	Summer								
		Winter								
10th Forecast Year	2023	Summer								
		Winter								
11th Forecast Year	2024	Summer								
		Winter								
12th Forecast Year	2025	Summer								
		Winter								
13th Forecast Year	2026	Summer								
		Winter								
14th Forecast Year	2027	Summer								
		Winter								

COMMENTS

This spreadsheet reflects transactions entered into as of 12/18/13. In 2012, sales to some utilities varied month-by-month within a season. Data shown is for the peak month of each season. The data reported for each season follows MISO's planning year construct because it is according to that construct that MMPA purchases capacity. Under that construct -- and as reported here -- summer of a given planning year corresponds to June-November of that year, and winter of a given planning year corresponds to December of that year through May of the next year.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

			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 (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2012	Summer	322		322	322			322	322	292	60	13	339	24	346	-7
		Winter	226		226	322			226	322	292	50	12	330	17	243	87
Present Year	2013	Summer	329		329	329			329	329	294	80	13	361	25	354	7
		Winter	238		238	329			238	329	294	80	13	361	18	256	105
1st Forecast Year	2014	Summer	319		319	319			319	319	287	55		342	24	343	-1
		Winter	245		245	319			245	319	287	55		342	18	264	78
2nd Forecast Year	2015	Summer	326		326	326			326	326	297	50		347	24	351	-4
		Winter	246		246	326			246	326	297	50		347	18	265	82
3rd Forecast Year	2016	Summer	327		327	327			327	327	312	35		347	25	352	-5
		Winter	249		249	327			249	327	312	35		347	19	267	80
4th Forecast Year	2017	Summer	330		330	330			330	330	327			327	25	355	-28
		Winter	250		250	330			250	330	327			327	19	268	58
5th Forecast Year	2018	Summer	332		332	332			332	332	342			342	25	356	-15
		Winter	303		303	332			303	332	342			342	23	326	16
6th Forecast Year	2019	Summer	402		402	402			402	402	367			367	30	432	-65
		Winter	305		305	402			305	402	367			367	23	328	39
7th Forecast Year	2020	Summer	405		405	405			405	405	392			392	30	436	-44
		Winter	309		309	405			309	405	392			392	23	333	59
8th Forecast Year	2021	Summer	411		411	411			411	411	417			417	31	441	-25
		Winter	313		313	411			313	411	417			417	23	336	81
9th Forecast Year	2022	Summer	415		415	415			415	415	442			442	31	446	-4
		Winter	316		316	415			316	415	442			442	24	339	102
10th Forecast Year	2023	Summer	419		419	419			419	419	442			442	31	451	-9
		Winter	318		318	419			318	419	442			442	24	342	100
11th Forecast Year	2024	Summer	422		422	422			422	422	442			442	32	454	-12
		Winter	323		323	422			323	422	442			442	24	347	95
12th Forecast Year	2025	Summer	428		428	428			428	428	442			442	32	460	-19
		Winter	327		327	428			327	428	442			442	24	351	91
13th Forecast Year	2026	Summer	433		433	433			433	433	442			442	32	466	-24
		Winter	330		330	433			330	433	442			442	25	355	87
14th Forecast Year	2027	Summer	439		439	439			439	439	442			442	33	471	-30
		Winter	334		334	439			334	439	442			442	25	359	83

COMMENTS

Seasonal Demands as shown include 2.5% Transmission System Losses. Net Generating capability accounts for EFORDs. Assumption for Net Reserve Capacity Obligation is 7.5%.

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 November of that year and extending into the next 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)

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

		ADDITIONS	RETIREMENTS
Past Year	2012		
Present Year	2013		
1st Forecast Year	2014	8	
2nd Forecast Year	2015	10	
3rd Forecast Year	2016	15	
4th Forecast Year	2017	15	
5th Forecast Year	2018	15	
6th Forecast Year	2019	25	
7th Forecast Year	2020	25	
8th Forecast Year	2021	25	
9th Forecast Year	2022	25	
10th Forecast Year	2023		
11th Forecast Year	2024		
12th Forecast Year	2025		
13th Forecast Year	2026		
14th Forecast Year	2027		

COMMENTS
Wind Additions are not noted as they have no firm capacity value

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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 the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	NG	Name of Fuel	FO2	Name of Fuel		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		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	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2012	5,562,980	763,377	-	-								
Present Year	2013	4,236,538	574,507	13,580	1,585								
1st Forecast Year	2014	3,259,535	449,347	19,320	2,500								
2nd Forecast Year	2015	3,368,597	462,487	19,320	2,500								
3rd Forecast Year	2016	3,541,066	483,430	19,320	2,500								
4th Forecast Year	2017	3,695,783	501,907	19,320	2,500								
5th Forecast Year	2018	3,859,376	521,617	19,320	2,500								
6th Forecast Year	2019	4,132,031	554,467	19,320	2,500								
7th Forecast Year	2020	4,413,562	588,550	19,320	2,500								
8th Forecast Year	2021	4,677,341	620,167	19,320	2,500								
9th Forecast Year	2022	4,949,996	653,017	19,320	2,500								
10th Forecast Year	2023	4,949,996	653,017	19,320	2,500								
11th Forecast Year	2024	4,958,872	654,250	19,320	2,500								
12th Forecast Year	2025	4,949,996	653,017	19,320	2,500								
13th Forecast Year	2026	4,949,996	653,017	19,320	2,500								
14th Forecast Year	2027	4,949,996	653,017	19,320	2,500								

LIST OF FUEL TYPES

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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)

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	DATE	
	7/2/12	12/10/12	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	193	142	
0200	182	138	
0300	174	138	
0400	169	139	
0500	170	143	
0600	178	157	
0700	197	179	
0800	226	196	
0900	249	198	
1000	266	200	
1100	285	199	
1200	297	200	
1300	306	200	
1400	313	198	
1500	318	197	
1600	322	196	
1700	322	206	
1800	319	226	
1900	312	225	
2000	303	221	
2100	294	214	
2200	287	201	
2300	268	181	
2400	243	165	

COMMENTS
MMPA's reported MW include 2.5% transmission system losses.

Appendix C. IRP 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 Filing
7843.0400 Subp. 1	Include most Advance Forecast filed with DOC	Appendix B
7843.0400 Subp. 2	File a proposed plan for meeting the service needs of its customers	Sections 11 and 12
7843.0400 Subp. 3A	Describe resource options considered, including information supporting selection of proposed resources	Sections 9 and 10
7843.0400 Subp. 3A	Include descriptions of the overall process and of the analytical techniques used to create resource plan from available options	Section 10
7843.0400 Subp. 3C	Include a five-year action plan	Section 11
7843.0400 Subp. 3D	Explain why the plan is in the public interest	Section 15
7843.0400 Subp. 4	Include a non-technical summary not to exceed 25 pages	Section 1
216B.1612 Subd. 5	Consideration of C-BED Projects	Section 11
216B.1691 Subd. 2e	Rate impact of compliance with Renewable Energy Standard	Section 14
216B.1691 Subd. 3	Description of efforts towards meeting REO/RES	Section 14
216B.2422 Subd. 2	Include in IRP a least cost plan for meeting 50% and 75% of all new and refurbished capacity needs through a combination of conservation and renewable energy resources	Section 14
216B.2422 Subd. 3	Use commission values and other external factors including socioeconomic costs when evaluating and selecting resource options	Section 10