DAHLEN, BERG & CO.

ENERGY SUPPLY MANAGEMENT

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MN PUBLIC UTILITIES COMMISSION

IP6 202/CN-02-2006

November 26, 2002

Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101

Re: Certificate of Need Application by Faribault Energy Park, LLC

Dear Mr. Haar:

In response to your deficiency letter, I enclose a corrected copy of the Certificate of Need Application by Faribault Energy Park, LLC, dated November 19, 2002, consisting of an original and three copies of the corrected non-public version, and an original and three copies of the corrected public version.

In addition, two copies each of the corrected non-public and public versions of the filing have been served on the Department of Commerce, at 85 7th Place East, Suite 500, St. Paul, MN 55101-2198.

Also enclosed is a statement of justification explaining how the data meets the definition of a trade secret under Minnesota Statutes section 13.37, consisting of an original statement and three copies. Two copies of the statement have been served upon the Department of Commerce.

Very truly yours,

Dahlen, Berg & Co.

James D. Larson

cc: Kathy Aslakson, MDOC
Curt Nelson, RUD
Alan R. Mitchell, EQB

200 SOUTH SIXTH STREET, SUITE 300 | MINNEAPOLIS, MINNESOTA 55402 | PHONE 612/349-6868 | FAX 612/349-6108

DAHLEN, BERG & CO.

ENERGY SUPPLY MANAGEMENT

November 26, 2002

Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101

Re: Certificate of Need Application by Faribault Energy Park, LLC

Dear Mr. Haar:

The purpose of this letter is to provide justification for the designation as "trade secret" of certain identified portions of the above referenced Certificate of Need Application.

The Minnesota Municipal Power Agency will be marketing electric energy produced at the Faribault Energy Park in wholesale energy markets. Certain aspects of the plant design are unique to Faribault Energy Park, are not generally known or readily ascertainable, and will provide a competitive marketing advantage to the MMPA. These aspects of plant design have been marked as "trade secret" pursuant to Minnesota Statutes Section 13.37.

Moreover, the MMPA will obtain economic benefit from certain operating characteristics and maintenance requirements of the plant that will not be generally known or readily ascertainable by competitors of MMPA. Accordingly, those commercially sensitive operating characteristics and maintenance requirements were marked "trade secret" pursuant to Minnesota Statutes Section 13.37.

Also, the MMPA has presented summarized load information and rate impacts that are not generally known or ascertainable, which information would provide economic value to MMPA competitors. The MMPA has identified the sensitive load information and rate impact information as "trade secret" pursuant to Minnesota Statute Section 13.37.

This statement of justification and three copies are being filed with the Commission pursuant to Commission procedures. Two copies of this statement have also been served on the Department of Commerce.

Very truly yours,

Dahlen, Berg & Co.

James D. Larson

cc: Kathy Aslakson, MDOC
Curt Nelson, RUD
Alan R. Mitchell, EQB

200 South Sixth Street, Suite 300 | Minneapolis, Minnesota 55402 | Phone 612/349-6868 | Fax 612/349-6108

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by local delivery service the indicated number of corrected copies of the Certificate of Need Application of Faribault Energy Park, LLC, upon the Commission and the Department of Commerce. Others on the attached list were served by US Mail.

Dated at Minneapolis, Minnesota, this 26th day of November, 2002.

Catharina Zuber

Catharina Zuber

Application to the Minnesota Public Utilities
Commission for Certificate of Need for Faribault Energy Park

Burl Haar (8)
Executive Secretary
Minnesota Public Utilities Commission
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100 Washington Ave South
Minneapolis, MN 55401-2138

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

APPLICATION FOR CERTIFICATE OF NEED FOR FARIBAULT ENERGY PARK

TO THE PUBLIC UTILITIES COMMISSION BY
FARIBAULT ENERGY PARK, LLC

November 17, 2002

Table of Contents

Application for Certificate of Need
Completeness of Rules Checklist

Authority		Required Information	Location in the Document
Minnesota Rule 7849.0120 A		Denial would adversely affect adequacy, reliability, and/or efficiency of energy supply to applicant, its customers, and/or the people of Minnesota	
	1	Forecast for type of energy supplied by facility is accurate	Section 2
	2	Effects of applicant's conservation program and state and federal programs	Section 2
	3	Effects of applicant's promotional practices on energy demand	Section 3
	4	Ability of current facilities and facilities not requiring CON to meet demand	Section 2
	5	Effect of proposed facility in making efficient use of resources	Section 2, 3, 4, 5, 6
7849.0120 B		A more reasonable and prudent alternative has not been demonstrated	
	1	Appropriate size, type, and timing compared to reasonable alternatives	Section 1, 2, 3, 4, 5
	2	Cost of facility and of its energy compared to reasonable alternatives	Section 5
	3	Effects of facility on natural and socioeconomic environment compared to reasonable alternatives	Section 3, 4, 5
	4	Expected reliability of project compared to reasonable alternatives	Section 4, 5
7849.0120 C		Project will provide benefits to society	
	1	Relationship of proposed facility to overall state energy needs	Section 2
	2	Effects of facility on natural and socioeconomic environment compared to not building the facility	Section 3, 4, 6
	3	Effects of facility in inducing future development	Section 3
	4	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	Section 3, 4, 5, 7
7849.0120 D		Projects will comply with relevant policies and regulations	Exec. Summary, Section 4, 7
7849.0210		Filing fees and payment schedule	Section 1
7849.0240 Subp. 1		Major factors that justify need for the facility	Section 2
7849.0240 Subp. 2	A	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	Section 3, 4, 5, 7
	B	Promotional activities that may have given rise to demand	Section 3
	C	Effects of facility in inducing future development	Section 3

7849.0250 A	1	Nominal generating capability and effects of economies of scale on size and timing	Section 4
	2	Description of operating cycle and capacity factor	Section 4
	3	Type of fuel used, reason for its selection, projection of availability over the life of the plant, and alternate fuels	Section 4
	4	Anticipated heat rate	Section 4
	5	Anticipated areas where facility could be located	Section 4
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	2	Increased efficiency of existing facilities, including transmission lines	Section 5
	3	New transmission lines	Section 5
	4	New generating facilities of different size and/or energy source	Section 5
	5	Any reasonable combination of the above	Section 5
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	2	The service life	Section 4, 5
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	4	The fuel cost in current $/kWh	Section 4, 5
	5	The variable O&M costs in current $/kWh	Section 4, 5
	6	The total costs in current $/kWh	Section 4, 5
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	8	Energy efficiency expressed as the estimated heat rate	Section 4, 5
	9	Major assumption for 1-8, including fuel and O&M escalation and capacity factor	Section 5
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7849.0270 Subp. 3		Forecast methodology	Appendix A-3
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7849.0270 Subp. 5		Assumptions and Special Information	Appendix A-5
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7849.0280 B	Seasonal firm purchases and seasonal firm sales	Appendix B
7849.0280 C	Seasonal participation purchases and seasonal participation sales	N/A
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7849.0280 E	For the summer and winter season for each forecast year subsequent to the year of application, the load and generation capacity data requested in item D (1-13), including purchases, sales, and generating capability contingent on the proposed facility	Appendix B
7849.0280 F	For the summer and winter season for each forecast subsequent to the year of application, the load and generation capacity data requested in item D (1-13), including all projected purchases, sales, and generating capability	N/A
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	2	For each viable alternative LEGF, estimated maximum contributions to 24-hr average ground level concentrations of above major emittants (in micrograms per cubic meter)	Section 4
7849.0320 E	1	For each viable alternative LEGF, water use of alternate cooling systems, including gpm groundwater pumping and cf/second surface appropriations	Section 5
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	3	For each viable alternative LEGF, annual water consumption in acre-feet	Section 5

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7849.0320 J	Estimated work force required for construction and operation	Section 3, 4, 5
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7849.0340 C	Equipment and measures that may be used to reduce the environmental impact of the alternative of no facility	Section 6

Executive Overview

Faribault Energy Park, LLC Is Applying for a Certificate of Need to Meet the Energy Needs of MMPA, MAPP, and Minnesota

Faribault Energy Park, LLC, which is owned by the Minnesota Municipal Power Agency (MMPA, the Agency), is applying for a Certificate of Need (CON) for a project consisting of one combined-cycle combustion turbine located in Faribault, Minnesota (the Project). The total accredited output of the Project will be a nominal 250 megawatts (MW). The Project is part of an energy supply plan to meet MMPA's and MAPP's intermediate needs through 2012.

The need for the Project is based on forecasted load growth for the next four years and the expiration of existing short-term capacity purchases. MMPA's need is for an Intermediate Resource. An Intermediate Resource is one that generates energy during medium to high load periods. The Project will satisfy MMPA's Intermediate Resource needs for the year 2006, its first full year of operation, and beyond. Without the Project, MMPA will be deficit by a projected 113 MW in 2006. MMPA's need for increased generating capacity results from strong regional economic growth over the past decade. During that period, MMPA has met its increasing obligations through purchases of capacity from others in the Mid-Continent Area Power Pool (MAPP). Excess capacity in MAPP has now largely been absorbed and continued purchases are no longer possible at competitive prices.

MMPA cannot satisfy its needs through the existing Minnesota River peaking facility. Further upgrades would neither be economical nor meet the energy needs identified in this filing. The addition of Intermediate Resource capacity also complements the high percentage of existing baseload resources in the MMPA resource mix.

Denial Would Adversely Impact Reliability and Efficiency for MMPA, its Customers, and the People of Minnesota

The Faribault Energy Park is expected to provide the capacity and energy resources needed by MMPA's member cities as well as other users of generation in the state and region. In addition, the Project will enhance the overall reliability of the transmission system, which has been under increasing stress in recent years. Denial of this application would adversely impact MMPA's ability to reliably serve its member cities at a reasonable cost, and would negatively affect other users of generation in the state and region. The MAPP region has been projecting a tightening balance of load and capacity for several years and very few committed new generation projects have been announced. In fact, MAPP will be deficit beginning in 2005. Recent proposals to obtain long-term power supply needs have resulted in limited quantities of capacity resources being offered at prices higher than the cost of building the Project.

There Is No More Reasonable and Prudent Alternative to the Project

The Project is the appropriate type of resource to cover intermediate demand and energy requirements. Conventional simple-cycle, baseload, and renewable resources were considered and rejected as resources to cover MMPA's Intermediate Resource needs.

Conventional simple-cycle peaking facilities are not economic when operated at the high capacity factors expected for Intermediate Resources, while baseload resources require large plants and fuels that are economically and environmentally unattractive. Similarly, renewable resources, including wind, wood, hydro, solar, and geothermal, are either non-dispatchable energy producing resources or do not compete economically at the high capacity factor associated with Intermediate Resources. In addition, it is very unlikely that a sufficient quantity of these resources could be sited, permitted, and constructed in the time frame needed to meet MMPA's need.

The Project Will Provide Benefits to Society Compatible With the Natural and Socioeconomic Environments

The Project is environmentally attractive. The Project utilizes a clean fuel and a highly efficient combustion technology. Thus, it will have a minimal impact on the surrounding environment. The Project is being sited to minimize the length of the gas pipeline and transmission lines needed to serve the Project.

The Project represents a new Intermediate Resource for MMPA. An Intermediate Resource generates energy during medium to high load periods that could range anywhere from 2000 to 7000 hours per year. The gas-fired combined-cycle Project reduces the Agency's reliance on older, dirtier coal-fired plants to meet its needs.

MMPA has a long history of cost-effective conservation programs, which have delayed the need for intermediate capacity projects. Cost-effective programs will be continued but are not expected to diminish peak demands in the near future sufficient to eliminate the need for the Project. Conservation programs have reduced the peak load and energy use overall but have not made a large scale contribution to the need for Intermediate energy generation.

The suburban service territory of MMPA's member cities will benefit from the Project. The Project will help MMPA's member cities continue to supply competitively priced power to their customers. Low cost electricity is an important component in supporting stable economic growth in the region.

This Project Will Comply With All Local, State, and Federal Requirements

Consistent with MMPA's overall business philosophy, this Project will be carried out in a manner compatible with all local, state, and federal rules, laws, and policies applicable to the Project.

This application shows that the Project is needed, that there are no reasonable and prudent alternatives, and that the Project will provide significant benefits to society through maintaining a reliable and economic energy supply while upholding the state's paramount goal for protection of natural resources. Therefore, issuing a CON for the Project is justified.

Section 1. Introduction

Faribault Energy Park, LLC Is Requesting a Certificate of Need to Meet Capacity and Energy Needs

Faribault Energy Park, LLC is submitting this application to the Minnesota Public Utilities Commission (PUC) to request a Certificate of Need for a nominal 250 megawatt combined-cycle power plant fueled by natural gas with No. 2 fuel oil as the back-up fuel. The project will be located immediately north of the existing corporate limit of the City of Faribault, Minnesota. Faribault Energy Park, LLC is owned by the Minnesota Municipal Power Agency, a Minnesota municipal corporation.

This project is being developed in order to meet MMPA's existing and future Intermediate Resource needs with estimated usage of 4000-6000 hours per year. A utility's Intermediate Resources often represent as much as 40 percent of its capacity requirements and provide up to 40 percent of its total energy requirements. This favors slightly higher capital cost technologies because of the increased number of kilowatt-hours over which to spread the fixed costs.

MMPA has covered its growth in capacity needs through a combination of load management programs and capacity transactions with other members in the Mid-Continent Area Power Pool. These strategies have deferred, until now, the need for making capital investments in new energy facilities. The tightening capacity situation in the MAPP region leaves MMPA vulnerable to capacity shortages and/or significant increases in the cost of purchasing power.

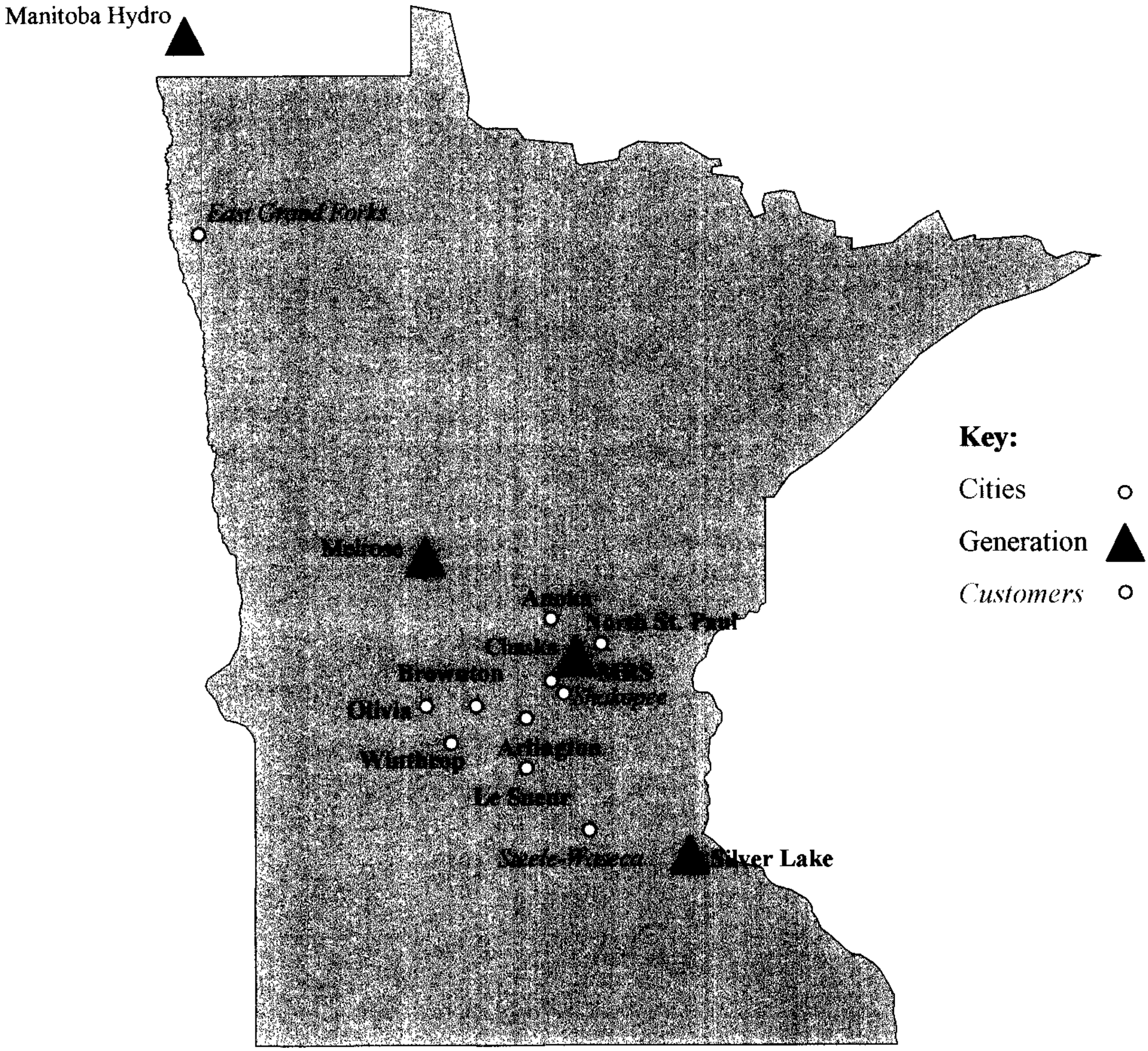
The Project described in this application is consistent with MMPA's mission of providing reliable, low-cost priced electricity to its member cities. MMPA's member cities have approved the installation of this capacity addition through their elected board members.

Who Is the Minnesota Municipal Power Agency?

The MMPA is a Minnesota municipal corporation and political subdivision of the State of Minnesota. MMPA's mission is to provide member cities with reliable, low-cost energy at an acceptable level of risk. The eight member cities (Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia, and Winthrop) have an aggregate peak load (excluding reserve requirements) of 180 MW, with peak demand for individual cities ranging from 1 MW to 65 MW. These eight cities serve a retail customer base of approximately 40,000 and a population of approximately 85,000. The Agency also serves two non-member municipal utility customers and a part of a cooperative's load. The two non-member cities (East Grand Forks and Shakopee) and the cooperative (Steele-Waseca Cooperative Electric) have an aggregate peak demand of 80 MW. Figure 1-1 shows the geographic locations of MMPA's members and customers.

MMPA purchases a majority of its electricity from other suppliers, purchases transmission from Xcel Energy, and obtains management and operations services from Dahlen, Berg, & Co., a Minneapolis-based energy supply management firm.

Figure 1-1
MMPA Locations



Applicant Information	Mailing Address:	Faribault Energy Park, LLC C/O Dahlen, Berg & Co. 200 S. 6th Street, Suite 300 Minneapolis, MN 55402
	Telephone Number:	(612) 349-6868
	SIC Code:	4911
	Project Contact:	Randy Porter Faribault Energy Park, LLC 200 S. 6th Street, Suite 300 Minneapolis, MN 55402 (612) 252-6526

Fees

The Certificate of Need application fees are based on the expected capacity of 250 MW using the formula included in Minnesota Rules pt. 7849.0210 Subpart 1. The total fee paid by MMPA will be $22,500. This fee will be paid in 4 equal installments of $5,625 as prescribed by Minnesota Rules pt. 7848.0210 Subpart 2. The payments will be administered as follows:

With Application:	$5,625
Within 45 Days of Submittal:	$5,625
Within 90 Days of Submittal:	$5,625
Within 135 Days of Submittal:	$5,625

Section 2. Capacity and Energy Need Summary

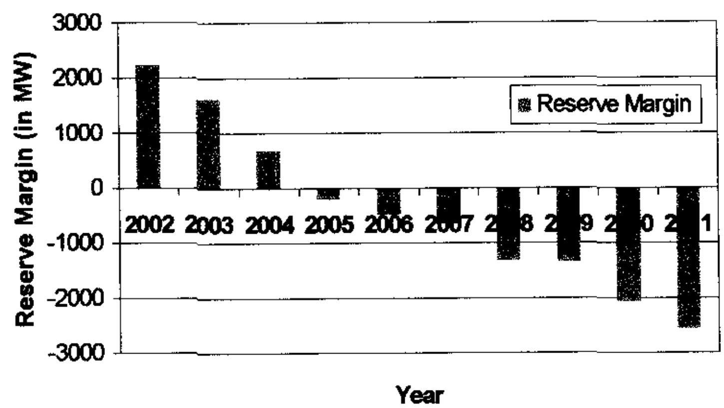
The Faribault Energy Park's CON application is for a single 250 MW combined-cycle combustion turbine plant located in southern Minnesota. The Project is needed to provide electric capacity and energy to the MAPP region and MMPA member municipalities. The MAPP region capacity deficit is projected to be 492 MW by 2006. In the same year, MMPA is forecasting a controlled summer peak of 267 MW resulting in a deficit of 113 MW if the Project is not completed. These projections include the minimum 15% capacity reserve required by MAPP.

MAPP Resources Are Inadequate to Meet Future Needs

The July 31, 2002 MAPP Load and Capability Report describes the regional capacity situation. This report compiles the MAPP member load forecasts, existing resource capabilities, and projected resource additions in order to calculate the regional electric generation capacity. The report indicates that MAPP members need to build additional capacity. Under the minimum reserve requirements of the pool, deficits are indicated from summer 2005 onward. Capacity additions will be needed to maintain sufficient reserve levels to ensure a safe, reliable system.

Figure 2-1 shows the projected reserve margins for the summer season from 2002 through 2011.

Figure 2-1
MAPP Summer Season Reserve Margins



MAPP Capacity Deficit Is Growing

The MAPP 2002 Load and Capability Report outlines an ever-worsening situation. The 2002 Load and Capability Report forecasts a deficit starting in the summer of 2005 that grows to 492 MW by the summer of 2006 and reaches 2,567 MW by the summer of 2011.

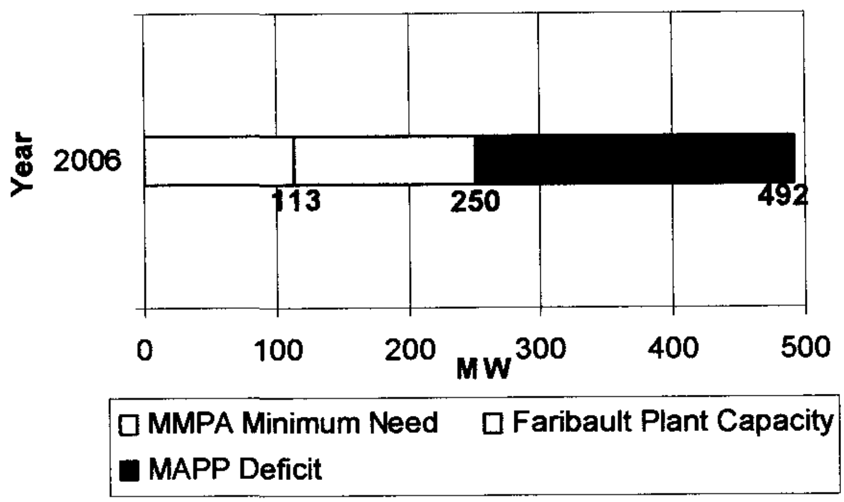
The growing MAPP deficit shows that regional load is increasing an average of 400-500 MW per year. In spite of recent committed or planned resources, additional plants are needed in the near future. Of particular note is the nearly 1200 MW drop in reserve margin between 2004 and 2006, during which the Faribault Energy Park would become operational.

MAPP members typically maintain a reserve margin 3-5% above the 15% required minimum to avoid severe penalties. If a deficit were to occur, MMPA would be penalized by MAPP and be required to purchase capacity after the occurrence. Additional generation needs to be constructed in order for the Pool to have adequate capacity. Recent stress on the regional transmission system suggests that reserve margins may need to be raised in order to maintain reliability, or more capacity needs to be built near load centers.

Both MAPP and MMPA Have Resource Needs

The need for the Faribault Energy Park is two-pronged. MMPA has a large capacity and energy need commencing in 2006. In that same year, MAPP is projected to be almost 500 MW deficient in generating reserve margin, and the Pool's need for intermediate energy resources is growing. This development is shown graphically below in Figure 2-2.

Figure 2-2
2006 MAPP Capacity Deficit Projection



MAPP Capacity Deficits Drive the Need for Faribault Energy Park

Expected MMPA load growth and expiration of capacity purchases justify a minimum of 113 MW of the Project beginning in 2006. The remainder of the plant is needed to address MMPA's future growth needs, MAPP's summer season reserve deficits, and to meet the energy market's need for environmentally safe, low-cost electric capacity and energy. Various arguments could be made that portions of MMPA's projected deficit are already included in MAPP projections. While it is possible to debate about the exact allocation of the need, it is undeniable that MAPP is nearly 500 MW short of its minimum reserve margin for 2006. This fact alone could justify the plant. Thus, MAPP's 15% reserve requirement is the primary criterion to establish need. Until the Project plant becomes available, MMPA will purchase short-term capacity from the market when it is cost-effective and available to meet its reserve obligation.

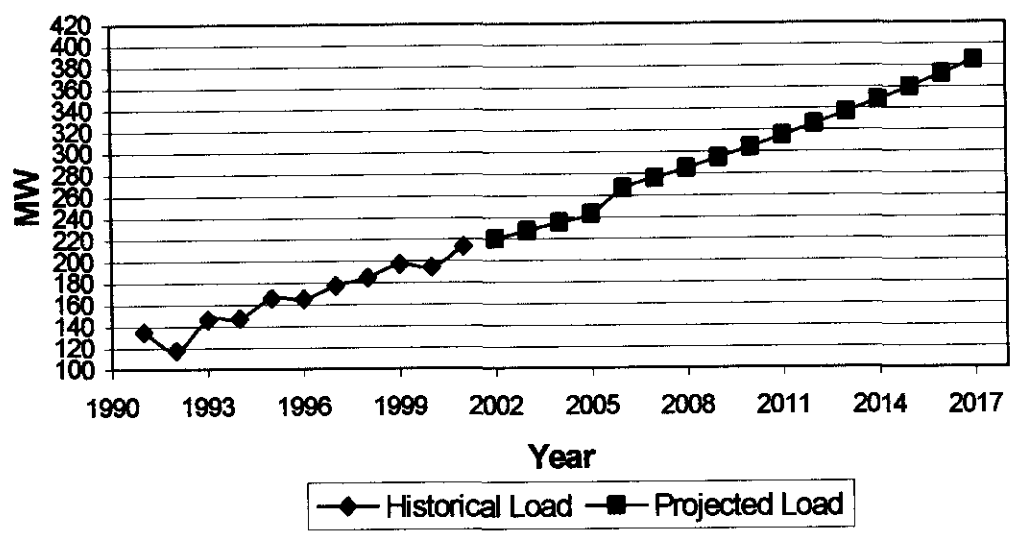
MMPA Resource Planning

Dahlen, Berg & Co. performs resource planning for MMPA under contract. Dahlen, Berg & Co. has successfully planned for MMPA's energy needs since 1992. This planning has enabled MMPA to minimize costs, increase reliability, and minimize environmental impact.

Demand Is Projected to Grow Approximately 3.75% Annually

MMPA submits a seasonal load forecast to MAPP on a yearly basis. Utilizing this historical load data, MMPA capacity forecasts recognizing various future trends were prepared. This basis in historical fact gives MMPA confidence in the load forecast. MMPA's membership includes many dynamic and rapidly growing communities. The significance of the long-term accuracy of the load forecast is minimized because the generating facility is expected to be operational in three years. Forecast accuracy becomes more crucial when constructing generation facilities that require longer construction and approval times. Figure 2-3 below illustrates the historic and projected future demand growth for MMPA over the next 15 years.

Figure 2-3
MMPA Demand Forecast



From the MMPA's inception in 1992 until 2001, the annual growth rate in peak electric demand has varied from –7.1% to 10.7%. The average peak historical load growth is 3.75%. A "lower growth" scenario of 2.5% and a "growth" scenario that factors in the possibility of additional members joining the Agency in 2006 have also been projected. These additional scenarios are outlined in Appendix A.

An equally weighted average of the three scenarios was subjected to a regression analysis. This regression line lies very close to the 3.75% growth scenario and shows the Agency adding an average 10.7 MW per year throughout the forecast period.

Existing MMPA Resources Are of a Diversified Fuel Mix

Figure 2-4 shows the existing resources utilized by MMPA. The Agency pursues a diversified fuel mix within its power supply portfolio.

Figure 2-4
Existing Resources

Purchased Resources	
Melrose (diesel)	8 MW
Silver Lake (coal)	100 MW
Manitoba Hydro (hydro)	60 MW
Member Owned Resources	
MN River Station (gas)	44 MW

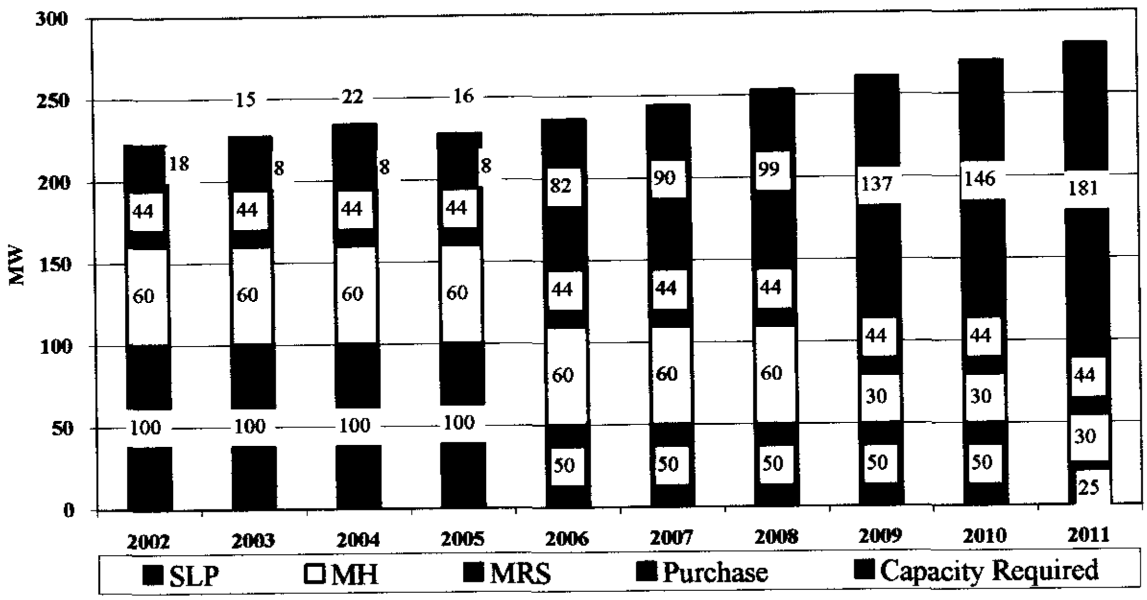
Long-Term Purchase Resources Will Diminish By 2006

MMPA has entered into long-term purchase contracts with Rochester Public Utilities (RPU), Manitoba Hydro (MH), and the City of Melrose. A large part of the Agency's need for additional resources by the summer of 2006 is driven by the reduction of the RPU Silver Lake purchase from 100MW to 50MW.

One Agency member has a Western Area Power Administration (WAPA) allocation of approximately 5 MW. One of the Agency's major customers receives a WAPA allocation of approximately 11 MW. These total allocations of 16 MW are MAPP firm purchases that include 15% for planning reserves. These allocations reduce the amount of MMPA's need and are not included in the demand forecast.

Figure 2-5 shows the estimated minimum needs for MMPA from 2002 through 2011 based on projected loads and existing member owned and purchased resources. The "Capacity Required" column represents the minimum capacity MMPA needs to acquire in order to meet its growing capacity needs.

Figure 2-5
ESTIMATED MINIMUM NEEDS CASE



MMPA Operates Generation Resources

The City of Chaska owns and MMPA operates the 44 MW Minnesota River Station (MRS). MRS is a natural gas fired turbine operated in a simple cycle in order to meet peaking needs. The MRS electrical generation facility is located in Chaska, Minnesota.

MMPA and Its Members Have Implemented Demand Side Management Resources

MMPA members have implemented significant load control and conservation programs. The member cities have had various programs over many years. Recently, these programs were integrated into an overall agency Demand Side Management (DSM) plan under the supervision of Jeffrey M. Jansen, who is an employee of Dahlen, Berg & Co. This allows for more efficient use of MMPA's resources.

DSM programs implemented by the Agency and/or its member cities include distributed standby generation, controlled air-conditioning, water-heating control, interruptible load, and voltage reduction programs. These programs are expected to reduce the MMPA summer peak by more than 8.3 MW, which is nearly 4% of the total Agency's member peak loads. Conservation programs that reduce the peak electric demand without load control include grant, finance, and rebate programs. Quantifying those programs involves more judgment, and MMPA estimates they reduce peak demand by approximately 2.0 MW. The existing 8.3 MW of agency-managed load is expected to grow to 10.5 MW by the end of 2006.

Short Term Capacity Purchases Are Becoming Volatile

MMPA's need is due in part to the expiration of short-term summer capacity purchases, which have been needed to meet the existing peak demand. As MAPP reserve margins continue to shrink, most MAPP members are not willing to sell existing capacity. Quoted prices for new capacity are high as a result of uncertainties of siting, equipment availability, and financing. The energy market has changed dramatically in the last few years as capacity has tightened with wholesale market deregulation, causing energy price spikes during times of extreme energy shortages.

Private Financing Is Unavailable for Investor Owned Utilities to Construct Power Plants

With financial problems plaguing the entire energy sector in the wake of Enron's bankruptcy, it appears very unlikely that private financing will be available to build the power plants to recreate a robust short-term energy market or to meet Minnesota needs. Relying on short-term capacity purchases with spot market energy prices leaves MMPA exposed to the vagaries and volatility of the market. Given the present market chaos, it would be imprudent to rely on short-term capacity and energy purchases.

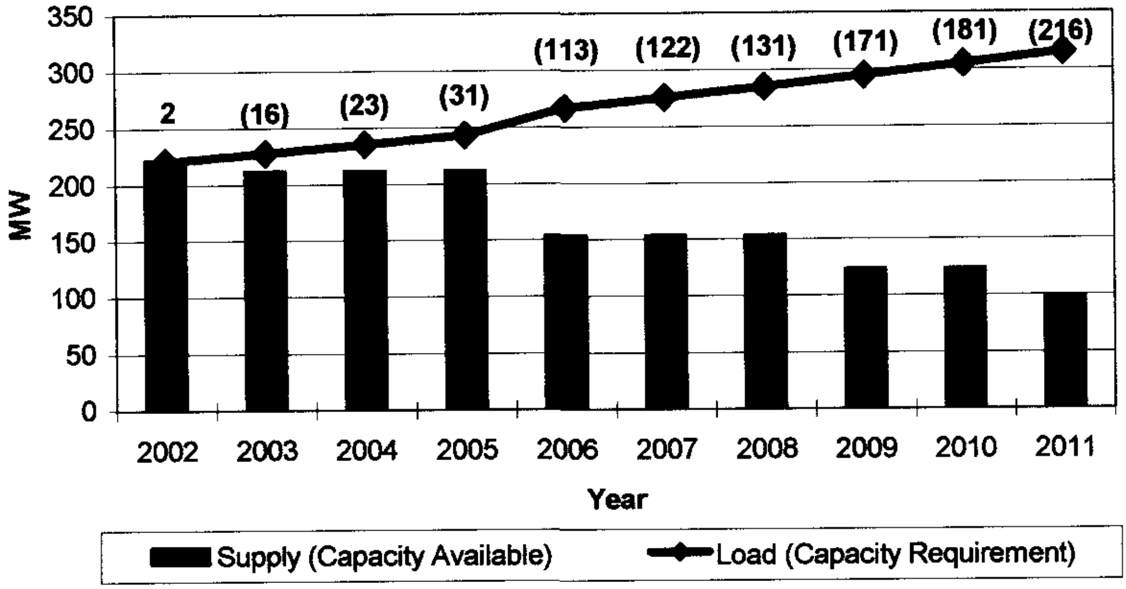
MMPA's Capacity Situation Is Worsening

MMPA's planning criteria are based on MAPP's 15% reserve requirement. The previously presented load forecast is used in making long-term capacity decisions. The mean load forecast has a 50% chance of being exceeded. For short-term capacity situations, MMPA's criterion is to maintain a surplus of approximately 10 MW over that required by MAPP. This short-term criterion is based on a forecast, which has approximately a 20% chance of being exceeded.

Figure 2-6 summarizes the MMPA capacity situation without the Project based on data from MMPA's load forecast (Figure 2-3). The load forecast and the load and capability tables are based on historical trends. The load in the load and capability tables also reflects all requirements and load obligations to customers other than MMPA members.

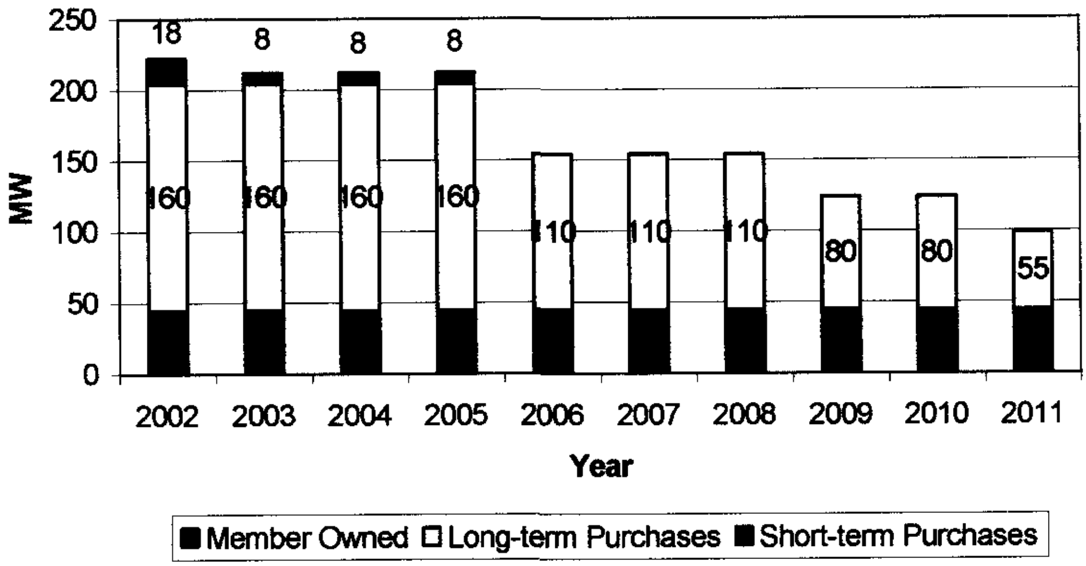
In order to present data for this application, some simplifications are needed and, as a result, the chart does not readily appear to tie to the load and capability tables. Figure 2-5 and the 2002 Load and Capability Report are based on the minimum needs case. The deficit shown in Figure 2-5 (labeled "Capacity Required") and the surplus/deficit shown on line 26 for MMPA's forecasted seasonal load and capability of the 2002 Load and Capability Report (pages III-71 and III-73) should agree. Pertinent excerpts of the 2002 MAPP Load and Capability Report are attached as Appendix B.

Figure 2-6
Summer Capacity Needs



In Figure 2-6, the line labeled "Load" is the total load obligation for MMPA. This load is the average forecast that includes the 15% MAPP reserve requirement. The columns represent the resources MMPA has available to meet its load obligations in MAPP. The numbers represent the surplus or deficit for MMPA in any given year. The components that constitute the power supply columns are further detailed in Figure 2-7.

Figure 2-7
MMPA Power Supply



The element labeled "Member Owned" is the existing generation resource owned by Chaska, the Minnesota River Station. The element labeled "Long-term" represents power purchases from others. This element becomes significantly smaller over time as some of the purchases end.

The Project can Help Meet both MMPA's and MAPP's Capacity Needs

Figure 2-6 shows MMPA will need small amounts of capacity beginning in 2003. More significant, however, is the large increase in the Agency's need starting in 2006. The Faribault Energy Park is planned to come on-line in the latter half of 2005 in order to meet this need. The Agency's smaller capacity needs before that time will be covered by purchases.

As shown in Figure 2-6, MMPA has a capacity need of 113 MW in 2006. In the same year, MAPP will be deficient 492 MW. The nominal 250 MW of the Project can reduce the Pool's deficit, providing energy security to Minnesota and all the Upper Midwest.

MMPA and MAPP Also Have Energy Needs

MMPA has a need for economic electric energy. The MAPP region shares a similar need. MAPP resources are biased toward baseload capability and recent additions to the pool have been strictly peaking facilities. A definitive need for intermediate capacity exists. The Faribault Energy Park will fill this need cleanly and economically in 2006 and beyond.

A load duration curve (LDC) illustrates how resources serve load. The capacity of the resources available to serve load is stacked under a curve created by sorting the hourly loads from largest to smallest. The loads have been adjusted to reflect MAPP's 15% planning reserve requirement. Based on the extent a particular resource is "covered" by the LDC, one can understand how the resource will be used. Actual dispatch of the units is complicated by operational considerations such as unit minimum loading, market energy transactions, and daily load swings. Figure 2-8 exemplifies the existing baseload resources covered by the LDC, consistent with that resource type. The load duration curve indicates a need for additional Intermediate Resources operating a large number of hours during the year in the "flat" portion of the curve.

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Need Summary

A dual need for both additional capacity and energy exists in the MAPP region. The MAPP reserve capacity will be deficient by almost 500 MW in 2006. The 250 MW Faribault Energy Park can help meet that need. Furthermore, both MAPP and MMPA have a need for new Intermediate capacity by 2006. Expected MMPA load growth and expiration of capacity purchases justify a minimum of 113 MW of the Project beginning in 2006. The remainder of the plant is needed to address MMPA's future growth needs, MAPP's summer season reserve deficits, and to meet the energy market's need for environmentally safe, low-cost electric capacity and energy.

MMPA has pursued a combination of cost-effective DSM programs, peaking generation, and capacity and energy purchases to defer the need for this project. The low-cost energy that will be provided by the project is expected to limit MMPA's exposure to volatile energy prices.

Baseload and peaking resources make up a high percentage of MMPA's and MAPP's existing generation mix and provide a very high percentage of the region's energy needs. The proposed Project provides economic intermediate capacity and energy to balance the mix of energy producing resources the state and region need.

Natural gas capacity has the lowest capital costs and will produce energy at a reasonable price. The following sections of this application will provide details showing that the Faribault Energy Park is the best alternative to meet the needs of MAPP, MMPA, and the State of Minnesota.

Section 3. Additional Considerations

The Project Minimizes Gas Pipeline, Transmission, and Environmental Impacts

The Project is the best alternative to provide MMPA Intermediate Resources for its customers. The Project utilizes a clean fuel and a combustion technology that has minimal impacts on the surrounding environment. The Project is being sited to minimize the length of gas pipeline and transmission line construction, which limits the potential environmental impacts. In addition, the transmission improvements associated with the Project will help improve transmission system reliability. The Midwest Independent System Operator (MISO) approves new generation facilities and ensures that the transmission reliability is maintained or improved. This process is covered in more detail in Appendix D.

MMPA has not conducted any promotional activities that have measurably contributed to the need for the Project. MMPA has implemented DSM programs that are designed to shift electrical usage to off-peak hours and reduce the summer peak demand. Air conditioner usage has contributed heavily to the increasing summer peak demand, and MMPA has promoted air conditioner cycling to help reduce demand.

The Project Will Provide Social Benefits

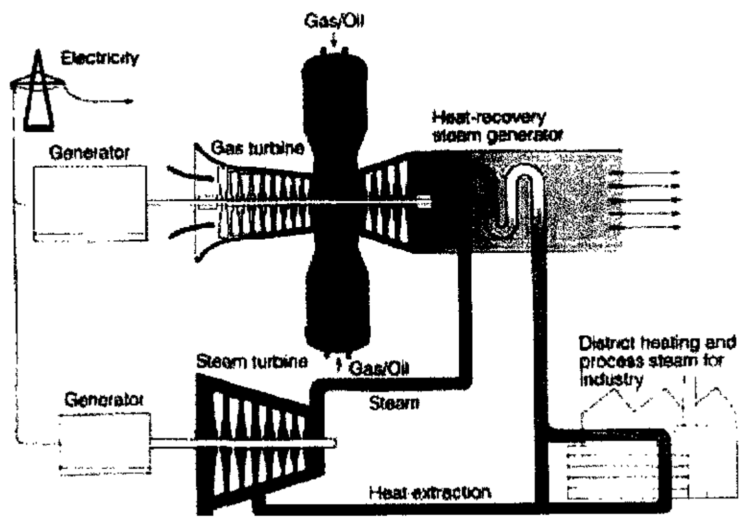
The Project will provide socially beneficial uses by supplying the member-owners with reliable, low-cost power. Maintaining the economic health of a region is a social benefit and is dependent on having reliable, low-cost electricity. Future development in the plant vicinity will be stimulated by its addition to an existing Industrial Park. The southern Minnesota area will also benefit from the revenues generated during construction by approximately 250 workers and from the estimated 17 skilled workers needed to operate the Project.

Section 4. Project Description

Major Equipment

Figure 4-1 shows a schematic diagram of a combined-cycle combustion turbine. Figure 4-2 on page 15 shows a typical plant layout with the major components identified. The plant footprint will require approximately 13 acres. This includes area for water tanks, oil tanks, substation, and lay-down area. Figures 4-3 and 4-4 below provide data on the expected operating and environmental performance of the Project. The base plant design consists of the following major equipment.

Figure 4-1: Combined Cycle Combustion Turbine Schematic



Combustion Turbine/ Generator (CT)

The combustion turbine will consist of one "F" technology machine. "F" technology is the latest commercial generation of combustion and material design developed by turbine manufacturers. "F" technology is state-of-the-art with a proven track record. Peak nominal electrical output of the turbine's generator during MAPP summertime conditions is 150 MW. The turbine will be the heart of one of the most efficient combined-cycle combustion turbine installations in the MAPP region.

Heat Recovery Steam Turbine/Generator

The use of a Heat Recovery Steam Generator (HRSG), which utilizes the exhaust heat of the combustion turbine to generate steam, makes highly efficient use of the fuel and increases the electric output of the plant by over 65%. Steam from the HRSG is sent to a steam turbine that drives a generator with a nominal output of 100 MW. This highly efficient use of resources allows us to help protect our environment while generating more electricity than is possible using traditional fuels and methods.

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Fuel Oil Storage

A backup fuel-oil supply will be installed on-site to provide approximately 72 operation-hours of fuel to the combustion turbines in the event of an interruption in the natural gas supply. Fuel oil will be stored in aboveground steel tanks with monitoring and secondary containment systems. Total fuel oil storage capacity on-site will be approximately 700,000 gallons.

Water Storage

A water storage tank will be provided for storage of approximately 300,000 gallons of de-mineralized water to be used for control of nitrogen oxides (NO_X) when firing on fuel oil. In addition, 2,500,000 gallons of water will be available for chilled water storage and 1,500,000 gallons of untreated water will be stored for plant use, process requirements, and fire protection.

Balance of Plant Equipment

Additional equipment located on-site will include starting motors, fuel oil and lubrication of oil pumps, water injection pumps, transformers, and coolers.

Substation

A new 115 kV substation will receive the electrical output from the gas and steam turbines. The substation will be located adjacent to the existing 115 kV transmission line and will connect to that line as well as possibly having a new 161 kV outlet to the Southern Minnesota Municipal Power Agency's (SMMPA's) system.

The Primary Fuel Will be Natural Gas

The primary fuel for the Project will be natural gas. Natural gas was chosen because of its low air emissions, ready availability, and low commodity and demand price relative to alternatives. Fuel usage rates for the turbines are provided in Figure 4-3.

Natural gas will be delivered to the Project site via the Northern Natural Gas (NNG) system in southern Minnesota. Natural gas service to the Project will be secured through agreements with gas suppliers. Natural gas is projected to be available over the 30 year life of the facility.

Natural gas is expected to be available during most of the year. Gas supply will be secured from market locations such as Ventura, Iowa into the NNG pipeline system. Gas prices for Ventura and other market locations are available on a daily, weekly, or monthly basis and can be priced on competitive indices. NNG will transport the gas from the market location to the Project site. Gas deliveries will be arranged the day before normal operation is required, within the Gas Industry Standards Board (GISB) guidelines. Gas supply for a MAPP emergency situation will be secured through agreements with gas suppliers. The backup low sulfur No. 2 fuel oil will be used if gas suppliers are unable to provide gas during an emergency.

The No. 2 fuel oil will be shipped to the facility by rail or truck. For the initial filling of the storage tanks, the oil will be shipped from a regional source. Occasional use of fuel oil would require smaller deliveries most likely from a more local delivery source.

Figure 4-3

Typical Expected Plant Performance at 59° F	"F" Technology Machine
Number of Units	1
Project Accredited Output	250 MW
Fuel Gas Usage Rate (lbs/hr)	76,691
(Mcf/hr)	1.823
Annual Fuel Consumption (50% Capacity Factor)	
-(lbs)	335,905,182
-(Mcf)	7,986
Heat Rate – LHV (Btu/kWh)	6,600
Fuel Heating Value – LHV (Btu/lb)	21,515
Fuel Requirements	
- Sulfur content	<0.05% by weight
- Ash content	<0.007 lb/mmBtu
- Moisture	0; 50° F superheat min.
Heat Rejected	520 mmBtu/hr
Cooling Tower Water Usage	1,500 gpm
Wastewater Discharges	300 gpm
Solid Wastes	Small quantities of miscellaneous wastes including rags and packaging materials
Noise	68 dBA at 400 ft for each unit; additional sound attenuation will be added as necessary to meet MPCA noise standards at surrounding properties

The Project Will Be a State-of-the-Art Combined-Cycle Facility

The Project will be a state-of-the-art, low capital, dispatchable, natural gas-fired, combined-cycle intermediate generation facility. It is expected to have an annual availability factor in excess of 95 percent and can be called upon to deliver up to its seasonal peak capacity within 4 hours. The expected service life for the facility is 30 years. The standard start-up sequence time from a cold condition is approximately three hours from start initiation to baseload. The expected annual capacity factor is variable, but will likely range between 40 percent and 80 percent. In most years, it is expected that the capacity factor will be approximately 50 percent. Because the efficiency of the "F" technology machine is high, it is likely that this facility will be used to generate energy for many hours of the year. In addition, the higher efficiencies may allow use of the unit for load following during certain times of the year. Heat rates for a combined-cycle generation plant vary with ambient weather conditions, altitude, and load. Heat rates for the Project at 55% relative humidity and 59° F at peak output are provided in Figure 4-3.

Maintenance Activities Will Be Based on Industry Practices and Manufacturers Recommendations

Maintenance activities for the Project's combustion turbine and balance of plant equipment will be based on power industry practices and the equipment manufacturer's recommendations. The frequency of combustion turbine maintenance activities consistent with base firing conditions using natural gas will include the following inspections: **[TRADE SECRET DATA BEGINS**

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Operation with fuel oil would accelerate the frequency of each of the above inspections since one hour of oil firing is the equivalent of 1.5 hours of gas firing.

Sites Were Screened Based on Proximity to Transmission Lines and Supplies of Natural Gas

MMPA determined the possible site locations for the Project through an analysis of the existing transmission network and natural gas routes in Minnesota. Sites were initially screened based on the proximity to an adequate supply of high-pressure natural gas and the proximity to locations on the regional transmission grid with adequate capacity. Sites that met these criteria were reviewed to determine costs, the availability of adequate land, the proximity to residences, and other potential environmental impacts.

Based on this analysis, the Project is proposed to be located in southern Minnesota near the intersection of a major 115 kV transmission line and a large natural gas main line. Transmission analysis has shown that most of the generation serving loads in Minnesota is coming from plants to the north and west of the Twin Cities. Because the Twin Cities represent the largest load in the area, siting new generation without significant new transmission infrastructure can best be accomplished by locating to the south and east of the Twin Cities area. This minimizes negative effects on the regional transmission constraints and does not degrade system stability.

Access to the Plant Will Be Via Paved Roads

Main access to the plant site will be via existing paved city, county, or township roads and a new plant entrance road. Roadway development will occur in cooperation with the City of Faribault and the neighboring industrial park developer.

Rail Lines Exist Near to the Site

A rail line exists approximately ¼ mile east of the plant site. This line may be used for construction purposes and/or fuel oil delivery.

The Project Will Be Located Near a Major Transmission Line

The Project is located near the intersection of a major natural gas pipeline and a major electrical transmission line, the Lake Marion – West Faribault 115 kV line. This location was selected so that the Project will provide the most benefits to regional and local area transmission while minimizing construction of new transmission facilities. When the project is completed, the overall performance of the entire integrated regional transmission system will meet or exceed all NERC and MAPP reliability criteria. The Project will improve some of the transmission constraints, or bottlenecks, which impede regional and inter-regional transactions. For instance, the Project counteracts the prevailing flow and reduces loading on the MAPP-defined constrained interfaces in southern Minnesota, central Wisconsin, and North Dakota and does not increase the flow on any other constrained interface in MAPP more than the acceptable standard. The Project improves the reliability of the regional transmission system by reducing possible overloads of nearby regional transmission facilities that can presently occur during high stress conditions and facility outages.

In coordination with MISO and Xcel Energy, MMPA is studying two options for the Project's interconnection with the transmission grid. One possibility is to rebuild the Lake Marion – West Faribault 115 kV line to a higher capacity. This would entail the reconstruction of approximately 20 miles of line on the existing right-of-way. Alternatively, one could forego the rebuilding of the 115 kV line and add a new 161 kV circuit from the plant site to the SMMPA system. The new line could interconnect at either the South Faribault substation or at a new site further south along the South Faribault-West Owatonna 161 kV line.

The addition of a new 161 kV circuit from the Project site to the existing SMMPA System would provide a new transmission source to Owatonna and the surrounding area. There is a slight increase in 69 kV facility loading near Faribault during certain facility outages, but this can be mitigated by an operating procedure or line re-build. A new 161 kV line from the Project site to the SMMPA system has 3 routing options. The longest of these would only require approximately 5 miles of new right-of-way. Final determination of interconnect configuration and cost will be made in accordance with the MISO tariff. Attachment R of the tariff, which details these procedures, is included as Appendix D.

The Project puts a new significant generation source in close proximity to major loads such as the Twin Cities metro area, Rochester, and the cities of south central Minnesota. This will improve energy supply reliability to these areas during extreme transmission outage and disturbance conditions such as those that occurred due to the June 25, 1998 storms.

Natural Gas Will Be Provided by Northern Natural Gas

Natural gas will be provided to the plant site by a new 16-inch line off the Northern Natural Gas mainline. The NNG mainline traversing the property consists of two 30 inch pipes.

The new 16-inch line to the plant site will consist of approximately ¼ mile of line and will be routed to the plant site completely within plant property.

Because the gas distribution system is designed around a wintertime peak, there is sufficient excess natural gas available to serve the maximum needs of the plant (summer, hot weather operation).

Fire Protection Will Follow Requirements of the State Fire Marshal

The site will include a raw water storage tank with approximately 1,500,000 gallons of storage capacity. The design of the facility will include the ability to withdraw water at a rate suitable for fire protection needs. The fire protection system will follow requirements of the State Fire Marshal as well as insurance company and local requirements.

The Facility Will Not Jeopardize Any National Ambient Air Quality Standards

Figure 4-4 below identifies the expected air emissions from the Project. Emissions from combustion gas turbines are dependent upon many factors such as type of fuel, ambient temperatures, and turbine loads. It is anticipated that emissions from the combustion turbine proposed for this location will be controlled to best available control technology limits with internal design, add-on controls, or use of clean fuels to minimize the emissions of regulated pollutants. In addition, restriction of source operation and fuel oil use will further reduce potential emissions. Impacts to ambient air quality in areas surrounding the Project are expected to be insignificant given the fuel type and capacity factors. Estimates of projected ground level contributions from the Project for sulfur dioxide, nitrogen oxides, and particulate matter are dependent upon specific site conditions and are not yet available. However, preliminary analyses have indicated that the ground level impacts will be less than significant, as defined by the Minnesota Pollution Control Agency (MPCA). Therefore, this facility will not jeopardize any National Ambient Air Quality Standard for regulated pollutants. Other sources of emissions that will be evaluated include duct burners, emergency generators, oil storage tanks, and cooling towers. All of these sources have substantially less emission potential and will not cause significant ambient concentrations. Cooling tower location and vapor drift from the cooling towers will also be evaluated to avoid impact with adjacent Interstate 35 traffic. This information will be an integral part of the Project's applications to the Environmental Quality Board as well as for the Minnesota Pollution Control Agency. This information will be available for the Department of Public Service Draft Environmental Report.

Figure 4-4

Pollutant	Natural Gas Emissions Total Annual Fuel 8760 hours		Distillate Oil Emissions Total Annual Fuel 8760 hours		Total facility Potential to Emit Gas & Oil	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_X	23.28	55.86	34.66	8.67	57.95	64.53
CO	32.44	77.83	68.69	17.17	101.13	95.00
PM	9.31	22.32	34.47	8.62	43.77	30.94
PM_{10}	9.31	22.32	34.28	8.57	43.59	30.89
VOC	3.07	7.36	7.97	1.99	11.04	9.36
SO_X	5.49	13.18	59.52	14.88	65.01	28.06
HAPS						
1,3 Butadiene						
25321-22-6	0.000048	0.00012	0.01977	0.00494	0.01981	0.00506
75-07-0	0.000070	0.00017	0.04536	0.01134	0.04543	0.01151
Arsenic	0.000408	0.00098	0.00000	0.00000	0.00041	0.00098
Benzene						
Beryllium	0.000022	0.00005	0.02517	0.00629	0.02520	0.00635
Chlorobenzene						
Cadmium	0.002044	0.00490	1.41812	0.35453	1.42016	0.35943
Chloroform						
Chromium	0.002556	0.00613	0.00217	0.00054	0.00473	0.00667
Chromium VI						
Dioxins						
100-41-4	0.0574	0.13771	0.02007	0.00502	0.07747	0.14273
Ethylene Dichloride						
50-00-0	1.2775	3.06487	0.50474	0.12618	1.78224	3.19105
Furans						
Lead	0.000920	0.002207	0.044997	0.011249	0.045917	0.013456
Manganese	0.000715	0.001715	0.000000	0.000000	0.000715	0.001715
Mercury	0.000510	0.001224	0.000000	0.000000	0.000510	0.001224
Methylene Chloride						
PAH	0.129203	0.30997	0.07192	0.01798	0.20112	0.32795
91-20-3	0.002324	0.00558	0.00867	0.00217	0.01099	0.00774
N-Nitrosodimethyl amine						
N-Nitrosomorpholine						
Nickel	0.003884	0.009318	0.000000	0.000000	0.003884	0.009318
Selenium	0.000044	0.000106	0.000000	0.000000	0.000044	0.000106
108-88-3	0.223536	0.536288	0.505765	0.126441	0.729301	0.662730
1330-20-7	0.000110	0.000264	0.347376	0.086844	0.347486	0.087108
71-43-2	0.021584	0.051782	0.102507	0.025627	0.124091	0.077409
107-02-8	0.000011	0.000026	0.014183	0.003546	0.014194	0.003572
110-54-3	0.072000	0.172736	0.000568	0.000142	0.072568	0.172878
Cobalt	0.000003	0.000007	0.008345	0.002086	0.008348	0.002093

Wastewater Will Be Discharged into Created Wetlands

Preliminary engineering has identified an estimated instantaneous maximum demand of 1,500 gallons per minute (gpm) of cooling water for the facility. Raw water will be treated and either stored in water-holding tanks or sent directly to a cooling tower to feed the evaporative and convective cooling process. Cooling water for the steam turbine will be circulated in a closed loop through the condenser on the steam turbine, and cooling water for the combustion turbine will be used for various hydraulic and lubricating processes associated with that unit. Preliminary engineering calculations indicate that process wastewater will be a maximum of 300 gpm. Management of wastewater is a function of regulatory approval processes. At this time, discharge into a created wetland located on site (in accordance with a National Pollutant Discharge Elimination System (NPDES) permit) is anticipated. MMPA intends to pursue the created wetlands option, as it uses the plant's wastewater stream, promotes infiltration and groundwater recharge, creates wildlife habitat, and enhances recreational opportunities for the community.

It is anticipated that the plant's relatively low sanitary waste load will be managed by an on site septic system.

Surface Water Will Be Discharged into Created Wetlands

Stormwater management is a critical aspect of the Project. Construction of the facility will require a stormwater permit. The objective of this permitting program, which is a part of the National Pollutant Discharge Elimination System, is to reduce the amount of sediment/pollution entering surface waters both during and after construction projects.

The program requires that any project disturbing more than five acres of total land area be covered under the storm water permit for construction activity. Construction activities requiring a permit include landscape clearing, grading, excavation, road building, and construction of homes, office buildings, industrial parks, landfills and airports.

There are two main permit requirements which are key to successful erosion and sediment control on a project:

- The Temporary Erosion and Sediment Control Plan. The goal of this plan is to prevent erosion from occurring and keep sediment on-site during active construction.
- The Permanent Erosion and Sediment Control Plan. The goal of this plan is to minimize long-term erosion and manage storm-water runoff discharging from the Project's ultimate impervious surface after construction is complete.

Once the facility is constructed, it will require an Industrial Stormwater Permit. The objective of this permitting program, which also is a part of NPDES, is to reduce the amount of pollution that enters surface and ground water from industrial facilities in the form of stormwater runoff.

Stormwater at the plant site may come into contact with any number of pollutants including toxic metals, oil/grease, de-icing salts, and other chemicals from roads, rooftops, and parking lots.

Facilities that need a permit must develop and implement a Storm Water Pollution Prevention Plan under this program. This plan must be tailored to specific site conditions and designed with the goal of controlling and minimizing the amount of pollution in storm water that leaves the site. This is accomplished through the use of Best Management Practices (BMPs) selected for site-specific conditions.

At this time, preliminary engineering is being conducted to evaluate alternatives for stormwater management. The preferred alternative is to direct stormwater to constructed wetlands on-site to allow for sediment removal, infiltration, controlled release of stormwater, and for the beneficial creation of additional natural habitat for the area.

A Spill Prevention Control and Countermeasure (SPCC) plan will be required to address management of petroleum stored on-site. At this time the quantity of fuel oil (to be used as a back-up fuel source and for emergency generation) stored on-site is undetermined, but it will exceed regulatory thresholds requiring a SPCC plan. This plan is maintained on-site and is updated every three years. The purpose of a SPCC plan is to document engineering controls necessary to mitigate spills of petroleum materials, as well as to provide a contingency plan to address management of releases.

Oil Wastes Will Be Disposed Off-Site

On rare occasions (for instance an abortive start event), fuel oil may be purged through a combustor shell drain. Lubricating oils generated through ongoing maintenance activities will be changed periodically and collected. These wastes will be collected and disposed off-site, preferably recycled if possible, or otherwise disposed in accordance with applicable regulatory requirements.

Little Solid Waste Will Be Generated

All construction wastes will be removed from the site and disposed in accordance with applicable regulatory requirements. Based on past experience, there will be little in the way of solid wastes generated during normal operation. Solid wastes will be managed in accordance with applicable regulatory requirements. Those wastes potentially exhibiting a hazardous characteristic will be tested, and if exceeding regulatory thresholds, will be managed as a Resource Conversation and Recovery Act (RCRA) Subtitle C waste. Other solid wastes will be recycled if possible, or disposed in a RCRA Subtitle D facility.

Water Will Be Withdrawn From the Jordan Aquifer

Preliminary engineering calculations indicate the primary water use at the Project will be an instantaneous maximum demand of 1,350 gpm. Preliminary evaluations indicate that withdrawal from the underlying Jordan bedrock aquifer under a Groundwater Appropriation Permit granted by the Minnesota Department of Natural Resources will be feasible.

The facility will also require water for drinking and sanitary purposes. The anticipation is that this will be a small-scale use, and that this water will be acquired from an extension of a water main from the City of Faribault.

Noise Levels Will Meet All State Noise Standards

MMPA will require the construction contractor(s) to mitigate construction noise impacts by using properly muffled equipment, by routing truck traffic to minimize disturbances to area residents, and by restricting some activities to daytime hours. As the site is located in a rural area, proximity to sensitive receptors is low. However, an evaluation of noise levels at the facility lot line and at the nearest residences will be made to demonstrate acceptable levels. In addition, noise from construction will be noticeable during development of this site; however, construction activities will be temporary and thus will not have a significant impact.

Noise levels due to operation of the Project are anticipated to be slightly higher at site boundaries than background noise levels. Major noise sources associated with a combustion turbine are related to the movement of great quantities of air into the compressor section and being exhausted from the stack. The combustion turbine has a far field (400 feet from the unit) rating of 68 dBA. Additional sound mitigation equipment can be installed to further limit measured noise from the unit. Other noise sources associated with the Project include vehicles and electrical equipment. On the selected site, ambient noise monitoring was conducted near residences closest to the site and was used to model operating noise levels. This information is part of MMPA's application to the Minnesota Environmental Quality Board for Site Certification. With a combination of sound mitigation equipment and siting the Project with a sufficient setback to residences, noise levels will meet all state noise standards for the applicable classification of land use surrounding the Project site.

Heat Rejected Will Be 520 mmBtu/hr

Heat rejected and lost through the exhaust stacks of the combustion turbine is estimated at 520 million Btu per hour for the 250 MW combustion turbine.

The Site Will Generate Little Traffic

During construction, traffic increases on the local county and township roads will be intermittent and will vary during the various phases of the construction period. The number of construction workers expected may reach 250 during peak construction activities. Additional traffic due to the delivery of equipment and supplies will be expected on an intermittent basis.

During operation, the site will generate little additional traffic. The remote start capability of the unit means that twenty-four hour staffing will not be required. The number of staff needed to maintain and operate the turbine is dependent upon the projected number of operating hours. Currently, an operating staff of 17 personnel is expected. If frequent or extended operation of the units on fuel oil is needed, the traffic increases due to fuel oil deliveries will be managed to insure safe conditions.

The Site Is Expected to Be 37 Acres

The overall Project site is anticipated to be up to 37 acres. Of that, about 13 acres will be needed for the power generating facility and ancillary facilities. The remaining acreage may be used for creating wetlands or may be utilized for industrial or recreational purposes.

Fugitive Dust Will Be Generated from Vehicles

Project construction will produce dust from earth moving and construction vehicle traffic. The construction period will be relatively short and dust generation will be intermittent depending upon the construction phase. Localized impacts during construction will be controlled through the application of water or other dust control measures.

Once the facility is operational, the primary dust source would be due to travel on any unpaved roads on the site. The number of trips to the plant is expected to be quite small and main access roads to the site are expected to be paved, which would mitigate vehicle-generated dust.

The Project Is the Most Economical Choice to Meet MMPA's Needs

Figure 4-5 summarizes cost information for the Project. An economic analysis with other alternatives is included in Section 5. Based on this analysis, the Project is the most economical choice to meet MMPA's capacity and energy needs. Appendix C provides trade secret non-public information on the rate impacts of the project.

Figure 4-5
Cost Information

	Units	Combined Cycle Natural Gas
Assumptions:		
MAPP Accredited Capacity	MW	250
Construction Time	Months	24
Projected Earliest Possible Commercial Operation Date (COD)		2006
Capital Cost of Power Plant	Million $	150
Capital Recovery Factor		0.0726
Capacity Factor	%	50
Hours Generating Per Year		4,380
Net Plant Heat Rate (LHV)	Btu/kWh	6,600
O&M Costs	2002 $/MWh	3.40
O&M Costs	2002 $/kWh	0.0034
Fuel Cost	2001 $/mmBtu	3.57
Power Plant Service Life	Years	30
Capacity Cost		
Capital Cost (Recovery)	2002 $/year	10,890,000
O&M Costs	2002 $/year	3,723,000
Annual Plant Capacity Cost	2002 $/year	14,613,000
Annual Plant Capacity Cost	2002 $/kW	58.45
Annual Plant Capacity Cost	2002 $/kWh	0.0133
Energy Cost		
Net Generation Per Year	MWh	1,095,000
Fuel Consumption when Generating	mmBtu/year	7,227,000
Fuel Cost for Generation	2002 $/year	25,800,390
Fuel Cost for Generation	2002 $/kW	103.20
Fuel Cost for Generation	2002 $/kWh	0.0236
Combined Capacity and Energy Cost (Total Cost)	2002 $/year	40,413,390
Total Cost	2002 $/kW	161.65
Total Cost	2002 $/kWh	0.0369

Unit Size Yields Economies of Scale

The size of the project was based on the capacity shortfall projected for MMPA in the year 2006. Utilization of the "F" technology allows MMPA to take advantage of the cost efficiencies associated with these larger units. In addition, given the size of MMPA's capacity deficit, the larger units allow MMPA to meet this need in the time frame required. Utilization of a greater number of smaller turbines would likely result in the need for permitting and construction at multiple sites due to land availability and noise issues. Project development at multiple sites would likely prevent the Project from being available for the year 2006 summer peaking season. In addition, operations and maintenance costs per kilowatt are substantially less for larger plant configurations, such as MMPA's Project, than for smaller plant configurations.

Other Required Permits

The following are anticipated permits and associated environmental activities required for the Project:

- Public Utilities Commission Certificate of Need
- MEQB Site Permit (Environmental Assessment)
- Prevention of Significant Deterioration (PSD) of Air Quality/Construction Permit
- Phase I Environmental Site Assessment
- Clean Water Act (CWA) – Section 404 Dredge and Fill Permit (Wetlands CWA – Section 401 Water Quality Certification) – should wetlands be disturbed
- NPDES Industrial Wastewater Discharge Permit
- NPDES Storm Water Permit
- NPDES Storm Water Permit for Construction Activities
- Storm Water Pollution Prevention Plan
- Spill Prevention Control and Countermeasure (SPCC)
- FAA Stack Height Notification
- Title IV – Acid Rain Permit
- Ground Water Appropriation Permit
- Noise Study
- Title V Operating Permit
- City of Faribault Zoning and Development Approval

Section 5. Alternatives to the Proposed Project

There Are Various Ways to Determine the Type of Resources Needed

There are various ways to evaluate and determine the appropriate resource MMPA needs to add next. Historically, a utility would focus on the kind of resources needed to serve native load. This type of analysis is included below based on the load duration curve (LDC). Another way that may be more appropriate in the developing electricity market is to see how competitive the resource would be in the future.

A Load Duration Curve Illustrates How Resources Are Used in Serving Load

A load duration curve can be used to illustrate how resources are used in serving load. The capacity of the resources available to serve load is stacked under a curve created by sorting the hourly loads from largest to smallest. The area under the curve reflects the energy for the time period covered by the curve. If the curve were completely flat, only baseload facilities would be required. Conversely, a short-term spike can best be served by peaking facilities.

Based on the extent a particular resource is "covered' by the LDC, the chart indicates the amount of energy supplied by the different resources. Figure 5-1 shows MMPA's baseload resources largely covered by the load duration curve, consistent with the resource type. Actual dispatch of the units is complicated by operational considerations including minimum load on units, market energy transactions and daily load swings. The portion of the LDC "breaking through" the stack of resources is the portion needed for new resources.

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Intermediate Facilities Would Provide MMPA and MAPP with an Improved Resource Mix

Baseload and peaking resources make up MMPA's existing generation mix and provide a very high percentage of MMPA's energy needs. The MAPP resource mix is very similar to MMPA's – heavily biased towards low energy cost baseload resources combined with the relatively high energy cost existing peaking generation. The high cost of the peaking generation is a function of relatively low efficiency (compared with modern combustion turbine equipment) and the relatively higher cost of using oil for fuel.

The Project would use modern combustion turbine generation, which will be much more efficient with full load heat rates of 6,600 Btu/kWh. Consequently, the Project will provide MMPA and MAPP with an improved resource mix.

Several Characteristics of Needed Resource Were Considered

In reviewing the possible alternatives to the proposed Project, the following characteristics were considered:

- Suitability for operating at a 75 percent capacity factor
- Availability of the alternative in the time frame required to meet MMPA's need
- Reliability and timeliness when called upon to operate
- Energy efficiency (heat rate)
- Cost effectiveness
- Environmental impacts including externalities analysis

- Ability to limit the risk to MMPA from financial, social, and technological factors that MMPA and its member-owners cannot control

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Three Primary Objectives Were Used to Evaluate Alternatives

Three primary objectives were used to evaluate alternatives to the Project:

1. Procurement and installation to provide at least 250 MW prior to the summer of 2006
2. Operating characteristics suitable to intermediate operation (high capacity factor, extremely reliable operation)
3. The resource must be cost-effective when compared to the proposed Project

If an alternative was unable to meet any of these three objectives, it was rejected as a suitable alternative for further analysis.

Many Different Alternatives Were Considered

The alternatives considered were:

1. Purchased Power
2. Upgrades to existing resources
3. New Transmission
4. Coal
5. Oil fired combustion turbine
6. Simple cycle combustion turbine
7. Customer-owned distributed generation
8. DSM
9. Renewables
   a. Hydro
   b. Biomass
   c. Wind
   d. Solar
10. Emerging technologies
    a. Fuel cells
    b. Micro turbines
    c. Energy storage
       i. Batteries
       ii. Compressed air energy storage
       iii. Pumped storage hydro
       iv. Super conducting magnetic energy storage

Purchased Power Is Not a Viable Solution for MMPA

Since its inception, MMPA has effectively utilized capacity purchases to defer the need to construct intermediate capacity. As MAPP reserve margins continue to shrink, the availability of purchased power will naturally decline with it. With the decline in availability, prices will increase. Financing for privately owned generation facilities is virtually non-existent in the present market so the Agency cannot look to these entities to mitigate the future shortages. Relying on today's energy supply market would expose the Agency to social and financial risks that it cannot control. MMPA is a power agency that has the advantage of relatively low cost financing and is not required to earn a profit. These factors further add to the cost of purchased power alternatives compared to the cost of the Project.

Purchased power also tends to be less flexible than desired for an intermediate type of resource. Purchase transactions require scheduling energy on a day-ahead basis and usually for all the on-peak hours. A generation resource can be controlled to follow load in a manner a power purchase usually cannot.

Purchased power for Intermediate Resources is not a viable solution for MMPA until later in the next decade. The capacity shortage in MAPP is likely to stimulate construction of new peaking capacity. The additional capacity may result in a short-term surplus and may be a cost-effective capacity resource for MMPA's future needs beyond those being met by the Project. This projected surplus will not occur in time to meet MMPA's current needs, but it will be considered for future capacity needs.

Purchasing intermediate capacity is not cost-effective, nor is it an efficient method for meeting MMPA's needs for 2006. This alternative is excluded from further evaluation.

Upgrades to Existing Facilities Will Not Meet the Agency's Need in 2006

The City of Chaska owns and MMPA operates the Minnesota River Station located in Chaska, Minnesota. The addition of a HRSG and steam generator to the existing GTX 100 combustion turbine would only increase plant output by 20-30 MW. This is not enough to meet the Agency's need in 2006 and thus, this alternative is excluded from further evaluation.

New Transmission Fails to Meet the Primary Objectives

As indicated previously, MAPP is nearing a generating capacity deficit situation. Building additional transmission facilities in the region would only help provide additional capacity if excess generation capacity was available.

Generation resources are scarce in the MAPP region. Therefore, utilizing new transmission fails to meet the project's primary objectives and is excluded from further evaluation as a viable alternative.

Other Fossil Fuel Technologies Were Screened

The following conventional fossil fuel technologies were screened to determine if they meet the primary project objectives:

- Coal-fired technologies including pulverized coal, fluidized bed and gasification simple-cycle
- Oil-fired combustion turbine
- Natural gas-fired simple-cycle combustion turbine

Coal-Fired Technologies Are Not Well Suited for Meeting Intermediate Resource Need

These technologies are usually associated with baseload facilities due to their high capital costs and slower start-up times. Operating one of these coal-fired technologies as an intermediate facility by keeping them in "stand-by" mode greatly reduces their efficiency and increases emissions.

In addition, siting and permitting of a new coal-based power plant in Minnesota would likely be a drawn out and contentious process due to social concerns regarding sulfur dioxide, particulate, and mercury emissions. This process, along with the additional time needed to construct a coal-based facility, would push the availability of the capacity past the summer 2006 time frame needed to satisfy one of the Project's primary objectives.

Coal-fired technologies are not well suited for meeting an Intermediate Resource need. In addition, these technologies fail to meet the primary objectives due to the lengthy time needed to site, permit, and construct them. Thus, this alternative is excluded from further evaluation.

Oil-Fired Combustion Turbine (Combined-Cycle) Meets the Primary Screening Objectives

This alternative is similar to the proposed Project, except No. 2 fuel oil would be the primary fuel. No back-up fuel would be needed since on-site oil storage tanks would be used to provide the necessary run time. The same units as described in Section 4 would be utilized, resulting in the same number of land required and workers needed for construction and operation. In addition, discharges, solid wastes, noise, traffic as well as the number of transmission facilities needed are identical for both alternatives. Furthermore, this alternative is expected to operate at the same availability factors as the proposed Project.

Siting the unit is simplified since the need to be near an adequate gas supply would no longer be a concern. When burning fuel oil, the turbines produce higher emissions of sulfur dioxide, carbon monoxide, and nitrogen oxides than a natural gas fired alternative. Using oil for fuel results in higher operating costs than a natural gas fired alternative. Higher operating costs mean this alternative will not run as much, limiting the opportunities to provide energy.

Because of the similarities between this alternative and the proposed Project, this alternative meets the first two primary objectives for the Project and it thus evaluated further.

Simple-Cycle Combustion Turbine Meets the Preliminary Requirements

This alternative would use the same combustion turbine as the proposed project, operating in a simple-cycle instead of a combined-cycle. The simple-cycle combustion turbine alternative is very similar to the proposed project. Discharges, solid wastes, noise, traffic as well as the number of transmission facilities needed are identical for both alternatives. In addition, this alternative would require the same number of construction workers. However, only three workers would be needed to operate the facility. With regards to land requirements, this alternative would need approximately five acres less than the proposed facility. Vehicular and rail traffic generated by the construction and operation of this alternative would be the same as for the proposed facility. This alternative is expected to operate at the same availability factor as the proposed Project.

The major drawback of this alternative is the dramatic loss of efficiency, which would preclude the alternative from having the high capacity factor needed for the Project. However, this alternative meets the preliminary requirements and thus is evaluated further.

Figure 5-2 summarizes the major operational differences between these alternatives and MMPA's proposed project.

Figure 5-2
Comparison of Operating and Environmental Data

	MMPA Project: Natural Gas Fired Combined-Cycle Combustion Turbine	**Oil-Fired Combined-Cycle Combustion Turbine**	**Natural Gas Fired Simple-Cycle**
Project Accredited Output	250 MW	250 MW	250 MW
Fuel Usage Rate	1.823 Mcf/hr	12,320 gal/hr	2.555 Mcf/hr
Annual Fuel Consumption (50% Capacity)	7,986 Mcf	53,962 mgal	11,192 Mcf
Heat Rate – LHV (Btu/kWh)	6,600	6,850	9,250
Fuel Heating Value – LHV (Btu/lb)	21,515	18,300	21,515
Fuel Requirements			
- Sulfur	<0.05%	<0.05%	<0.05%
- Ash	<0.007 lb/mmBtu	trace	<0.007 lb/mmBtu
- Moisture	0; 50° F superheat min.	trace	0; 50° F superheat min.
Heat Rejected	520 mmBtu/hr	528 mmBtu/hr	N/A
Water Use			
- gpm	1,500	1,500	1,500
- mmgal/yr	394	394	394
- acre-ft/yr	1,210	1,210	1,210
Wastewater Discharges			
- gpm	300	300	300
- mmgal/yr	79	79	79
- acre-ft/yr	242	242	242
Solid Wastes	Small quantities of miscellaneous wastes	Small quantities of miscellaneous wastes	Small quantities of miscellaneous wastes
Noise	68 dBA @ 400 ft.	68 dBA @ 400 ft.	68 dBA @ 400 ft.

New Customer-Owned Generation Does Not Meet the Primary Screening Criteria

Several of MMPA's member systems have very actively promoted installing customer-owned generation ("distributed generation"). Approximately 4.3 MW of customer-owned generation are already in place and 1.2 MW of additional customer-owned generation are expected to be in place by 2006. If the distributed generation is utilized to serve loads that are interrupted from this system, the amount of avoided capacity is the peak reduction plus 15 percent. This is because each MW of peak load demand requires 15 percent more capacity due to the MAPP reserve requirement and the distributed generation reduces the peak load. If the generation is accredited by MAPP and operated in parallel to the system, the 15 percent adjustment would not apply. Accredited capacity does not need to operate during the peak hour to be included in the generation capacity total. These additional expected installations are reflected in the load forecast as new demand-side management.

In addition to the already planned distributed generation, it would require more than 55 diesel engine generator sets of 2 MW to be installed by 2006 to meet MMPA's needs. This is not realistic due to the large number of sites involved and the associated infrastructure needs for each site.

Using oil for fuel results in higher operating costs for diesels than a natural gas-fired alternative. Higher operating costs mean this alternative will not run as much, limiting the opportunities to provide ancillary services such as load following and regulation while operating.

The small size of each distributed generation unit allows them to be subject to less stringent air emission requirements, resulting in higher total emissions than larger alternatives, which are subject to more stringent air emission restrictions.

This alternative does not meet the primary screening criteria/objectives and is not included in further economic analysis.

New or Expanded Demand Side Management Does Not Meet the Criteria

It takes many years for DSM programs to deliver maximum results. The current DSM peaking reductions are the result of many years of having programs in place. Achieving additional peaking reduction of the magnitude need to impact the need for the proposed Project is not feasible, particularly considering that the reduction would need to occur before the summer of 2006.

MMPA reduced the 2001 summer peak load by over 8.3 MW (about 4 percent) using cost-effective DSM programs. Load control programs make up the largest share of the DSM programs and include cycled air conditioner, C & I interruptible with distributed backup generation, and peak shave water heaters. These load management programs have deferred the need to add peak capacity.

DSM programs are expected to reduce the peak load by an additional 2.2 MW by 2006. These programs cannot provide enough capacity to defer the proposed Project. While continuing expansion of the load management program is expected, it will not provide enough capacity to avoid building the Project. Limiting factors include customer receptivity and the potential for secondary peaks that are higher than the original peaks due to reduced system load diversity. MMPA's summer peak hourly load-shape is becoming increasingly flattened due to the implementation of DSM. This flattening increases the number of control hours needed to achieve increased levels of demand reduction. This alternative does not meet the required criteria because it can neither provide enough capacity nor can it provide an Intermediate Resource. DSM is thus not selected for further economic analysis.

Renewable Technologies Were Considered

The following renewable technologies were considered as alternatives to the proposed Project.

Hydropower Fails to Meet the Project's Primary Objectives

Hydro resources are typically Baseload Resources rather than Intermediate Load Resources as is needed by MMPA. Initial capital costs are also usually quite high compared with Intermediate Resources.

MMPA is in the process of developing two small Hydro plants in the Northern Metro area suburbs. While desirable, these small plants cannot meet all the Agency's needs.

Within Minnesota (and the region) the potential for new hydro facilities is limited. In his direct testimony in Docket NO. IP3/CN-98-1453, (Lakefield Junction, pages 8 and 9), Steve Rakow (DPS) cited a DOE study which indicated no sites within Minnesota with the potential for 100 MW or more of new hydro generation. The study indicated that three sites in South Dakota with greater than 100 MW of capacity could be developed but all are significantly less than the capacity contemplated by this Project. Mr. Rakow concluded that while Manitoba has substantial potential hydro resources yet to be developed, significant additional transmission would need to be built in order to bring those resources into the U.S.

The cost of the added transmission (an estimated $180 – 200 million) makes further development of Canadian hydropower uneconomic compared with this Project. Domestic or Canadian hydropower cannot meet the Project's size, availability, and cost-effectiveness objectives. Therefore, hydro is not a reasonable alternative and is not evaluated further.

Sufficient Biomass not Available by 2006

Biomass resources encompass using a wide variety of renewable fuels. Renewable fuels may be utilized via burning in a steam cycle, gasified for use in a combustion turbine, or burned in a combustion turbine or other internal combustion device. Solid biomass fuels include wood and waste wood, switchgrass, and alfalfa stems. Ethanol derived from corn is also considered a renewable fuel.

Having 250 MW of solid fuel biomass capacity available by 2006 is not possible due to limited fuel availability and siting issues.

Solid fuel power plants have operating characteristics consistent with being a baseload resource. Baseload resources operate at a high capacity factor, allowing for planning and scheduling for growing and delivering the fuel to the power plant. Having a dedicated source of solid fuel is incompatible with a resource such as an Intermediate Resource, which operates on a less regular basis.

Solid fuel based biomass is excluded from further analysis based on unavailability by the summer of 2006.

Wind Generation Fails to Meet the Primary Objectives

Wind energy is a renewable resource that has been utilized because it has a reasonable average energy cost and perceived unlimited supply. Improvements have been made to increase wind turbine reliability and decrease costs over the last several years. However, the average cost of wind generation is not a meaningful measure of how it fits into the resource mix. Wind generation is not an effective resource to meet Intermediate Resource needs because of its intermittent nature and low correlation of wind output to summer peaking conditions. MAPP has defined a procedure to accredit capacity to account for the intermittent nature of the resource. The accredited value for wind is the median of all the hourly output from the plant over a four-hour period that includes the expected peak hour. Based on that procedure, the DPS calculated the July MAPP accreditation to be 16.8 percent of the maximum output (three hour period from 4:00 p.m. to 7:00 p.m.). Using this estimate, 6 MW of wind would need to be installed to receive 1 accredited MW of capacity. Achieving 250 MW of accredited capacity would require installing almost 1500 MW of wind capacity. Assuming reasonable wind resource areas could be found, it would take an extended period of time to site and construct such a large amount of wind capacity. Xcel Energy has taken the better part of a decade to complete the 425 MW of wind capacity it has been required to build on the Buffalo ridge. MMPA would require over three times the total amount installed by Xcel Energy.

Having to build nearly six times the installed capacity to achieve the needed accredited capacity reflects that wind generation is not reliable. Therefore wind is not a cost-effective Intermediate Resource.

A key objective of this project is having a dispatchable resource. Wind, due to its intermittent nature, is not a dispatchable resource and thus fails to meet a key Project objective.

Because wind generation fails to meet the primary objectives, it is not considered for further evaluation.

Solar Power Fails to Meet the Primary Objectives

Solar is another intermittent resource similar to wind, which is used by converting sunlight into electricity. There is less experience with solar generation in this region than with wind, reflecting the greater availability of the wind resource compared to solar. Under the MAPP capacity accreditation process, solar also receives a relatively low ratio of accredited capacity to nameplate rating, requiring substantially greater amounts of solar capacity to meet the Project's capacity objectives.

Solar, like wind generation, also fails to meet the primary objectives and is not considered for further evaluation.

Figure 5-3 summarizes the results of the screening of the renewable alternatives.

Figure 5-3
Renewable Alternatives Screening

	Hydropower	Biomass	Wind	Solar
Description	Since the late 1800s, the energy in falling water has been used to produce electrical energy. In Minnesota, there are approximately 180 MW of hydropower facilities.	Biomass is an energy resource derived from organic matter. At present, wood waste and agricultural residues are the major sources of biomass for the generation of electricity.	Wind energy is generated by converting wind (kinetic energy) into mechanical energy. Developments in the region have been concentrated on the Buffalo Ridge due to high wind speeds found there.	Solar photovoltaic (PV) cells are solid-state semiconductor devices that convert sunlight into direct-current electricity. PV technologies range from large-scale concentrator systems to customer located PV cells.
Availability and Applicability	There is not sufficient undeveloped hydropower potential in Minnesota or the surrounding region to meet the project needs. Additional EHV transmission facilities would be required for any Canadian generated power.	Biomass generation technologies are baseload facilities that are not well suited to meet intermediate demand.	Wind is an intermittent resource that is not suited to provide on-demand electric production. Regional transmission constraints may limit future large-scale development.	There are no utility-scale solar developments in Minnesota or the surrounding region due to the region's marginal solar resources and the high costs associated with the technology.
Reliability	Hydropower is not capable of meeting intermediate needs because electricity production is dependent on the flow of the river, which can vary widely depending on the season and year.	The technology for direct combustion boiler/steam is mature and reliable. An economic source of biomass is the limiting reliability factor.	Wind is an intermittent resource that cannot meet on-demand intermediate needs. Wind availability varies depending on the day, season, and year.	Solar energy is an intermittent resource that cannot meet on-demand electric production demands. Solar resources will vary depending on the day, season, and year.
Economic Impacts	It is unlikely that new hydropower facilities will be developed in the region due to the lack of resource potential and possible environmental degradation.	At the present time, biomass is generally more expensive than fossil fuel alternatives.	Wind energy is more expensive than gas-fired combustion turbines.	Although the costs of PV systems continue to fall, they are not competitive with the proposed Project.
Environmental Impacts	Environmental impacts from hydropower can include: lower water quality, loss of native habitat for plants and animals, and changes in land uses.	Thousands of acres of cropland would be required. Mobile source emissions would be generated in the planting, harvesting, processing, and transportation of the biomass. Ash disposal would be necessary.	Environmental impacts include: noise, aesthetic intrusions, avian mortality, and changes in land use.	Significant tracts of land would be required for the construction of a PV system capable of meeting project needs.

Emerging Technologies Have High Impact Potential

There are a number of emerging technologies that have the potential to dramatically impact how electricity is produced, delivered, and used. A key characteristic common to many of these technologies is that they are small enough to be located very close to the point of consumption, minimizing the need for new transmission and distribution. These technologies include:

- Fuel Cells
- Micro-Turbines
- Energy Storage

Fuel Cells Will Not Be Available in Sufficient Quantity by 2006

Fuel cells convert hydrogen rich fuels directly into electricity through electrochemical reactions. The reactants, fuel and oxidant (air or oxygen), are fed to separate anode and cathode electrodes. Electricity is generated by the transport of ions. These ions are generated by the anode reaction across the electrolyte separating the anode and cathode. Because this is not a combustion process, there are no air emissions other than water vapor and carbon dioxide. Even in small plant sizes fuel cells are very efficient.

Phosphoric acid fuel cells (PAFC) are currently available in 200 kW unit sizes. Their cost is in excess of $2000/kW, making them uneconomical. Molten carbonate (MCFC) and solid oxide fuel cells (SOFC) are not yet commercially available although the developers are hopeful they will become available in the next several years. Proton exchange membrane (PEM) fuel cells have created interest primarily for automotive and transit applications. They are also under development for stationary power applications but are not yet commercially available.

While there is much interest in fuel cells and great expectations for commercial availability of various fuel cell technologies, it is unreasonable to expect them to be available in sufficient quantity to meet the identified need by 2006. Most fuel cells are also baseload in nature and would not be cost effective at the capacity factors typical of an Intermediate Resource. Therefore, this alternative is excluded from further analysis.

Micro-Turbines Are Not Commercially Proven

Micro-turbines are small combustion turbines with capacities in the range of 30 to 250 kW. Micro-turbines are well suited for distributed generation applications. The units are small and relatively efficient for their size. Installed costs range from $450 to $700 per kW and efficiencies range from 22 percent to 30 percent. Several potential vendors are developing micro-turbines for distributed generation. These units have a single shaft with the generator, air compressor, and turbine mounted on air bearings to eliminate the need for bearing lubrication. Power electronics convert the high frequency AC current from the generator to DC current. An inverter then converts the DC current to AC current at a standard distribution voltage. Due to the small size of the units, they can be on line in a relatively short time and can be mounted on a pole, on a platform, in a substation, on a roof, in a vault, or on a pad.

Micro-turbines are a rapidly developing technology. Although long-term reliability is projected to be good, micro-turbines are just entering commercial use at this time and, therefore, their reliability has not been demonstrated in real world applications. There is considerable uncertainty on the long-term O&M costs and operating life for this technology. Because micro-turbines are not commercially proven at this time, they are not selected for further evaluation.

There Are Several Energy Storage Alternatives

Energy storage can be used to dampen out fluctuations in the demand for electrical energy. It also allows for the possibility that electricity can be generated at low cost at times of low demand and then retrieved from storage during periods of high demand. Energy storage options include:

- Batteries
- Compressed air
- Pumped storage
- Superconducting magnets

Batteries Are Not Cost Effective

Batteries are well known for their ability to store electrical energy. Batteries represent a resource option for electric utilities but lead acid batteries, the most common type used for storage in larger scale applications, have a limited life (1500 to 2000 charge-discharge cycles) and are expensive. Advanced batteries that may increase the cycle life and lower costs are currently being developed.

As a result of the high cost of this option and limited experience in the use of batteries and utility sized applications, this option is not considered for further evaluation.

Compressed Air Is an Immature Technology

With this option, electricity is used during off-peak periods to compress air in underground cavern or porous rock reservoirs. During on-peak periods, the stored air can be released to provide compressed air for the combustion portion of a combustion turbine.

This is an immature technology. A highly specialized geological site is required to make use of compressed air storage and existing prototype plants have not performed to expectations. Therefore compressed air is not considered for a detailed evaluation.

No Suitable Sites for Pumped Storage Hydro Can Be Found

Pumped storage hydro refers to an energy storage technology wherein water is pumped to a high reservoir during off-peak hours and released to generate electricity during on-peak hours. This is a mature technology. However, a primary problem with pumped hydro is locating suitable sites. Minnesota state law prohibits the use of the Mississippi River as a water source for pumped storage facilities.

Because no suitable sites were identified, this option is not considered for a detailed evaluation.

Superconducting Magnets Are Not Fully Developed

A superconducting magnet refers to a coil that can store electrical energy. Because the coil is superconducting, storage losses are very low. Although it appears that superconducting magnetic storage is suitable for short-term power quality applications, no high capacity factor units have been manufactured. This is an emerging technology that is not fully developed yet. Thus, it is not considered for a detailed evaluation.

Emerging Technologies Are Not Reasonable Alternatives

None of these emerging technologies is a reasonable alternative based on either the immature state of its development or its inappropriateness (cost factors) for intermediate applications at this time.

Only Two Alternatives Met the Primary Screening Criteria

Figure 5-4 summarizes the conclusions reached in the preceding descriptions of the alternatives with respect to the primary Project objectives. It indicates those alternatives that have been screened for further consideration. The next section provides the economic comparison of the selected alternatives.

Figure 5-4
Summary of Alternatives

Alternative	Primary Objectives: 250 MW Available for 2006	Primary Objectives: Suitable Operating Characteristics	Considered in Further Economic Screening
Purchased Power	No	Less Flexible	No
Upgrades to Existing Resources	No	No	No
New Transmission	No	No	No
Coal	No	No	No
Oil Fired Combustion Turbine	Yes	Yes	Yes
Simple-Cycle Gas Combustion Turbine	Yes	Yes	Yes
DG/Customer Owned	No	No	No
DSM	No	No	No
Renewables			
Hydro	No	No	No
Biomass	No	No	No
Wind	No	No	No
Solar	No	No	No
Emerging Technologies			
Fuel Cells	No	No	No
Micro Turbines	No	No	No
Energy Storage			
Batteries	No	Yes	No
Compressed Air Energy Storage	No	Yes	No
Pumped Storage Hydro	No	Yes	No
Superconducting Magnetic Energy Storage	No	No	No

An Economic Comparisons Is Provided Below

Figure 5-5 provides the cost comparison between the Project and the alternatives, which have met the initial screening criteria (oil-fired combustion turbine and a simple-cycle turbine).

Figure 5-5
Economic Comparison

	Units	Combined-Cycle Natural Gas	Combined-Cycle No. 2 Fuel Oil	Simple-Cycle Natural Gas
Assumptions:				
MAPP Accredited Capacity	MW	250	250	250
Construction Time	Months	24	24	18
Projected Earliest Possible Commercial Operation Date (COD)		2006	2006	2006
Capital Cost of Power Plant	Million $	150	150	110
Capital Recovery Factor		0.0726	0.0726	0.0726
Capacity Factor	%	50	50	50
Hours Generating Per Year		4,380	4,380	4,380
Net Plant Heat Rate (LHV)	Btu/kWh	6,600	6,850	9,250
O&M Costs	2002 $/MWh	3.40	3.40	3.32
O&M Costs	2002 $/kWh	0.0034	0.0034	0.0033
Fuel Cost	2001 $/MMBtu	3.57	5.48	3.57
Power Plant Service Life	Years	30	30	30
Capacity Cost				
Capital Cost (Recovery)	2002 $/year	10,890,000	10,890,000	7,986,000
O&M Costs	2002 $/year	3,723,000	3,723,000	3,635,400
Annual Plant Capacity Cost	2002 $/year	14,613,000	14,613,000	11,621,400
Annual Plant Capacity Cost	2002 $/kW	58.45	58.45	46.49
Annual Plant Capacity Cost	2002 $/kWh	0.0133	0.0133	0.0106
Energy Cost				
Net Generation Per Year	MWh	1,095,000	1,095,000	1,095,000
Fuel Consumption when Generating	MMBtu/year	7,227,000	7,500,750	10,128,750
Fuel Cost for Generation	2002 $/year	25,800,390	41,104,110	36,159,638
Fuel Cost for Generation	2002 $/kW	103.20	164.42	144.64
Fuel Cost for Generation	2002 $/kWh	0.0236	0.0375	0.0330
Combined Capacity and Energy Cost (Total Cost)	2002 $/year	40,413,390	55,717,110	47,781,038
Total Cost	2002 $/kW	161.65	222.87	191.12
Total Cost	2002 $/kWh	0.0369	0.0509	0.0436

This table shows that the Project is the lowest-cost alternative for the anticipated capacity factor. In addition, even though the Project is expected to run approximately 4,400 hours per year for either serving load or providing competitive energy into the energy market, the Project is even more cost-effective at higher capacity factors. This observation suggests the Project is a robust choice in meeting the capacity and energy needs of MMPA's members. A further observation is that while this Project is being characterized as an Intermediate Resource, it also has characteristics that are similar to existing baseload resources.

The escalation of the fuel, O&M costs, and the capacity factor has been levelized across the projected service life of the plant.

The clean nature of the proposed Project produces low emissions. Consequently, externality costs have a minimal impact on the cost of energy produced by the Project.

The rate impact of the various alternatives is considered trade secret and is included in Appendix C of the nonpublic document.

Based on the Primary Objectives, the Project Is the Best Alternative

MMPA has examined alternatives to the proposed Project. Based on the primary objectives, there are no reasonable alternatives to the proposed Project that would reliably and economically meet MMPA's Intermediate Resource needs.

Section 6. Consequences of Delay

Delaying Construction of the Proposed Facility Could Have Significant Negative Consequences

Delays in construction would cause many problems including rising costs, difficulty in meeting capacity obligations, increased use of less efficient peaking facilities, and reduced electric system reliability.

If the Project were not constructed, MMPA's costs would increase because more expensive alternative resources would be utilized to meet capacity and energy needs. The impact of a construction delay would depend on the length of the delay and the variance from the normal forecast.

Prices for short-term capacity are likely to rise in the next few years due to the shortage of supply. If the Project were delayed one to two years, MMPA would have to purchase short-term capacity at sharply increased prices.

If construction were delayed two to three years or indefinitely, MMPA would need to purchase long-term capacity or add expensive peaking capacity at prices that are expected to be higher than the cost of the Project. In the event of an indefinite delay, MMPA's costs would also increase due to expenses already incurred for this project.

A delay could also result in MMPA not having enough capacity to meet its MAPP peak load obligation. MAPP requires that members have 15 percent more capacity than their peak load to ensure regional electric system reliability. If deficits occur, MMPA would be "penalized" by MAPP and would be required to purchase capacity after the fact at a sliding scale of $43,000 to $87,000/MW of deficit. MMPA projects a 113 MW deficit by the summer of 2006 without the Project or some other alternative. If this deficit were to occur in the summer of 2006, the MAPP penalty would be over $9,900,000.

The values in the following table are based on meeting MAPP's 15 percent reserve criteria. Figure 6-1 summarizes MMPA's projected MW deficits for the three forecast levels and five levels of delay required by Minnesota rules for a CON.

Figure 6-1
MMPA Surplus/Deficit for Various Forecast Delay Scenarios

Low Forecast					
	No Delay	1 Year	2 Years	3 Years	Indefinite
2006	163	-87	-87	-87	-87
2007	157	157	-93	-93	-93
2008	150	150	150	-100	-100
2009	144	144	144	144	-106
Medium Forecast					
	No Delay	1 Year	2 Years	3 Years	Indefinite
2006	137	-113	-113	-113	-113
2007	128	128	-122	-122	-122
2008	119	119	119	-131	-131
2009	109	109	109	109	-141
High Forecast					
	No Delay	1 Year	2 Years	3 Years	Indefinite
2006	102	-148	-148	-148	-148
2007	90	90	-160	-160	-160
2008	79	79	79	-171	-171
2009	66	66	66	66	-184

The amount of energy needed from MMPA's existing baseload resources will not change if the Project is delayed. MMPA's existing peaking facility would likely be dispatched more frequently, resulting in higher fuel costs and more emissions. As a result, the expected service life of the existing facilities would be shortened tremendously. MMPA has not identified any equipment or other measures that could be used to reduce the environmental impact of not building the facility.

Delaying Construction of the Project Would Expose MMPA to the Uncertainties of the Developing Electricity Market

In the past, MMPA has successfully pursued a strategy of purchasing capacity surpluses from other pool members. Unfortunately, the transactions supporting that strategy frequently include energy priced at "the market". This means that even though MMPA has covered its capacity obligations in the pools, it has left itself vulnerable to the energy price volatility in the electricity market. Electricity is currently the most volatile commodity in America. The proposed facility will provide a cap on the energy price risk associated with that volatility.

Electric system reliability is extremely complicated and is dependent on having adequate generation and transmission capacity. MMPA's neighboring systems and other pool members could experience lower reliability if the Project were delayed. Additional generation capacity will improve system reliability. Large generation and transmission investments have not been made in the last 10 years due to previously adequate capacity and increased regional competition. Circumstances have changed and the MAPP region needs additional capacity to assure continued reliability. The severity of the MAPP capacity penalty provides the incentive to build additional capacity.

The following factors would not significantly change if this facility is delayed or not constructed:

- Amount of land required
- Labor requirements
- Fuel requirements
- Induced traffic
- Airborne emission
- Water appropriation
- Water consumption
- Discharges to water
- Reject heat
- Radioactive releases
- Solid waste production
- Audible noise

Section 7. Conclusion

The Project Is Needed and Denial Would Adversely Impact Reliability and Efficiency of Energy Supply for MMPA, its Customers, MAPP, and the People of Minnesota

The Project is needed and denial would adversely impact reliability and efficiency of energy supply for MMPA, its customers, the MAPP region, and the people of Minnesota. The need for the Project is based on forecasted load growth for the next four years, the expiration of existing short-term contracts for capacity, and MAPP's increasing reserve capacity deficit. This project will satisfy MMPA's Intermediate Resource needs for the year 2006, it's first year of operation. Without the Project, in 2006 MMPA will be deficit by 113 MW.

Denial of this application would adversely impact MMPA's ability to reliably serve its members at a reasonable cost.

A tightening of load and capacity for the MAPP region has been projected for several years and few committed new generation projects have been announced. Recent requests for proposals to supply long-term power needs have resulted in either limited quantities of capacity resources or higher prices than the cost of building the Project.

There Is No More Reasonable and Prudent Alternative to the Project

There is no more reasonable and prudent alternative to the Project. MMPA has a history of cost-effective DSM and conservation programs, which have delayed the need for capacity projects. Cost-effective programs will be continued but are not expected to reduce demand in the immediate future sufficient to eliminate the need for the proposed additions.

Further upgrades to the existing Minnesota River Station would not meet the needs identified in this filing.

The project complements the existing resources in the MMPA resource mix.

The Project is the appropriate type of resource to cover intermediate demands including a large portion of energy requirements. Conventional simple cycle and baseload resources are not economic when operated at the capacity factors expected for Intermediate Resources. Renewable resources, including wind, wood, hydro, solar, and geothermal, are all energy producing resources that do not effectively cover intermediate demands. They also do not compete economically at the capacity factors associated with Intermediate Resources.

The Project Will Provide Significant Benefits to Society

The Project will provide benefits to society compatible with the natural and socioeconomic environments. The Project is expected to provide needed capacity and energy resources for MMPA's member cities as well as the state and the MAPP region.

The Project is both economically and environmentally attractive. The Project utilizes a clean fuel and a combustion technology that has minimal impacts on the surrounding environment. The Project is being sited to minimize the construction of gas pipeline and transmission lines. In addition, the Project will enhance the overall reliability of the regional transmission system, which has been under increasing stress in recent years.

The increased need for generating capacity in the MMPA system results from strong regional economic growth over the past decade. During that period, MMPA has met its increasing obligations through purchases of capacity in MAPP. Excess capacity in MAPP has now largely been absorbed and continued purchases are no longer possible at competitive prices.

Conservation programs have increased utilization of the existing resources but cannot eliminate the need for Intermediate Resources. The suburban service territory of MMPA's members will benefit from the Project. The Project will help MMPA's members continue to supply low cost power to their customers. Low cost electricity is an important component in supporting stable economic growth in the region.

The Project Will Comply With All Applicable Local, State, and Federal Requirements

The project will comply with all applicable local, state, and federal requirements. Consistent with MMPA's overall business philosophy, this Project will be carried out in a manner compatible with all local, state and federal rules, laws, and policies pertinent to the Project.

In summary, this application shows that the Project is needed, that there are no reasonable and prudent alternatives to this Project, and that the project will provide significant benefits to society through maintaining a reliable and economic energy supply while upholding the state's paramount goal for protection of natural resources. Therefore, issuing a CON for this Project is justified.

Appendix A – Detailed Load Forecasting Information

This Appendix provides details of MMPA's load forecast. The first section provides information regarding MMPA's summer demand forecast, which is a primary driver in determining MMPA's 2006 summer capacity need. The sections two through six complete the remaining details requested in Minnesota Rule 7849.0270.

The sections are subdivided as follows:

- A-1 Peak Demand Forecast
- A-2 Data for Minnesota Rule 7849.0270
- A-3 Load Forecast Methodology
- A-4 Minnesota Rule 7849.0270 Subpart 4: Database for Forecasts
- A-5 Minnesota Rule 7849.0270 Subpart 5: Assumptions and Special Information
- A-6 Minnesota Rule 7849.0270 Subpart 6: Coordination if MMPA Forecast with other Systems

Section A-1. Peak Demand Forecast

MMPA Is a Summer Peaking System

MMPA is a summer peaking system. Summer demand is anticipated to continue to grow at a faster rate than winter demand and thus is the primary determinant of MMPA's need. Taking this into account, three scenarios, a "minimum", a "probable", and a "growth" scenario, were developed to forecast the Agency's future peak demand.

Over the last half decade, MMPA load has grown at an average rate of 3.75% per year. Therefore, this growth rate was used as a "probable" growth scenario for the Agency's Demand forecast. The equally weighted average of the three forecast scenarios was used to determine MMPA's need for the upcoming decade. As such, the weighted average reflects expected system peak conditions.

MMPA's Core Peak Load Is Driven by Air Conditioning

MMPA's core suburban peak load is driven by air conditioning. This means the forecast peaks in this Certificate of Need reflect expected peaking conditions with temperatures in the low to mid nineties. Extreme conditions would cause higher peaks. Similarly a cool summer could produce a lower than expected peak for that year.

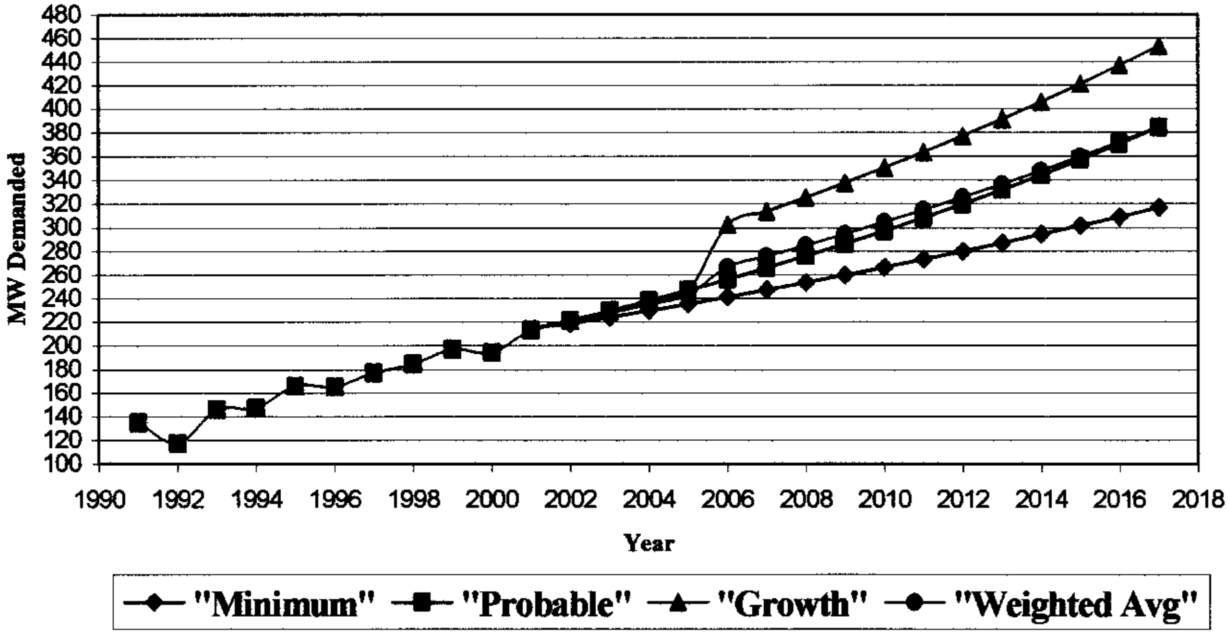
As mentioned above, three forecast scenarios were prepared.

1. "Minimum": Slowing Municipal economic conditions result in lower loads.
2. "Probable": Growth continues at recent historical rates.
3. "Growth": Growth continues at recent historical rates and the Agency acquires new members or customers.

Factors such as weather and the economy could cause fluctuations in the actual peaks experienced by the Agency.

The graph below reflects the three forecast scenarios and the weighted average.

Figure A-1
MMPA Demand Forecast



Section A-2. Data for Minnesota Rule 7849.0270

MMPA provides power to 8 member cities. The Agency member's entire load is located in Minnesota. Data to comply with Rule 7849.0270 subpart 2 A-D concerns consumer types and annual electric consumption on the MMPA system. This data is presented in the following tables.

Figure A-2
Number of Customer Types

Historical Consumers

Year	Farm	Non-Farm	Irrigation	Commercial	Industrial	Mining	St&Hi Light	Elec. Heating	Other	Total
1991	194	25,576	0	2,745	459	0	20	0	239	29,233
1992	194	26,647	0	2,744	366	0	23	0	299	30,273
1993	194	27,320	0	2,806	371	0	72	0	330	31,093
1994	194	28,015	0	2,887	379	0	66	0	131	31,672
1995	194	28,197	0	2,928	390	0	68	0	96	31,873
1996	194	28,483	0	2,990	412	0	72	0	95	32,246
1997	194	28,560	0	2,987	435	0	77	0	123	32,376
1998	194	28,899	0	3,035	456	0	75	0	119	32,778
1999	194	28,601	0	2,998	450	0	76	0	119	32,438
2000	194	28,966	0	3,091	458	0	76	0	79	32,864
2001	194	29,614	0	3,292	366	0	80	0	116	33,662

Projected Consumers

Year	Farm	Non-Farm	Irrigation	Commercial	Industrial	Mining	St&Hi Light	Elec. Heating	Other	Total
2002	194	30,725	0	3,415	380	0	83	0	120	34,917
2003	194	31,877	0	3,544	394	0	86	0	125	36,219
2004	194	33,072	0	3,676	409	0	89	0	130	37,570
2005	194	34,312	0	3,814	424	0	93	0	134	38,972
2006	194	35,599	0	3,957	440	0	96	0	139	40,426
2007	194	36,934	0	4,106	456	0	100	0	145	41,935
2008	194	38,319	0	4,260	474	0	104	0	150	43,500
2009	194	39,756	0	4,419	491	0	107	0	156	45,124
2010	194	41,247	0	4,585	510	0	111	0	162	46,809
2011	194	42,794	0	4,757	529	0	116	0	168	48,557
2012	194	44,398	0	4,935	549	0	120	0	174	50,370
2013	194	46,063	0	5,121	569	0	124	0	180	52,252
2014	194	47,791	0	5,313	591	0	129	0	187	54,204
2015	194	49,583	0	5,512	613	0	134	0	194	56,229
2016	194	51,442	0	5,718	636	0	139	0	202	58,331
2017	194	53,371	0	5,933	660	0	144	0	209	60,511

Figure A-3
Energy Use

Historical Energy

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1991	2,635	210,656	0	157,801	222,949	0	8,474	0	10,551	613,066
1992	2,635	195,770	0	131,089	266,728	0	8,649	0	9,893	614,764
1993	2,635	206,619	0	128,262	296,416	0	7,393	0	12,541	653,866
1994	2,635	213,485	0	133,012	333,783	0	11,319	0	8,583	702,817
1995	2,635	226,268	0	138,763	360,294	0	11,281	0	7,095	746,336
1996	2,635	225,153	0	146,140	373,047	0	11,406	0	7,625	766,006
1997	2,635	218,903	0	145,448	398,274	0	10,772	0	10,277	786,309
1998	2,635	224,505	0	152,295	403,530	0	12,980	0	7,122	803,067
1999	2,635	225,629	0	159,543	415,859	0	20,941	0	5,012	829,619
2000	2,635	232,686	0	163,004	447,838	0	22,582	0	5,121	873,866
2001	2,635	244,850	0	169,188	434,313	0	18,992	0	7,948	877,926

Projected Energy

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2002	2,635	254,032	0	175,533	450,600	0	19,704	0	8,246	910,749
2003	2,635	263,558	0	182,115	467,497	0	20,443	0	8,555	944,804
2004	2,635	273,441	0	188,944	485,028	0	21,210	0	8,876	980,135
2005	2,635	283,696	0	196,030	503,217	0	22,005	0	9,209	1,016,791
2006	2,635	294,334	0	203,381	522,088	0	22,830	0	9,554	1,054,822
2007	2,635	305,372	0	211,008	541,666	0	23,686	0	9,913	1,094,279
2008	2,635	316,823	0	218,920	561,978	0	24,575	0	10,284	1,135,216
2009	2,635	328,704	0	227,130	583,053	0	25,496	0	10,670	1,177,688
2010	2,635	341,030	0	235,647	604,917	0	26,452	0	11,070	1,221,752
2011	2,635	353,819	0	244,484	627,601	0	27,444	0	11,485	1,267,469
2012	2,635	367,087	0	253,652	651,136	0	28,473	0	11,916	1,314,900
2013	2,635	380,853	0	263,164	675,554	0	29,541	0	12,363	1,364,110
2014	2,635	395,135	0	273,033	700,887	0	30,649	0	12,826	1,415,165
2015	2,635	409,953	0	283,272	727,171	0	31,798	0	13,307	1,468,135
2016	2,635	425,326	0	293,894	754,439	0	32,991	0	13,806	1,523,092
2017	2,635	441,275	0	304,915	782,731	0	34,228	0	14,324	1,580,109

Figure A-4
Peak Demand by Consumer Category (kW)

Historical Demand

Year	Farm	Non-Farm	Irrigation	Commercial	Industrial	Mining	[illegible]	[illegible]	Other	Total
1991	505	40,340	0	30,218	42,694	0	1,623	0	2,020	117,400
1992	438	32,577	0	21,814	44,385	0	1,439	0	1,646	102,300
1993	512	40,163	0	24,932	57,618	0	1,437	0	2,438	127,100
1994	480	38,911	0	24,244	60,837	0	2,063	0	1,564	128,100
1995	510	43,778	0	26,848	69,709	0	2,183	0	1,373	144,400
1996	541	46,265	0	30,029	76,654	0	2,344	0	1,567	157,400
1997	552	45,879	0	30,484	83,473	0	2,258	0	2,154	164,800
1998	562	47,861	0	32,467	86,026	0	2,767	0	1,518	171,200
1999	578	49,498	0	35,000	91,230	0	4,594	0	1,100	182,000
2000	509	44,973	0	31,505	86,558	0	4,365	0	990	168,900
2001	556	51,707	0	35,729	91,718	0	4,011	0	1,678	185,400

Projected Demand

Year	Farm	Non-Farm	Irrigation	Commercial	Industrial	Mining	[illegible]	[illegible]	Other	Total
2002	557	53,652	0	37,073	95,168	0	4,162	0	1,742	192,353
2003	557	55,670	0	38,467	98,747	0	4,318	0	1,807	199,566
2004	557	57,763	0	39,914	102,460	0	4,480	0	1,875	207,049
2005	557	59,935	0	41,414	106,313	0	4,649	0	1,946	214,814
2006	557	62,189	0	42,972	110,310	0	4,824	0	2,019	222,869
2007	557	64,527	0	44,587	114,457	0	5,005	0	2,095	231,227
2008	557	66,952	0	46,263	118,759	0	5,193	0	2,173	239,898
2009	557	69,469	0	48,002	123,223	0	5,388	0	2,255	248,894
2010	557	72,080	0	49,806	127,854	0	5,591	0	2,340	258,228
2011	557	74,788	0	51,678	132,659	0	5,801	0	2,428	267,911
2012	557	77,599	0	53,620	137,644	0	6,019	0	2,519	277,958
2013	557	80,515	0	55,635	142,816	0	6,245	0	2,614	288,381
2014	557	83,540	0	57,725	148,182	0	6,480	0	2,712	299,196
2015	557	86,678	0	59,894	153,749	0	6,723	0	2,814	310,415
2016	557	89,935	0	62,144	159,525	0	6,976	0	2,919	322,056
2017	557	93,313	0	64,478	165,518	0	7,238	0	3,029	334,133

Figure A-5
Peak Demand by Month (MW)

Historical Demand

Year	January	February	March	April	May	June	July	August	September	October	November	December	Annual
1991	79.5	76.0	71.9	75.7	87.6	112.9	117.0	117.4	93.3	73.8	80.2	84.4	117.4
1992	84.1	78.2	75.4	75.6	89.7	102.3	99.3	95.5	99.5	81.1	85.3	86.6	102.3
1993	88.7	85.9	82.7	81.1	81.4	101.9	110.4	127.1	89.1	82.2	89.1	90.5	127.1
1994	92.8	92.4	82.5	82.8	91.8	128.1	120.7	124.0	120.8	87.7	92.5	96.1	128.1
1995	97.3	93.8	91.6	87.6	86.8	133.1	144.4	135.9	120.6	90.7	95.4	102.1	144.4
1996	110.7	113.6	104.9	98.1	95.2	144.7	141.7	145.6	140.0	101.1	110.0	115.6	145.6
1997	116.4	106.9	105.0	100.7	95.2	140.0	154.2	131.9	116.9	109.3	109.7	111.2	154.2
1998	115.5	108.8	108.0	101.9	144.0	136.8	160.7	148.5	134.7	103.7	108.4	120.7	160.7
1999	120.2	107.8	105.5	104.2	110.6	145.9	171.4	158.6	154.3	105.9	120.9	127.8	171.4
2000	120.8	113.1	107.3	108.7	128.7	152.8	166.3	168.9	134.6	112.7	123.7	134.1	168.9
2001	119.2	120.4	114.4	115.1	150.7	170.0	180.8	185.4	144.5	115.0	123.2	124.1	185.4

Projected Demand

Year	January	February	March	April	May	June	July	August	September	October	November	December	Annual
2002	123.7	124.9	118.7	119.4	156.4	176.4	187.6	192.4	149.9	119.3	127.8	128.8	192.4
2003	128.3	129.6	123.1	123.9	162.2	183.0	194.6	199.6	155.5	123.8	132.6	133.6	199.6
2004	133.1	134.5	127.8	128.5	168.3	189.9	201.9	207.0	161.4	128.4	137.6	138.6	207.0
2005	138.1	139.5	132.5	133.4	174.6	197.0	209.5	214.8	167.4	133.2	142.7	143.8	214.8
2006	143.3	144.7	137.5	138.4	181.2	204.4	217.3	222.9	173.7	138.2	148.1	149.2	222.9
2007	148.7	150.2	142.7	143.6	187.9	212.0	225.5	231.2	180.2	143.4	153.7	154.8	231.2
2008	154.2	155.8	148.0	148.9	195.0	220.0	233.9	239.9	187.0	148.8	159.4	160.6	239.9
2009	160.0	161.6	153.6	154.5	202.3	228.2	242.7	248.9	194.0	154.4	165.4	166.6	248.9
2010	166.0	167.7	159.3	160.3	209.9	236.8	251.8	258.2	201.3	160.2	171.6	172.8	258.2
2011	172.2	174.0	165.3	166.3	217.8	245.7	261.3	267.9	208.8	166.2	178.0	179.3	267.9
2012	178.7	180.5	171.5	172.6	225.9	254.9	271.1	278.0	216.6	172.4	184.7	186.1	278.0
2013	185.4	187.3	177.9	179.0	234.4	264.4	281.2	288.4	224.8	178.9	191.6	193.0	288.4
2014	192.4	194.3	184.6	185.7	243.2	274.3	291.8	299.2	233.2	185.6	198.8	200.3	299.2
2015	199.6	201.6	191.5	192.7	252.3	284.6	302.7	310.4	241.9	192.5	206.3	207.8	310.4
2016	207.1	209.1	198.7	199.9	261.8	295.3	314.1	322.1	251.0	199.8	214.0	215.6	322.1
2017	214.8	217.0	206.2	207.4	271.6	306.4	325.8	334.1	260.4	207.3	222.0	223.7	334.1

MMPA Does not Use Revenue Requirements Approach to Establish Prices per kWh

MMPA, as a non-regulated entity, does not use a revenue requirements approach to establish prices per kWh. Prices are determined by the MMPA Board of Directors annually based on a budget approved by the Board each year.

This information is considered confidential and can be found in the non-public version in Appendix C.

Minnesota Rule 7849.270 Subp. 2 (F)

Figure A-6
Average Systems Weekday Load Factor by Month

Month	Load Factor (%)
Jan-01	88.55%
Feb-01	88.73%
Mar-01	88.94%
Apr-01	86.80%
May-01	85.75%
Jun-01	84.52%
Jul-01	83.34%
Aug-01	85.25%
Sep-01	87.18%
Oct-01	87.31%
Nov-01	86.34%
Dec-01	86.73%

Section A-3. Load Forecast Methodology

Historical Trend Analysis Determines MMPA's Future Demand

Based upon an examination of MMPA's historical growth rates, three possible growth scenarios were analyzed. Relying upon a combination of historical trend analysis and judgment, an equally weighted average of these scenarios was then used to determine the Agency's most likely demand in the future.

The three growth scenarios are a probable scenario, minimum scenario, and growth scenario. The "probable," or base case, growth scenario is simply the five-year historic average growth rate, 3.75% per year. The "minimum" growth rate scenario of 2.50% per year represents growth under slowing economic conditions, while the "growth" scenario indicates a one-time addition of new members or customers by the Agency with growth continuing at recent historical rates of 3.75% per year.

As required by Minnesota state rule, forecasts of the number of consumers and their energy usage were prepared for the farm, non-farm, commercial, industrial, and street and highway lighting sectors. Each forecast includes reserve requirements and line losses. MMPA did not exist prior to 1994; thus, data for the years 1991-1994 were compiled by aggregating information from NSP and the individual cities' records.

Strengths: Historical Trend Models Are Simple and Easy to Implement

The primary strengths of a historical trend model lie in its overall simplicity and its ease to implement. Utilizing a straightforward historic trend model tempered by staff judgment makes the most sense for MMPA, given the size of its staff and the limited time it can dedicate to forecasting.

Weakness: Historical Trend Models Assume History Repeats Itself

Although easy to use and understand, the main weakness of historical trend models is that they assume that the historical trend being forecast will continue into the future. If the future relationship changes, then the forecast will be incorrect. Another weakness of historical trend models is that they are not sensitive to changes in weather or economic activity, both large drivers in energy use.

Section A-4. Minnesota Rule 7849.0270 Subpart 4: Database for Forecasts

The data used in arriving at the forecast presented in this application come from seasonal load files. This hourly load data by city was obtained from SCADA.

No adjustments were made to the raw data to adopt them for use in the forecast.

Section A-5. Minnesota Rule 7849.0270 Subpart 5: Assumptions and Special Information

The forecast assumed there would be no major new sources of energy available in the near future. In addition, it is assumed that electric consumption patterns would remain stable. Furthermore, the forecast did not anticipate any major changes in the weather or general economic conditions in Minnesota over the next decade.

Section A-6. Minnesota Rule 7849.0270 Subpart 6: Coordination of MMPA Forecast with Other Systems

MMPA's forecast is not coordinated with any other system.

Appendix B – System Capacity

Excerpts of the MAPP 2002 Load and Capability Report Are Attached

Minnesota Rule 7849.0280 calls for a discussion of the ability of the applicant's existing system to meet the demand for electrical energy forecast in response to Minnesota Rule 7849.0270 and the extent to which the proposed facility will increase this capability. The MAPP 2002 Load and Capability Report contains most of the information required for this rule. Attached are the excerpts most pertinent to MMPA from the MAPP 2002 Load and Capability Report. Upon request, the complete document can be made available or else be retrieved from the MAPP website.

MMPA Power Supply Planning Is Performed by Dahlen, Berg & Co.

MMPA is a member of MAPP and thus has to comply with the criteria set by MAPP, such as the 15 percent reserve capacity margin. Dahlen, Berg & Co performs power supply planning for the MMPA. Dahlen, Berg & Co. addresses issues of fuel diversity and unit dispatch while meeting the 15 percent reserve requirement.

New Facility Affects Surplus/Deficit Capacity in 2006 and thereafter

Figure B-1, which is attached at the end of Appendix B behind the excerpts from the MAPP 2002 Load and Capability Report, portrays the forecasted seasonal load and capability contingent on the proposed facility. Up to the Winter of 2005, the numbers are identical to the MAPP 2002 Load and Capability Report. Starting with Summer 2006, 250 MW are added to the net generating capacity. This addition positively affects the surplus/deficit capacity for MMPA.

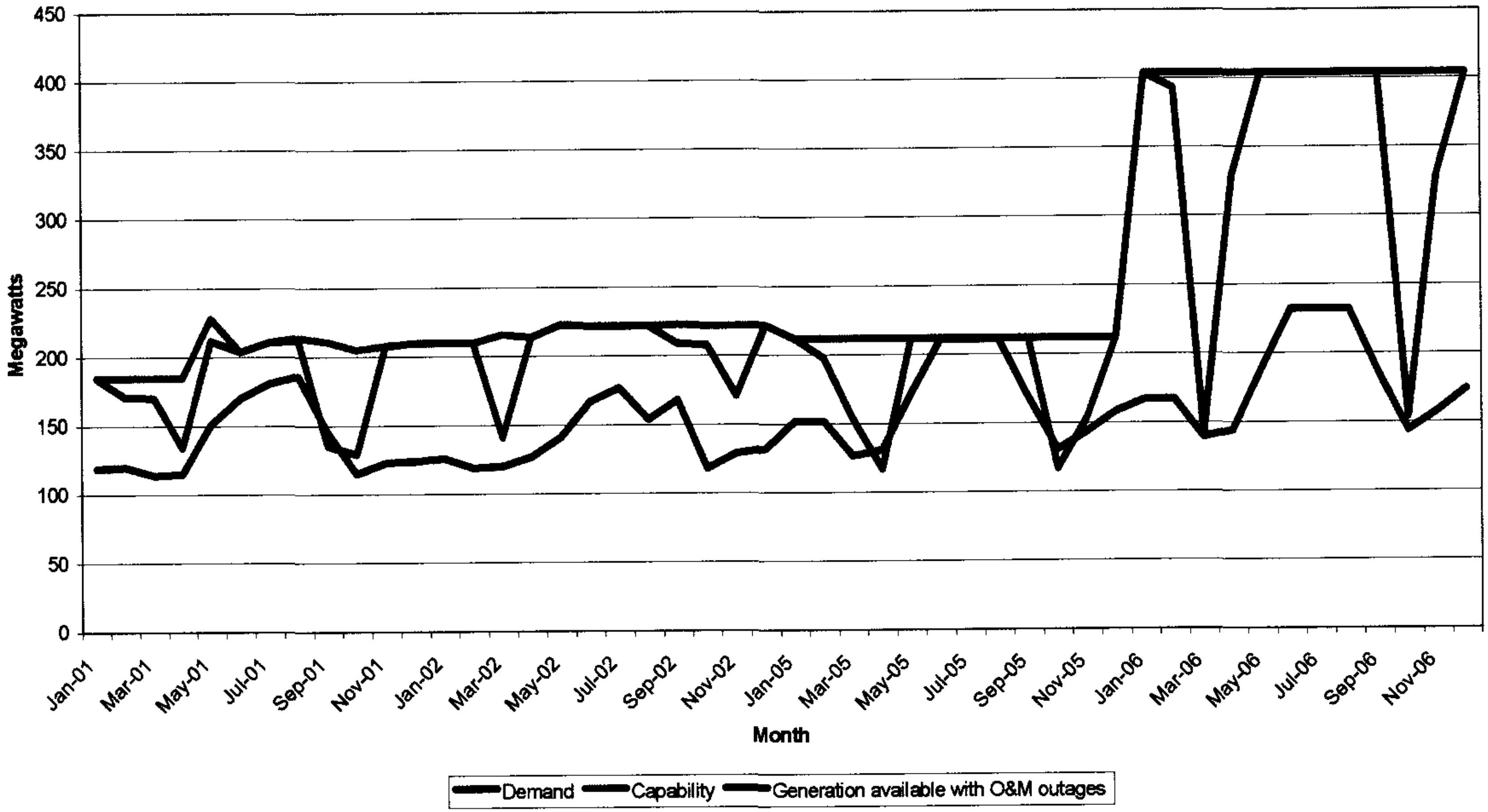
Additions and Retirements in Generating Capability

The MMPA does not anticipate the retirement of any generating capability during the forecast years. Furthermore, the Agency only anticipates the addition of the Faribault Energy Park during the same time period.

Monthly Adjusted Net Demand and Capability are presented in Figure B-2

Figure B-2 on the next page shows the monthly adjusted net demand and monthly adjusted net capability as well as the difference between the adjusted net capability and actual, planned, or estimated maintenance outages for the previous calendar year, the current year, the first full calendar year before the proposed facility is expected to be in operation (2005), and the first full calendar year of operation (2006).

Figure B-2
Monthly Adjusted Net Demand and Capability



Method of Determining the Reserve Margin Is Appropriate

Minnesota Rule 7849.0280 (System Capacity) Subpart I requires a discussion of the appropriateness and the method of determining system reserve margins, considering the probability of forced outages of generating units, deviation from load forecasts, scheduled maintenance outages of generation and transmission facilities, power exchange arrangements as they affect reserve requirements, and transfer capabilities.

MAPP established a 15 percent reserve capacity margin in order to cover the historical patterns of forced outages of generating units and scheduled maintenance of generation and transmission facilities. As the existing generation and transmission facilities continue to age, the actual levels of forced outages might exceed those historically experienced, making 15 percent too low a reserve requirement.

The reserve margin is also expected to cover deviations from load forecasts. While it is possible to cover the deviations from forecasts of individual MAPP members, it is not possible to do so for a large portion of the MAPP members if the deviations are widespread.

The regional transmission system was built for two primary purposes: to serve native load and to provide emergency ties to other regions. Today, it is being used on a regular basis in a manner, which was never intended, such as for bulk power transfers between regions. There is continuing pressure to use the transmission system at higher and higher levels due to transfers/power exchanges. Power transfers, which primarily result in export of power and energy out of the region due to the attractiveness of the low cost energy available here, tend to stress the transmission system more than in the past. To counteract this development, procedures have been put in place intending to assure that the transmission system is operated in such a manner that reliability is not jeopardized.

MAPP 15 Percent Reserve Requirement Is Adequate at this Time

In summary, the MAPP 15 percent reserve capacity requirement is appropriate for now. But as the existing facilities inevitably age, more frequent forced outages will be the case. Additional generation will help increase reliability if it is sited appropriately. If it is not sited appropriately it may exacerbate transmission related reliability concerns. Alternatively, large investment in replacing the existing generation and transmission infrastructure would alleviate aging concerns and allow reserve capacity to remain near historic levels.

MID-CONTINENT AREA POWER POOL

LOAD AND CAPABILITY

REPORT

July 31, 2002
FINAL DRAFT

Approved by AWG
July 25, 2002

QUESTIONS REGARDING THIS REPORT MAY BE DIRECTED TO:

MID-CONTINENT AREA POWER POOL
MAPP Center
1125 Energy Park Dr.
St. Paul, MN 55108-5001
(651) 632- 8400

TABLE OF CONTENTS

INTRODUCTION

Section I

GENERAL COMMENTS

The MAPP Load and Capability Report May 2002 is prepared in response to the requirement set forth in the MAPP Agreement and the MAPP Reliability Handbook for a two-year monthly and a ten-year seasonal load and capability forecast from each MAPP Participant. The report contains forecasts of monthly load and capability data for the 24-month period May 2002 through December 2003 and seasonal load and capability data for the ten-year period Summer 2002 through Summer 2011.

The information in the report is dated May 31, 2002 and is prepared in conjunction with the May 1, 2002 MAPP Regional Reliability Council Report on Coordinated Bulk Power Supply Program (EIA-411) submitted to the North American Electric Reliability Council.

MAPP RELIABILITY COUNCIL

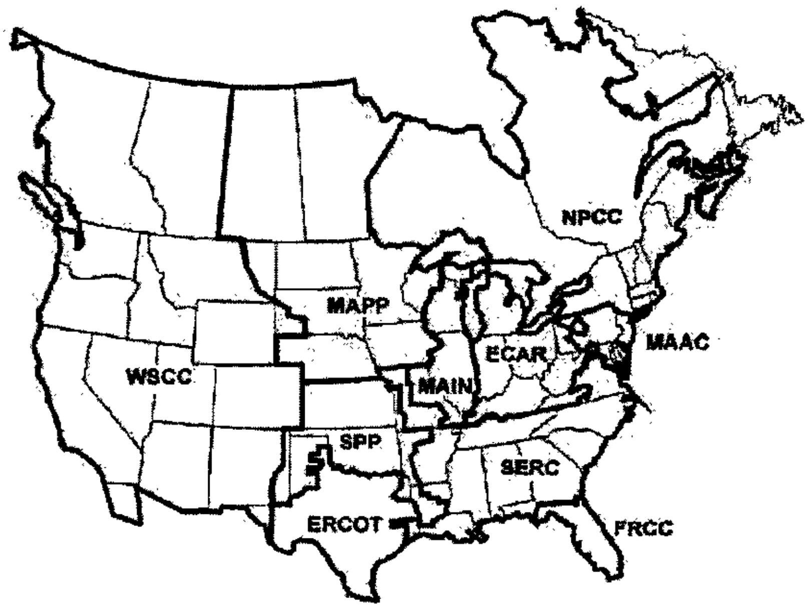
The Mid-Continent Area Power Pool (MAPP) is one of the nine regional reliability councils comprising the North American Electric Reliability Council (NERC). The MAPP region covers all of the states of Minnesota, Nebraska, North Dakota, most of South Dakota, and portions of the states of Iowa, Illinois, Michigan, Missouri, Montana and Wisconsin. The Canadian provinces of Manitoba and Saskatchewan are included in the MAPP region as well. The region is outlined on the map of the NERC regional councils on page I-4.

MAPP oversees the planning and operating activities in the region with respect to reliability. MAPP membership now totals 108 members and includes 14 transmission-owning members, 48 transmission-using members, 77 Power and Energy Market members, 18 associate members, and 8 regulatory participants. Two of the municipal utilities, IAMU and MMUA, are Joint Members and each contains 4 End-Use Load reporting members. Manitoba Hydro is a Member and Saskatchewan Power Corporation is an Associate Member of MAPP.

Information pertaining to the electrical utilities within the MAPP region that are Associate Members of MAPP or non-MAPP members and to the non-utility generators in the MAPP region is incorporated in the report as appropriate. Information about non-utility generators was supplied through inquiries to and responses by MAPP Members, MAPP Associate Members, and non-MAPP member electric utilities in the MAPP region.

This overview of regional planning is a compilation of each Member's load forecasts, planned new facilities and the resulting generating capacity and reserves. The overall projected system is tested periodically according to criteria contained in the MAPP System Design Standards. These standards include a set of contingencies referred to as probable disturbances. The overall system must be capable of withstanding these disturbances without interruption of load due to instability or cascading. Another set of contingencies is referred to as extreme disturbances. The system is designed to minimize the spread of any interruption that might result from such extreme disturbances. These procedures provide the basis for reporting on advance planning in this document. Similarly, the overview of operating activities based upon System Operating Standards provides the basis for the operating data contained in this document.

North American Electric Reliability Council

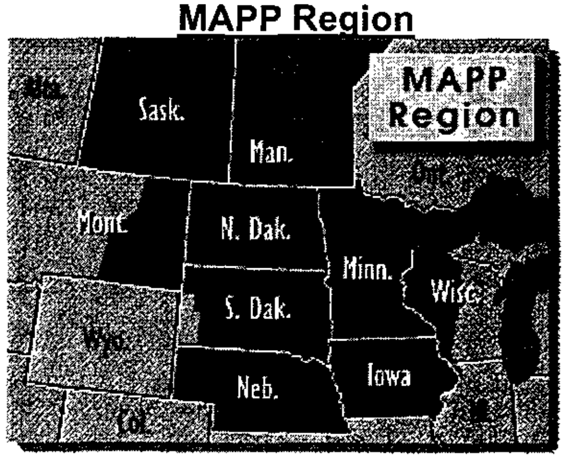


ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

Affiliate

ASCC	Alaska Systems Coordinating Council

MAPP Region



MID-CONTINENT AREA POWER POOL

REPORTING SYSTEMS

SYSTEM NAME	INITIALS
Algona Municipal Utilities (1)	ALGN
Ames Municipal Electric System	AMES
Atlantic Municipal Utilities (1)	ATL
Basin Electric Power Cooperative	BEPC
Central Minnesota Municipal Power Agency (2)	CMMPA
GEN~SYS Energy (DPC)	GSE
Great River Energy (CP & UPA)	GRE
Harlan Municipal Utilities (1)	HMU
Hastings Utilities	HSTG
Heartland Consumers Power District	HCPD
Hutchinson Utilities Commission (2)	HUC
Lincoln Electric System	LES
MidAmerican Energy Company/ Corn Belt Power Cooperative/ Cedar Falls Municipal Utilities/ City of Indianola/ Montezuma Municipal Electric Utilities/ Esthervill Ia./ Waverly Ia./North Iowa Municipal Electric Cooperative Association	MEC
Minnesota Municipal Power Agency	MMPA
Minnesota Power	MP
Minnkota Power Cooperative Inc.	MPC
Missouri River Energy Services	MRES
Montana-Dakota Utilities Co.	MDU
Municipal Energy Agency of Nebraska	MEAN
Muscatine Power & Water	MPW
Nebraska Public Power District	NPPD
New Ulm Public Utilities (2)	NULM
Northwestern Public Service Company	NWPS
Omaha Public Power District	OPPD
Otter Tail Power Company	OTP
Pella Municipal Power and Light Department (1)	PELLA
Rochester Public Utilities	RPU
Southern MN Municipal Power Agency	SMMPA
Western Area Power Administration – Upper Great Plains Region	WAPA
Willmar Municipal Utilities (2)	WLMR
Wisconsin Public Power Inc.	WPPI
Xcel Energy	XCEL
Manitoba Hydro	MHEB
SaskPower	SPC

(1) Joint Member through Iowa Association of Municipal Utilities (IAMU)
(2) Joint Member through Minnesota Municipal Utilities Association (MMUA)

EXPLANATION OF CODES – Section IV

I. UNIT TYPES

CA	Combined Cycle Steam Turbine Portion
CC	Combined Cycle Total Unit
CE	Compressed Air Energy Storage
CT	Combined Cycle Combustion Turbine Portion
CS	Combined Cycle Single Shaft
FC	Fuel Cell
GT	Combustion (Gas) Turbine (includes jet engine design)
HY	Hydraulic Turbine - Conventional
IC	Internal Combustion (piston)
NA	Unknown at this time
OT	Other (describe in "notes")
PS	Hydraulic Turbine - Pumped Storage
PV	Photovoltaic
ST	Steam Turbine, including nuclear, geothermal, and solar steam
WT	Wind Turbine

II. FUEL TYPES

BFG	Blast-Furnace Gas
BIT	Bituminous
DFO	Distillate Fuel Oil
GEO	Geothermal
JF	Jet Fuel
KER	Kerosene
LFG	Landfill Gas
LIG	Lignite
MSW	Municipal Solid Waste
NA	Not Available
NG	Natural Gas
NUC	Nuclear (Uranium, Plutonium, Thorium)
OBG	Other Biomass Gases
OBL	Other Biomass Liquids
OBS	Other Biomass Solids
OG	Other Gas
PC	Petroleum Coke
PG	Propane
RFO	Residual Fuel Oil
SUB	Subbituminous
SUN	Solar
WAT	Water
WC	Waste/Other Coal
WDL	Wood Waste Liquids
WDS	Wood/Wood Waste Solids
WH	Waste Heat (reject heat)
WND	Wind
WO	Oil – Other than Waste Oil

EXPLANATION OF CODES – Section IV

III. STAUS CODES

Utility Units:

OP	Operating, available to operate, or on short-term scheduled or forced outage (less than three months).
OS	On long-term scheduled (maintenance) or forced outage; not available to operate (greater than three months).
SB	Cold standby (Reserve): deactivated (mothballed), in long-term storage and cannot be made available for service in a short period of time, usually requires three to six months to activate.
RE	Retired (no longer in service and not expected to be returned to service).

A	Generating unit capability increased (rerated or relicensed)
CO	Proposed Change of Ownership
D	Generating unit capability decreased (rerated or relicensed)
FC	Existing generator planned for conversion to another fuel or energy source
IP	Planned generator indefinitely postponed or canceled
L	Regulatory approval pending. Not under construction (started site preparation).
M	Generating unit put in deactivated shutdown status
OT	Other (describe under "notes")
P	Planned for installation but not utility-authorized. Not under construction.
RA	Previously deactivated or retired generator planned for reactivation
RP	Proposed for repowering or life extension
RT	Existing generator scheduled for retirement
T	Regulatory approval received but not under construction.
TS	Construction complete, but not yet in commercial operation (including low power testing of nuclear units).
U	Under construction, less than or equal to 50% complete (based on construction time to first electric date).
V	Under construction, more than 50% complete (based on construction time to first electric date).

SEASONAL
LOAD AND CAPABILITY DATA

Section III

SEASONAL LOAD AND CAPABILITY

Summer 2002 through Summer 2011

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-US

		SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
1	Internal Demand	27924	23521	28382	23951	29013	24286	29506	24765	30033	25108
2	Standby Demand	0	0	0	0	0	1	1	2	2	3
3	Total Internal Demand (1+2)	27924	23521	28382	23951	29013	24287	29507	24767	30035	25111
4	Direct Control Load Management	996	338	997	349	999	360	1001	346	1003	331
5	Interruptable Demand	373	216	374	216	375	217	377	217	378	218
6	Net Internal Demand (3-4-5)	26555	22966	27010	23385	27638	23710	28130	24203	28655	24562
7	Resources (8+9+10+11)	31544	31832	31921	32089	31751	32268	31744	32331	31738	32409
8	Distributed Generator Capacity (1 MW or greater)	337	324	324	417	403	421	407	424	409	429
9	Other Capacity (1 MW or greater)	30171	30455	30488	30600	30331	30823	30321	30886	30316	30959
10	Distributed Generator Capacity (less than 1 MW)	7	8	7	8	7	8	7	8	7	8
11	Other Capacity (less than 1 MW)	41	40	42	41	42	41	42	37	38	37
12	Uncommitted Resources	28	31	380	484	422	527	612	731	844	960
13	Total Capacity (7+12)	31572	31863	32301	32573	32173	32795	32356	33062	32581	33369
14	Inoperable Capacity	0	207	0	207	0	200	0	200	0	200
15	Net Operable Capacity (13-14)	31572	31656	32301	32366	32173	32595	32356	32862	32581	33169
16	Total Capacity Purchases	6718	4507	4698	3159	4068	2229	3007	2091	2950	2005
17	Full Responsibility Purchases	2222	1269	1912	1237	1858	1242	1858	1243	1851	1242
18	Total Capacity Sales	4616	4000	3424	3187	2873	3103	2329	2607	2177	2514
19	Full Responsibility Sales	745	1020	510	1047	487	999	459	979	459	973
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	33673	32163	33575	32338	33368	31722	33034	32346	33355	32661
22	Adjusted Net Capability (13+16-17+20-18+19)	32196	32121	32173	32355	31997	31679	31635	32282	31963	32592
23	Annual Adjusted Net Demand (27-17+19)	25392	26640	25922	27188	26614	27744	27053	28177	27543	28707
24	Net Reserve Capacity Obligation (23 x 15%)	3752	3939	3832	4021	3935	4105	4001	4170	4075	4249
25	Total Firm Capacity Obligation (28+24)	29948	26756	30538	27318	31301	27661	31845	28138	32455	28569
26	Surplus or Deficit(-) Capacity (22-25)	2248	5364	1635	5037	696	4018	-211	4144	-492	4023
27	Annual System Demand	26869	26890	27324	27378	27985	27987	28451	28441	28935	28976
28	Monthly Adjusted Net Demand (3-29-17+19)	26196	22817	26706	23297	27366	23557	27844	23969	28380	24320
29	Schedule L Purchases	250	454	274	464	276	487	264	534	263	522

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-US

		SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
1	Internal Demand	30601	25533	31181	25960	31861	26383	32453	26819	33015
2	Standby Demand	3	4	4	5	5	6	6	7	7
3	Total Internal Demand (1+2)	30604	25537	31185	25965	31866	26389	32459	26826	33022
4	Direct Control Load Management	1004	322	1005	303	1006	313	1007	323	1009
5	Interruptable Demand	379	218	380	218	381	219	382	219	383
6	Net Internal Demand (3-4-5)	29221	24997	29800	25444	30479	25858	31070	26284	31630
7	Resources (8+9+10+11)	31740	32511	31740	32563	31740	32640	31740	32717	31740
8	Distributed Generator Capacity (1 MW or greater)	412	432	414	435	416	438	418	441	420
9	Other Capacity (1 MW or greater)	30314	31059	30312	31107	30310	31181	30308	31255	30306
10	Distributed Generator Capacity (less than 1 MW)	7	8	7	8	7	8	7	8	7
11	Other Capacity (less than 1 MW)	38	37	38	37	38	37	38	37	38
12	Uncommitted Resources	1369	1485	1369	1485	2269	2385	2269	2385	2269
13	Total Capacity (7+12)	33108	33996	33108	34048	34008	35025	34008	35102	34008
14	Inoperable Capacity	0	200	0	200	0	200	0	200	0
15	Net Operable Capacity (13-14)	33108	33796	33108	33848	34008	34825	34008	34902	34008
16	Total Capacity Purchases	2737	1827	2632	1785	2442	1757	2391	1651	2328
17	Full Responsibility Purchases	1712	1120	1712	1123	1712	1126	1712	1125	1704
18	Total Capacity Sales	2016	2435	1940	2363	1890	2316	1890	2191	1681
19	Full Responsibility Sales	372	896	297	824	297	777	297	780	222
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	33829	33188	33800	33270	34560	34266	34509	34362	34655
22	Adjusted Net Capability (13+16-17+20-18+19)	32488	33164	32384	33171	33144	34117	33093	34217	33172
23	Annual Adjusted Net Demand (27-17+19)	28167	29326	28674	29849	29370	30467	29944	31059	30436
24	Net Reserve Capacity Obligation (23 x 15%)	4168	4342	4244	4420	4349	4513	4435	4602	4509
25	Total Firm Capacity Obligation (28+24)	33136	29122	33710	29569	34492	30020	35171	30538	35740
26	Surplus or Deficit(-) Capacity (22-25)	-648	4042	-1326	3602	-1348	4097	-2078	3678	-2567
27	Annual System Demand	29508	29550	30090	30148	30786	30816	31360	31404	31919
28	Monthly Adjusted Net Demand (3-29-17+19)	28968	24780	29466	25149	30144	25507	30737	25937	31231
29	Schedule L Purchases	269	520	276	504	279	520	279	531	280

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-CANADA

		SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
1	Internal Demand	5361	6578	5484	6723	5683	6822	5736	6871	5832	6963
2	Standby Demand	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand (1+2)	5361	6578	5484	6723	5683	6822	5736	6871	5832	6963
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	195	195	195	268	268	269	269	270	270	271
6	Net Internal Demand (3-4-5)	5166	6383	5289	6455	5415	6553	5467	6601	5562	6692
7	Resources (8+9+10+11)	8648	8996	8863	9054	8924	9054	8924	9054	8924	9054
8	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0	0
9	Other Capacity (1 MW or greater)	8648	8990	8857	9054	8924	9054	8924	9054	8924	9054
10	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
11	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
12	Uncommitted Resources	0	6	6	0	0	0	0	0	0	0
13	Total Capacity (7+12)	8648	9002	8869	9054	8924	9054	8924	9054	8924	9054
14	Inoperable Capacity	241	0	241	0	156	0	316	0	241	0
15	Net Operable Capacity (13-14)	8407	9002	8628	9054	8768	9054	8609	9054	8683	9054
16	Total Capacity Purchases	0	550	0	550	0	500	0	500	0	500
17	Full Responsibility Purchases	0	550	0	500	0	500	0	500	0	500
18	Total Capacity Sales	1510	960	1510	760	1260	760	710	210	710	210
19	Full Responsibility Sales	750	200	750	0	500	0	500	0	500	0
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	6897	8592	7118	8844	7508	8794	7899	9344	7973	9344
22	Adjusted Net Capability (13+16-17+20-18+19)	7888	8242	8109	8344	8164	8294	8714	8844	8714	8844
23	Annual Adjusted Net Demand (27-17+19)	7133	6033	7133	5955	6955	6053	7053	6101	7101	6192
24	Net Reserve Capacity Obligation (23 x 15%)	854	739	854	739	839	752	852	761	861	773
25	Total Firm Capacity Obligation (28+24)	6965	6966	7088	6962	7022	7075	7089	7132	7193	7236
26	Surplus or Deficit(-) Capacity (22-25)	923	1275	1021	1382	1142	1219	1625	1712	1521	1608
27	Annual System Demand	6383	6383	6383	6455	6455	6553	6553	6601	6601	6692
28	Monthly Adjusted Net Demand (3-17+19)	6111	6228	6234	6223	6183	6322	6236	6371	6332	6463

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-CANADA

		SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
1	Internal Demand	5896	7009	5957	7074	6023	7134	6096	7201	6164
2	Standby Demand	0	0	0	0	0	0	0	0	0
3	Total Internal Demand (1+2)	5896	7009	5957	7074	6023	7134	6096	7201	6164
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	271	272	272	273	273	274	274	275	275
6	Net Internal Demand (3-4-5)	5625	6737	5685	6801	5750	6860	5822	6926	5889
7	Resources (8+9+10+11)	8924	9054	8924	9054	8924	9024	8900	9024	8900
8	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0
9	Other Capacity (1 MW or greater)	8924	9054	8924	9054	8924	9024	8900	9024	8900
10	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
11	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
12	Uncommitted Resources	0	0	0	0	0	0	0	0	0
13	Total Capacity (7+12)	8924	9054	8924	9054	8924	9024	8900	9024	8900
14	Inoperable Capacity	156	0	231	0	156	0	156	0	231
15	Net Operable Capacity (13-14)	8768	9054	8694	9054	8768	9024	8744	9024	8670
16	Total Capacity Purchases	0	500	0	500	0	500	0	500	0
17	Full Responsibility Purchases	0	500	0	500	0	500	0	500	0
18	Total Capacity Sales	710	110	610	110	580	80	530	30	530
19	Full Responsibility Sales	500	0	500	0	500	0	500	0	500
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	8058	9444	8084	9444	8188	9444	8214	9494	8140
22	Adjusted Net Capability (13+16-17+20-18+19)	8714	8944	8814	8944	8844	8944	8870	8994	8870
23	Annual Adjusted Net Demand (27-17+19)	7192	6237	7237	6301	7301	6360	7360	6426	7426
24	Net Reserve Capacity Obligation (23 x 15%)	873	778	878	786	886	793	893	801	901
25	Total Firm Capacity Obligation (28+24)	7268	7287	7335	7360	7409	7427	7489	7502	7565
26	Surplus or Deficit(-) Capacity (22-25)	1446	1657	1479	1584	1435	1517	1381	1492	1305
27	Annual System Demand	6692	6737	6737	6801	6801	6860	6860	6926	6926
28	Monthly Adjusted Net Demand (3-17+19)	6396	6509	6457	6574	6523	6634	6596	6701	6664

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-TOTAL

		SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
1	Internal Demand	33285	30098	33866	30674	34695	31108	35243	31636	35866	32071
2	Standby Demand	0	0	0	0	0	1	1	2	2	3
3	Total Internal Demand (1+2)	33285	30098	33866	30674	34695	31109	35244	31638	35868	32074
4	Direct Control Load Management	996	338	997	349	999	360	1001	346	1003	331
5	Interruptable Demand	568	411	569	484	643	486	646	487	648	489
6	Net Internal Demand (3-4-5)	31721	29349	32300	29840	33053	30263	33597	30805	34217	31254
7	Resources (8+9+10+11)	40192	40828	40784	41143	40675	41322	40668	41385	40662	41463
8	Distributed Generator Capacity (1 MW or greater)	337	324	324	417	403	421	407	424	409	429
9	Other Capacity (1 MW or greater)	38819	39444	39345	39655	39255	39877	39245	39940	39240	40014
10	Distributed Generator Capacity (less than 1 MW)	8	9	8	8	7	8	7	8	7	8
11	Other Capacity (less than 1 MW)	41	40	42	41	42	41	42	37	38	37
12	Uncommitted Resources	28	37	386	484	422	527	612	731	844	960
13	Total Capacity (7+12)	40220	40865	41170	41627	41097	41849	41280	42116	41505	42423
14	Inoperable Capacity	241	207	241	207	156	200	316	200	241	200
15	Net Operable Capacity (13-14)	39979	40658	40929	41420	40941	41649	40964	41916	41264	42223
16	Total Capacity Purchases	6718	5057	4698	3709	4068	2729	3007	2591	2950	2505
17	Full Responsibility Purchases	2222	1819	1912	1737	1858	1742	1858	1743	1851	1742
18	Total Capacity Sales	6126	4960	4934	3947	4133	3863	3039	2817	2887	2724
19	Full Responsibility Sales	1495	1220	1260	1047	987	999	959	979	959	973
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	40571	40755	40693	41182	40876	40516	40932	41690	41328	42005
22	Adjusted Net Capability (13+16-17+20-18+19)	40084	40362	40282	40699	40161	39973	40349	41126	40677	41436
23	Annual Adjusted Net Demand (27-17+19)	32524	32673	33055	33143	33569	33797	34106	34279	34644	34899
24	Net Reserve Capacity Obligation (23 x 15%)	4606	4678	4685	4761	4774	4857	4853	4930	4935	5022
25	Total Firm Capacity Obligation (28+24)	36913	33723	37626	34280	38323	34736	38934	35270	39648	35804
26	Surplus or Deficit(-) Capacity (22-25)	3171	6639	2656	6419	1838	5237	1415	5856	1029	5631
27	Annual System Demand	33252	33273	33707	33833	34440	34540	35005	35043	35536	35668
28	Monthly Adjusted Net Demand (3-29-17+19)	32308	29045	32940	29520	33548	29879	34081	30340	34713	30783
29	Schedule L Purchases	250	454	274	464	276	487	264	534	263	522

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORCASTED SEASONAL LOAD AND CAPABILITY
MEGAWATTS

MAPP-TOTAL

		SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
1	Internal Demand	36497	32542	37139	33034	37885	33517	38549	34020	39179
2	Standby Demand	3	4	4	5	5	6	6	7	7
3	Total Internal Demand (1+2)	36500	32546	37143	33039	37890	33523	38555	34027	39186
4	Direct Control Load Management	1004	322	1005	303	1006	313	1007	323	1009
5	Interruptable Demand	650	490	652	491	654	493	656	494	658
6	Net Internal Demand (3-4-5)	34846	31734	35485	32245	36229	32718	36892	33210	37519
7	Resources (8+9+10+11)	40664	41565	40664	41617	40664	41664	40640	41741	40640
8	Distributed Generator Capacity (1 MW or greater)	412	432	414	435	416	438	418	441	420
9	Other Capacity (1 MW or greater)	39238	40113	39236	40162	39234	40206	39208	40280	39206
10	Distributed Generator Capacity (less than 1 MW)	7	8	7	8	7	8	7	8	7
11	Other Capacity (less than 1 MW)	38	37	38	37	38	37	38	37	38
12	Uncommitted Resources	1369	1485	1369	1485	2269	2385	2269	2385	2269
13	Total Capacity (7+12)	42032	43050	42032	43102	42932	44049	42908	44126	42908
14	Inoperable Capacity	156	200	231	200	156	200	156	200	231
15	Net Operable Capacity (13-14)	41876	42850	41802	42902	42776	43849	42752	43926	42678
16	Total Capacity Purchases	2737	2327	2632	2285	2442	2257	2391	2151	2328
17	Full Responsibility Purchases	1712	1620	1712	1623	1712	1626	1712	1625	1704
18	Total Capacity Sales	2726	2545	2550	2473	2470	2396	2420	2221	2211
19	Full Responsibility Sales	872	896	797	824	797	777	797	780	722
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	41887	42632	41883	42714	42748	43710	42723	43856	42795
22	Adjusted Net Capability (13+16-17+20-18+19)	41202	42108	41198	42115	41988	43061	41963	43211	42042
23	Annual Adjusted Net Demand (27-17+19)	35360	35563	35912	36150	36671	36827	37304	37485	37863
24	Net Reserve Capacity Obligation (23 x 15%)	5041	5120	5122	5206	5235	5306	5328	5403	5410
25	Total Firm Capacity Obligation (28+24)	40404	36409	41046	36929	41902	37447	42661	38041	43304
26	Surplus or Deficit(-) Capacity (22-25)	798	5699	153	5186	87	5614	-697	5170	-1262
27	Annual System Demand	36200	36287	36827	36949	37587	37676	38220	38330	38846
28	Monthly Adjusted Net Demand (3-29-17+19)	35364	31289	35923	31723	36667	32141	37333	32638	37895
29	Schedule L Purchases	269	520	276	504	279	520	279	531	280

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
ALGN	5	12	6	13	10	13	10	17	9	17
AMES	15	49	6	49	2	24	-24	21	-26	19
ATL	3	17	3	16	2	16	3	16	2	15
BEPC	340	546	355	494	314	534	299	511	296	576
CMMPA	-14	37	14	39	24	42	55	68	54	80
GRE	126	640	250	506	182	440	93	373	97	369
GSE	-3	95	-11	81	-32	73	-52	61	-71	50
HCPD	14	12	3	1	5	1	-24	-24	-46	-46
HMU	2	6	5	6	4	6	4	8	7	8
HSTG	10	37	19	37	8	38	15	46	12	43
HUC	7	56	12	54	32	53	31	53	30	52
LES	42	185	93	188	62	229	40	214	17	199
MDU	5	75	-1	71	-6	66	-12	62	-17	-9
MEAN	14	34	13	29	-20	-3	-31	-19	-33	-21
MEC	22	1562	191	1532	20	1259	-280	1372	-380	1295
MMPA	4	47	-15	40	-22	34	-16	-4	-82	-18
MP	188	140	111	42	88	37	73	7	37	-26
MPC	60	47	52	48	49	48	46	43	62	38
MPW	41	58	47	65	44	61	64	82	61	79
MRES	103	136	87	124	86	112	72	97	55	83
NPPD	162	371	167	422	242	432	591	785	778	988
NULM	16	43	15	43	10	41	9	40	8	40
NWPS	20	67	19	64	-35	58	-40	56	-43	53
OPPD	66	437	104	370	100	372	106	278	90	238
OTP	39	50	30	98	30	30	30	30	30	30
PELLA	32	36	18	26	13	26	11	25	10	24
RPU	41	29	34	79	16	77	8	127	50	127
SMMPA	-13	111	-34	113	-36	105	-41	108	-42	109
WAPA	406	45	406	-33	-41	-34	-41	-32	-39	-31
WLMR	-1	0	-18	-2	-19	-2	-18	-1	-18	-2
WPPI	16	21	18	23	17	22	15	21	14	26
XCEL	483	363	-362	400	-453	-192	-1206	-294	-1413	-382
MHEB	708	931	645	1177	836	1143	1392	1718	1349	1679
SPC	215	344	376	205	306	76	233	-5	172	-71
MAPP-US	2248	5364	1635	5037	696	4018	-211	4144	-492	4023
MAPP-Canada	923	1275	1021	1382	1142	1219	1625	1712	1521	1608
MAPP-Total	3171	6639	2656	6419	1838	5237	1415	5856	1029	5631

FORECASTED SEASONAL SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
ALGN	9	16	8	16	8	16	6	15	6
AMES	-29	17	-31	13	-32	12	-33	11	-34
ATL	29	28	30	28	30	28	29	28	33
BEPC	437	647	418	628	400	607	383	679	358
CMMPA	57	80	56	79	55	78	54	78	53
GRE	0	262	-136	203	-224	140	-319	101	-291
GSE	-101	30	-119	18	161	304	143	291	123
HCPD	-47	-46	-47	-47	-48	-47	-48	-48	-49
HMU	7	8	5	7	5	7	5	7	5
HSTG	34	66	30	64	27	61	23	58	20
HUC	28	51	27	50	26	49	24	48	22
LES	-5	187	-26	172	-46	159	-65	142	-85
MDU	-89	-13	-95	-17	-100	-21	-106	-26	-112
MEAN	16	28	15	27	12	26	11	24	9
MEC	-59	1648	-176	1558	-293	1466	-409	1378	-521
MMPA	-90	-23	-99	-29	-137	-66	-146	-97	-181
MP	-5	-37	38	-18	-8	-37	-44	-72	-75
MPC	79	38	96	27	112	27	109	27	106
MPW	59	77	57	76	54	73	52	72	50
MRES	41	71	27	58	13	46	-1	31	-19
NPPD	747	961	716	934	684	906	652	876	715
NULM	5	38	4	37	2	36	1	35	-1
NWPS	-47	51	-51	48	-58	45	-64	43	-71
OPPD	93	195	35	145	380	682	318	644	258
OTP	30	30	30	30	27	30	-31	-22	-32
PELLA	9	23	7	21	6	20	4	19	3
RPU	45	127	39	126	35	126	29	126	25
SMMPA	-51	101	-107	49	-116	42	-126	35	-136
WAPA	-37	-31	-37	-31	-37	-31	-37	-31	-37
WLMR	-20	-3	-22	-5	-24	-6	-26	-37	-58
WPPI	19	25	18	23	16	22	15	20	14
XCEL	-1811	-609	-2039	-690	-2279	-706	-2482	-774	-2664
MHEB	1304	1755	1367	1716	1347	1706	1347	1714	1304
SPC	142	-98	112	-133	87	-189	34	-222	2
MAPP-US	-648	4042	-1326	3602	-1348	4097	-2078	3678	-2567
MAPP-Canada	1446	1657	1479	1584	1435	1517	1381	1492	1305
MAPP-Total	798	5699	153	5186	87	5614	-697	5170	-1262

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

Minnesota Municipal Power Agency

		SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
1	Internal Demand	190	142	197	147	204	152	199	141	206	146
2	Standby Demand	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand (1+2)	190	142	197	147	204	152	199	141	206	146
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	0	0	0	0	0	0	0	0	0	0
6	Net Internal Demand (3-4-5)	190	142	197	147	204	152	199	141	206	146
7	Resources (8+9+10+11)	44	49	44	49	45	49	45	49	45	49
8	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0	0
9	Other Capacity (1 MW or greater)	44	49	44	50	45	50	45	50	45	50
10	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
11	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
12	Uncommitted Resources	0	0	0	0	0	0	0	0	0	0
13	Total Capacity (7+12)	44	49	44	49	45	49	45	49	45	49
14	Inoperable Capacity	0	0	0	0	0	0	0	0	0	0
15	Net Operable Capacity (13-14)	44	49	44	49	45	49	45	49	45	49
16	Total Capacity Purchases	178	168	168	168	168	168	168	118	110	110
17	Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0
18	Total Capacity Sales	0	0	0	0	0	0	0	0	0	0
19	Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	222	217	212	217	213	217	213	167	155	159
22	Adjusted Net Capability (13+16-17+20-18+19)	222	217	212	217	213	217	213	167	155	159
23	Annual Adjusted Net Demand (27-17+19)	190	190	197	197	204	204	199	199	206	206
24	Net Reserve Capacity Obligation (23 x 15%)	29	29	30	30	31	31	30	30	31	31
25	Total Firm Capacity Obligation (28+24)	219	171	227	177	235	183	229	171	237	177
26	Surplus or Deficit(-) Capacity (22-25)	4	47	-15	40	-22	34	-16	-4	-82	-18
27	Annual System Demand	190	190	197	197	204	204	199	199	206	206
28	Monthly Adjusted Net Demand (3-17+19)	190	142	197	147	204	152	199	141	206	146

PURCHASES AND SALES

	SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
PURCHASES										
RPU	100	100	100	100	100	100	100	50	50	50
MHEB	60	60	60	60	60	60	60	60	60	60
MHEB	10	0	0	0	0	0	0	0	0	0
MELROSE	8	8	8	8	8	8	8	8	0	0
TOTAL PURCHASES	178	168	168	168	168	168	168	118	110	110
SALES										
TOTAL SALES	0	0	0	0	0	0	0	0	0	0

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

Minnesota Municipal Power Agency

		SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
1	Internal Demand	213	150	221	155	228	161	236	166	244
2	Standby Demand	0	0	0	0	0	0	0	0	0
3	Total Internal Demand (1+2)	213	150	221	155	228	161	236	166	244
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	0	0	0	0	0	0	0	0	0
6	Net Internal Demand (3-4-5)	213	150	221	155	228	161	236	166	244
7	Resources (8+9+10+11)	45	49	45	49	45	49	45	49	45
8	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0
9	Other Capacity (1 MW or greater)	45	50	45	50	45	50	45	50	45
10	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
11	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
12	Uncommitted Resources	0	0	0	0	0	0	0	0	0
13	Total Capacity (7+12)	45	49	45	49	45	49	45	49	45
14	Inoperable Capacity	0	0	0	0	0	0	0	0	0
15	Net Operable Capacity (13-14)	45	49	45	49	45	49	45	49	45
16	Total Capacity Purchases	110	110	110	110	80	80	80	55	55
17	Full Responsibility Purchases	0	0	0	0	0	0	0	0	0
18	Total Capacity Sales	0	0	0	0	0	0	0	0	0
19	Full Responsibility Sales	0	0	0	0	0	0	0	0	0
20	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0
21	Planned Capacity Resources (15+16+20-18)	155	159	155	159	125	129	125	104	100
22	Adjusted Net Capability (13+16-17+20-18+19)	155	159	155	159	125	129	125	104	100
23	Annual Adjusted Net Demand (27-17+19)	213	213	221	221	228	228	236	236	244
24	Net Reserve Capacity Obligation (23 x 15%)	32	32	33	33	34	34	35	35	37
25	Total Firm Capacity Obligation (28+24)	245	182	254	188	262	195	271	201	281
26	Surplus or Deficit(-) Capacity (22-25)	-90	-23	-99	-29	-137	-66	-146	-97	-181
27	Annual System Demand	213	213	221	221	228	228	236	236	244
28	Monthly Adjusted Net Demand (3-17+19)	213	150	221	155	228	161	236	166	244

PURCHASES AND SALES

	SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
PURCHASES									
RPU	50	50	50	50	50	50	50	25	25
MHEB	60	60	60	60	30	30	30	30	30
MHEB	0	0	0	0	0	0	0	0	0
MELROSE	0	0	0	0	0	0	0	0	0
TOTAL PURCHASES	110	110	110	110	80	80	80	55	55
SALES									
TOTAL SALES	0	0	0	0	0	0	0	0	0

GENERATOR CAPABILITY DATA

Section IV

GENERATOR CAPABILITY DATA

FORECASTED SEASONAL GENERATION CAPABILITY SUMMARY
MEGAWATTS

	SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
ALGN	38	39	38	39	39	39	39	39	39	39
AMES	121	126	121	126	121	126	121	126	121	126
ATL	31	31	31	31	31	31	31	31	31	31
BEPC	1753	1770	1753	1768	1756	1768	1756	1768	1756	1768
CMMPA	150	150	150	150	150	150	150	150	150	150
GRE	2445	2612	2445	2612	2445	2612	2445	2612	2445	2612
GSE	1081	1151	1083	1152	1083	1152	1083	1152	1083	1152
HCPD	51	51	51	51	51	51	51	51	51	51
HMU	9	9	9	9	9	9	9	9	9	9
HSTG	132	132	132	132	132	132	132	132	132	132
HUC	102	106	102	106	102	106	102	106	102	106
LES	475	461	529	573	637	625	637	625	637	625
MDU	434	449	434	449	434	448	434	448	434	448
MEAN	87	88	87	88	87	88	87	88	87	88
MEC	4708	4868	4708	4784	4708	4784	4708	4784	4708	4784
MMPA	44	49	44	49	45	49	45	49	45	49
MP	1777	1773	1777	1772	1775	1772	1775	1748	1752	1724
MPC	541	552	541	552	541	552	541	576	564	600
MPW	235	229	235	229	235	229	235	229	235	229
MRES	412	430	412	430	424	430	424	430	424	430
NPPD	2886	2913	2886	2913	2886	2913	2886	2907	2880	2907
NULM	71	80	71	80	71	80	71	80	71	80
NWPS	312	332	312	332	312	332	312	332	312	332
OPPD	2235	2172	2553	2172	2553	2174	2554	2174	2554	2175
OTP	638	664	638	665	683	713	675	705	675	705
PELLA	38	38	66	66	66	66	66	66	66	66
RPU	184	140	184	190	183	190	183	190	183	190
SMMPA	579	566	566	574	569	574	569	574	569	574
WAPA	2457	2017	2457	2008	2017	2008	2017	2008	2017	2008
WLMR	35	23	23	23	23	23	23	23	23	23
WPPI	128	128	128	128	128	128	128	128	128	128
XCEL	7356	7684	7356	7839	7456	7916	7456	7993	7456	8070
MHEB	5445	5446	5445	5499	5493	5499	5493	5499	5493	5499
SPC	3203	3549	3418	3555	3431	3555	3431	3555	3431	3555
MAPP-US	31544	31832	31921	32089	31751	32268	31744	32331	31738	32409
MAPP-Canada	8648	8996	8863	9054	8924	9054	8924	9054	8924	9054
MAPP-Total	40192	40828	40784	41143	40675	41322	40668	41385	40662	41463

FORECASTED SEASONAL GENERATION CAPABILITY SUMMARY
MEGAWATTS

	SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
ALGN	39	39	39	39	39	39	39	39	39
AMES	121	126	121	126	121	126	121	126	121
ATL	31	31	31	31	31	31	31	31	31
BEPC	1756	1768	1756	1768	1756	1768	1756	1768	1756
CMMPA	150	150	150	150	150	150	150	150	150
GRE	2445	2612	2445	2612	2445	2612	2445	2612	2445
GSE	1083	1152	1083	1152	1083	1152	1083	1152	1083
HCPD	51	51	51	51	51	51	51	51	51
HMU	9	9	9	9	9	9	9	9	9
HSTG	132	132	132	132	132	132	132	132	132
HUC	102	106	102	106	102	106	102	106	102
LES	637	625	637	625	637	625	637	625	637
MDU	434	448	434	448	434	448	434	448	434
MEAN	87	88	87	88	87	88	87	88	87
MEC	4708	4784	4708	4784	4708	4784	4708	4784	4708
MMPA	45	49	45	49	45	49	45	49	45
MP	1728	1726	1705	1677	1682	1677	1682	1677	1682
MPC	587	623	611	647	634	647	634	647	634
MPW	235	229	235	229	235	229	235	229	235
MRES	424	430	424	430	424	430	424	430	424
NPPD	2880	2907	2880	2907	2880	2907	2880	2907	2880
NULM	71	80	71	80	71	80	71	80	71
NWPS	312	332	312	332	312	332	312	332	312
OPPD	2556	2175	2556	2175	2556	2175	2556	2175	2556
OTP	675	705	675	705	675	705	675	705	675
PELLA	66	66	66	66	66	66	66	66	66
RPU	183	190	183	190	183	190	183	190	183
SMMPA	569	574	569	574	569	574	569	574	569
WAPA	2017	2008	2017	2008	2017	2008	2017	2008	2017
WLMR	23	23	23	23	23	23	23	23	23
WPPI	128	128	128	128	128	128	128	128	128
XCEL	7456	8147	7456	8224	7456	8301	7456	8378	7456
MHEB	5493	5499	5493	5499	5493	5499	5493	5499	5493
SPC	3431	3555	3431	3555	3431	3525	3407	3525	3407
MAPP-US	31740	32511	31740	32563	31740	32640	31740	32717	31740
MAPP-Canada	8924	9054	8924	9054	8924	9024	8900	9024	8900
MAPP-Total	40664	41565	40664	41617	40664	41664	40640	41741	40640

Generator Information - Existing Generators
MEGAWATTS

Minnesota Municipal Power Association

Plant Name	Gen ID	Prime Mover	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Date of Operation
Minnesota River Station	1	GT	NG	44.00	49.00	May-01

FORECAST OF SYSTEM DEMAND

Section V

FORECASTED SEASONAL SYSTEM DEMAND SUMMARY
MEGAWATTS

	SUM 2002	WIN 2002	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006
ALGN	24	17	24	17	25	18	25	18	26	18
AMES	115	77	117	81	123	84	126	86	128	88
ATL	27	17	27	17	28	18	28	18	28	18
BEPC	1138	1137	1149	1150	1162	1165	1175	1185	1195	1203
CMMPA	76	53	78	56	79	57	80	57	81	58
GRE	2163	1809	2236	1858	2315	1910	2391	1959	2382	1952
GSE	796	758	811	767	826	776	843	786	860	794
HCPD	81	81	82	82	82	82	83	83	84	84
HMU	15	11	15	11	16	11	16	12	16	12
HSTG	100	67	92	69	106	70	108	72	111	74
HUC	60	41	61	43	61	44	62	44	63	45
LES	752	503	768	512	781	521	800	532	819	545
MDU	434	378	438	382	443	385	448	389	453	392
MEAN	136	108	137	113	139	115	140	116	142	117
MEC	4625	3238	4725	3329	4806	3387	4905	3453	4992	3517
MMPA	190	142	197	147	204	152	199	141	206	146
MP	1605	1605	1633	1689	1646	1693	1661	1699	1673	1707
MPC	379	770	382	780	385	790	388	800	391	810
MPW	144	121	146	122	147	124	149	125	151	127
MRES	269	253	283	263	294	274	306	287	321	298
NPPD	2133	1660	2158	1682	2184	1704	2210	1726	2237	1748
NULM	48	30	49	30	53	31	54	32	55	32
NWPS	276	224	279	226	302	228	306	230	309	232
OPPD	2020	1503	2062	1555	2119	1526	2137	1618	2237	1644
OTP	586	692	604	694	608	701	614	712	620	715
PELLA	44	33	42	33	46	33	47	34	49	35
RPU	255	173	261	179	276	184	283	188	290	193
SMMPA	346	238	356	259	366	261	375	263	384	264
WAPA	1087	1137	1087	1137	1087	1138	1087	1138	1089	1138
WLMR	61	43	62	47	64	48	65	49	67	50
WPPI	59	53	60	54	61	55	62	57	63	58
XCEL	7880	6549	7960	6566	8179	6702	8334	6858	8514	6996
MHEB	2844	3723	2907	3754	2988	3784	2979	3762	3024	3797
SPC	2517	2855	2577	2969	2694	3038	2757	3109	2808	3166
MAPP-US	27924	23521	28382	23951	29013	24287	29507	24767	30035	25111
MAPP-Canada	5361	6578	5484	6723	5683	6822	5736	6871	5832	6963
MAPP-Total	33285	30098	33866	30674	34695	31109	35244	31638	35868	32074

FORECASTED SEASONAL SYSTEM DEMAND SUMMARY
MEGAWATTS

	SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011
ALGN	26	19	27	19	27	19	28	20	28
AMES	130	90	132	93	133	94	134	95	135
ATL	29	18	29	19	30	19	30	19	30
BEPC	1210	1221	1226	1238	1242	1256	1257	1279	1278
CMMPA	81	58	82	59	83	59	84	60	85
GRE	2455	1998	2530	2046	2607	2097	2689	2154	2766
GSE	877	804	893	814	910	825	926	836	943
HCPD	85	84	85	85	86	85	86	86	87
HMU	16	12	17	12	17	12	17	12	17
HSTG	114	76	117	78	120	80	123	82	126
HUC	64	45	65	46	66	47	68	48	70
LES	838	554	856	566	874	576	890	590	906
MDU	458	396	463	399	468	403	472	406	477
MEAN	143	118	144	119	146	120	147	122	149
MEC	5102	3595	5204	3670	5305	3746	5405	3820	5504
MMPA	213	150	221	155	228	161	236	166	244
MP	1690	1718	1708	1734	1728	1750	1761	1781	1788
MPC	394	820	397	830	400	840	403	850	406
MPW	153	129	155	130	157	132	159	133	161
MRES	333	309	345	320	357	330	370	343	385
NPPD	2264	1771	2291	1794	2318	1817	2346	1841	2374
NULM	57	33	58	34	60	35	61	36	63
NWPS	312	234	316	236	322	238	327	240	333
OPPD	2284	1685	2325	1728	2495	1766	2549	1795	2600
OTP	626	723	633	727	639	733	647	736	649
PELLA	50	36	51	37	52	38	54	39	55
RPU	294	196	299	199	303	202	308	205	312
SMMPA	393	268	402	271	410	273	420	276	428
WAPA	1089	1138	1089	1138	1089	1138	1089	1138	1089
WLMR	69	51	70	52	72	53	74	54	76
WPPI	64	58	65	59	66	60	67	62	68
XCEL	8692	7129	8890	7258	9055	7384	9232	7502	9390
MHEB	3067	3819	3101	3854	3147	3891	3194	3929	3233
SPC	2829	3190	2856	3220	2876	3243	2902	3272	2931
MAPP-US	30604	25537	31185	25965	31866	26389	32459	26826	33022
MAPP-Canada	5896	7009	5957	7074	6023	7134	6096	7201	6164
MAPP-Total	36500	32546	37143	33039	37890	33523	38555	34027	39186

NET ENERGY REQUIREMENTS

Section VI

FORECAST ANNUAL NET ENERGY
GIGAWATT HOURS

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
ALGN	111	114	116	119	121	123	126	128	131	133
AMES	513	528	544	560	571	583	594	603	613	622
ATL	107	109	110	112	113	115	117	119	120	122
BEPC	6447	6509	6578	6656	6766	6853	6974	7062	7151	7273
CMMPA	368	376	379	383	387	391	395	399	403	407
GRE	11258	11605	11940	12299	12663	12829	13194	13563	13914	14301
GSE	4388	4459	4537	4620	4702	4786	4868	4957	5053	5141
HCPD	527	535	539	546	554	559	564	569	574	579
HMU	64	65	66	67	68	69	70	71	72	73
HSTG	632	651	666	683	701	719	738	757	777	797
HUC	309	315	320	326	332	337	343	348	353	360
LES	3383	3460	3540	3640	3730	3832	3925	4015	4110	4199
MDU	2148	2163	2178	2190	2205	2220	2234	2246	2257	2268
MEAN	597	612	624	636	649	662	675	689	703	717
MEC	20757	21253	21684	22150	22557	22953	23401	23797	24194	24595
MMPA	885	914	944	917	914	941	969	999	1029	1060
MP	12286	12276	12316	12294	12310	12361	12477	12495	12609	12674
MPC	3658	3750	3843	3940	4038	4139	4242	4349	4457	4569
MPW	916	930	944	958	972	986	1001	1015	1030	1045
MRES	1531	1628	1686	1755	1836	1900	1953	2027	2091	2173
NPPD	10815	11047	11245	11435	11629	11827	12027	12229	12434	12641
NULM	206	210	214	219	223	227	232	237	241	246
NWPS	1323	1349	1376	1403	1431	1459	1488	1518	1548	1580
OPPD	9341	9707	9975	10171	10652	10866	11066	11300	11462	11689
OTP	3924	4033	4080	4117	4186	4011	4051	4082	4124	4135
PELLA	183	185	187	189	191	193	195	197	199	202
RPU	1291	1320	1363	1397	1430	1464	1503	1537	1574	1612
SMMPA	2791	2876	2937	3000	3062	3123	3186	3249	3310	3372
WAPA	5887	5887	5887	5887	5890	5890	5890	5890	5890	5890
WLMR	267	274	281	287	293	299	306	313	320	326
WPPI	307	313	319	325	331	337	343	349	355	361
XCEL	40303	41143	45693	46607	47663	48140	48621	49107	49598	50094
MHEB	20869	21354	21677	21959	22235	22488	22746	23029	23336	23631
SPC	18634	19064	19547	19907	20324	20469	20675	20804	20985	21261
MAPP-US	147524	150595	157110	159886	163170	165193	167768	170215	172696	175255
MAPP-Canada	39503	40419	41224	41866	42559	42957	43421	43833	44321	44892
MAPP-Total	187026	191013	198334	201753	205728	208150	211189	214049	217017	220147

Figure B-1

Forecasted Seasonal Load & Capability - Contingent on Proposed Facility

All Numbers in Megawatts

	Sum 2002	Win 2002	Sum 2003	Win 2003	Sum 2004	Win 2004	Sum 2005	Win 2005	Sum 2006	Win 2006
1 Seasonal System Demand	190	142	197	147	204	152	199	141	206	146
2 Annual System Demand	190	190	197	197	204	204	199	199	206	206
3 Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0
4 Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Net Demand (1-3+4)	190	142	197	147	204	152	199	141	206	146
6 Annual Adjusted Net Demand (2-3+4)	190	190	197	197	204	204	199	199	206	206
7 Net Generating Capacity	44	49	44	49	45	49	45	49	295	299
8 Total Capacity Purchases	178	168	168	168	168	168	168	118	110	110
9 Total Capacity Sales	0	0	0	0	0	0	0	0	0	0
10 Adjusted Net Capability (7+8-9)	222	217	212	217	213	217	213	167	405	409
11 Net Reserve Capacity Obligation	29	29	30	30	31	31	30	30	31	31
12 Total Firm Capacity Obligation (5+11)	219	171	227	177	235	183	229	171	237	177
13 Surplus/Deficit (-) Capacity (10-12)	3	46	-15	40	-22	34	-16	-4	168	232

Figure B-1
Forecasted Seasonal Load & Capability - Contingent on Proposed Facility
All Numbers in Megawatts

	Sum 2007	Win 2007	Sum 2008	Win 2008	Sum 2009	Win 2009	Sum 2010	Win 2010	Sum 2011
1 Seasonal System Demand	213	150	221	155	228	161	236	166	244
2 Annual System Demand	213	213	221	221	228	228	236	236	244
3 Full Responsibility Purchases	0	0	0	0	0	0	0	0	0
4 Full Responsibility Sales	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Net Demand (1-3+4)	213	150	221	155	228	161	236	166	244
6 Annual Adjusted Net Demand (2-3+4)	213	213	221	221	228	228	236	236	244
7 Net Generating Capacity	295	299	295	299	295	299	295	299	295
8 Total Capacity Purchases	110	110	110	110	80	80	80	55	55
9 Total Capacity Sales	0	0	0	0	0	0	0	0	0
10 Adjusted Net Capability (7+8-9)	405	409	405	409	375	379	375	354	350
11 Net Reserve Capacity Obligation	32	32	33	33	34	34	35	35	37
12 Total Firm Capacity Obligation (5+11)	245	182	254	188	262	195	271	201	281
13 Surplus/Deficit (-) Capacity (10-12)	160	227	151	221	113	184	104	153	69

Appendix C – Rate Impact of Economic Analysis

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Appendix D – MISO Tariff

Attached are excerpts from the MISO Tariff. Upon request, the complete document can be made available or else be retrieved from the MISO website.

ATTACHMENT R

GENERATOR INTERCONNECTION PROCEDURES AND AGREEMENT

Generator Interconnection Procedures

1. Definitions.

1.1 General. When used in these Generator Interconnection Procedures with initial capitalization, the terms specified below in this Section 1 shall have the meanings indicated. Terms used in these Generator Interconnection Procedures with initial capitalization but not defined in this Section 1 shall have the meanings specified in the Midwest ISO OATT and/or meanings that are consistent with the definitions of such terms set forth in the *pro forma* Interconnection and Operating Agreement that is a part of this Attachment R. The definitions of the *pro forma* Interconnection and Operating Agreement shall govern any conflicts with the Midwest ISO OATT definitions.

1.1.1 "Affected Transmission Owner" shall mean the Transmission Owner or Transmission Owners whose facilities will be affected by the Interconnection Request.

1.1.2 "Generator" shall mean a person proposing to interconnect the Facility to the Transmission System or to increase the capacity of an existing Facility connected to the Transmission System.

1.1.3 "Interconnection Facilities Study Agreement" shall mean an agreement to conduct an Interconnection Facilities Study.

1.1.4 "Interconnection and Operating Agreement" shall mean the *pro forma* Interconnection and Operating Agreement that is included in these Procedures as Attachment R-4.

1.1.5 "Interconnection Evaluation Study Agreement" shall mean an agreement to conduct an Interconnection Evaluation Study.

2. Scope and Application.

2.1 General. A Generator that proposes to interconnect a new generating facility or to increase the capacity of an existing generating facility, shall follow the terms, conditions and procedures set forth in this Attachment R to the Midwest ISO OATT and pay for any Transmission Owner Interconnection Facilities and Interconnection System Upgrades in accordance with the Interconnection and Operating Agreement. These Generator Interconnection Procedures apply to the interconnection or increase in capacity of all generation, including generation owned by the Transmission Owners and affiliates, for which Transmission Service will be provided under the Midwest ISO OATT, regardless of whether such generation is interconnected at transmission voltages, sub-transmission voltages, or distribution voltages. Any existing generator or new generator connecting at transmission voltages, sub-transmission voltages, or distribution voltages planning to engage in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT must apply to the Midwest ISO for interconnection service. If the proposed new generation facility or increase in generating capacity to an existing generating facility connected to the Transmission System is less than twenty (20) MW, including the aggregate of distributed generation units or energy collection systems, the expedited generation interconnection procedures for such generation are set forth in Section 12 of these Procedures.

2.2 **Role of the Midwest ISO.** The Midwest ISO shall serve as the central and only authority for receiving and processing Interconnection Requests to which these Generator Interconnection Procedures apply under Section 2.1. The Midwest ISO shall coordinate its processing and analysis of Interconnection Requests with any Affected Transmission Owner. The Interconnection and Operating Agreement shall be a three (3)-party agreement among the Generator, the Midwest ISO, and Transmission Owner to which the Facility is to be connected.

2.3 **No Applicability to Transmission Service.** This Attachment R provides only for the interconnection of a generating facility. Interconnection Evaluation Studies and Interconnection Facilities Studies made pursuant to this Attachment R will not include an evaluation of the ability of the Generator to deliver the output of the new generating facility or the proposed generator capacity addition to any load. An

Interconnection Request under this Attachment R does not constitute a request for the delivery portion of transmission service. A Generator may request the delivery portion of transmission service under the Midwest ISO OATT at the time of its Interconnection Request or thereafter. All rates, terms and conditions of Parts I, II and III of the Midwest ISO OATT shall apply to any such request for the delivery portion of transmission service.

2.4 **Interconnections to Distribution.** A Generator not intending to engage in the sale of wholesale energy, capacity, or ancillary services under the Midwest ISO OATT, that proposes to interconnect a new generating facility to the distribution system of a Transmission Owner or local distribution utility interconnected with the Transmission System shall apply to the Transmission Owner or local distribution utility for interconnection. Where facilities under the control of the Midwest ISO are affected by such interconnection, such interconnections may be subject to the planning and operating protocols of the Midwest ISO and agreements applicable to the interconnection of the Transmission System with the distribution system of the Transmission Owner or local distribution utility.

3. **Interconnection Requests.**

3.1 **General.** A Generator shall submit to the Midwest ISO an Interconnection Request in the form of Attachment R-1 provided as a part of this Attachment R. An Interconnection Request shall include (i) the location of the proposed new generating facility site by county and state or, in the case of an existing generating facility site, the name and specific location of the facility; (ii) the maximum megawatt electrical output of the proposed new generating facility or the amount of megawatt increase in the generation capacity at an existing generating facility; (iii) the planned in-service date (month and year) for the proposed generating units; and (iv) a refundable deposit of $10,000. The refundable deposit will be applied toward the cost of an Interconnection Evaluation Study. The Midwest ISO shall refund to Generator any portion of the deposits that exceeds the cost of the Interconnection Evaluation Study. Generator must submit a separate Interconnection Request for each site.

3.2 **Valid Interconnection Request.** An Interconnection Request will not be considered to be a valid Interconnection Request until all of the items specified in Section 3.1 have been received by the Midwest ISO. If an Interconnection Request fails to include such items, the Midwest ISO shall notify Generator within seven (7) days of the receipt of the initial Interconnection Request that the Interconnection Request is not valid and the reasons for such invalidity. Generator shall provide the Midwest ISO with the information needed to constitute a valid Interconnection Request within fifteen (15) days after receipt of such notice. If Generator fails to provide the information within such fifteen (15)-day period, the Interconnection Request shall be deemed abandoned.

3.3 OASIS Posting. The Midwest ISO will maintain on its OASIS a list of all valid Interconnection Requests. The list will identify the size in maximum megawatt electrical output of each proposed generation capacity addition, location by county and state of the generation capacity addition, and the station or transmission line or lines where the proposed generation capacity addition is likely to be connected. The list will not disclose the identity of Generator.

3.4 Coordination with Adjacent Systems. Upon receipt of a valid Interconnection Request, the Midwest ISO shall provide notice of the Interconnection Request to any adjacent regional transmission organization, transmission owner that is not a participant in a regional transmission organization, and local distribution utility that may be affected by the proposed interconnection. The Midwest ISO shall use Reasonable Efforts to coordinate with such other regional transmission organizations, transmission owners, and local distribution utilities in the performance of any studies and Interconnection System Upgrades that may be necessary on the systems of a regional transmission organization, transmission owner, and local distribution utility as the result of the Interconnection Request.

4. Queue Position.

4.1 General. The queue position of each Interconnection Request, for the purpose of performance of necessary studies and determining cost responsibility for Interconnection System Upgrades, shall be based upon the date on which the

Midwest ISO receives a valid Interconnection Request from Generator. To retain such queue position, Generator must strictly adhere to all deadlines, information requirements and other provisions of this Attachment R. Failure to strictly adhere to all deadlines, information requirements and other provisions of this Attachment R will result in forfeiture of the queue position and termination of the Interconnection Request.

4.2 **Transferability of Queue Position.** The queue position of an Interconnection Request is specific to the Point of Interconnection for the project and site identified in the Interconnection Request. A queue position may not be assigned, leased, sold or otherwise transferred to any other entity, unless such entity acquires the specific project identified in the Interconnection Request and that the Point of Interconnection does not change after the transfer.

4.3 **Queue Position for Interconnection Requests submitted prior to Effective Date of Interconnection Procedures.** All requests to a Transmission Owner or the Midwest ISO for interconnection of generation facilities to the Transmission System submitted on or before the date on which FERC permits this Attachment R to become effective shall be assigned a queue position based on the date upon which such Interconnection Request was received by Transmission Owner or the Midwest ISO, provided that Generator complies with all provisions of this Attachment R and provided further that:

(a) if an Interconnection Evaluation Study or an equivalent study has not commenced as of the effective date of this Attachment R, the request for interconnection shall be processed in accordance with this Attachment R. Any deposit provided by Generator to Transmission Owner shall be transferred to the Midwest ISO;

(b) if an Interconnection Evaluation Study or an equivalent study has been commenced but is not completed as of the effective date of this Attachment R, the Midwest ISO shall coordinate with Transmission Owner to complete such study. Once the Interconnection Evaluation Study or equivalent study has been completed and the results of such study provided to Generator, the request for interconnection shall be processed in accordance with this Attachment R;

(c) if an Interconnection Facilities Study or equivalent study has been commenced but is not completed as of the effective date of this Attachment R, the Midwest ISO shall coordinate with Transmission Owner in completing the study. Once the study has been completed and the results of such study provided to Generator, the request for interconnection shall be processed in accordance with this Attachment R; and

(d) if an Interconnection Facilities Study or equivalent study has been completed but an Interconnection and Operating Agreement or equivalent agreement has not been signed as of the effective date of this Attachment R, Generator, the Midwest ISO and Transmission Owner shall work in good faith towards the execution of the *pro forma* Interconnection and Operating Agreement included in this Attachment R.

4.3.1 Request for Reasonable Extension. A Generator who has submitted a request for interconnection to a Transmission Owner or the Midwest ISO prior to the effective date of this Attachment R may request a reasonable extension of any deadline set forth in this Attachment R if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted if in the judgment of the Midwest ISO (i) the need for the extension is not caused by the Generator; (ii) it is necessary to avoid undue hardship to the Generator; and (iii) it is consistent with the intent and process provided in this Attachment R.

5. Interconnection Evaluation Study.

5.1 Interconnection Evaluation Study Agreement. Within thirty (30) days of its receipt of an Interconnection Request, the Midwest ISO shall provide to

Generator an Interconnection Evaluation Study Agreement in the form of Attachment R-2. Pursuant to the Interconnection Evaluation Study Agreement, Generator shall compensate the Midwest ISO for the cost of the Interconnection Evaluation Study that exceeds the ten thousand dollar ($10,000) deposit. The Interconnection Evaluation Study Agreement shall specify the Midwest ISO's estimate of the cost of, and the time estimated to complete each phase of, the Interconnection Evaluation Study, the relevant technical data that must be provided by Generator for the Interconnection Evaluation Study, and the names of any affected adjacent regional transmission organizations, transmission owners, and/or local distribution utilities with which the study will be coordinated. To the extent known by the Midwest ISO, such estimate shall include any costs expected to be incurred by affected adjacent regional transmission organizations, transmission owners, and/or local distribution utilities in the performance of coordinated studies. The Midwest ISO will also provide a *pro forma* Interconnection and Operating Agreement to Generator so that Generator may begin reviewing the terms and conditions required by the Midwest ISO and the Transmission Owner. The *pro forma* Interconnection and Operating Agreement shall be in the form of the *pro forma* Interconnection and Operating Agreement included as a part of this Attachment as Attachment R-4.

5.2 **Execution of Interconnection Evaluation Study Agreement.** Generator shall execute the Interconnection Evaluation Study Agreement and deliver the executed agreement to the Midwest ISO within fifteen (15) days of its receipt and provide to the Midwest ISO a payment of the estimated cost to perform the Interconnection Evaluation Study (included in the agreement) less the Ten Thousand Dollar ($10,000) deposit paid by Generator at the time of submitting the Interconnection Request. If the executed Interconnection Evaluation Study Agreement and payment of the estimated cost are not received within fifteen (15) days, the queue position of the Interconnection Request will be forfeited and the Interconnection Request terminated

5.3 **Scope of Interconnection Evaluation Study.** The Interconnection Evaluation Study will be conducted in accordance with Good Utility Practice to assess the impact of the proposed generation capacity addition on the reliability of the Transmission System and the systems of adjacent regional transmission organizations, transmission owners, and local distribution utilities. The Interconnection Evaluation Study will not assess the adequacy of Generator's proposed Facility or the proposed Generator Interconnection Facilities. The Interconnection Evaluation Study will consider, at a minimum, all generating facilities physically interconnected to the Transmission System on the date the Interconnection Evaluation Study is commenced, all generating facilities that are not physically interconnected to the Transmission System but that have an executed Interconnection and Operating Agreement (including Interconnection and Operating Agreements that the Generator has requested the Midwest ISO to file with FERC on an unexecuted basis), and generating facilities physically interconnected to the systems of an adjacent regional transmission organizations, transmission owners, and local distribution utilities on the date the study is commenced that may affect the proposed interconnection. As the default assumption, unless the Generator requesting the Interconnection Evaluation Study specifies otherwise, or the Midwest ISO judges that consideration of other generating facilities in the queue would likely result in a greater adverse impact on system reliability than the default assumption, the Interconnection Evaluation Study will not consider any proposed generating facility in the queue that has not resulted in an executed Interconnection and Operating Agreement or has not resulted in a written request by the Generator that Midwest ISO file an Interconnection and Operating Agreement with FERC on an unexecuted basis. Where a Generator requests that the Midwest ISO consider proposed generating facilities without executed or filed interconnection agreements in its studies, the requesting Generator shall specifically identify the proposed generating facilities, that are in the interconnection queue, that the Midwest ISO should consider as being interconnected in the proposed Interconnection Evaluation

Study. The Midwest ISO will perform the Interconnection Evaluation Studies with the identified generating facilities considered interconnected, provided that, in the judgment of the Midwest ISO and the Affected Transmission Owners, the specified interconnection scenario would likely result in a greater adverse impact on system reliability than the default assumption. The Interconnection Evaluation Study will be conducted in two phases. Phase 1 will consist of a power flow analysis. Phase 2 will consist of short circuit and stability analyses. The power flow analysis, at a minimum, will determine the extent of thermal overloading on the Transmission System and the systems of adjacent regional transmission organizations, transmission owners, and local distribution utilities due to the proposed generation capacity addition. The short circuit analysis will evaluate, at a minimum, the impact of the proposed generation capacity addition on the short circuit current capability of the circuit breakers at the Point of Interconnection and at other affected stations. The stability study will be carried out to (a) assess the ability of the proposed generation facility to remain in synchronism following credible system events, including faults; (b) assess the adequacy of damping of generation/transmission oscillations; and (c) evaluate the impact of the generation facility (and associated required network additions) on stability performance of generators within the scope of the Interconnection Evaluation Study. The study criteria that the Midwest ISO will use in the Interconnection Evaluation Study will be the criteria of Affected

Transmission Owners that reflect, to the extent appropriate, the unique characteristics of the Transmission System at the Point of Interconnection and the systems of adjacent regional transmission organizations, transmission owners, and local distribution utilities. In conducting an Interconnection Evaluation Study, the Midwest ISO shall utilize existing studies to the extent practicable. Generator has the option of requesting the Midwest ISO to perform Phase 1 and Phase 2 concurrently and receive one Interconnection Evaluation Study Report at the time of completion of both phases; or, requesting that Phase 1 and Phase 2 be performed sequentially with a preliminary report being issued at the completion of Phase 1 and a final report after the completion of Phase 2. If Generator elects to have Phase 1 and Phase 2 performed sequentially, Generator may elect not to proceed with Phase 2 of the Interconnection Evaluation Study in which case the queue position of the Interconnection Request will be forfeited and the Interconnection Request terminated. Upon the request of Generator, the Midwest ISO shall include in the Interconnection Evaluation Study consideration of the implications associated with use of the Point of Interconnection for Generator to receive electric energy for start-up and station auxiliary service purposes.

5.4 **Interconnection Evaluation Study Procedures.** Upon receipt of an executed Interconnection Evaluation Study Agreement, payment of the estimated cost, and all relevant technical data necessary for completing the Interconnection Evaluation Study, the Midwest ISO will use due diligence to complete the Interconnection Evaluation Study within sixty (60) days after receipt of the executed Interconnection Evaluation Study Agreement, payment of such estimated cost and all such relevant technical data, provided that Generator does not elect to have Phase 1 and Phase 2 performed sequentially as provided in Section 5.4. If Generator fails to provide such payment and/or all such necessary relevant technical data, the Midwest ISO shall notify Generator of such deficiencies within seven (7) days of the receipt of the executed Interconnection Evaluation Study Agreement. Generator shall provide the Midwest ISO with the required payment and/or information within fifteen (15) days after receipt of such notice. If Generator fails to provide the payment and/or information within such fifteen (15)-day period, the Interconnection Request shall be deemed abandoned.

If the Midwest ISO is unable to complete the required Interconnection Evaluation Study within such sixty (60)-day period, it shall so notify Generator and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the Interconnection Evaluation Study. If Generator elects to have Phase 1 and Phase 2 of the Interconnection Evaluation Study performed sequentially, the Midwest ISO shall provide Generator with a preliminary report on Phase 1 within sixty (60) days after the commencement of

Phase 1 of the Interconnection Evaluation Study. Generator will have fifteen (15) days after receipt of the preliminary report to notify the Midwest ISO in writing of Generator's election to proceed with Phase 2 and to provide any additional information and cost reimbursement required by the Midwest ISO. If Generator elects to have Phase 2 of the Interconnection Evaluation Study performed, the Midwest ISO shall provide the final report to Generator within sixty (60) days after Generator has notified the Midwest ISO to proceed with Phase 2 and has provided any additional information and cost reimbursement required by the Midwest ISO. If the Midwest ISO is unable to complete either Phase 1 or Phase 2, or both, within the sixty (60)-day period, it shall so notify Generator and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the Phase or Phases.

5.5 **Standards.** The Midwest ISO will use the same due diligence in completing the Interconnection Evaluation Study for all Generators, whether owned by Transmission Owners who are participants in the Midwest ISO, their affiliates or others.

5.6 **Completion of Interconnection Evaluation Study.** Upon completion of each phase of the Interconnection Evaluation Study, a final report documenting the results of the Interconnection Evaluation Study will be provided to Generator. The

Interconnection Evaluation Study will state the assumptions upon which it is based and identify potential problems that may occur on the Transmission System as a result of the proposed interconnection. If Generator has requested that Phase 1 and Phase 2 of the Interconnection Evaluation Study be performed sequentially, the preliminary report on Phase 1 shall show only the results of the power flow analysis. Upon completion of the Interconnection Evaluation Study, Generator may request and the Midwest ISO shall provide, subject to appropriate confidentiality arrangements with Generator, supporting documentation for the Interconnection Evaluation Study.

5.7 **Posting on OASIS.** Upon completion of the final Interconnection Evaluation Study Report, the Midwest ISO shall post the final Interconnection Evaluation Study Report to its OASIS with the name of the Generator omitted.

6. **Interconnection Facilities Study.**

6.1 **Election to Proceed with Interconnection Facilities Study**. Upon receipt of the final Interconnection Evaluation Study, Generator shall have fifteen (15) days to inform the Midwest ISO of its request for an Interconnection Facilities Study. Within fifteen (15) days after receipt of such request, the Midwest ISO shall respond with an Interconnection Facilities Study Agreement in the form of Attachment R-4 that includes the estimated cost to Generator for the Midwest ISO to conduct the Interconnection Facilities Study. If Generator elects to proceed with the

Interconnection Facilities Study, Generator shall execute the Interconnection Facilities Study Agreement and return it with payment of the estimated cost of the Interconnection Facilities Study to the Midwest ISO within fifteen (15) days after receipt of the Interconnection Facilities Study Agreement. If Generator does not provide the executed Interconnection Facilities Study Agreement and the payment of the estimated cost to the Midwest ISO within such fifteen (15)-day period, Generator's queue position will be forfeited and its Interconnection Request will be terminated. If Generator does not proceed with an Interconnection Facilities Study, the Midwest ISO shall determine the actual costs of performing the Interconnection Evaluation Study and issue a bill or credit to Generator for the difference in the amounts paid and the costs incurred.

6.2 Scope of Interconnection Facilities Study. Upon receipt of an executed Interconnection Facilities Study Agreement and payment of the estimated cost to perform the Interconnection Facilities Study, an Interconnection Facilities Study will be carried out by, or on behalf of, the Midwest ISO and the Midwest ISO shall use Reasonable Efforts to coordinate the Interconnection Facilities Study with any affected adjacent regional transmission organizations, transmission owners, and local distribution utilities to determine the work required to effect the physical and electrical connection of the proposed Facility at the Point of Interconnection and to address, in accordance with Good Utility Practice, reliability problems identified in the Interconnection Evaluation Study. The electrical switching configuration of the connection equipment, including without limitation, transformer, switchgear and other station equipment, and required transmission lines, if any, will be determined as part of the Interconnection Facilities Study. Good faith cost estimates for Transmission Owner Interconnection Facilities and Interconnection System Upgrades necessary to accommodate the Interconnection Request and the time required to complete construction of Transmission Owner Interconnection Facilities and Interconnection System Upgrades will also be determined as part of the Interconnection Facilities Study. The Interconnection Facilities Study shall be performed in accordance with Good Utility Practice, including NERC planning standards, and planning standards and practices filed on FERC Form 715. The Midwest ISO shall apply the same standards to all generator interconnects, including those for Transmission Owners who are Midwest ISO Members and their affiliates.

6.3 **Letter Agreement.** At the request of Generator and upon Generator's execution of a Interconnection Facilities Study Agreement, the Midwest ISO shall provide to Generator a Letter Agreement which authorizes the Affected Transmission Owner to begin engineering, design and siting activities and procurement of long lead-time items necessary for the establishment of the interconnection. The Letter Agreement is an optional procedure to be elected by Generator if it desires to accelerate the interconnection process and, if elected, will not alter Generator's queue position. The Letter Agreement will require Generator to pay the cost of all activities authorized by Generator and to make advance payments or provide other satisfactory security. Generator shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for the project whether or not such items or equipment later become unnecessary. No construction activities shall be undertaken until after the Interconnection and Operating Agreement is executed and delivered to the Midwest ISO or an unexecuted Interconnection and Operating Agreement is filed in accordance with the provisions of this Attachment R and Applicable Laws and Regulations.

6.4 **Completion of the Interconnection Facilities Study.** Upon receipt of an executed Interconnection Facilities Study Agreement and payment of the estimated costs to perform the Interconnection Facilities Study, the Midwest ISO will use due diligence to complete the required Interconnection Facilities Study and issue a preliminary Interconnection Facilities Study Report to Generator within sixty (60) days. If the Midwest ISO is unable to complete the Interconnection Facilities Study and issue a preliminary Interconnection Facilities Study Report within such sixty (60) days, the Midwest ISO shall notify Generator and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the Interconnection Facilities Study and issue a preliminary Interconnection Facilities Study Report. Generator shall have thirty (30) days after receipt of the preliminary Interconnection Facilities Study Report to provide written comments to the Midwest ISO for its consideration for inclusion in the final Interconnection Facilities Study Report. Within fifteen (15) days after the receipt of such comments or notification from Generator that it is does not have comments, the Midwest ISO shall issue the final Interconnection Facilities Study Report provided that the Midwest ISO, in the reasonable exercise of its discretion, may extend such fifteen (15)-day period if such comments require the performance of additional studies or other significant modifications prior to the issuance of the final Interconnection Facilities Study. The Midwest ISO shall provide Generator with a good faith estimate of the duration of such time extension. When completed, the final Interconnection Facilities Study Report will include a good faith estimate of (i) the costs to be charged to Generator for Transmission Owner Interconnection Facilities and Interconnection System Upgrades and (ii) the time required to complete engineering and construction and initiate the requested Interconnection Service. Upon completion of the Interconnection Evaluation Study, Generator may request and the Midwest ISO shall provide, subject to appropriate confidentiality arrangements with Generator, supporting documentation for the Interconnection Evaluation Study.

6.5 Posting on OASIS. Upon completion of the final Interconnection Facilities Study Report, the Midwest ISO shall post the Interconnection Facilities Study Report to its OASIS with the name of the Generator omitted.

7. Interconnection and Operating Agreement.

7.1 Tender. Within thirty (30) days after issuance of the final Interconnection Facilities Study Report to Generator, the Midwest ISO shall tender to Generator a final draft of the Interconnection and Operating Agreement. The final draft of the Interconnection and Operating Agreement shall be in the form of the *pro forma* Interconnection and Operating Agreement included in this Attachment R as Attachment R-4 with blanks and appendices completed with information available to the Midwest ISO. Appendices developed for the final draft of the Interconnection and Operating Agreement will contain provisions that address the unique characteristics of the Facility, the Generator Interconnection Facilities, Transmission Owner Interconnection Facilities, Interconnection System Upgrades and the Point of Interconnection.

7.2 Execution. To retain the queue position of its Interconnection Request, within thirty (30) days following the Midwest ISO's tender of the final draft of the Interconnection and Operating Agreement, Generator must execute and return three (3) originals of the tendered Interconnection and Operating Agreement, or submit to the Midwest ISO a written request for the filing of an unexecuted Interconnection and Operating Agreement. If Generator requests the filing of an unexecuted Interconnection and Operating Agreement, it must provide the Midwest ISO with a Letter Agreement in which Generator agrees to abide by all of the provisions of the Interconnection and Operating Agreement filed by the Midwest ISO, except as such provisions may later be modified by FERC. At any time after submitting such request and Letter Agreement to the Midwest ISO, Generator may withdraw its Interconnection Request by written notification to the Midwest ISO at any time before or after resolution of the unexecuted Interconnection and Operating Agreement by FERC provided that Generator shall remain liable for the payment of all costs associated with termination of the Interconnection and Operating Agreement and the Interconnection Request. Upon the receipt by the Midwest ISO of such written request for the filing of an unexecuted Interconnection and Operating Agreement and such Letter Agreement, all Parties shall be bound by the terms and conditions of the Interconnection and Operating Agreement and shall immediately enter into full performance thereof without regard to the fact that the Interconnection and Operating Agreement has not been executed, provided that such Interconnection and Operating Agreement, including its Appendices, and the Parties' performance thereof, shall be subject to modification based upon orders of FERC with regard to the unexecuted Interconnection and Operating Agreement.

7.3 **Filing with FERC.** As soon as practicable, but not later than thirty (30) days after receiving three (3) executed originals of the Interconnection and Operating Agreement, without any modifications not previously agreed to, the Midwest ISO and Transmission Owner shall execute such originals and the Midwest ISO shall file a copy of the fully executed Interconnection and Operating Agreement with FERC in accordance with Applicable Laws and Regulations. As soon as practicable, but not later than thirty (30) days after receiving Generator's written request that the Midwest ISO file an unexecuted Interconnection and Operating Agreement and the Letter Agreement referred to in Section 7.2 of these Procedures, the Midwest ISO shall file an unexecuted Interconnection and Operating Agreement with FERC in accordance with Applicable Laws and Regulations.

7.4 **Filing of Unexecuted Interconnection and Operating Agreement.** If Generator requests the Midwest ISO to file an unexecuted Interconnection and Operating Agreement pursuant to Section 7.2, the filing shall consist of the *pro forma* Interconnection and Operating Agreement contained in this Attachment R with Appendices reflecting terms and conditions available to Transmission Owner and the Midwest ISO.

8. Modification or Withdrawal of Interconnection Request.

8.1 Modifications. Generator may submit to the Midwest ISO modifications to any information provided in the Interconnection Request. In such event Generator shall retain its queue position only if the modifications, in the judgment of the Midwest ISO, do not materially affect its Interconnection Request, the results of its Interconnection Evaluation Study or Interconnection Facilities Study, and/or the results of the Interconnection Evaluation Study or Interconnection Facilities Study performed with regard to any other Interconnection Request in the queue. Prior to making such modifications, Generator may request the Midwest ISO determine in writing whether the modifications would have such a material affect.

8.2 Withdrawal. Generator may withdraw its Interconnection Request at any time provided that Generator shall pay to the Midwest ISO or the Affected Transmission Owner all costs prudently incurred by the Midwest ISO or the Affected Transmission Owner prior to the Midwest ISO's receipt of notice of such withdrawal. In the event of such withdrawal, the Midwest ISO, subject to the provisions of Section 10.1 of these Procedures, shall provide Generator with all information developed by the Midwest ISO for the purpose of completing any study required with regard to the Interconnection Request to the extent that the final study report has not been delivered to Generator.

9. Construction of Interconnection Facilities and Interconnection System Upgrades.

9.1 Schedule. The Midwest ISO, the Affected Transmission Owner, and Generator shall negotiate in good faith to agree to a schedule acceptable to each for the construction of the Interconnection Facilities and the Interconnection System Upgrades.

9.2 Permits. The Midwest ISO, the Affected Transmission Owner, and Generator shall be responsible for obtaining all permits, licenses and necessary authorizations to comply with Applicable Laws and Regulations and shall cooperate with each other in obtaining any such permits, licenses and necessary authorizations for the construction of the Interconnection Facilities and Interconnection System Upgrades. Responsibility for obtaining such permits, licenses and necessary authorizations shall be set forth in Appendices A and B of the Interconnection and Operating Agreement.

10. Miscellaneous.

10.1 Confidentiality. Until completion of each study required under this Attachment R, the Midwest ISO, any Affected Transmission Owner and any affected adjacent regional transmission organization, transmission owner, and local distribution utility shall keep confidential all information that was provided by Generator relating to such study, provided that, upon completion of each study performed under this

Attachment R, a report of the study will be posted to the Midwest ISO's OASIS in accordance with this Attachment R.

10.2 Transmission Credits. Generator shall be entitled to credits for transmission service taken from the Point of Interconnection in accordance with the provisions of the Interconnection and Operating Agreement.

10.3 Transmission Owners. The Midwest ISO may use the services of one or more Transmission Owners, as it deems appropriate, to perform its obligations under this Attachment R; provided that the Midwest ISO shall require such Transmission Owners to comply with all applicable terms and conditions of this Attachment R in providing such services.

10.4 Subcontractors. The Midwest ISO and Affected Transmission Owner may use the services of such subcontractors, as it deems appropriate, to perform its obligations under this Attachment R; provided that the Midwest ISO and Affected Transmission Owner shall require its subcontractors to comply with all applicable terms and conditions of this Attachment R in providing such services and the Midwest ISO and Affected Transmission Owner shall remain primarily liable to the Generator for the performance of such subcontractors.

10.5 Must-Run. The Midwest ISO may designate one or more units of a Facility as a must-run unit in order to ensure a secure and reliable Transmission System under normal operating and first contingency conditions. This determination will be made by a Midwest ISO study that identifies a substantial unavoidable need for use of the unit or units to support the Transmission System and will be based on projected and actual operating conditions. Must-run units shall not be designated for economic reasons. If a must-run unit determination is made pursuant to this Section 10.5, Generator shall enter into good faith negotiations with the Midwest ISO for the purpose of entering into a separate agreement setting forth the terms and conditions, including compensation, for must-run operations of the unit or units and the Midwest ISO shall file the must-run agreement with FERC. If the Parties are unable to agree to the terms and conditions of such agreement within sixty (60) days after commencing negotiations, the Midwest ISO may file an unexecuted must-run agreement with FERC and such agreement shall be effective on the date authorized by FERC.

11. Expedited Procedures to Connect Generation Under 20 MW.

11.1 Applicability. The provisions of this Section 11 shall apply to the interconnection of new generating facilities of less than 20 MW, including the aggregate of distributed generation units or energy collection systems, to the Transmission System and for the connection of increased generating capacity of existing generating facilities of less than 20 MW to the Transmission System.

11.2 Interconnection Request. A Generator desiring to connect a new generating facility of less than 20 MW, including the aggregate of distributed generation units or energy collection systems, to the Transmission System or to connect an increase in the generating capacity of less than 20 MW to an existing generating facility connected to the Transmission System, must submit a completed Interconnection Request in the form of Attachment R-1. All requirements related to the submission of an Interconnection Request under this Attachment R must be satisfied for purposes of this Section 11 except that the refundable Ten Thousand Dollar ($10,000) deposit requirement shall be reduced to Five Thousand Dollars ($5,000). In submitting an Interconnection Request pursuant to this Section 11, Generator may strike out and replace all references to the refundable Ten Thousand Dollar ($10,000) deposit with Five Thousand Dollars ($5,000). While the deposit requirement shall be reduced, Generator shall be responsible for all costs associated with the processing of the Interconnection Request and the performance of the Interconnection Evaluation Study and the Interconnection Facilities Study related to the Interconnection Request and will be billed for such costs in excess of the deposit following the completion of such studies.

11.3 Queue. Upon receipt of a valid Interconnection Request, the Midwest ISO will enter the Interconnection Request into its generation interconnection queue for analysis. The Interconnection Request will be identified in the queue on the OASIS by the size of the capacity addition and its proposed Point of Interconnection.

11.4 Interconnection Evaluation Study Agreement. Within thirty (30) days after receipt of a valid Interconnection Request under this Section 11, the Midwest ISO shall provide to Generator an Interconnection Evaluation Study Agreement for Generator to execute before the Interconnection Evaluation Study will be initiated. To remain in the interconnection queue, Generator shall execute the Interconnection Evaluation Study Agreement and return it to the Midwest ISO within fifteen (15) days after its receipt.

11.5 Interconnection Evaluation Study. The Interconnection Evaluation Study for a Generator seeking interconnection under this Section 11 can generally be expedited and completed much earlier than the sixty (60) days required for an Interconnection Evaluation Study for a larger generating facility, by examining a limited contingency set that focuses on the impact of the small capacity addition on contingency limits in the vicinity of the capacity resource. Generally, small capacity additions are expected to have very limited and isolated impacts on system facilities in the immediate vicinity. In many cases, the addition of small capacity resources could improve local area performance. However, if local area performances are known to be limited and marginal, the impact of the new resource will be evaluated based on its impact on the contingencies limiting such local area performance. Generation additions will be tested using linear load flow analysis tools. In many cases, small capacity additions will have no adverse impact on generator addition in an area. If violations are observed, more detailed testing using AC load flow analysis tools will be required. Stability analysis generally will not be performed for small capacity additions. If the capacity of an existing generating resource will be increased by less than twenty (20) MW, stability will be evaluated for critical contingencies only if existing stability margins are small. Stability analysis for new capacity resources of less than twenty (20) MW will only be conducted if the new resource is connected at a location where stability margins associated with existing resources are small. Short circuit calculations are performed as part of the Interconnection Evaluation Study for small resource additions, while taking into consideration all elements of the regional plan, to ensure that circuit breaker capabilities will not be exceeded.

11.6 Interconnection Evaluation Study Report. Once the Interconnection Evaluation Study has been completed, an Interconnection Evaluation Study Report will be prepared and transmitted to Generator along with an Interconnection Facilities Study Agreement.

11.7 Interconnection Facilities Study Agreement. In order to remain in the interconnection queue, Generator must return the executed Interconnection Facilities Study Agreement within fifteen (15) days, along with a deposit in the amount of the estimated cost of the Interconnection Facilities Study. If no Transmission Owner Interconnection Facilities or Interconnection System

Upgrades are required to be installed to facilitate the interconnection, the Interconnection Facilities Study may not be required and the project will proceed directly to the execution of an Interconnection and Operating Agreement.

11.8 Interconnection Facilities Study. As with larger generation projects, transmission facilities design for any required Transmission Owner Interconnection Facilities and/or Interconnection System Upgrades will be performed through the execution of an Interconnection Facilities Study Agreement between the Generator and the Midwest ISO. Facilities design for small capacity additions will be expedited to the extent possible and will be completed much earlier than the sixty (60) days required for the Interconnection Facilities Study associated with a larger project. In many cases, few or no Interconnection System Upgrades may be required for small capacity additions. Transmission Owner Interconnection Facilities for some small capacity additions, may, in part, be elements of a "turn key" installation. In such instances, the design of "turn key" Transmission Owner Interconnection Facilities will be reviewed by Transmission Owners or their contractors.

11.9 General. As with larger generation projects, an Interconnection and Operating Agreement in the form provided with this Attachment R must be executed and filed with FERC. In general, the Interconnection and Operating Agreement for an interconnection subject to this Section 11 will be the same as for larger projects, subject to modification to reflect the simplified operation of the smaller units.

12. Existing Generator Interconnections on the Operational Date of the Midwest ISO.

12.1 General. The owner of each generating facility interconnected to the Transmission System, or connected at sub-transmission or distribution voltage and that engages in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT shall follow the operating protocols for existing generators interconnected to the Midwest ISO Transmission System as contained in the business practices and protocols of the Midwest ISO Security Coordination Manual.