GE Power Systems

MAPP Reserve Capacity Obligation Review

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Foreword

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Executive Summary

The Reserve Capacity Obligation (RCO) is the minimum generation reserve margin that each Mid-Continent Area Power Pool (MAPP) member utility must maintain in order to support MAPP's reliability objectives. MAPP's original RCO requirement of 15% for thermal systems was established in the 1972 MAPP Agreement, and corroborated in 1974 based on a generating system loss of load study, which considered load forecast uncertainty, load diversity among pool members, and different maintenance schedules.

The reserve requirement obligation is studied periodically to determine whether the current RCO meets acceptable reliability objectives. The present RCO requirement remains unchanged from the original requirement and is 15% for MAPP members with thermally-dominant systems. This minimum is established based on a periodic review of the reliability of the pool.

The most recent, complete reliability study examining the appropriate RCO level for the thermally-dominant portion of the MAPP generation system was a product of the MAPP Reserve Requirements Task Force (RRTF) in 1991. This task force analyzed a number of items such as forced outage rates for generating units, load diversity in MAPP, load forecast uncertainty, etc., in order to conclude that 15% was the optimum RCO level for MAPP members. In 1994, the Reserve Requirements Working Group (RRWG) revisited the 1991 study with updated and improved data for the MAPP system and reviewed the RCO level. The 1994 RCO study confirmed the findings of the 1991 study and recommended continuation of the 15% RCO.

The 1991 and 1994 reserve requirement studies examined reserve requirements for the electric generating capacity of MAPP as an isolated system, which assumed the transmission system in the MAPP Pool was 100% available. Recognizing that transmission interface capacity transfer constraints among areas as well the unavailability of the transmission interfaces when required can negatively impact the reliability of the MAPP system, the assumption of a 100% available MAPP transmission system was recognized as not valid in the 1994 study. One of the recommendations of the 1994 study was to perform in the future a MAPP multi-area generation system study that considers the impact of transmission interface capacity transfer limitations and the reliability of the interfaces among areas within the existing reserve requirements obligation. The study presented in this report is essentially the same as those completed in 1991 and 1994, except that the MAPP electric system has been modeled as multiple areas with transmission interfaces between adjacent areas. The transfer limitations between areas as well the reliability of interfaces have been adequately reflected in the study in order to examine the optimum RCO level for the MAPP system per recommendations in the 1994 *Review of the Reserve Capacity Obligation.*

The basic differences between this study and the past RCO studies include:

- This study essentially investigated the same MAPP-US thermal system with the exception that the MAPP-US thermal system has been modeled as four separate areas with transfer limitations between them due to the unavailability of

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interfaces. The thermal and stability limited transfer limitations over the interfaces have been explicitly modeled in this study.

- Past RCO studies used NERC GADS forced outage rate data for MAPP generating units, but these data were lumped into classes based on generating unit size and fuel type. This RCO study used the specific forced outage rate data for each MAPP generating unit.

- Past RCO studies addressed the load forecast uncertainty implicitly. This study illustrated the impact of load forecast uncertainty on RCO level by probabilistic modeling of load forecast uncertainty.

- Past RCO studies utilized analytical computer models requiring many simplifying assumptions. This RCO study used a state-of-the-art, multi-area generation capacity reliability assessment model based on Monte Carlo simulation approach. This approach can eliminate most assumptions associated with the previous RCO studies' analytical tools.

- The analytical tools used in past RCO studies used load duration curve (LDC) as load models, whereas the Monte Carlo Simulation tool in this study used 8760 chronological hourly loads as the load model. The LDC does not maintain chronological hourly load shape for the system.

The basic objective of this study was to simulate the 1994 RCO study for the MAPP-US thermal system using the best generation, load and transmission data available at this time using a better computer tool where most modeling assumptions could be relaxed and calculated reserve margins compared. Both the 1994 study and this study included different maintenance schedules for generating units. The Monte Carlo simulation model used in this study used a maintenance optimization method in scheduling generating unit maintenance periods. This study's scope was to determine the Reserve Capacity Obligation (RCO) for the MAPP-US thermal system for the years 2003, 2006, 2009, and 2012 including transmission limitations between the MAPP-US areas. Similar studies had been done in 1991 and 1994, and one of the purposes of this study was to determine whether or not the recommendations from the previous studies were still valid

An attempt was made early in this study effort to model the MAPP region together with all MAPP-US and MAPP-Canada combined system. This study's aim did not include a call to alter the historical process surrounding the determination of MAPP RCO levels. Historically and to the present time, MAPP RCO is established separately for thermal-dominant and hydro-dominant systems. It is at least theoretically possible to construct a study to produce a rational result concerning planning reserve margin for a highly heterogeneous regional thermal and hydro system. At present, however, such a study's result informs on neither a thermal system's optimal RCO nor a hydro system's optimal RCO.

Wind energy was modeled in the study with fixed amount of accredited capacity for each wind turbine generator due to the unavailability of hourly output data from these wind turbines. Not all of the installed wind energy was modeled in this study, but the impact of those units that were not included is negligible to the results of this study.

This study focused primarily on the installed reserves required to maintain the interconnected system at the widely accepted reliability criterion of 0.1 day per year loss-of-load expectation (LOLE).

A range of sensitivity studies were performed to see the impacts of load forecast uncertainty, unit forced outage rate uncertainty, transmission limitations and unavailability, and loading in an extremely hot summer (1995 hourly loads) on the RCO levels.

As described above, in this study, the hourly load profiles for the four MAPP-US areas were developed from the actual hourly load data for 1999 for the MAPP-US region. As such, there was some level of diversity built into the hourly shapes. However, since all of the areas used the same hourly shape, which was adjusted by the program to produce the forecasted annual peak for each area, there was not as much diversity modeled as would be if the area loads had been developed from bus-level load data. Demand Side Management (DSM) was not explicitly modeled in the study. However, in the chronological hourly load model used in the study, the assumption was that any existing DSM had been netted from the load data that were submitted by each MAPP company.

The results of this study indicate the need for installed reserves in the range of 9.96% (no internal transmission limitations) to 12.75% (Load Forecast Uncertainty) in the MAPP-US thermal portion of the system in order to maintain a reliability level of 0.1 day per year. The results suggest that a reserve level of 10% to 13% may be justifiable for the MAPP-US thermal system considering load forecast uncertainty, and forced outage rate increasesfor generating units. However, because deliverability, integrated hydro with thermal and hydro-dominant issues were not specifically or adequately addressed, the present 15% thermal RCO and 10% hydro RCO values are still considered valid and no changes are being recommended. Specific recommendations to address these issues, and more, in subsequent RCO studies are made in the Recommendations section of this report.

The two input assumptions with the largest impact on the installed reserve requirements for the thermal-dominated MAPP-US system were uncertainty in the peak load forecast and variations in the forced outage rates. Each of these factors, when evaluated separately, increased the reserves required to maintain an LOLE of 0.1 day per year by approximately 2.5%. The presence of internal transfer limits within the system was less significant, contributing only about 0.25% to the installed reserve requirements. The interface unavailability data used in the study were based on historical performances of these transmission lines. The transfer limitations on the interfaces were based on thermal- and stability-limited simulation runs of the MAPP integrated system. The calculated results indicate that the impact of transfer limitations between areas on the reserve level is insignificant.

A second set of reserve margin requirements was also computed using a cost-benefit analysis to determine the economic level of reserves. The impacts on the required reserves of several key study assumptions were determined through a number of sensitivity cases.

To judge the optimum level of the RCO using the reliability cost/reliability worth planning approach, it is necessary to estimate the direct customer and indirect societal costs due to generation outages. The customer survey approach is widely used in estimating the direct customer interruption cost of outages. The 1994 study used $9 per kWh as direct customer interruption cost and $90 per kWh as the societal cost in calculating the optimal reserve level for the MAPP-US thermal portion of the system. The interruption cost figures were based on several published documents from different US, Canada and European utilities. This study investigated available published data at this time on value of service reliability including the ones listed in the 1994 RCO study and decided to use $10 per kWh as the direct interruption cost and $100 per kWh as the societal cost. A $20 per kWh direct interruption cost was also used in the study based on a recent customer interruption cost survey study conducted by a Midwest utility. The calculated results indicate that with an assumed outage costs of 100 $/kWh, installed reserves of between 9.5% and 10% could be economically justified. Similar to the case 1994 RCO study, it is important to point out that the reliability cost/reliability worth methodology was included in this study as a demonstration only, and should not be considered to provide a new guideline or criterion for determining the reserve capacity obligation.

1. Introduction

The objective of this study was to determine the Reserve Capacity Obligation (RCO) for the MAPP-US thermal system for the years 2003, 2006, 2009, and 2012. Similar studies had been done in 1991 and 1994, and one of the purposes of this study was to determine whether or not the recommendations from the previous studies were still valid.

The MAPP system was modeled to determine the level of installed reserves required to maintain the interconnected system at the widely accepted reliability criterion of 0.1 day per year loss-of-load expectation (LOLE). The impacts on the required reserves of several key study assumptions were determined through a number of sensitivity cases.

The Base Case for this study was defined as the thermal-dominated portion of MAPP-US, without the WAPA or Manitoba Hydro load and generation. The impact of extreme hot and normal hot summer loading conditions on RCO levels was investigated using 1995 extreme hot summer and 1999 normal hot summer loading conditions.

A second set of reserve margin requirements was computed for the Base Case using a cost-benefit analysis in which the costs of providing higher levels of reserves were compared with the outage costs that could be avoided as a result of higher installed reserves. This analysis, which looked at three assumed levels of customer outage costs, served to indicate the extent to which the assumed reliability level of 0.1 day per year LOLE was justified on an economic basis. This type of reliability cost/reliability worth analysis is performed for illustration purposes only.

2. Methodology

Multi-Area Reliability Simulation Program (MARS)

The generation system reliability for MAPP was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the specified or economic level of system reliability. The primary tool used for this study was GEII's Multi-Area Reliability Simulation program (MARS). MARS was used to calculate the MAPP system reliability in terms of daily loss-of-load expectation (LOLE) and expected unserved energy (EUE, also termed loss-of-energy expectation, LOEE) at various levels of installed reserves.

MARS uses a sequential Monte Carlo simulation to calculate the reliability of a generation system that is made up of a number of interconnected areas. The areas are defined based on the limiting interfaces within the transmission system. Generating units and an hourly load profile are assigned to each area. MARS performs a chronological hourly simulation of the system, comparing the hourly load in each area to the total available generation in the area, which has been adjusted for planned maintenance and randomly occurring forced outages.

If an area's available generation is less than its load, the program will attempt to deliver assistance from areas that have a surplus that hour, subject to the transfer limits between the areas. If the assistance is not available or it cannot be delivered to the deficient area, the area will be considered to be in a loss-of-load state for that hour, and the statistics required to compute the reliability indices will be collected. This process is repeated for all of the hours in the year. The year is then simulated with different random forced outages on the generating units and transmission interfaces until the simulation has converged. For this study, each study year was simulated 2,000 times.

The reliability calculations in MARS are done at the area level – the generating units are assigned to areas, the hourly load profiles are defined by area, and the interface transfer limits are modeled between areas. The pool indices in MARS are computed from the area results: if one or more of the areas in a given pool are deficient in an hour, then the pool is considered as being deficient. In this study, MAPP-US was modeled as four interconnected areas, so if at least one of the MAPP-US areas were deficient in an hour, then the MAPP-US pool was counted as being deficient.

A detailed description of the MARS program can be found in Appendix A.

Installed Reserves

Various levels of installed reserves on the system can be modeled by adjusting either the installed capacity or the loads. The approach used in this study is the same as was used in the 1994 and 1991 studies in which the capacity was held constant and the annual peak load was varied to give different levels of reserves. (Page 58 of *Review of Reserve Capacity Obligation, May 1994* says "In the 1991 Study, various reserve margins were represented by scaling the hourly load on an annual basis so that the generating capability in the case equaled the scaled load plus the desired reserve margin. Appendix B of the

1991 Study report provides the formula for this scaling." Appendix B from the 1991 Study report is included as Appendix J in this study report.) The same percentage adjustment was made to the peak loads of each of the study areas, and this same percentage adjustment was applied to the loads for all of the hours in the year.

MARS was used to calculate the reliability of the MAPP system at various levels of installed reserves for the years 2003, 2006, 2009, and 2012. Linear interpolation was then used to determine the reserve margins that would result in a daily LOLE of 0.1 day per year.

Separate Thermal and Hydro Systems

Since this study focused on the RCO of the predominantly thermal areas in MAPP, the MAPP system data was modified to remove the hydro-dominated Manitoba Hydro and WAPA systems. For this study, the Base Case was defined as the MAPP-US system without the WAPA load and generation, consistent with the previous studies. However, unlike previous studies that modeled all of the load and generation in MAPP-US as being connected to a single bus, this study modeled MAPP-US as four interconnected areas with limits on the transfers between the areas.

There were two possible ways to remove Manitoba Hydro from the system when creating the Base Case system. The first was to isolate Manitoba Hydro by simply removing the ties between MAPP-US and Manitoba Hydro (please see Figure 3-1). The second approach was to leave the ties in place but to remove all of the Manitoba Hydro load and generation. This approach would result in slightly lower reserves due to the presence of the additional transfer path through Manitoba between the study areas named ND and MN that could be used to deliver assistance to areas that were deficient. For consistency with previous studies, the first approach was taken.

The remaining U.S. portion of MAPP was then modified to remove the WAPA load and generation. The MAPP-US hourly loads that were used to create the hourly load profiles for the four MAPP-US areas were adjusted by the amount of load belonging to WAPA. The annual peak load projections for the four areas were adjusted by the WAPA peak load located in each of the area. The WAPA peak load was assumed to grow at the same rate as the MAPP-US peak. Technically speaking, WAPA's loads (i.e., allocations) are fixed and do not grow. WAPA is not a "total provider." However, each of WAPA's customers retains a co-supplier that, almost without exception, is located within the MAPP region. As these loads grow, WAPA's commitment to each specific load decreases and the co-supplier increases proportionally. Assigning growth to WAPA load is effectively correct for the purposes of this study. The WAPA contribution has merely decreased slightly while the co-supplier's has increased slightly. The error induced by this approach is a potential slight skew of the overall proportion of hydro-served to thermal-served loads within MAPP.

Transactions with Outside Systems

When calculating reserve margins, transactions with outside systems can be viewed as either load or generation. A capacity purchase into the MAPP region was modeled as a decrease in the receiving area's load, and a capacity sale out of the MAPP region was modeled as an increase in the selling area's load. Modeling in this manner assumes a 100% availability of purchases. While not exactly the same as called for when actually determining a system's RCO, this method is reasonably close, and allowed the study to progress in a timely way when faced with data sources that were indeterminate as to firm or participation contracts.

Consequently, the reserve margin (in per unit) was computed as:

Reserve margin = [Capacity – (Load – Purchases + Sales)] / (Load – Purchases + Sales)

Economic Analysis

A cost-benefit analysis was also done to determine the economic level of reserves based on the costs of providing higher levels of reserves compared with the outage costs that could be avoided as a result of higher installed reserves. The reserve levels were computed for a range of assumed outage costs of 10, 20, and 100 $/kWh with either gas turbines or combined cycle units providing the additional reserves.

The cost of providing installed reserves is computed from the economic carrying charge of the capacity providing the reserves. The economic carrying charge represents all of the costs associated with a new unit, including the depreciation of and return on the initial investment, and property taxes and fixed operating and maintenance costs over the life of the unit. The economic carrying charge varies through time with inflation, but has the same net present value as the levelized stream of costs. The calculation of the economic carrying charge for a gas turbine unit installed in 2003 is shown in Table G-1. The data assumptions for the economic calculations are summarized in Table 3-7.

In Table G-1, the Annual Levelized Cost of 41.41 $/kW/year equals the 2003 plant cost of 321 $/kW multiplied by the levelized fixed charge rate of 12.9%. The cost for a simple cycle CT seem low compared to some utility's recent experience. Since the reliability cost/reliability worth analysis is performed for demonstration purposes only, this low cost figure does not impact the over all conclusions of the study. The net present value to the beginning of 2003 of the levelized cost for 30 years is 416.53 $/kW/year. The economic carrying charge of the plant cost is the $/kW/year value in 2003 which, when inflated through time, results in the same net present value as that of the levelized fixed charge rate. For the gas turbine installation in 2003, the economic carrying charge is 33.74 $/kW/year.

Table G-1 also shows the similar calculations for the economic carrying charge of the property tax (PT) and fixed O&M (FOM) of the gas turbine addition in 2003. Table 2-1 summarizes the economic carrying charges for gas turbine and combined cycle unit additions in the four study years. These values were then used to compute the annual costs of providing a given level of reserves. These costs were compared with the outage costs calculated from the expected unserved energy for MAPP computed by MARS for different levels of assumed reserves. The economic reserve margin is the reserve level at which the incremental cost of providing additional reserves equals the incremental savings in outage costs as a results of increased reserves. Alternatively, it would be the point at which the total of the reserve costs and outages costs is at its minimum.

Table 2-1. Economic Carrying Charges ($/kW/year)

		2003	2006	2009	2012
Gas Turbine	ECC – Plant	33.74	35.75	37.92	40.11
	ECC-PT + FOM	15.07	16.00	17.04	18.06
	Total	**48.81**	**51.75**	**54.96**	**58.17**
Combined Cycle	ECC – Plant	56.23	59.59	63.27	66.81
	ECC-PT + FOM	27.26	28.96	30.81	32.68
	Total	**83.49**	**88.55**	**94.08**	**99.49**

3. Data Assumptions

A MARS base case for this study was developed from data primarily provided by MAPP. Generic data and other assumptions were used in cases where data was not available. This section describes the data required by MARS, the source of the data used in this study, and any assumptions that were made relative to the data.

TRANSMISSION

System Representation

In MARS, the generation system can be modeled as a number of interconnected areas. The program assumes that there are no transmission limits within an area; consequently, any generating units assigned to an area can serve any load associated with that area. MARS does model transfer limits between the areas, and so the areas are typically defined by the limiting interfaces that may exist throughout the transmission system.

For this study, MAPP was modeled as five interconnected areas, four to represent the portion of MAPP in the United States (North Dakota, Minnesota, Western Nebraska / South Dakota, and Eastern Nebraska / Iowa), and a single area for Manitoba Hydro. Figure 3-1 shows the interfaces between the areas and the transfer limits (in MW) that were modeled in each direction between the pairs of interconnected areas. Appendix B contains a map showing the definition of the areas that were modeled in MARS.

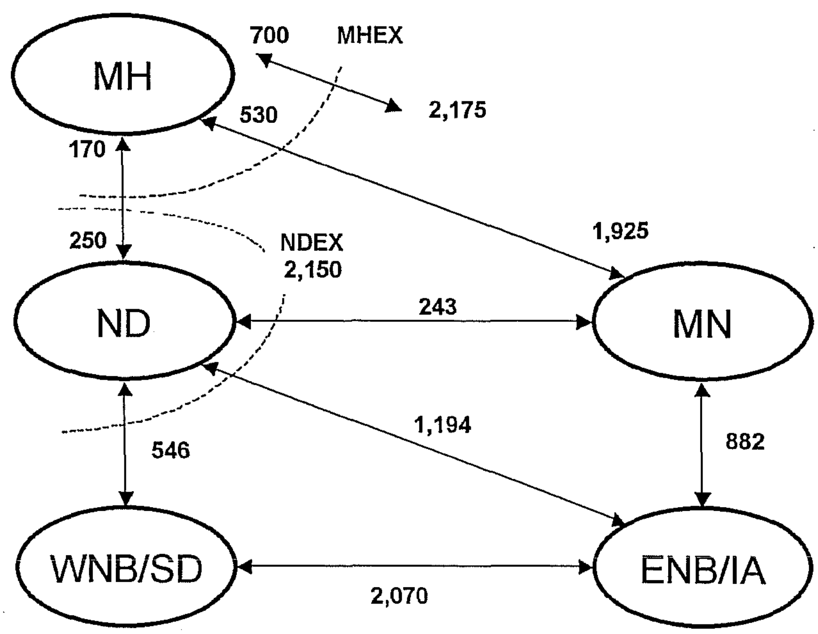

Figure 3-1. Assumed Transmission System Transfer Limits (MW)

In addition to modeling limits on individual interfaces between areas, MARS can also limit the simultaneous flow on groups of interfaces. As shown on Figure 3-1, two simultaneous limits were modeled: the net transfers with Manitoba Hydro (limited to 2,175 MW out, 700 MW in), and the net exports from North Dakota (2,150 MW out).

For this study, the Base Case was defined as the thermal portion of MAPP-US. To accomplish this, the transfer limits on the interfaces between Manitoba Hydro and MAPP-US were set to 0 MW.

DC Ties

The interface limits used in the model were developed from the AC portion of the transmission system and did not include the effects of the DC ties within MAPP. Since the flow on a DC tie would not affect the interface flows in MARS, the generating units at the sending end of a DC tie were assigned to the area at the receiving end of the tie. Since the generation tied to DC is modeled at the receiving end, the DC ties forced outages are not included in the reliability calculations as the DC tie outages are included in the unit forced outages.

Interface Forced Outages

MARS can simulate random forced outages on the interfaces between areas. The forced outage data is specified in terms of the various capacity states in which the interface could operate and state transition rates that describe the number of transitions between states per unit of time in the originating state. The transition rate data is then used by MARS to compute the probability of transitioning to a given capacity state, and the amount of time that the interface will be in that state.

Appendix C contains details on the development of the capacity states and transition rates for the interfaces.

The interface capacity states and outage rates are summarized in Table 3-1.

LOADS

Hourly Profiles

MARS requires a chronological hourly load shape for each area being modeled. This data is often developed from historical hourly load data from a year with weather, economic, and other characteristics similar to the year to be studied. In other words, the hourly shape from a year with "normal" weather conditions would typically be used as a base case load model, while a shape from a year with "extreme" weather conditions may be used for a sensitivity case.

MARS will then adjust the input hourly load profile to generate a load model with the specified forecasted peaks and energies, on a monthly or annual basis.

The historical hourly load profile for MAPP-US for the year 1999 was selected as being representative of a year with normal hot summer weather, and was used in developing the Base Case load model. Using the bus loads in the 2001 Summer Peak power flow case, the company peak loads were allocated to the four MAPP-US study areas for MARS. The sum of the company loads for each area was used to compute the percentage of the total MAPP-US load for that area. This percentage was then used to develop from the

MAPP-US data the hourly load profiles and peak load projections for each MAPP-US area.

Table 3-1. Interface Capacity States and Outage Rates

Interface	Capacity States (MW)		Time in State (p.u.)		EFOR (%)
MANITOBA TO N. DAKOTA (one-way)	250.0		0.9990		0.019
	225.0		0.0005		
	175.0		0.0005		
N. DAKOTA TO MANITOBA (one-way)	170.0		0.9990		0.015
	165.0		0.0005		
	120.0		0.0005		
MANITOBA TO MINNESOTA (one-way)	1,925.0		0.9712		1.281
	1,465.0		0.0192		
	270.0		0.0096		
MINNESOTA TO MANITOBA (one-way)	530.0		0.9712		1.223
	375.0		0.0192		
	160.0		0.0096		
N. DAKOTA TO MINNESOTA	242.9		0.9929		0.246
	160.9		0.0052		
	153.1		0.0019		
N. DAKOTA TO ENB/IOWA	1,194.3		0.9932		0.192
	1,115.9		0.0001		
	987.3		0.0000		
	956.2		0.0006		
	842.9		0.0061		
N. DAKOTA TO WEST NEB SD	546.3		0.9819		0.502
	492.6		0.0021		
	476.3		0.0084		
	277.3		0.0076		
MINNESOTA TO ENB/IOWA	881.8		0.0023		10.675
	789.4		0.9900		
	744.0		0.0021		
	664.4		0.0027		
	280.7		0.0029		
WEST NEB SD TO ENB/IOWA	2,070.4		0.9871		0.139
	2,011.3		0.0000		
	1,942.6		0.0048		
	1,788.3		0.0080		
	0.0		0.0000		

The 1999 hourly load shape and peak load projections for Manitoba Hydro were separately specified. In addition, load data for the MAPP-US areas with the WAPA loads removed were also provided. These are summarized in Tables 3-2 and 3-3. Because the Base Case was defined as the MAPP-US system without WAPA, the loads excluding the WAPA were used in this study.

Table 3-2. Peak Load Projections, including WAPA (MW)

	2003	2006	2009	2012
ENB/IA	13,398	14,179	15,043	15,907
MN	10,111	10,700	11,352	12,004
ND	2,925	3,096	3,284	3,473
WNB/SD	1,947	2,061	2,187	2,312
MAPP-US	28,382	30,035	31,866	33,697

Table 3-3. Peak Load Projections, excluding WAPA (MW)

	2003	2006	2009	2012
ENB/IA	12,704	13,444	14,264	15,083
MN	10,088	10,675	11,362	11,977
ND	2,581	2,731	2,898	3,064
WNB/SD	1,787	1,891	2,006	2,121
MAPP-US	27,159	28,741	30,493	32,245

Hourly load profiles from 1995 historical data were used in the sensitivity case that looked at the impact of extreme hot summer weather. While the load shape was different, the projected peaks were the same as those shown above for the Base Case, excluding WAPA.

Load Diversity

As described above, the hourly load profiles for the four MAPP-US areas were developed from the actual hourly load data for 1999 for the MAPP-US region. As such, there was some level of diversity built into the hourly shapes. However, since all of the areas used the same hourly shape, which was adjusted by the program to produce the forecasted annual peak for each area, there was not as much diversity modeled as would be if the area loads had been developed from bus-level load data.

GENERATION

MARS can model several different types of generating units. For this study, all of the generation was modeled as either thermal or hydro units. Most of the generating units were modeled as thermal units, for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. The hydro category was used to model those units for which the output may be constrained due to energy limits. This is typically used to model hydro units with a limited amount of storage capacity. MARS does not explicitly model forced outages on hydro units.

Each unit was specified in terms of its installation and retirement dates, the area in which it was located, maximum rating, and planned maintenance requirements. In addition, the forced outages on the thermal units were specified in terms of capacity states that represent the various possible partial outage states, and the state transition rates between capacity states. Additional data for the hydro units included the minimum rating (which represented the run-of-river portion of the unit) and the available energy on a monthly basis. Appendix A contains more details on the modeling of generation in MARS.

Several sources were used in developing the data for the generation. The initial list of generating units for MAPP-US was taken from the MAPP EIA-411 for 1999. Units installed from 1999 through 2002 were then separately added. For shared generation units, only the portion of shared generation units that are accredited to MAPP members based on the MAPP EIA-411 were included in the study. Each unit was then assigned to one of the four MAPP-US study areas. The listing of units for Manitoba Hydro was taken from the 2001 NERC ES&D database.

Thermal generating units of less than 10 MW and hydro units of less than 5 MW were equivalenced, by area, into units of approximately 50 MW. Summer and winter unit rating were also modeled. The total installed capacity by area and unit type and for MAPP-US, excluding the WAPA generation, is shown in Table 3-4. Data for the individual units modeled in the study can be found in Appendix E.

Table 3-4. Installed Capacity – Summer 2003 (MW)

TYPE	ENB/IA	MN	ND	WNB/SD	MAPP-US
Nuclear	1,703	1,646			3,349
Steam	6,718	7,199	3,286	2,049	19,253
G.T.	3,361	1,360	117	51	4,889
I.C.	586	199	52	79	915
Jet	48				48
Wind	21				21
Hydro	62	409	4	119	594
Total Capacity	**12,499**	**10,813**	**3,459**	**2,298**	**29,068**

Hydro Data

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit, which represents the run-of-river portion of the unit, is dispatched across all of the hours of the month. The remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system.

The minimum capacity for each hydro unit was assumed to be 30% of the unit's maximum. This value was based on an analysis of data from FERC Form 12, Schedule 2 for the MAPP region.

For most of the hydro units, the monthly available energy used for the study was based on a five-year average of the monthly generation by unit from 1995 through 1999. The averaging process ignored those months in which the unit output was 0 MWh due to outages. For those units for which historical data was not available, a 50% capacity factor was assumed, based on an analysis of FERC Form 12, Schedule 2 data.

Outage Data

MARS models both planned and forced outages on the generating units. The planned outages are scheduled by the program on a weekly basis so as to levelize the available reserves over the entire year. The forced outages are specified in terms of state transition rates and are modeled during the Monte Carlo simulation as events that remove units from service at random times throughout the year.

NERC GADS (Generator Availability Data System) performance data for the MAPP units for 1995 through 1999, which lists the type of each outage and its duration, was analyzed to derive both the planned and forced outage rate data for most of the units in the study. Because of the postponable nature of the maintenance outages, the working group decided to include the maintenance outages with the planned outages rather than with the forced outages

The working group heavily reviewed the transition rates that had been derived from the NERC GADS performance data for the years 1995 through 1999. There were approximately 20 to 40 units for which the working group decided to adjust the transition rates in order to arrive at more realistic average performance expectations. Details of these adjustments are intentionally omitted from this report on the basis of proprietary concerns.

For those units on which historical data were not available for deriving outage rates, generic default values were used. These are summarized in Table 3-5. The default values for the planned outage rates were based on the Scheduled Outage Factor for all sizes within the unit type from the 1995 – 1999 GADS data. The default value for the gas turbine forced outage rate was based on the EFORd for gas turbines 50 MW and larger from the 1995 – 1999 GADS data.

Table 3-5 Default Values for Planned and Forced Outage Rates

	Default Values		Weighted-Average
Unit Type	**P.O.R. (%)**	**F.O.R. (%)**	**F.O.R. (%)**
GT	6.3	6.9	4.7
IC	1.1	-	3.9
Steam	9.7	10.0	5.7
Hydro	6.3	-	-
Nuclear	-	-	5.0

The default forced outage rate for steam units was developed from a review of preliminary forced outage rate data of the MAPP steam units for which data was initially available. Much of the forced outage rate data for the steam units was subsequently reviewed and updated, and the default value of 10% was used for only about 4% of the installed steam capacity in the study.

Table 3-5 also shows the MW-weighted average value of the forced outage rates for all of the generating units that were modeled in the study. A comparison with the forced outage rates assumed for the 1994 study (Table 17, page 72, of *Review of Reserve Capacity Obligation, May 1994*) shows a significant decrease in forced outage rates since the previous study.

TRANSACTIONS

Capacity transactions between MAPP-US members were not modeled explicitly as they would have no net effect on the installed reserve requirements.

A capacity purchase into the MAPP region was modeled as a decrease in the receiving area's load, and a capacity sale out of the MAPP region was modeled as an increase in the selling area's load. Modeling in this manner assumes a 100% availability of purchases. While not exactly the same as called for when actually determining a system's RCO, this method is reasonably close, and allowed the study to progress in a timely way when faced with data sources that were indeterminate as to firm or participation contracts.

Table 3-6 summarizes the capacity transactions with outside systems that were modeled. The MW value of several of the transactions varied from month to month; the values shown are those for July. Data was available only through 2009; any transactions in place in 2009 were also assumed for 2012.

Table 3-6. Transactions Modeled with Outside Systems

	From	To	Study Area	Study Years	MW
Purchases					
	SPC	BEPC	ND	03	50
	WAPA-RMR	MEAN	NB	03, 06, 09	16
	Cordova	MEC	ENB/IA	03	251
	Basin-West	XCEL	ND	03, 06	50
	WPPI-MAIN	WPPI	MN	03	55
Sales					
	BEPC	PPLM	ND	03, 06, 09, 12	98
	MP	WPL	MN	03, 06	75
	NPPD	SJLP	ENB/IA	03, 06, 09, 12	90
	OPPD	WPS	ENB/IA	03, 06	5
	WAPA	ALTA	ND	03, 06, 09, 12	12
	WPPI	WPPI-MAIN	MN	03	104
	XCEL	NWEC	MN	03	14

Aside from the firm transactions described above, no other outside assistance was modeled in this study. Historically, the MAPP region has not received emergency assistance from outside systems. Furthermore, there are no formal agreements with adjoining reliability regions or adjacent non-MAPP utilities to provide any outside assistance.

ECONOMIC ASSUMPTIONS

In addition to the reserves required to maintain a specified level of generation system reliability, a second set of reserve margin requirements was computed for the Base Case using a cost-benefit analysis in which the costs of providing higher levels of reserves were compared with the outage costs that could be avoided as a result of higher installed reserves. This analysis, which looked at three assumed levels of customer outage costs, served to indicate the extent to which the assumed reliability level of 0.1 day per year LOLE was justified on an economic basis.

Table 3-7 summarizes the economic assumptions used in the calculation of the economic reserve margins. This study assumed the same after-tax discount rate, levelized fixed charge rate, and property tax rate for a typical MAPP member as were used in the 1994 study. The assumed values for the plant cost and fixed O&M cost of a new gas turbine or combined cycle were nominal representative values for General Electric equipment.

Table 3-7. Economic Assumptions (2000 $)

After-tax discount rate	9.24 %
Levelized fixed charge rate	12.9 %
Property tax rate	3.31 %
Gas Turbine	300 $/kW plant cost 6 $/kW/yr fixed O&M
Combined Cycle	500 $/kW plant cost 12 $/kW/yr fixed O&M

One of the key factors in determining the optimum level of installed reserves using value-based planning is an estimate of the direct customer and indirect societal costs associated with generation outages. Customer surveys are one source of information on the direct costs of outages. Another indication of the direct customer outage costs are the rates negotiated with interruptible customers. If a customer is willing to experience an outage in return for certain rate incentives, the outage costs must be somewhat less than the interruptible rate incentive.

This study did not attempt to independently develop customer outage costs, but instead relied on the information that was used for the 1994 study (page 26 of *Review of the Reserve Capacity Obligation, May 1994*). The 1994 study assumed customer outage costs of 6 $/kWh in 1990 dollars. Limited data was available on the societal costs of a widespread outage, but the limited data indicated that it could be as high as ten times the customer outage costs. Based on the information from the 1994 study, outage costs of 10, 20, and 100 $/kWh were assumed for this study.

4. Results

The reserve requirements for the Base Case and sensitivity cases studied are summarized in Table 4-1. The details of the LOLE at the various reserve margins modeled are shown in Appendix F.

Table 4-1. Summary of Required Installed Reserve Margins

Case / Year	2003	2006	2009	2012
Base Case (normal hot summer)	10.10	10.19	9.98	10.18
Load Forecast Uncertainty	12.75	12.77	12.71	12.71
1995 Shape (extremely hot summer)	16.44	10.30	10.21	10.27
No Internal Transfer Limits	9.96	9.93	9.93	10.08
Increased Forced Outage Rates	12.45	-	-	-

Base Case MAPP-US system modeled as four interconnected areas, without Manitoba Hydro or WAPA load or generation. Ties with transfer limits between the four MAPP-US areas, but ties between MAPP-US and Manitoba Hydro removed. Uses 1999 hourly load shape.

Load Forecast Uncertainty Base Case with seven-point load forecast uncertainty distribution of 0, ±3%, ±6%, and ±9% variation in projected loads.

1995 Shape Base Case using 1995 hourly load shape.

No Internal Transfer Limits Base Case with no transfer limits between the MAPP-US areas.

Increased Forced Outage Rates Base Case with all unit FOR increased by 25%.

Base Case

To be consistent with previous studies on reserve capacity obligations, the Base Case for this study was defined as the thermal-dominated portion of MAPP-US, without the WAPA or Manitoba Hydro load and generation. However, unlike previous studies which modeled all of the load and generation in MAPP-US as being connected to a single bus, this study modeled MAPP-US as four interconnected areas with limits on the transfers between the study areas.

The results for the Base Case indicate that the MAPP-US portion of the system, without Manitoba Hydro or WAPA, requires installed reserves of approximately 10% in order to maintain a system daily LOLE of 0.1 day per year. The results vary slightly for year to year as a result of the changing amount of firm transactions being modeled with the outside system. The reduction in the required installed reserves as compared to the base case results from the 1994 study (approximately 12%) is most likely due to the improvement in the assumed forced outage rates (see Table 3-5).

Load Forecast Uncertainty

The Base Case assumed that the peak load forecast through time was known with a high level of certainty. An actual peak load that differs from the forecasted peak can result in significant changes in system reliability. The impact of uncertainty on installed reserve requirements in the load forecast was determined by calculating the LOLE for a range of possible peak projections.

The assumed normal distribution in the peak load forecast is shown in Table 4-2.

Table 4-2. Load Forecast Uncertainty Assumptions

Variation in Forecast Peak Load (%)	Probability of Occurrence (%)
-9	0.62
-6	6.06
-3	24.17
0	38.30
+3	24.17
+6	6.06
+9	0.62

Reliability calculations were done at each of the seven levels of projected peak load. For example, the calculations were done as though all of the hourly loads were 9% less than the forecasted value. They were repeated with all of the hourly loads being 6% less than the forecasted values, and so on. From the reliability indices calculated for the seven assumed load levels, a weighted average value was computed using the specified probabilities of occurrence. This weighted-average value was then used to determine the reserves required to maintain an LOLE of 0.1 day per year.

Uncertainty in the load forecast results in reserve requirements over the study period of approximately 12.75%, an increase of more than 2.5% over the Base Case.

Extremely Hot Summer (1995) Hourly Load Shape

The historical hourly load profile for MAPP-US for the year 1999 was selected as representative of a year with normal hot summer weather and was used in developing the load shape used in this study. The impact on reserve requirements of extreme hot summer weather was measured through a set of simulations based on the 1995 hourly load shape.

MARS automatically schedules the planned maintenance of the generating units. For this study, the maintenance was scheduled for each of the study years on an area basis. The maintenance was scheduled against the weekly peak loads so as to levelize the available reserves (available reserves = installed capacity – capacity on schedule maintenance – peak load). Changes in the hourly load shape, such as using the 1995 shape, could result in a different maintenance schedule. However, for this scenario, we used the maintenance schedules that were developed for the study years from the 1999 shape, assuming that the actual maintenance schedule would be developed based on assumed normal weather conditions. With the appearance of extreme hot weather as in the 1995 load shape, there may be some flexibility for rescheduling maintenance, depending on how far in advance the extreme weather was predicted, but for the most part, the original maintenance schedule would remain.

MARS scheduled little, if any, maintenance during the summer months (July and August) when most of the days of forced outages are most likely to occur, and so the maintenance schedule should not be an issue. From Table 4-1, we can see that this is true for 2006, 2009, and 2012 with the reserve requirements being only slightly higher than in the Base Case.

For 2003, however, a significant number of days of outage occurred in the third week of June when using the 1995 hourly load shape, leading to reserve requirements of 16.44%. With the 1995 load shape, the MAPP-US peak for this week was more than 7,000 MW higher than with the 1999 shape, which resulted in the increased risk. The weekly peak in the 1995 shape was in line with the peaks in the adjoining weeks, and it was the sizable dip in the weekly peak in the 1999 shape that resulted in nearly 3,000 MW being scheduled on maintenance during that week. A slight shifting of the maintenance schedule would bring the 2003 results in line with those of the other study years.

With the slight shifting of hourly loads that was required in order to align the day of the week of the input hourly loads with the day of the week of the first day of the year for the other study years, the maintenance schedules for the other study years were such that this was not a problem.

No Internal Transfer Limits

Unlike the previous studies which modeled all of the load and generation in MAPP-US as being connected to a single bus, the Base Case for this study modeled MAPP-US as four interconnected areas and assumed limits on the amount of assistance that could flow between the areas, as shown in the system diagram in Figure 3-1. This scenario looked at the effects of these transfer limits on the reserve requirements.

As shown in Table 4-1, removing the transfer limits within MAPP-US reduced the reserve requirements only slightly (about 0.25% in the most extreme case), indicating that with the current distribution of generation and load throughout MAPP-US, the internal transfer limits are not a significant constraint.

Increased Forced Outage Rates

One of the key assumptions in determining the reserve requirements is the forced outage rate data for the generating units. The source of the forced outage rate data assumed in the Base Case is described in Section 3 – Data Assumptions. For this scenario, we assumed that the forced outage rates on all of the generating units were increased by 25%.

The forced outage data is input to MARS in the form of state transitions rates. The development of state transition rates requires information on the number of times that each unit transitions from each of its available capacity states to each other of its capacity states. Consequently, adjusting state transition rates to model an increase in the forced outage rate of a unit requires assumptions regarding how the increase is to be distributed among the possible outage states; there are many ways in which the transition rates can be adjusted that result in the same forced outage rate.

To allow for a consistent comparison between the Base Case and the case with increased forced outage rates, the Base Case for 2003 was rerun using the forced outage rates calculated from the original state transition rates and an assumed number of transitions between states. The assumption regarding the number of transitions between states is most important when calculating frequency and duration indices, and has a lesser effect on the daily and hourly LOLE and unserved energy.

For the sensitivity case, the forced outage rates were increased by 25% and MARS was then allowed to compute the revised transition rates used for the reliability calculations.

For the 2003 case using forced outage rates as input rather than the original state transition rates, the reserve requirements were 9.91%, a slight change from the original 10.10%. Increasing the input forced outage rates increased the reserve requirements to 12.45%, an increase of slightly more than 2.5%. Adjustments to the assumed number of transitions used to compute the transition rates from the forced outage rates could bring the 2003 Base Case reserves closer to the original 10.10%, but the amount of change (approximate 2.5%) would not be expected to vary.

Capacity Additions Versus Load Adjustments

For this study, variations in installed reserves were modeled by adjusting the peak loads. This is the same approach that was used in previous studies. This is equivalent to adding perfect capacity with no outages. Since the only planned outages being scheduled during the summer peak period were in Manitoba Hydro, the reserves in MAPP-US would not have to be adjusted for planned outages on units added to maintain reserves. However, additional capacity may be needed to account for the forced outages on these units. If the new units have a forced outage rate of 7% and the new units were to make up 20% of the system by 2012, the adjustment would be an increase in the installed reserves of roughly 1.5%.

Economic Reserves

The economic reserves for the Base Case were calculated assuming outage costs of 10, 20, and 100 $/kWh. The details of the calculations are shown in Appendix H – Economic

Reserve Calculations. Because the lowest level of reserves simulated for the reliability portion of the analysis was 9.5%, economic reserve levels below 10% could not be determined.

For both gas turbine and combined cycle additions, the economic reserve margin was less than 10%, although in 2003 with outage costs of 100 $/kWh, the economic reserves appear as though they would fall between 9.5% and 10% with the addition of gas turbines. With reserve margins of approximately 10% required to maintain a reliability of 0.1 day per year, the results of this study showing economic reserve margins of less than 10% are consistent with the 1994 study in which the economic reserves were a couple of percentage points below the reserves required for reliability.

5. Conclusions

The results of this study indicate the need for installed reserves in the range of 9.96% (no internal transmission limitations) to 12.45% (25% increase in forced outage rates) up to 12.75% (Load Forecast Uncertainty) in the MAPP-US thermal portion of the system in order to maintain a reliability level of 0.1 day per year LOLE. The calculated results suggest that a reserve level of 10% to 13% may be justifiable for the MAPP-US thermal system considering load forecast uncertainty, and forced outage rate increases for generating units. The modeling circumstances surrounding the 2003 Extreme Hot Summer (1995 Load Shape) led to an anomalous, high reserve requirement for that case. This result is not considered indicative of the MAPP-US system.

The transmission transfer limits developed between the five study regions are based on Total Transfer Capability (TTC) values for the significant transmission elements connected between these regions. At issue is what is truly available for transfer capability between these study areas while maintaining a secured state for the MAPP Region. Careful review of the criteria used (i.e. which state case truly represents secure operating conditions for determination of the transfer limits between the study regions, TRM component effects on transfer capability) must be performed to validate the limits set and subsequent impacts on RCO for each of the study areas.

The lower level of calculated reserve levels in this study are largely due to the decreased forced outage rates for generating units utilized. The forced outage rates were derived from historical performance of the individual MAPP units.

The two input assumptions with the largest impact on the installed reserve requirements for the thermal-dominated MAPP-US system were uncertainty in the peak load forecast and variations in the forced outage rates. Each of these factors, when evaluated separately, increased the reserves required to maintain a LOLE of 0.1 day per year by approximately 2.5%. The presence of internal transfer limits within the system was less significant, contributing only about 0.25% to the installed reserve requirements. The interface unavailability data used in the study were based on historical performances of these transmission lines. The transfer limitations on the interfaces were based on thermal- and stability-limited simulation runs of the MAPP integrated system. The calculated results indicate that the impact of transfer limitations between areas on the reserve level is insignificant.

A second set of reserve margin requirements was also computed using a cost-benefit analysis to determine the economic level of reserves. The impacts on the required reserves of several key study assumptions were determined through a number of sensitivity cases.

To judge the optimum level of the RCO using the reliability cost/reliability worth planning approach, it is necessary to estimate the direct customer and indirect societal costs due to generation outages. The customer survey approach is widely used in estimating the direct customer interruption cost of outages. The 1994 study used $9 per kWh as direct customer interruption cost and $90 per kWh as the societal cost in calculating the optimal reserve level for the MAPP-US thermal portion of the system. The interruption cost figures were based several published documents from different US, Canada and European utilities. This study investigated available published data at this time on value of service reliability including the ones listed in the 1994 RCO study and decided to use \$10 per kWh as the direct interruption cost and \$100 per kWh as the societal cost. A \$20 per kWh direct interruption cost was also used in the study based on a recent customer interruption cost survey study conducted by a Midwest utility. The calculated results indicate that with an assumed outage costs of 100 \$/kWh, installed reserves of between 9.5% and 10% could be economically justified. Similar to the 1994 RCO study, it is important to point out that the reliability cost/reliability worth methodology provided in the this study as a demonstration only, and should not be considered to provide a new guideline or criterion for determining the reserve capacity obligation.

6. Recommendations

The following are the recommendations from this study for MAPP Participants excluding WAPA and Manitoba Hydro:

1. The technical results of the study suggest that a reserve level of 10% to 13% may be justifiable for the MAPP-US thermal system considering forced outage increases, and load forecast uncertainty. However, because deliverability and integrated hydro with thermal issues were not specifically or adequately addressed, the present 15% thermal RCO is still considered valid and no changes are being recommended.
2. Because deliverability and hydro-dominant issues were not specifically or adequately addressed, the present 10% hydro RCO is still considered valid and no changes are being recommended.
3. The MAPP CSRWG should:
    a. Develop and recommend to the RRC a study method that will fully inform MAPP participants on an optimal RCO level for highly interconnected, hydro-dominant systems such as Western Area Power Administration.
    b. Develop and recommend to the RRC a method for studying all of MAPP as one system, to guide decisions as to whether MAPP should or could have one RCO level, instead of the existing approach that calls for separate thermal- or hydro-dominant RCO levels.
    c. Develop a study method and produce a study scope to examine specifically the intra-regional issues surrounding the deliverability of reserves among participants in the MAPP Generation Reserve-Sharing Pool.
4. In future RCO studies, do not include economic reserve considerations unless MAPP formally adopts a reserve requirement based on economic factors.
5. Further studies should be conducted with internal transfer limits recalculated when characteristics of MAPP system generation and transmission systems change with facility additions. Expand the transmission transfer analysis to address the impacts of actual flows between the various study areas to determine valid transfer limits.
6. Each MAPP participant must provide adequate resources and input data to perform a rigorous study of this nature.
7. Model firm and participation contracts in the same manner as called for in the established MAPP procedure for determination of each member system's RCO.
8. Verify that the effects of extended accreditation are accounted for in the RCO study's generation data.
9. The MAPP RRC should establish and promulgate a regularly recurring cycle for MAPP RCO studies.