Manual No. 011

Business Practices Manual

Resource Adequacy

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This Business Practices Manual (BPM) contains information to augment the filed and accepted Tariff. In all cases the Tariff is the governing document and not the BPMs. Additionally, if not otherwise defined herein, all capitalized terms in this BPM have the meaning as defined in the Tariff.

Time Zone

In 2006, Central Indiana, where MISO offices are located, began observing Daylight Savings Time. However, MISO, its systems, and the Midwest Markets, will continue to do business in Eastern Standard Time year-round.

Revision History

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	FERC order 890		

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1. Introduction

This introduction to the Midwest Independent System Operator (ISO) BPM for Resource Adequacy includes basic information about this BPM and the other MISO BPMs. Section 1.1 of this Introduction provides information about MISO BPMs. Section 1.2 is an introduction to this BPM. Section 1.3 identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM. Bracketed entries [xx.xx] provide references to the MISO Tariff.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is contained in the *List of BPMs and Definitions* BPM. This and other BPMs are available for reference through MISO's website.

1.2 Purpose of this Business Practices Manual

This *Resource Adequacy BPM* describes MISO's and other entities' roles and responsibilities in terms of the reliability issue of Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin.

MISO prepares and maintains the *Resource Adequacy BPM* as it relates to the determination of Resource Adequacy. This BPM conforms and complies with MISO's EMT, NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines, and standards and is designed to facilitate administration of efficient Energy Markets.

This BPM benefits readers who want answers to the following questions:

- How is Resource Adequacy determined?

- How do the multiple state jurisdictions relate with regard to Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities with regard to Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Planning Resource Credit (PRC) and how can it be used to comply with Resource Adequacy Requirements (RAR)?
- What are the consequences if a Planning Resource Credit (PRC) is from a Planning Resource that is determined to be undeliverable to all load within the Region?
- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under Module E of the Tariff?

This BPM provides the necessary detail to aid MISO Market Participant's (MP) understanding of their primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint with respect to the issue of Resource Adequacy.

1.3 References

Other reference information related to this BPM include:

- Other MISO BPMs
- Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004

- Federal Energy Regulatory Commission (FERC) Order Nos. 890 , Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- PowerGADS Users Manual

2. Overview of Resource Adequacy

Achieving reliability in the bulk electric systems requires, among other things, that the amount of resources exceeds customer demand by an adequate margin. The margins necessary to promote Resource Adequacy need to be assessed on both a near-term operational basis and on a longer-term planning basis. The focus of this BPM is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, only resources dedicated to meet Demand (including resources to meet the Planning Reserve Margin Requirement (PRMR)) have an obligation to be available to meet real-time customer demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance;
- Unplanned or forced outages of generating equipment;
- Deratings in the capability of Generation resources and Demand Response Resources;
- System effects due to reasonably anticipated variations in weather; and
- Variations in customer demands or forecast demand uncertainty.

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources and Load Modifying Resources. The relationships and key attributes of the Planning Resource types are as follows.

Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of MISO), and loads that can be dispatched to reduce demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market and are available during emergencies.

Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) (loads that can be interrupted or directly controlled to reduce demand) which are available during emergencies. .

Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate an unforced capacity value (UCAP) for the resource. A Market Participant can use Capacity Resources up to their UCAP values to contribute towards Resource Adequacy to the extent the MP is willing to subject the Capacity Resource to MISO's must offer commitment and meet all other RAR obligations. A MP may convert UCAP amounts that are subject to the must offer commitment to Planning Resource Credits (PRCs). Resource Adequacy at any particular Commercial Pricing Node (CPNode) is achieved for a given month if an LSE has at least as many PRCs as its forecasted peak demand for that month plus its PRM.

MISO conducts Loss of Load Expectation (LOLE) studies each year to make an annual determination what the planning reserve margin needs to be to attain the 1 day in 10 years common industry reliability standard. MISO may determine separate planning reserve margins for different zones if there are system constraints that impede system wide reserve sharing. Also, MISO will defer to state authority in cases where a state establishes its own PRM.

Whether or not Resource Adequacy is achieved at a particular CPNode for a particular month depends upon whether or not there are sufficient PRCs designated for that CPNode to cover forecasted peak demand plus the PRM in a before-the-fact determination. Each LSEs total obligation at each CPNode will be referred to as the Planning Reserve Margin Requirement (PRMR). Forecasted peak demands are submitted by LSE's using a 50%-50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the actual peak demand) using CPNode granularity and including all losses downstream from the generator bus (transmission and distribution).

Forecasts of Demand are subject to after-the-fact assessments using standard deviation bandwidths and normalization factors provided by LSEs to identify potentially improper forecasting.

LSEs who determine that they do not have sufficient Planning Resources of their own to cover their PRMR forecasted peak demands and planning reserve margin may acquire additional PRCs through bilateral transactions with other Market Participants or by bidding on PRCs in MISO's Voluntary Capacity Auction (VCA) which is conducted each month.

In the event that an LSE fails to achieve Resource Adequacy for a particular CPNode for a month (i.e. does not have enough PRCs to cover its PRMR) the LSE will be subject to a deficiency charge. The charge will be paid to MISO who will distribute it among LSE that did achieve Resource Adequacy. Deficiency charges will be based in part upon a rate determined annually by MISO, known as the Cost of New Entry (CONE).

The following sections of this BPM explain the concepts described in this Section 2 overview in greater detail.

3. Reserve Margin Analysis and Determination of PRM [68]

An LSE shall conform to Resource Adequacy Requirements by demonstrating that the LSE has met the procedures and requirements of Module E and this BPM, including the demonstration that sufficient PRC have been designated to meet the PRMR.

3.1 Purpose

This section describes the LOLE study process and the process used by MISO to establish the PRMs for each LSE in its Region for each Planning Year. MISO Planning Years run from June 1 through May 31 of the following year. The initial Planning Year began on June 1, 2009.

3.2 Intended Audience

This section is intended for stakeholders who need to understand the details behind how the LOLE study is performed and PRM set for each Planning Year.

3.3 Overview and Timeline

MISO shall perform a technical analysis on an annual basis to establish the PRMs for each LSE in the MISO Region and will publish the results by November 1st preceding the applicable Planning Year. The annual PRMs are included in Section 3.5 of this BPM This technical analysis shall be consistent with Good Utility Practices and the reliability requirements of the Regional Entities (RE) and applicable states in the MISO Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMRs), forecasting uncertainty, and system operating reserve requirements.

3.4 LOLE Analysis [68.1]

MISO shall coordinate with LSEs to determine the appropriate PRMs for the MISO Region based upon the probabilistic analysis of available Planning Resources being able to reliably meet each LSE's Forecast LSE Requirement for each Month of the Planning Year. This probabilistic analysis shall utilize an LOLE study. LOLE is the sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year. Typically the requirement is set such that the loss of Load is no greater than one (1) day in ten (10) years. MISO will initially determine zones consistent with the planning areas set forth in Attachment FF-3 of the Tariff (the MTEP Planning Zones). The associated LOLE studies may establish the need for different PRMs in such zones, as more fully described in section Appendix A.

3.4.1 LOLE Working Group

MISO has established the LOLE Working Group (LOLEWG) for the purpose of coordinating PRM study work with stakeholders. The duties of the working group are to help guide MISO in implementing the study methods outlined in the following sections. The LOLEWG will work with MISO staff to perform the LOLE analysis that calculates the PRM requirements for each LSE within MISO. This analysis will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable REs for reliability and resource adequacy. The LOLEWG will also review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analysis, as well as reviewing the results of the LOLE analysis and related sensitivity cases. The LOLEWG will use this information as the basis for providing recommendations on PRMs to MISO.

3.4.2 Probabilistic Analysis LOLE Study

The probabilistic study will use the GE MARS software application. Primary inputs are the generation data submitted to MISO through the GADS tool and forecasted Demands provided as described in section 5.4 of this BPM. Aside from the generation outage performance that has statistical parameters, the GE MARS model requires information to model sub-areas or zones in the Energy and Operating Reserves market and also to model transmission capability among such zones. LSEs are obligated to report GADS data for Generation Resources and External Resources through the MISO Market Portal. The specific $XEFOR_d$ outage parameter is developed from this data and together with the capacity of each resource are the key generator inputs to the GE MARS application. The $XEFOR_d$ and $EFOR_d$ metrics are more fully described below. The transmission modeling and zone information for the MARS application is included in section Appendix A.

Although the compliance rating for individual generators will be based on the $XEFOR_d$ metric, the LOLE study also will account for additional system wide outages beyond the outage causes captured in the $XEFOR_d$ metric. The $XEFOR_d$ metric focuses on the manageable performance differences among individual generators. There are also outages, however, that are caused by Force Majeure conditions that are outside of management control and can result in Generation Resources being unavailable, for example, due to weather conditions. The distinction is tracked with two specific forced outage metrics, $EFOR_d$ and $XEFOR_d$. The two terms are defined as:

> Equivalent demand Forced Outage Rate ($EFOR_d$): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
>
> $XEFOR_d$: Same meaning as $EFOR_d$, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example, loss of transmission outlet lines are considered as OMC relative to a unit's operation.

Currently, the MISO study utilizes 27 cause codes in its OMC set of outages The 27 OMC Codes approved by stakeholders for use in the MISO LOLE study are listed in Appendix C of this BPM.

The accommodation of Force Majeure outage causes by using the $EFOR_d$ metric as the input data to the GE MARS application is normal; however, a sensitivity run with the $XEFOR_d$ metric will normally be done to examine the impact of the Force Majeure event. Similarly, the allowance for carrying contingency reserves may be used as an input to the GE MARS application to study the impact of covering contingency reserve or any other component of operating reserves that may be desirable to quantify.

The formula for an LSE's Planning Reserve Margin Requirement obligation is as follows:

$$\mathbf{PRMR_{LSE} = [L_1 \times (1+PRM_{UCAP1})] + [L_2 \times (1+PRM_{UCAP2})] \ldots + [L_{n-1} \times (1+PRM_{UCAPn-1})] + [L_n \times (1+PRM_{UCAPn})]}$$ **Where:**

PRMR can be satisfied by the use of Capacity Resources and/or LMR.

L_1 = LSE's Forecast LSE Requirement in Zone 1 (after subtracting any applicable Demand Resources)

L_2 = LSE's Forecast LSE Requirement in Zone 2 (after subtracting any applicable Demand Resources). . . etc.

PRM_{UCAP1} = PRM_{UCAP} for Zone 1

PRM_{UCAP2} = PRM_{UCAP} for Zone 2 . . . etc.

3.5 Determination of PRM

MISO shall perform a technical analysis on an annual basis to establish the PRMs for each LSE in the MISO Region and will publish the results by November 1st preceding the applicable Planning Year. The PRMs for the initial and subsequent Planning Years are included in this section of the BPM.

Because Capacity Resources are being credited at their UCAP value the reserve requirements must also use a UCAP rating to be equitable. The PRM that is calculated in the LOLE study is determined on an ICAP basis. This ICAP value needs to be adjusted down, based on the system average $XEFOR_d$, to establish the system UCAP value. The PRMR is set to meet Forecast LSE Requirements multiplied by one (1) plus the applicable PRM established either by MISO or by the state having jurisdiction over the applicable LSE.

The equations for calculating system UCAP requirements are as follows:

ICAP Requirement= $\sum_{system}$ Forecast LSE Requirement * (1 + PRM_{ICAP})

UCAP Requirement = ICAP Requirement * (1 – System Average $XEFOR_d$)

Forecast LSE Requirement = the forecasted Demand including the effect of all losses for an LSE at a CPNode for a Month less the Full Responsibility Purchases plus the Full Responsibility Sales and minus the Demand Resources that were registered to net for a given Month all at the same CPNode.

Example:

PRM_{ICAP} = 12.7% (from LOLE study)

System Average $XEFOR_d$ = 6%

$\sum_{system}$ Forecast LSE Requirement = ($\sum_{system}$ Load)
= 100,000 MW

ICAP Requirement= $\sum_{system}$ Forecast LSE Requirement * (1 + PRM_{ICAP}) = 100,000 * 112.7%

= 112,700 MW

UCAP Requirement = ICAP Requirement * (1 – System Average $XEFOR_d$)

= 112,700 * (1 – 0.06) = 105,938 MW

Apply following equations to define UCAP requirement as a percentage:

PRM_{UCAP} = (1 – System Average $XEFOR_d$) (1+PRM_{ICAP}) -1

Example Assuming:

PRM_{ICAP}= 12.7%

System Average $XEFOR_d$ = 6%

Then (1 – System Average $XEFOR_d$) = 0.94

And,

PRM_{UCAP} = 0.94 (1+0.127) – 1

PRM_{UCAP} = 0.05938 = 5.94%

Alternatively, PRM_{UCAP} can be calculated by dividing the UCAP Requirement by the $\sum_{system}$ Forecast LSE Requirement:

PRM_{UCAP} = 105,938 / 100,000 -1

PRM_{UCAP} = 0.05938 = 5.94%

The Planning Reserve Margins for each Planning Year are documented in the table below:

	Non-Coincident Load Based[1] (UCAP)	MISO System wide Forced Outage Rate (XEFORd)	Non-Coincident Load Based (ICAP)	Load Diversity Factor	Coincident Load Based
Planning Year 1 (2009-2010) Total PRM	5.35%	6.51%	12.69%	2.35%	15.40%
Planning Year 2 (2010-2011) Total PRM	4.50%	6.64%	11.94%	3.00%	15.40%
Planning Year 3 (2011-2012) Total PRM	3.81%	7.36%	12.06%	4.55%	17.40%
Planning Year 2012-2013	3.79%	6.77%	11.32%	4.61%	16.7%

[1] Applicable to Forecast LSE Requirement

See MISO's website for current and previous LOLE studies.

3.6 State Authority to set PRM

The only entity other than MISO that may establish a PRM is a state. If a state utility commission establishes a minimum PRM for the LSEs under their jurisdiction, that state-set PRM would be adopted by MISO for affected LSEs in such state. If a state utility commission establishes a PRM that is higher than the MISO established PRM, the affected LSEs must meet the state set PRM. Similarly, if a state utility commission establishes a PRM that is lower than the MISO established PRM, the affected LSEs would only need to meet the state set PRM. Other entities such as reserve sharing groups or NERC Regional Entities do not have the authority to establish a PRM under Module E. MISO will translate any state-set PRM into the same terms as MISO's PRM (e.g., utilizing a UCAP basis) to facilitate comparison and compliance with reserve margin requirements.

4. Qualifying and Quantifying Planning Resources

4.1 Purpose

This section describes qualification requirements and obligation for Generation Resource, Intermittent Generation and Dispatchable Intermittent Resources, Use Limited Resources, External Resources, Demand Response Resources (DRR) Type I and Type II and Load Modifying Resources used in the MISO Resource Adequacy construct.

4.2 Intended Audience

This section is intended for entities that own or have contractual rights to Generation Resource, Intermittent Generation and Dispatchable Intermittent Resources, Use Limited Resources, External Resources, Demand Response Resources Type I and Type II and Load Modifying Resources and need to understand qualification requirements and obligations for participation in the MISO Resource Adequacy construct.

4.3 Overview and Timeline.

All resources that qualify will have a UCAP value determined by MISO.

The benefits of UCAP include:

- fair recognition of the contribution each unit provides towards Resource Adequacy
- market signals that promote generating unit availability performance and in turn the improved System Availability promotes improved regional Resource Adequacy
- supporting bilateral trades by recognizing the PRC value of each resource, while importantly shifting the resource performance risk to owners, where it more properly belongs

Generation Resources and DRR Type I and Type II in the Commercial Model that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have UCAP MWs calculated based on data submitted by the Asset Owner, as described in the Appendix I of this BPM. BTMG, DR, and External Resources must follow the registration procedures documented elsewhere in the BPM to be eligible to supply capacity in the MISO Resource Adequacy construct (mostly in the Appendices E thru G for BTMG including Section 4.4.4.1 for External Resources). Generation Resources and DRR Type I and Type II that do not have historical performance data will have UCAP calculated for them after they are listed in MISO's Commercial Model (which is updated quarterly) provided the Resource meets the Capacity Resource Module E requirements. The following Table outlines the relationship and key attributes of the Planning Resource types.

Module E Planning Resource Breakdown and Attributes

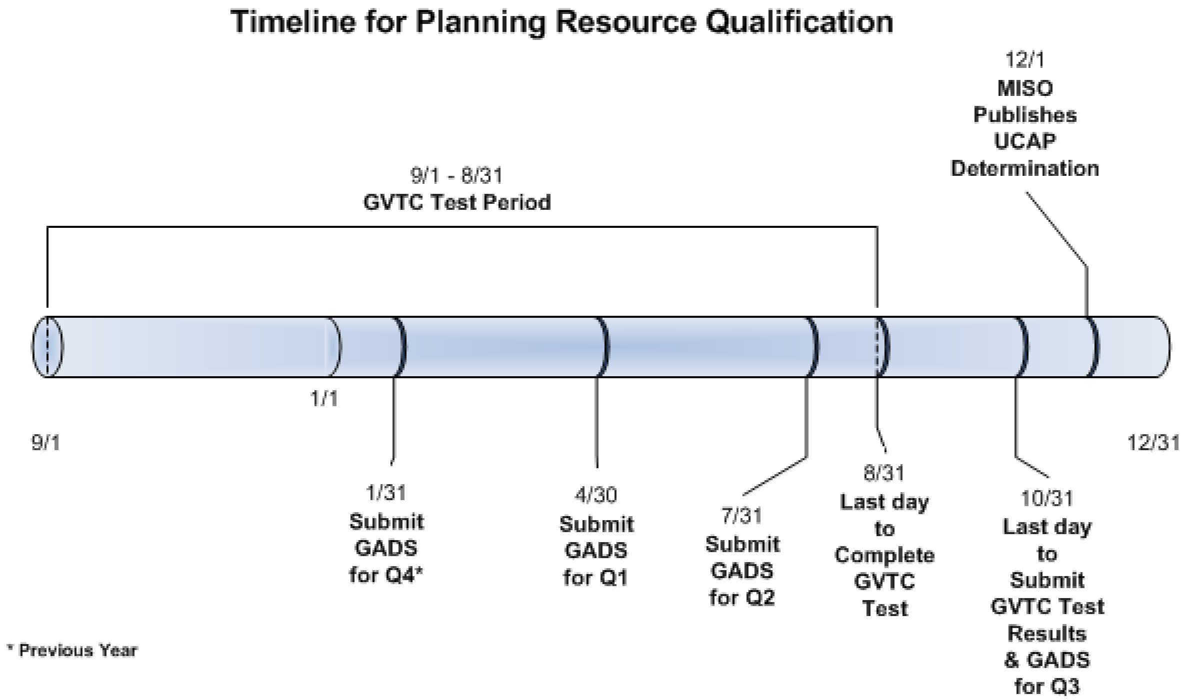
	Planning Resource			
	Capacity Resource		Load Modifying Resource	
	Generation and External	Demand Response Resource	BTM Gen	Demand Resource
Capacity Verification [1]	X	X	X	X
Must Offer [1]	X	X		
GADS Data Entry [2]	X		X	
Must Respond to Emergency Operating Procedures	X	X	X	X

Notes :

1 - Includes Intermittent Capacity with Must Offer requirement met as price taker in the DA Market.

2 - BTMG greater than 10 MW must supply GADS beginning June 2010

The timeline for qualifying Planning Resources on an annual basis is documented below:



4.4 Non-Intermittent Generation

4.4.1 Non-Intermittent Generation - Qualification Requirements

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within the MISO Region. The deliverability of Generation Resources to Network Load within the MISO Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. The Deliverability Test Results are provided on MISO public website at the

following location: Planning > Generator Interconnection > Generation Deliverability workbook . Generation Resources also must register with MISO as documented in the Market Registration BPM.

- Generation Resources greater than or equal to 10 MW based on Generation Verification Tested Capacity (GVTC) must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal. Definition of Generation Resources does not include Intermittent Generation and Dispatchable Intermittent Resources.
- Generation Resources less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information.
- New Generation Resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.
- The XEFORd for new Generation Resources in service less than twelve full calendar months will be the class average for the resource type. A Generation Resource will use the class average value until 12 consecutive months of data is available and a new planning year has occurred.
- Generation Resources are not in an Attachment Y status (retired/mothballed/suspended) and operational when being used as a Planning Resource for any Planning Month.
- Generation Resources must demonstrate capability on an annual basis as described below.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be between September 1st and August 31st prior to the upcoming Planning Year.

- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
- A real power test is required when returning from a "mothballed" state, and then submit the GVTC.
- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, and must be submitted at least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool. See Appendix L of this BPM for links to MISO GVTC rules and processes.

o Reporting

- Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User Manual, which is located on the MISO website under Planning > Resource Adequacy (Module E) > PowerGADS Documentation.

4.4.2 Non-Intermittent Generation – UCAP Determination

The UCAP value for a Generation Resource is based on an evaluation of the type and volume of interconnection service, GVTC value and XEFORD value of such Generation Resource as described in Appendix I.

The UCAP methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit, based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average $XEFOR_d$ of all the pooled resources, the generating units with better than average availability will reflect higher value than units with below average availability.

$EFOR_d$ options for units affected by catastrophic outages and zero service hours are further outlined in Appendix J.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix I-5.

4.4.3 Non-Intermittent Generation– Must Offer

A must offer requirement applies to the Installed Capacity of a Generation Resource, and not to the UCAP rating of the Generation Resource. Installed Capacity refers to the amount of PRCs divided by (1 – $XEFOR_d$) of the Capacity Resource.

An MP that converts a Generation Resource's UCAP MW into PRCs must submit the full operable capacity of the Resource but no less than the ICAP value of what was converted to PRCs for each hour of each day during the Operating Month and make an Offer into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC), except to the extent that the Generation Resource is unavailable due to a full or partial forced or scheduled outage. Outages must be reported in the MISO Outage

Scheduler (CROW). Derates of Generation Resources (excluding DRR Type I and Type II) are to be reported in the MISO Outage Scheduler (CROW).

Compliance with “must offer” requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze the compliance with must offers in both the Day-Ahead and RAC by taking into account information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

4.5 Intermittent Generation and Dispatchable Intermittent Resources

4.5.1 Intermittent Generation and Dispatchable Intermittent Resources– Qualification Requirements

Intermittent Generation and Dispatchable Intermittent Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Intermittent Generation and Dispatchable Intermittent Resources must be deliverable to Load within the MISO Region. The deliverability of Intermittent Generation and Dispatchable Intermittent Resources to Network Load within MISO Region shall be determined by System Impact Studies pursuant to the Tariff as conducted by MISO, which shall consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. The Deliverability Test Results are provided on the MISO public website at the following location: Planning > Generator Interconnection > Generation Deliverability Workbook.

- Intermittent Generation and Dispatchable Intermittent Resources are not in an Attachment Y status (retired/mothballed/suspended) and are operational when being used as a Planning Resources for a Planning Month.

- Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent three years of hourly net output (in MW) for hours 1500 – 1700 EST from June, July and August. For new resources or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours of 1500 - 1700 EST must be provided.

4.5.2. Intermittent Generation and Dispatchable Intermittent Resources - UCAP Determination

The Unforced Capacity for a Capacity Resource that is Intermittent Generation and Dispatchable Intermittent Resources will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service. Intermittent Generation and Dispatchable Intermittent Resources is not required to report generator availability data (GADs) and will be assigned a $XEFOR_d$ of zero. Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their annual UCAP determined based on interconnection service volumes and a Region wide capacity credit as a percentage of the Maximum Output as modeled in the effective Commercial Model at the time of calculating UCAP values (see table below for annual Intermittent Capacity Credit).

4.5.2.1 Intermittent Generation and Dispatchable Intermittent Resources - Wind Capacity Credit

MISO uses historical wind availability information to calculate Effective Load Carry Capacity (ELCC) to determine a wind capacity credit. The MISO LOLE Study Report explains the study methodology and the wind capacity result for each Planning Year. See MISO's website for current and previous LOLE studies.

MISO calculates specific wind capacity credit for each wind farm and applies it to its registered maximum capability in the Commercial Model or its registered Capacity through the LMR or External Resource registration process. The wind capacity credit is allocated to each wind farm based on its capacity value at each of MISO's highest coincident peaks that occurred during the Summer. The LOLE Study Report includes analysis and results. This is calculation is done on a CPNode basis for wind farms that are registered in the MISO Commercial Model, and on a wind farm basis submitted through Planning Resource registration process for External Resources and Behind the Meter Generation. A wind farm that does not have any commercial operation history will receive a wind capacity credit equivalent to the system wide wind capacity credit from the ELCC study, for their initial Planning Year, and there after metered data is will be used to calculate its future wind farm specific wind capacity credit, if no metered data is available then the wind farm with receive a capacity credit of 0%.

4.5.2.2 Intermittent Generation and Dispatchable Intermittent Resources – Non-wind

All other Intermittent Generation and Dispatchable Intermittent Resources will have their annual UCAP value determined based on the 3 year historical average output of the resource from 1500-1700 EST for the most recent Summer months (June, July, and August). Market Participants with non wind powered Intermittent Generation and Dispatchable Intermittent Resources will need to supply this historical data to MISO by October 31 of each year in order to have UCAP value determined. Non wind powered Intermittent Generation and Dispatchable Intermittent Resources that are new, upgraded or returning from extended outages shall submit all operating data of June, July, or August with a minimum of 30 consecutive days, in order to have their new or upgraded capacity registered with MISO. An example of a qualified extended outage is a resource that does not have a transmission path due to a planned or forced transmission outage. Resources that experience changing characteristics during the historical period due to changing nameplate capability will have the historical data adjusted by a ratio of the current nameplate rating divided by the nameplate rating in effect at the time the data was collected. For resources that experience partial outages not related to the supply of fuel (e.g. water conditions), regular maintenance, or shutdowns due to safety concerns (e.g. high water) the historical data may be prorated upward to reflect the expected value if all units had been on line. For units that experience reduced output due to reasons outside of management control (e.g. flood conditions) data from these periods may be excluded from the calculation of UCAP. The annual UCAP will be the three year average output value after the adjustments as described above have been made.

An increase in unit capability for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the annual UCAP values have been established will require written notification from the Market Participant to a member of the Resource Adequacy Team in order to update the values.

4.5.3 Intermittent Generation and Dispatchable Intermittent Resources – Must Offer

The must offer requirement applies to the Installed Capacity of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the UCAP rating. Installed Capacity refers to the amount of PRCs divided by (1 – $XEFOR_d$) of the Capacity Resource.

DA Reliability Forecasts submissions for Intermittent Generation and Dispatchable Intermittent Resources received by the DA Market close and Forward Reliability Assessment Commitment (FRAC) close will be used to monitor for compliance with the must offer requirement when the unit's availability is due to non-mechanical and/or non-maintenance reasons. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast.

The same Intermittent Forecast data file used in Day Ahead Must Offer compliance shall be utilized in FRAC if no further update is provided. DA Reliability Forecast shall replace the Installed Capacity as the Must Offer requirement if a DA Reliability Forecast is submitted. DA Reliability Forecasts must be in the required format and submitted via the portal in order to be used by the must offer compliance monitoring process. Format instructions are located at https://www.misoenergy.org/StakeholderCenter/MarketParticipants/Pages/MarketParticipants.aspx under Related Documents. A header row should be included at the beginning of the file in the format Resource, Day, HE, MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not provide the DA Reliability Forecast by DA Market close and FRAC close will be based on offers submitted and outages or derates submitted in the MISO Outage Scheduler (CROW). Additionally, maintenance and mechanical outages to Intermittent Generation and Dispatchable Intermittent Resources should be entered in the MISO Outage Scheduler (CROW).

For purposes of calculating the must offer requirement for Intermittent Generation and Dispatchable Intermittent Resources powered by wind an XEFORd of one minus the footprint wide capacity credit will be used (80% for the initial Planning Year). For non wind Intermittent Generation and Dispatchable Intermittent Resources the XEFORd will be set equal to the UCAP divided by the ICAP where the ICAP shall be the maximum value registered in the Commercial Model or the MECT.

4.6 Use Limited Resources

4.6.1 Use Limited Resources – Qualification Requirements

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for a minimum set of consecutive operating Hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across the Transmission Provider's peak;
- submits GADS Data to MISO;
- notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- demonstrates capability and submit the results to MISO; and
- identifies the resource as use limited when registering the asset.
- MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources may qualify as Capacity Resource provided that:

- The Use Limited Resources must be deliverable to Load within the MISO Region. The deliverability of Use Limited Resources to Network Load within the MISO Region shall be determined by System Impact Studies pursuant to the Tariff as conducted by MISO, which will consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. The Deliverability Test Results are provided on the MISO public website at the following location: Planning > Generator Interconnection > Generation Deliverability workbook. Use Limited Resources must register with MISO as documented in the Market Registration BPM.
- Use Limited Resources (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal.
- New Use Limited Resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.
- Use Limited Resources less than 10 MW based upon GVTC that begin reporting generator availability data to MISO must continue to report such data.

- The XEFORd for new Use Limited Resources in service less than twelve full calendar months will be the class average for the resource type. A Use Limited Resource will use the class average value until 12 consecutive months of data is available and a new planning year has occurred.
- Use limited Resources that are not in an Attachment Y status (retired/mothballed/suspended) and are operational when being used as a Planning Resource for a Planning Month.
- Use Limited Resources must demonstrate capability on an annual basis.
    - MISO has developed generator-testing standards for use in Planning Years 3 and beyond.

4.6.1.1 All Use Limited Resources being used as a Planning Resource are required to perform a real power test according to MISO Generator Test Requirements and submit the Generation Verification Test Capacity (GVTC) to the MISO PowerGADS no later than October 31st in order to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and corrected to the average temperature of the date and times of the MISO coincident Summer peak, measured at or near the generator's location, for the last 5 years, or provide past operational data that meets these requirements to determine its Generation Verification Test Capacity (GVTC) and submit its' GVTC to the MISO PowerGADS

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be between September 1st and August 31st prior to the upcoming Planning Year.

- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
- A real power test is required when returning from a "mothballed" state, and then submit the GVTC.
- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, and must be submitted at least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool.
- See Appendix L of this BPM for links to the MISO GVTC rules and processes.

▪ Reporting

- Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User Manual, which is located on the MISO website under Documents> Resource Adequacy Planning > Resource Adequacy (Module E) > PowerGADS Documentation.
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4.6.2 Use Limited Resources – UCAP Determination

The UCAP value for a Use Limited Resource is based on an evaluation of the type and volume of interconnection service, GVTC value and $XEFOR_d$ value of such Use Limited Resource as described in Appendix I.

The UCAP methodology is implemented to address the fact that not all Use Limited Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit, based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. The PRM_{UCAP} requirement is similarly adjusted by the weighted average $XEFOR_d$ of all the pooled resources, the generating units with better than average availability will reflect higher value than units with below average availability.

$EFOR_d$ options for units affected by catastrophic outages and zero service hours are further outlined in Appendix J.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix I-5.

4.6.3 Use Limited Resources Must Offer Requirement

A Use Limited Resource must offer into the Day-Ahead Market for at least four (4) continuous hours each day across the Transmission Provider's peak in such a way as to enable MISO to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. The Transmission Provider's peak will be based on the peak including 2 hours prior to the beginning of the peak hour through the end of the hour following the peak hour as specified in the Market Report provided at the link provided below. The peak information from the forecast published one day prior to the operating day will be used in the must offer check process.

https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx

Under report name, type “look ahead” in the box. A list of summary reports will appear and you can click on corresponding date.

An MP with a Use Limited Resource is required to submit a must offer for at least the number of minimum capacity hours optimized to match the expected peak load in the Region. Outages and derates for Use Limited Resources need to be reflected in the MISO Outage Scheduler (CROW). Thresholds for Use Limited Resources will only be applied during the four continuous hours across the Transmission Provider’s peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency, in accordance with the must offer provisions in section 4.4.3.1.

4.7 External Resources

4.7.1 External Resources - Qualification Requirements

External Resources can qualify as Capacity Resources as follows:

MPs may register an External Resource by providing the information listed below to MISO to qualify such resources as Capacity Resources by registering such resources through the MECT for the upcoming Planning Year. An MP that owns External Resources or contracts for an External Resource via a Power Purchase Agreement (PPA) may also register its External Resources. The MP shall notify MISO if the External Resource being registered is a Intermittent Generation or Use Limited Resource. External Resources that are also Intermittent Generation must meet all requirements in section 4.5. External Resources that are also Use Limited Resources must meet all requirements in section 4.6.

An MP will submit the completed applicable registration form and provide it to Customer Registration at least 60 days prior to the first month the External Resource is listed in an LSE’s monthly Resource Plan. The registration form will require the MP to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it is determined whether or not the External Resource has been accredited, or whether there are any deficiencies. If the External Resource qualifies, it will be given a unique name for tracking purposes.

MISO will coordinate with appropriate neighboring entities (RTOs, LBAs, etc.) to ensure External Resources are not being utilized for capacity purposes by such entities. The purpose for this coordination effort is to eliminate double counting of capacity across seams.

The following information will be required in order to register an External Resource:

The MPs that register External Resources may receive eligible UCAP provided that the MP:

- demonstrates that there is firm Transmission Service from the External Resource to the border of the MISO Region, and;
    - firm Transmission Service has been obtained to deliver at least the ICAP amount of the Capacity Resource seeking to be qualified on the Transmission System from the External Resource(s) to the CPNode. The CPNode will be interpreted as the Local Balancing Authority (LBA) that the MISO OASIS reservation sinks in for Network Customers, or ;
    - The External Resource has Network Resource Interconnection Service under Attachment X, and can demonstrate use of the Network Resource Interconnection Service by having firm Transmission Service to Load.
- demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program; is available in the event of an Emergency; and performs an annual GVTC test and reports data via GADS.
- External Resources greater than or equal to 10 MW based on Generation Verification Tested Capacity (GVTC) must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal. Definition of Generation Resources does not include Intermittent

Generation This 10MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs.

- External Resources less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information.

- New External Resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.

- The XEFORd for new External Resources in service less than twelve full calendar months will be the class average for the resource type. An External Resource will use the class average value until 12 consecutive months of data is available and a new planning year has occurred.
- External Resources must demonstrate capability on an annual basis as described below.

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When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be between September 1st and August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.

- A real power test is required when returning from a “mothballed” state, and then submit the GVTC.
- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, and must be submitted at least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool.
- See Appendix L of this BPM for links to MISO GVTC rules and processes.

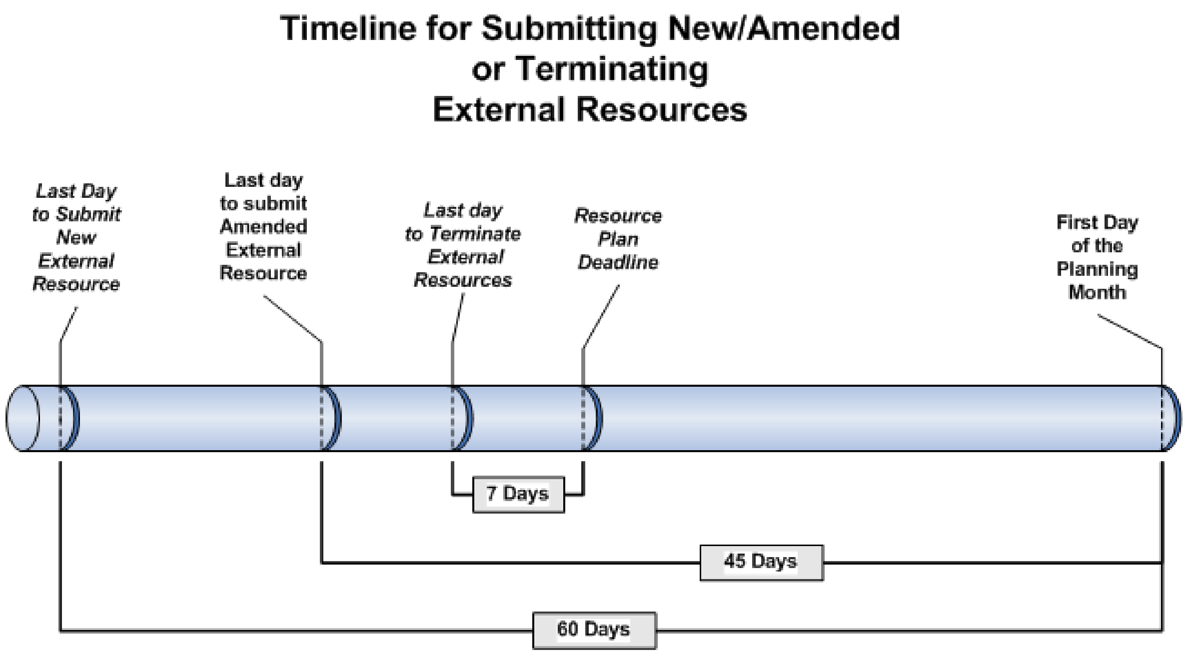
o Reporting

- Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User Manual, which is located on the MISO website under Planning > Resource Adequacy (Module E) > PowerGADS Documentation.

A Power Purchase Agreement (PPA) is a contract to buy/sell energy and/or capacity between parties. If the PPA involves a transfer of capacity within the MISO Region then this transaction should be represented in the MECT as either an Aggregate PRC or a Local PRC Transaction. If the PPA involves External Resources, once such External Resources are registered and accredited then the associated UCAP MWs may be converted to PRCs in accordance with the procedures in Section 5.1.3.

In order for a PPA to qualify as a Capacity Resource it must demonstrate that it complies with the requirements found in Section 69.3.1.c of the Tariff.

4.7.2 External Resources – Registration Process



4.7.2.1 Submission of new External Resources Registrations

A Market Participant will register their new External Resource via the LMR Registration screen in the MECT at least 60 days prior to the first month the External Resource is listed in an LSE's monthly Resource Plan. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Customer Registration team at register@misoenergy.org to become a Market Participant. The information registered in the Registration screen will require the Market Participant to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F of this BPM contains the information that must be submitted by an MP through the MECT External Resource registration screen. MISO will review the External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for External Resources. MISO will notify the Market Participant with 15 days after the registration from was submitted whether or not the resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.7.2.2 Termination of resources Accredited as External Resources

The MP can terminate the accreditation by amending the “Effective Stop Date” in the Registration screen in the MECT. The External Resource cannot be used for a time period beyond the “Effective Stop Date”, and a new External Resource registration request must be submitted to begin using the External Resource past the “Effective Stop Date”. Since LMR need to be accredited annually, The “Effective Stop Date” will default to the last day of the applicable plan year of no date is provided.

4.7.2.3 Amendments to Accredited External Resource Registration Data

The Market Participant can amend the registered effective end date for the External Resource, so that it is no longer valid for future time periods by providing MISO with seven (7) days advance notice. All amendments to a registered External Resource that do not affect the end date of the External Resource must be provided to MISO via the Registration screen at least forty-five (45) days prior to the first month the amended External Resource’s parameters will be used in an LSE’s annual or monthly Resource Plan.

If a Market Participant needs to modify any of the non-end date information submitted in the registration, which may affect the External Resource’s qualification, including, but not limited to, a change in operation or has either an increase or decrease in it MW capability, then the Market Participant shall submit a new or amended registration information in the Registration screen at least forty-five (45) days prior to the first month the amended External Resource parameters will be used in an LSE's annual or monthly Resource Plan in order for MISO to determine whether the resource still qualifies as an External Resource.

4.7.2.4 Renewal of External Resource for subsequent Planning Years

Each External Resource must be reviewed for accreditation as External Resource on an annual basis. A Market Participant can request renewal of External Resource accreditation for subsequent planning years through the MECT registration screens. Renewal of External Resource must be requested at least sixty (60) days prior to the month the MP want to use the resource as an External Resource. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for External Resource. MISO will notify the Market Participant with 15 days after the renewed registration from was submitted whether or not the External Resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

4.7.2.5 Review of Power Purchase Agreements Effective in the Future

Market Participants that have entered into power purchase agreement(s) for future planning years may request MISO to review the pertinent provisions of the agreements in order to make a preliminary determination of whether the agreement(s) would qualify as External Resources from Power Purchase Agreement(s) as set forth in sections 69.3.1.c.i through 69.3.1.c.vii of the Tariff. Market Participants must submit a written request for review of such power purchase agreements to the MISO Manager of Resource Adequacy. MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether MISO believes that the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of the their agreements will need to follow the procedures applicable to the planning period for

which such External Resource is intended to be relied to meet Capacity requirements. This includes the provision of the appropriate GVTC and GADS data, and other requirements then in effect for registering a new External Resource as set forth in the Tariff and in Section 4.7.2.1 of this BPM that is effective at the time of registration,, in order to have the External Resource modeled in the MECT and qualified as Capacity.

4.7.3 External Resources – UCAP Determination

External Resources will be accredited at the Capacity Resource's Unforced Capacity based on GVTC value(s), transmission service, and EFORd values of such External Resources based on the methodology documented in Appendix I of this BPM. MISO will determine UCAP values for External Resources that are Intermittent Generation as described in Section 4.5.2.
$EFOR_d$ options for units affected by catastrophic outages and zero service hours are further outlined in Appendix J.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix I-5.

4.7.4 External Resources – Must Offer Obligation

The maximum must offer requirement applies to the registered Capacity of the External Resource.

An MP that converts the External Resource UCAP MW into PRC must submit the full operable capacity of the Resource but no less than the registered Capacity of what was converted to PRCs for each hour of each day during the Operating Month and make an Offer in the Day-Ahead and each pre-Day-Ahead and first post Day-Ahead Reliability Assessment Commitment (RAC), except to the extent that the External Resource is unavailable due to a full or partial forced or scheduled outage. The full operable capacity for an offer into the Day-Ahead Market that is using firm MISO Network Integration Transmission Service will be the Network Customer's forecasted peak Demand for the day being offered. Offers in the Day-Ahead Market can only be Normal Energy type with the transaction type of either Fixed or Dispatchable and market type of Day-Ahead Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Reliability Assessment Commitment (FRAC) .

Therefore, the must offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via EOP-002.

The MP that converts the External Resource UCAP MW to PRC shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator via System Data Exchange (SDX). External Resources must be available to schedule Energy into the Transmission Provider Region during emergencies if needed by the Transmission Provider. EOP-002 includes a mechanism to schedule all external Capacity Resources into the MISO BAA. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR". The NERC IDC (Interchange Distribution Calculator) name must be identified in the Value field of the MISC section exactly as it appears in the approved registration in the MECT and Outage Scheduler (CROW) except in all caps.

External Resources that are Use Limited Resources must follow the Day-Ahead must offer requirements for Use Limited Resources as documented in section 4.6.3 of this BPM.

Compliance with “must offer” requirements will be evaluated by MISO on a nondiscriminatory basis. MISO will analyze the compliance with must offers in both the Day-Ahead and RAC by taking into account information provided by the MISO Outage Scheduler (CROW), NERC SDX and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation.

4.8 DRR Type I and Type II

4.8.1 DRR Type I and Type II– Qualification Requirements [69.3.1.b]

DRR Type I and Type II may qualify as Capacity Resources provided that:

(All references to generation availability and testing in this section pertain to DRRs backed by generation.)

- DRR Type I and Type II (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal.
- DRR Type I and Type II must demonstrate capability on an annual basis by performing a Generation Verification Test Capability (GVTC) for each generating resource. . New DRR Type I and Type II Resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.
- DRR Type I and Type II less than 10 MW based upon type and volume interconnection service, GVTC that begin reporting generator availability must continue to report such data.
- DRR Type I and Type II are registered as documented in the Market Registration BPM.

- The XEFORd for new DRR Type I and Type II Resources in service less than twelve full calendar months will be the class average for the resource type. A DRR Type I and Type II Resource will use the class average value until 12 consecutive months of data is available and a new planning year has occurred.
- A DRR that is also registered in the MECT as a Load Modifying Resource may only convert a combined UCAP not to exceed the maximum assigned value of the singular resource.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be between September 1st and August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
- A real power test is required when returning from a “mothballed” state, and then submit the GVTC.
- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, and must be submitted at

least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool.

- See Appendix L of this BPM for links to MISO GVTC rules and processes.

- Reporting
    - Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User Manual, which is located on the MISO website under Planning Resource Adequacy (Module E) > PowerGADS Documentation.

4.8.2 DRR Type I and Type II – UCAP Determination

MISO will determine the UCAP value for each DRR that is a behind the meter generation facility based on an evaluation of GVTC value and $XEFOR_d$ values of such behind the meter generation facility. If such behind the meter generation facility is interconnected to the Transmission System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average $EFOR_d$ of the resource type will used to calculate the forced outage rate.

MISO will determine the UCAP value for each DRR that interrupts or control load based on an evaluation of the supporting documentation supplied in the MECT during the registration of such programs. A $XEFOR_d$ value of zero will be applied to all DRR that interrupts or controls load.

$EFOR_d$ options for units affected by catastrophic outages and zero service hours are further outlined in Appendix J.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix I-5.

4.8.3 DRR TYPE I AND TYPE II – Must Offer

The must offer requirement applies to the Installed Capacity of DRR Type I and Type II, and not the UCAP rating. Installed Capacity refers to the amount of PRCs divided by (1 – $XEFOR_d$) of the Capacity Resource.

The MP that converts a DRR Type I or Type II UCAP MWs into PRCS must submit offers for an amount equal to the converted amount of capacity of the Resource for each of each day during the Operating Month and Offer in the Day-Ahead Energy and all pre Day-Ahead and the first post Day-Ahead RAC, except to the extent that the DRR is unavailable due to a full or partial forced or scheduled outage and that the outage is reported to MISO. The must offer thresholds established in Section 7.7 of this BPM will not be applied to DRR Type I and Type II resources.

4.9 Load Modifying Resources [69.3.2]

Load Modifying Resources are classified as either a Demand Resource (DR) or Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Control Load Management and other resources that result in additional and verifiable reductions in end-use customer demand during an Emergency. An LMR that relies solely on a generator to reduce load must register as a BTMG.

Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a CPNode. BTMG is not included in MISO's Dispatch Instructions.

LMR differ from Capacity Resource in that they do not have a must offer requirement, however they must be available for use during Emergency events declared by MISO. MISO's Emergency Operations Manuals, RTO-EOP-002 and RTO-EOP-004, include the procedures on how and when LMRs will be called on in an Emergency situation. Additionally, there are penalty provisions for LMR that fail to perform when called upon during Emergencies declared by MISO. This section details these and other requirements, obligations and provisions LMR must meet and maintain in order to qualify to provide capacity in the MISO Resource Adequacy construct.

DRR Type I and Type II are categorized as Capacity Resources under Module E (Section 69.3.1.b) and therefore are not an LMRs. An LMR is not required to be a Network Resource. An LMR may also qualify as an Emergency Demand Response resource (EDR) by meeting the requirements in Schedule 30 of the Tariff. A DRR Type I and Type II Resource can also register in the MECT as a Load Modifying Resource but can only convert a combined UCAP MWs to PRCs not to exceed the maximum assigned value of the singular resource.

4.9.1 Load Modifying Resource Obligations and Penalties

Accredited LMRs that have been converted to PRCs and such PRCs are designated to an LSE's PRMR must be available for use in the event of an Emergency declared by MISO. The LSE that has designated LPRCs from an accredited LMR (or had its accredited DRs netted from its LSE Forecast Requirement) would be subject to penalties if that LMR fails to respond in an amount greater than or equal to the target level of Load reduction for DRs or target level of generation increase for BTMG as directed by MISO or the LBA in accordance with emergency operating procedures. The target level of Load reduction for a DR will take into account the specified firm service level if specified at registration. However, MISO will not assign LMR penalties to EDR resources that have already been assessed penalties under Schedule 30 of the Tariff.

The operators of LMRs that properly report to MISO and to the LBA that an LMR is unavailable as the result of maintenance requirements or for reasons of Force Majeure will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction, for DR or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the credited amount of Behind the Meter Generation, or local reliability concerns) at the time the request for interruption is made. Likewise, for certain LMRs that are temperature dependant (*i.e.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted in a manner defined in the measurement and verification procedures to reflect the circumstances at the time an LMR is called upon to reduce Load or increase generation for BTMG.

An LSE that has designated LPRCs from an accredited LMR or netted accredited DRs against its Demand forecast in its Resource Plan will be subject to the penalties described in Section 69.3.9 of the Tariff if that LMR fails to respond in an amount greater than or equal to the target level of a Load reduction for DR or target level of generation increase for a BTMG. Such LSE shall be assessed the costs that were otherwise incurred to replace the deficiency at the time the LMR was dispatched according to Emergency Procedures by MISO.

A MP that registers an LMR will be permitted to provide MISO with documentation/rationalization that would justify penalty exemption if the LMR does not respond. However, MISO will continue to hold the LSE that has designated the LMR in its Resource Plan responsible if the LMR does not respond or does not respond at the targeted level of Load reduction or move to the specified firm service level. [69.3.9]

4.10 Behind the Meter Generation (BTMG)

4.10.1. BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Registering BTMG through the MECT BTMG registration screen according to the timeline and process documented in Section 4.10.2.

- Confirming through the registration process such BTMG can be available to provide energy with no more than 12 Hours advance notice from MISO or the LBA and sustain energy production for a minimum of four (4) consecutive Hours.
- BTMG is available at least (5) times during the Summer season when called on by MISO or the LBA for emergency purposes during the Planning Year.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce energy may qualify in meeting this requirement).
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal beginning no later than June 1, 2010 for non-intermittent BTMG greater than or equal to 10 MW based on GVTC or NDC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource has to submit information in accordance with Section 4.5.2 of this BPM.
- New BTMG resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a LMR.
- The XEFORd for new BTMG Resources in service less than twelve full calendar months will be the class average for the resource type. A BTMG resource will use the class average value until 12 consecutive months of data is available and a new planning year has occurred.
- Demonstrating capability for non-intermittent BTMG on an annual basis as described below.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or non-intermittent Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be from September 1st and August 31st immediately preceding the applicable Planning Year.

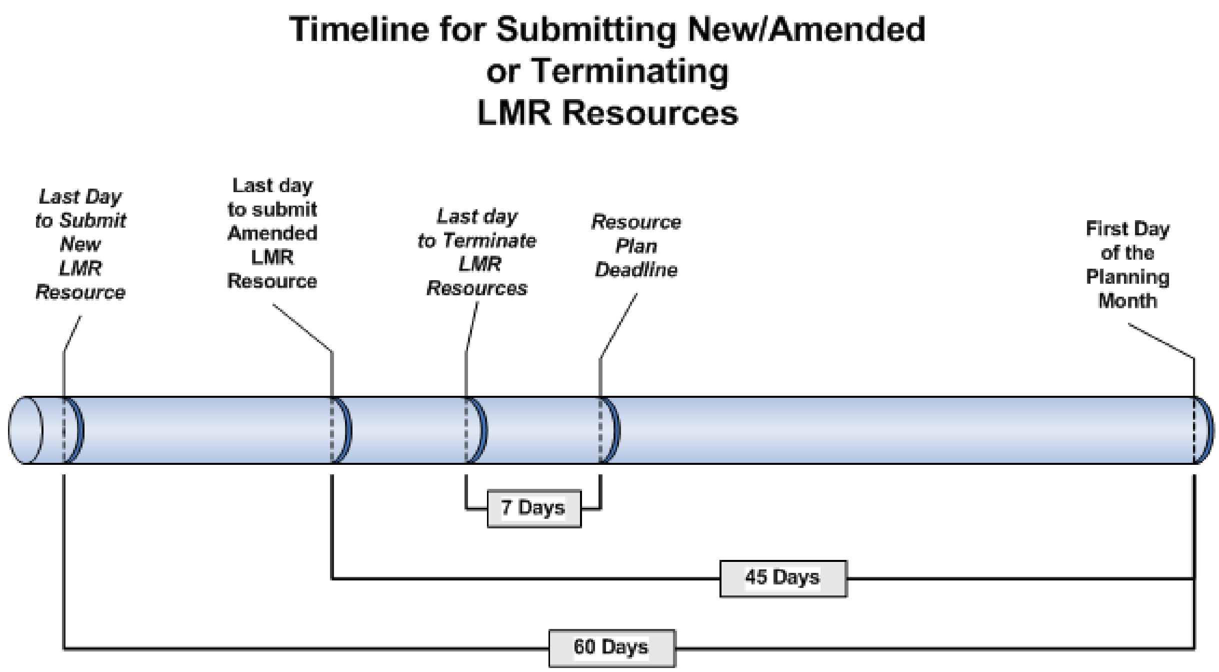
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
- A real power test is required when returning from a "mothballed" state, and then submit the GVTC.
- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, must be submitted at least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool.
- See Appendix L of this BPM for links to MISO GVTC rules and processes.

o Reporting

- Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User

Manual, which is located on the MISO website under Planning > Resource Adequacy (Module E) > PowerGADS documentation.

4.10.2 BTMG Registration Process and Timeline



4.10.2.1 Submission of New BTMG Registrations

A MP will register its new BTMG via the LMR Registration screen in the MECT at least 60 days prior to the first month the BTMG is listed in an LSE's monthly Resource Plan. The registering entity must be a MP prior to registering a BTMG. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.org to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E of this BPM contains the information that must be submitted by an MP through the MECT LMR registration screen. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will notify the MP within 15 days after the registration form was submitted regarding whether or not the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.10.2.2 Termination of BTMG Accredited as LMR

The MP can terminate the accreditation by amending the "Effective Stop Date" in the Registration screen in the MECT. The BTMG cannot be used for a time period beyond the "Effective Stop Date" and a new BTMG registration request must be submitted to begin using the BTMG past the "Effective Stop Date." Since LMRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable plan year if no date is provided.

4.10.2.3 Amendments to Accredited BTMG Registration Data

The MP can amend the registered effective end date for the LMR, so that it is no longer valid for future time periods by providing MISO with seven (7) days advance notice. All amendments to a registered LMR that do not affect the end date of the LMR must be provided to MISO via the Registration screen at least forty-five (45) days prior to the first month the amended BTMG's parameters will be used in an LSE's annual or monthly Resource Plan.

If a MP needs to modify any of the non-end date information submitted during registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation, startup notification requirements, maximum run time, or has either an increase or decrease in it MW capability, then the MP shall submit a new or amended registration information in the Registration screen at least forty-five (45) days prior to the first month the amended LMR parameters will be used in an LSE's annual or monthly Resource Plan in order for MISO to determine whether the resource still qualifies as an LMR. [69.3.6]

4.10.2.4 Renewal of BTMG for subsequent Planning Years

BTMG must be reviewed for accreditation as an LMR on an annual basis. A MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested at least sixty (60) days prior to the month the MP wants to use the BTMG as an LMR. NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.5.2.2, in order to have UCAP values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will notify the MP within 15 days after the revised registration from was submitted regarding whether or not the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

4.10.3. Behind the Meter Generation – UCAP Determination

The UCAP value for a BTMG is based on an evaluation of the type and volume of interconnection service if applicable, GVTC, and $XEFOR_d$ value of such BTMG as described below.

The Unforced Capacity methodology is implemented to address the fact that not all BTMG contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit, based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. The PRM is similarly adjusted by the weighted average $XEFOR_d$ of all the pooled resources, and the generating units with better than average availability will reflect higher value than units with below average availability.

The BTMG's accredited unforced capacity will be calculated using the same method that applies to Generation Resources that are Capacity Resources (the calculation methodology is described in the Appendix in section I.1), by applying an X $EFOR_d$ based upon historical availability data.

$EFOR_d$ options for units affected by catastrophic outages and zero service hours are further outlined in Appendix J.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix I-5.

4.10.4 BTMG Deliverability

BTMG should be deliverable to Load located within the MISO Region using one of the following:

- BTMG that is located at the same node as the LSE's demand
- LSE has obtained firm transmission service from the BTMG to its load
- BTMG may be used by any Network Customer within the LBA in which the BTMG is located provided that the Network Customer identifies the BTMG as a Network Resource on the MISO OASIS.
- The load is a network customer and the BTMG has been determined to be aggregate deliverable by acquiring Network Resource Interconnection Service, or the Market Transition Deliverability test provided the BTMG is interconnected to the MISO Transmission System,.

4.10.5 Measurement and Verification of BTMG

The measurement and verification procedures developed by MISO shall take into account any applicable state regulatory, RE, or other non-jurisdictional entities requirements regarding duration, frequency and notification processes for the candidate Demand Resources and will be included in future versions of this BPM.

For BTMG, the MP registering the BTMG must measure and record the electrical output of the generator(s) during the hour preceding an Emergency event and all hours the event is active. The MP shall submit meter data to MISO within 60 days following an Emergency event in which the BTMG was designated in an LSE's Resource Plan and deployed. MISO will review the meter data to verify that the BTMG increased energy output to the level instructed by the LBA. BTMG consisting of one or more generating units that have been identified by MISO must have metering (MWh) equipment for operational security purposes. BTMG consisting of multiple generating units at a single site that have been identified by MISO must have metering (MWh) equipment and may be metered as a single unit, however, multiple BTMG units that have a single meter will be treated as a single unit for purposes of Section 4.10.6 penalties. MISO may periodically audit MP performance reports and other data to ensure that it is consistent with the requirements described in this BPM.

All information submitted by the MP is subject to audit by MISO. Disputes concerning erroneous performance reporting shall be resolved through MISO's existing dispute resolution procedures by submitting a service request through the MISO portal (except for disputes between the MP and retail customer, which are not the responsibility of MISO).

4.10.6 BTMG Penalties

When a BTMG fails to perform during emergency conditions when called on by MISO or the LBA, penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) RSG Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increase and (b) the actual increased generation; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) the actual increased generation; and (2) the RSG First Pass Distribution rate for the applicable Hour.

The revenues from charges resulting from LMRs that fail to respond in an amount greater than or equal to the Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation, including those circumstances where the resource is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the LMR not being available when called upon, and may, if deemed appropriate, disqualify that resource from further utilization in meeting future RAR for that Planning Year.

In the event the same BTMG is not sufficiently responsive on a second occasion during a Planning Year (with a separation period of at least 24 hours) when called upon by the Midwest to increase generation, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the LSE that has designated LPRCs from an accredited LMR in its Resource Plan will be subject to the penalties described herein (if that LMR fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above, and the BTMG will no longer be eligible for utilization in meeting RAR for the remainder of the current Planning Year and for the next Planning Year. These LMR penalties are effective as of June 1, 2009.

If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

4.11 Demand Resource

4.11.1 Demand Resource – Qualification Requirements

MPs with DR can qualify the DR as an LMR by**:**

- Registering the DR through the MECT DR registration screen according to the timeline and process documented in Section 4.11.2 of this BPM.
- Confirming through the registration process such DR can be available to reduce Demand with no more than twelve (12) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the DR is not dependent on the dispatch of a BTMG owned or operated by the wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resource that can reduce Demand may qualify in meeting this requirement).
- Confirming through the registration process that the DR is capable of being interrupted at least (5) times during the Summer season when called on by MISO or the LBA for emergency purposes during the Planning Year.
- Confirming that the Demand Resource permits the Market Participant to interrupt the Load.
- Documenting capability to reduce demand to a targeted Demand reduction level or firm service level using one of the following options:

  - Provide documentation from the state that has jurisdiction that provides the amount and type of DR and the procedures for achieving the Demand reduction;

  - Verification from a third party auditor that is unaffiliated with the MP that documents the DR's ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.

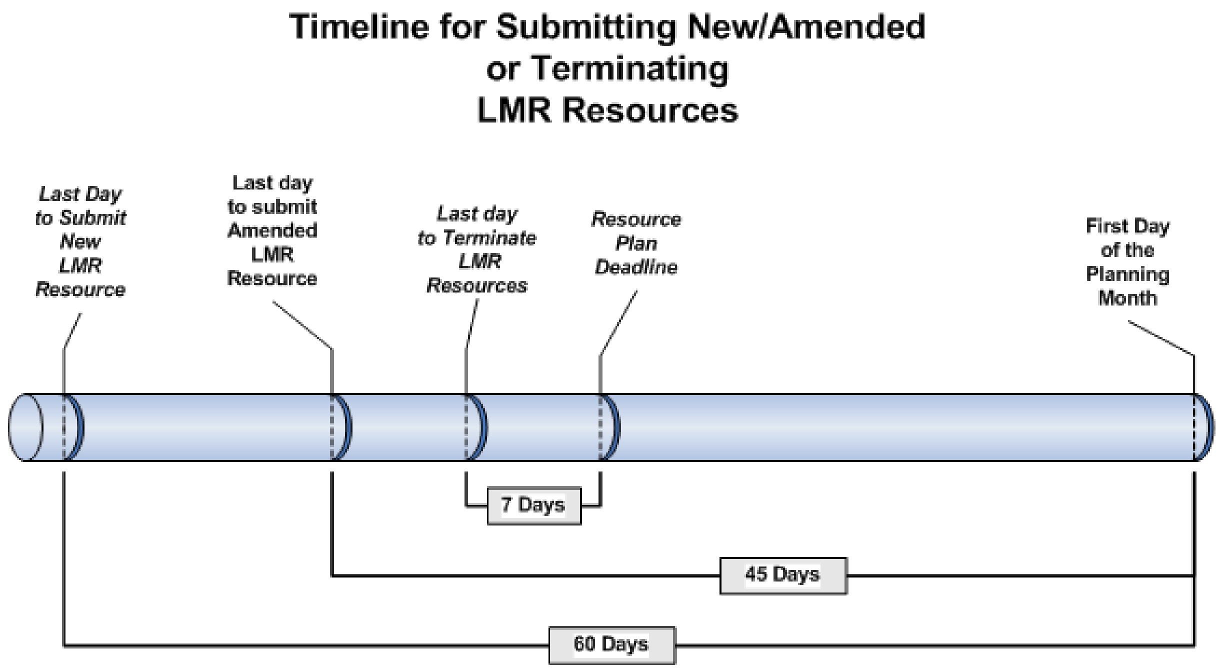
  - Provide past performance data from the previous Planning Year that demonstrates the DR's ability to reduce to the targeted Demand reduction level or firm service level when called upon to perform by MISO or the LBA. If past performance data does not exist from the previous Planning Year a mock test can be used to support the validity of the DR. The mock test should employ all systems necessary to initiate a Demand reduction short of actual Demand reduction

- Documenting the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 4.11.6 of this BPM. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE's load to weather.

An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69.3.5 of the Tariff.

4.11.2 Demand Resource Registration Process and Timeline

DR can be registered to be used to net against and LSE's Demand forecast, or to be used as a resource to receive UCAP MW that can be converted to PRCs. The MP must choose one of these options at the time of registration. A DR that an MP elects to use as a Planning Resource by creation of an LPRC may not also be netted from the LSE's forecasted Demand. MISO will subtract accredited DR from an LSE's Forecast LSE Requirement unless the LSE requests via the MECT that DR instead be afforded treatment similar to Capacity Resources. DR can be subtracted from an LSE's Forecast LSE Requirement in the RAR calculation, however, any DR that are used to reduce an LSE's Forecast LSE Requirement cannot also be used again to meet RAR obligations.



4.11.2.1 Submission of new DR Registrations

A MP will register their new DR via the LMR Registration screen in the MECT at least 60 days prior to the first month the DR is listed in an LSE's monthly Resource Plan. The registering entity must be a MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, must contact the Customer Registration team at register@misoenergy.org to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D of this BPM contains the information that must be submitted by an MP through the MECT LMR registration screen for DR. MISO will review the DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will notify the MP within 15 days after the registration from was submitted regarding whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.11.2.2 Termination of DR Accredited as LMR

The MP can terminate the accreditation by amending the “Effective Stop Date” in the Registration screen in the MECT. The DR cannot be used for a time period beyond the “Effective Stop Date”, and a new DR registration request must be submitted to begin using the BTMG past the “Effective Stop Date.” Since LMRs need to be accredited annually, the “Effective Stop Date” will default to the last day of the applicable plan year if no date is provided.

4.11.2.3 Amendments to Accredited DR Registration Data

The MP can amend the registration by amending the registered effective end date for the LMR, so that it is no longer valid for future time periods by providing MISO with seven (7) days advance notice. All amendments to a registered DR that do not affect the end date of the DR must be provided to MISO via the Registration screen at least forty-five (45) days prior to the first month the amended DR parameters will be used in an LSE’s annual or monthly Resource Plan.

If a MP needs to modify any of the non-end date information submitted in the registration, which may affect the DR’s qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation or has either an increase or decrease in either its targeted MW level or firm service level, then the MP shall submit new or amended registration information in the Registration screen at least forty-five (45) days prior to the first month the amended DR parameters will be used in an LSE’s annual or monthly Resource Plan in order for MISO to determine whether the resource still qualifies as an LMR. [69.3.5]

4.11.2.4 Renewal of DR for subsequent Planning Years

A DR must be reviewed for accreditation as an LMR on an annual basis. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT registration screens. Renewal of DR must be requested at least sixty (60) days prior to the month the MP want to use the DR as an LMR. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will notify the MP within 15 days after the renewed registration from was submitted regarding whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

4.11.3 Demand Resources – UCAP Determination

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the initial Planning Year. Capacity values for Demand Resources will be based on documentation from the state, third party auditor, or past performance.

MISO will determine through the registration process whether the BTMG or DR qualifies as an LMR under Module E. If a DR or BTMG does not qualify as an LMR under Module E that does not necessarily disqualify it from being an EDR resource under Schedule 30. Once the LMR and its MWs are accredited by MISO and entered into the MECT, then the MP that registered the LMR can elect to convert all or part of the LMR's accredited MWs into PRCs. The LSE that designates PRCs from an accredited LMR or uses Demand Resources in its Resource Plan will be subject to the penalty provisions contained in Section 69.2.2.3 of the Tariff, for not responding during an Emergency.

4.11.4 DR Deliverability

The owner of the local PRCs from a DR may not designate the LPRCs to an LSE located outside of the LBA in which the DR physically resides.

4.11.5 Measurement and Verification of DR

The measurement and verification procedures developed by MISO shall take into account any applicable state regulatory, RE, or other non-jurisdictional entities requirements regarding duration, frequency and notification processes for the candidate Demand Resources and will be included in future versions of this BPM.

The Baseline Usage or Customer Baseline for a DR is the average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for such Resource.

The Customer Baseline will be calculated by the MP registering the DR after an Emergency is called. The Customer Baseline used for computing performance for Demand Resources shall consist of eligible weekdays (weekdays that are non-Demand Response Holidays and non-interruption days). A Customer Baseline is required for a Demand Resource that is listed in an LSE's Resource Plan.

For an asset with no previously computed baseline, the Customer Baseline is based upon a simple average and will be calculated for each hour in a day based on meter data from the ten business days prior to an event, if the DR was deployed during an Emergency, which is referred to as the default baseline. This default baseline calculation will be used unless an alternative baseline calculation is proposed in the registration process and accepted by MISO.

The MP that registered the DR will collect and provide the meter data and its Customer Baseline. The MP shall document these comparisons and submit the results to MISO within 60 days of the declared Emergency during which a DR designated in an LSE's Resource Plan was deployed. In the event of an Emergency, MISO will review metering data to verify that the Demand Resource reduced to the targeted MW level or to a specified firm service level when called upon by the LBA.

4.11.6 DR Penalties

When a DR fails to perform during an Emergency when called on to reduce Demand by MISO or the LBA, penalties are calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction as the sum of: (1) the product of (a) the amount of Load reduction not achieved and (b) the LMP at the CPNode associated with the DR; and (2) RSG Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) the actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) the actual Load reduction; and (2) the RSG First Pass Distribution rate for the applicable Hour.

The revenues from charges resulting from LMRs that fail to respond in an amount greater than or equal to the Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction including those circumstances where the resource is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the LMR not being available when called upon, and may, if deemed appropriate, disqualify that resource from further utilization in meeting future RAR for that Planning Year.

In the event the same LMR is not sufficiently responsive on a second occasion during a Planning Year (with a separation period of at least 24 hours) when called upon by MISO to reduce Load for a DR or increase generation for a BTMG, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the LSE that has designated LPRCs from an accredited LMR or netted accredited DRs against its Demand forecast in its

Resource Plan will be subject to the penalties described herein (if that LMR fails to respond in an amount greater than or equal to the target level of a Demand Resource Load or to the firm service level). The MP using the DR shall be assessed the same penalty as indicated above, and the DR will no longer be eligible for utilization in meeting RAR for the remainder of the current Planning Year and for the next Planning Year. These LMR penalties are effective as of June 1, 2009.

5. Introduction to Planning Resource Credits (PRC)

5.1 Purpose

The purpose of a PRC is to create a fungible product that represents Planning Resources that can be easily tradable among MPs and used by LSEs to meet their PRMR. A PRC represents 1 MW-month of qualified unforced capacity from a Planning Resource for a given month in a specific Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable PRC qualification procedures described below. All types of Planning Resources are tracked in the MECT, which tracks Module E resources used for compliance against an LSE's obligations.

- Section 5.4 describes the procedures that an owner of a resource will follow to qualify a resource to receive eligible UCAP MWs which can then be converted to PRCs.
- Section 5.5 discusses conversion of UCAP MW to PRCs.
- Section 5.6 describes the procedures for an LSE to follow for designating PRCs to meet its PRMRs.
- Section 5.6 also addresses transfers of PRCs.
- Section 5.9 addresses the procedures for submission of Resource Plans.

MPs that own or possess contractual rights to a registered accredited External Resource can convert the UCAP MW of the External Resource to PRCs through the MECT. MPs may also unconvert, designate, un-designate, and transfer PRCs throughout the MECT.

5.2 Intended Audience

This section is intended for stakeholders that own or have contractual rights to resources that qualify as Planning Resource and are given a UCAP MW rating and LSE that have a PRMR and will need to designate PRCs towards meeting that requirement.

5.3 Overview of PRC Types

5.3.1 Aggregate PRCs (APRC)

Aggregate PRCs are PRCs that are associated with Planning Resources that MISO determined are aggregate deliverable throughout the MISO Region. APRCs are the only type of PRC that can be bought or sold in the monthly Voluntary Capacity Auctions (VCA). The VCA procedures are documented in Section 8 of this BPM.

5.3.2 Local PRCs (LPRC)

Local PRCs are associated with Generation Resources and LMRs that are not aggregate deliverable throughout the MISO Region. A LPRC is created by converting the UCAP MW of a BTMG, DR that is not netted against an LSE's Demand forecast, or a non-aggregate deliverable internal unit specific Generation Resource to LPRCs.

5.3.3 External PRCs

External PRCs (EPRC) are PRCs that are associated with External Resource(s) that: (1) have firm transmission service from the External Resource(s) to the MISO border; and (2) have firm transmission service within the MISO Region to a specific CPNode. An EPRC is created by converting the UCAP MW of an External Resource to EPRCs

5.4 Tracking of PRCs

The MECT will track: the UCAP MWs assigned to each Planning Resource; the UCAP MWs that the owner of a Planning Resource has converted to PRCs (called Available PRCs in the MECT); the amount of PRCs that a MP owns; and the amount of PRCs that an LSE has designated to be used to satisfy its PRMR. Depending upon the characteristics of the Planning Resource, the UCAP from the Planning Resource may be convertible to an APRC, an LPRC or an EPRC.

5.5 Procedures for Conversion of UCAP MW

To create a PRC, a MP must convert UCAP MW from each qualified Planning Resource to PRC through the MECT UCAP/PRC conversion screen.

When PRCs are converted from UCAP by the Planning Resource owner, the PRCs are populated in that MP's available PRC account. MISO will keep track of how many PRCs the MP has created, and how many remaining UCAP MWs for each Planning Resource are available for conversion to PRCs. Once created, APRCs are no longer identifiable with a specific Planning Resource and MISO will not require further documentation regarding the Planning Resources supporting the APRC. Planning Resources are only convertible into the eligible PRC categories (APRCs, LPRCs, or EPRCs) applicable to such Planning Resource types. MISO will track LPRCs back to the specific Planning Resources they were created from in order to properly assign LMR penalties and ensure adequate transmission service is in place.

5.6 Conversion Obligations

As a condition of converting available UCAP MWs of a Capacity Resource into PRCs, the MP must comply with all requirements for Planning Resources in the Tariff including but not limited to Section 69.5, the must offer requirement.

5.7 Transfer of PRCs

Available PRCs can be transferred between MPs using the MECT. This is accomplished in the 'PRC Transactions' tab in the MECT. Both the 'Buyer' and 'Seller' must confirm a transfer before the transfer will occur. Once the transaction has been confirmed by both parties the PRC transaction volumes documented for each month will be subtracted from the seller's available PRC account and added to the buyer's available PRC account. The MECT allows transactions based on type of PRCs.

5.8 Designating PRC to meet LSE PRMR

LSEs are obligated to provide MISO with Resource Plans demonstrating that sufficient PRCs from Capacity Resources and/or from LMRs will be available to meet their PRMR at each Load CPNode for the Planning Year. This is accomplished by the LSE designating in the MECT an amount of LPRCs, EPRCs, and APRCs that are together equal to or greater than the LSE's PRMR for each month of the Planning Year. LSEs must convert UCAP MW from Planning Resources to PRCs and designate such PRCs using the MECT to meet PRMR for a given month. To avoid potential double counting of Planning Resources and to enable MISO to track and verify Planning Resources, owners of Planning Resources will follow the procedures in Section 5 of this BPM to qualify Planning Resources to receive UCAP MWs (UCAP MWs that can be converted to PRCs), and procedures for converting such UCAP MWs to PRCs in Section 5.4 of this BPM.

Within the MECT, an LSE may designate any amount (down to the tenth of a MW) of the PRCs that it owns, as part of the LSE's Resource Plan, to fulfill its RAR for a specified Month or Months. MISO shall accept the designated amount of PRCs as an amount of MWs of Planning Resources, in fulfillment of RAR.

Once PRCs are designated by an LSE to fulfill RA requirements for a specified Month, the designated PRCs may not be transferred by the LSE. MISO will keep track of how many PRCs an LSE has designated, by Month, in the MECT.

In recognition of all or a portion of a Network Resource as of the Market Transition Deliverability Test (MTDT) that is being utilized by the same Network Customer as the MTDT, the LSE shall enter the OASIS number in the MECT for its Network Load when designating Local PRCs to their obligation at a CPNode. If the LSE is not a Network Customer then the OASIS number will be a firm point-to-point reservation. If the BTMG is located at the same CPNode where the Resource's UCAP was converted to PRCs as the Demand, then no MISO OASIS number is required.

An LSE that is a Network Customer may utilize an EPRC that sinks in the same LBA as the LSE's Demand.

5.9 Undesignation of PRCs Prior to Deadline

Within the MECT, an LSE that has previously designated PRCs to fulfill RAR for a particular Month may undesignate all or a portion of such PRCs, provided that the undesignation occurs prior to the first day of the Month preceding the applicable Month (the deadline for complying with RAR). The amount of previously designated PRCs undesignated shall be restored to the LSE's available PRC account by MISO, and thus will be able to be transferred to other MPs as PRCs.

For example, undesignation of previously designated PRCs could occur if an LSE's monthly load forecast is revised to be lower, and thus the LSE finds itself with excess PRCs due to a reduced RAR. Undesignation of previously designated PRCs would allow the LSE to transfer its extra PRCs to another party.

5.10 Conversion of PRCs to UCAP MW

An owner of PRCs that also owns Planning Resources from which any PRCs have been converted, may convert any PRCs to UCAP MW via the MECT UCAP/PRC Conversion screen, provided that such PRCs have not been designated to fulfill RAR. This is accomplished by reducing the number of PRCs in the owner's PRC account and increasing the number of UCAP MWs that are eligible for conversion to PRCs, for a specified resource.

The conversion of PRCs may be directed to any specified resource provided that: (a) the resource previously was used to create PRCs; and (b) that the increase in remaining UCAP MW from the conversion when added to the currently remaining UCAP MW eligible for conversion to PRCs does not exceed the maximum UCAP MW for the resource. An LPRC may be converted to UCAP MW only for a Local Capacity Resource whose local deliverable area matches the locality of the specified LPRCs. An EPRC may be converted to UCAP MW only for a Capacity

Resource for which there exists firm transmission from the External Resource to the CPNode specified for the EPRC.

The owner of the resource no longer has to meet the conversion obligations specified in Section 5.2.2 of this BPM for PRCs that have been converted to UCAP MW.

6. Obligations of Load Serving Entities

6.1 Purpose

This section outlines LSEs responsibilities for meeting their Resource Adequacy Requirements.

6.2 Intended Audience

This section is intended for LSEs who serve load with MISO.

6.3 Overview and Timeline

LSEs must report their non-coincident peak forecasted Demand to MISO by Load-Zone CPNode as described in Section 6.4 of this BPM. MISO will calculate the Forecast LSE Requirement as the forecasted Demand for an LSE (adjusted by FRP/FRS agreements and minus the DR that are registered to net) for each month of the next Planning Year.

6.4 Demand Forecast and Losses [69.1.1]

LSEs must report their non-coincident peak forecasted Demand to MISO at each CPNode for each month of the next two Planning Years and also for each summer period (May - October) and winter period (November - April) for an additional eight (8) Planning Years. The forecasts shall be based upon considerations including, but not limited to, average historical weather conditions and expected Load changes (addition or subtraction of demand). LSEs will separately register Demand Resources that qualify under Module E in order to have them subtracted from their forecasted Demand.

The Forecast LSE Requirement is: The forecasted Demand including the effect of all losses for an LSE at a CPNode for a Month less the Full Responsibility Purchases plus the Full Responsibility Sales and minus the Demand Resources that were registered to net for a given Month, all at the same CPNode.

It is necessary to provide forecasted Demand by CPNode so that MISO can assign the appropriate PRM to that load and ensure resource deliverability is maintained. LSEs must provide MISO with their forecasted Demand for the coming Planning Year no later than March 1. Updates to these forecasts may be submitted no later than the Resource Plan Deadline which is the first day of the Month preceding the applicable Month. If the forecasted Demand significantly varies from prior submissions for that same month in the Planning Year, LSEs are required to provide their justification in the comments field of the MECT's Demand Forecast screen.

Forecasted Demand for each CPNode should reflect the expected "50/50" peak Demand for each Month and include the effect of all distribution and transmission losses. This means that there is a 50% chance that actual Demand will be higher and a 50% chance actual Demand will be lower than the forecasted level. Thus, for example, if anticipated forecasted Demand is 100 MW with anticipated losses of 3%, then the forecasted Demand is 103 MW. Transmission losses must be reported separately for each load CPNode in the MECT.

6.4.1 Demand Forecast and Losses - Retail Choice

For LSEs serving load in retail choice states, the forecasting requirements are the same as for other LSEs and are specified above in Section 6.4 of this BPM. An LSE will submit its forecasted Demand into the MECT by the first day of the month preceding the applicable planning Month by Load-Zone CPNode. The LSE's forecasted Demand for the applicable planning Month will take into account all the retail Demand that the LSE expects to serve during the applicable planning Month. MISO is not authorized to assign load to a Provider of Last Resort (POLR).

6.5 After the Fact Forecast Assessment Data

6.5.1 Prior to the Planning Month:

In the timeframe between the Resource Plan Deadline for a certain month and the start of that Month, LSEs can submit standard deviation in MW, weather variable(s) and corresponding elasticity, price variable(s) and corresponding elasticity for each CPNode to MISO through the MECT. A comment field is available to provide MISO with information about the above variables outside of the input fields such as a description of which weather variable was used.

6.5.2 After the planning month:

Up until the last day of the second month following the Planning Month , LSEs can enter in the MECT actual weather and price variables as well as retail load shifts if load exists in a retail choice state. LSEs must be able to provide documentation to MISO on all assessment data entered in the MECT for each CPNode. MISO will conduct an after-the-fact assessment by CPNode based on the information entered in the MECT. The assessment is conducted on the CPNode monthly peak and not on the LSE's or MISO's coincident peak, therefore only data on a CPNode level can be used for the assessment.

MISO after the fact forecast assessment procedures are documented in Section 7.8 of this BPM.

6.6 Energy for Load

LSEs must report their net energy for forecasted Demand to MISO by Load-Zone CPNode for each month of the next two Planning Years and for each summer period (May – October) and winter period (November – April) for an additional eight (8) Planning Years no later than March 1. Net Energy for Load includes losses but excludes energy for storage at energy storage facilities and is reported in GWh. Net Energy for forecasted Demand by CPNode is necessary for MISO, as the Planning Authority to comply with NERC standard MOD-17, Aggregated Actual and Forecast Demands, and Net Energy for Load. NERC defines Net Energy for Load as Net

Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. Net Energy for Load includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.

6.7 Full Responsibility Purchases and Sales (FRP/FRS)

An LSE (purchaser) may contract with other entities (sellers) to be responsible for providing PRC for all or part of its load delivered to the purchaser through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted Demand information for the transferred Demand into the MECT. A MP with an FRS agreement is required to designate qualified PRCs through the MECT procedures to meet this additional obligation as though it was their own load, as described in Section 5. If the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of MISO, then the purchaser under an FRP/FRS agreement will remain responsible for any RAR deficiencies associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE under the jurisdiction of MISO, then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. Such a purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from responsibilities for any RAR deficiencies associated with the FRP/FRS agreement.

An LSE's RAR will be reduced for such purchases, by the amount of transaction load, which the LSE identifies in an FRP, multiplied by 1 plus the PRM at the Load-Zone CPNode. The RAR of the seller that identifies the complimentary FRS will be increased by the amount of transaction load that the seller identifies as an FRS multiplied by 1 plus the PRM at the Load-Zone CPNode.

The purchaser under an FRP agreement must provide to MISO, in their Resource Plan, the forecasted Demand as described in Section 5.4 of this BPM.

The seller under an FRS agreement must include Planning Resources for the transaction load multiplied by 1 plus the PRM in its Resource Plan. All sellers of an FRS to a MISO LSE must be an MP and submit a Resource Plan to MISO to account for the load multiplied by 1 plus the PRM, and Planning Resources for the FRS.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand at that CPNode (load) remains with the original LSE (purchaser).

As shown in the following formula found in Section 69.2 of the Tariff, the PRM for the zone in which the load resides will be applied to the load regardless of which LSE or MP has the reserve obligation.

The formula for the LSE's Planning Reserve Margin obligation is:

$$PR_{LSE} = \sum_{i \in zones} L_i \cdot (1 + PRM_{UCAPi})$$

Where:

PR_{LSE} = Sum of the LSE's RAR obligation at each Load CPNode

L_i = LSE's Forecast LSE Requirement per each Load CPNode in a Planning Reserve $Zone_i$

PRM_{UCAPi} = PRM_{UCAP} for Planning Reserve $Zone_i$ and/or state.

The purchasing and selling parties will be required to enter and verify the FRP/FRS transaction into the MECT full responsibility transactions screen. The parties must enter an FRP/FRS transaction into the MECT as a full responsibility transaction to enable MISO to track the load and reserve obligations shift.

6.8 Resource Plan and Designating PRCs

6.8.1 Procedures for Submission of Annual Resource Plans

By 11:59 p.m. EST on March 1 of each Planning Year, each LSE shall submit to MISO through the MECT, the LSE's Resource Plan by designating PRCs toward meeting its PRMR for the upcoming Planning Year. LSEs will have the opportunity to update their Resource Plans as they are finalized. The annual Resource Plan input through the MECT must contain the following information for each month for the applicable Planning Year:

- **Forecasted Demand** – The LSE must report to MISO their Demand forecast by Load-zone CPNode. All forecasted Demand shall include all losses.
- **Losses** - The LSE must report transmission losses through the MECT.
- **LMRs** – The LSE must report information regarding their LMRs to MISO.
- **Full Responsibility Purchases and Sales** – LSEs need to submit their purchases and sales in which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within the MISO Region, sellers are responsible for all of that LSE's PRMR associated with the sale. FRP and FRS are represented as an adjusted load reduction and addition respectively.

- **Designated PRCs** - LSEs are encouraged to designate the PRCs that will be used to meet the LSE's PRMR for each month of the Planning Year, from the PRCs that are available in the MECT. However, this designation is not required until the time of the Resource Plan Deadline for each Month (which is 11:59 PM EST of the first Calendar Day of the Month prior to each Month for which there exists a PRMR).

6.8.2 Procedures for Submission of Monthly Resource Plans

No later than the Resource Plan Deadline,, each LSE shall document its compliance via the MECT that for that Planning Month the LSE has a Resource Plan that includes a sufficient number of designated PRCs to meet the LSE's PRMR (called 'Obligation' in the MECT).

LSEs shall submit updates, via the MECT, to the forecasted Demand, FRP/FRS, or Capacity Resources and the associated PRCs designated to meet the LSE's PRMR by the Resource Plan Deadline. MISO will conduct an analysis on a monthly basis at the Resource Planning Deadline, to determine whether forecasts from the Annual Resource Planning Deadline have changed. Each LSE shall promptly notify MISO via email of any significant (20%) revision to its Forecasted Demand in the MECT.

MISO shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state utility commission, or FERC, subject to the confidentiality provisions of Section 38.9 of the Tariff.

6.8.3 Validation of Firm Transmission Service for Load

Each LSE shall document to MISO that the LSE has obtained sufficient firm Transmission Service for each Month adequate for its Load to be served. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement, when applicable. However, Demand does not require firm MISO Transmission Service provided that the LSE meets its PRMR using its own BTMGs and DRs and does not use the MISO Transmission System to serve such Demand.

6.8.4 Agency Contracts Supporting Resource Adequacy Requirements [68.4]

An LSE may contract with other entities to comply with RAR. The contracted for entity would perform functions on behalf of the applicable LSE including but not limited to submitting the LSE's forecasted Demand, committing Planning Resources, representation at stakeholder meetings, etc. Each individual LSE is ultimately responsible for conformance with the RAR, even if it enters into a contract with a third party acting on its behalf. Each LSE that contracts with another entity to demonstrate compliance with any part of Module E must notify MISO of the arrangement. The LSE must provide MISO with: the name of the organization representing them; primary and alternate contact information for the individuals representing them; and the scope of responsibilities the contracted for entity will provide.

7. Complying with Module E of the Tariff

7.1 Purpose

This section outlines the various process that MISO and MPs must follow in order to comply with the requirements in Module E of the Tariff including LSE deficiency determination, distribution of deficiency charges, Cost of New Entry (CONE) calculation, must offer compliance monitoring, and after-the-fact LSE Demand forecast assessments.

7.2 Intended Audience

This section is intended for all MPs who have a Module E compliance obligation.

7.3 Overview and Timeline

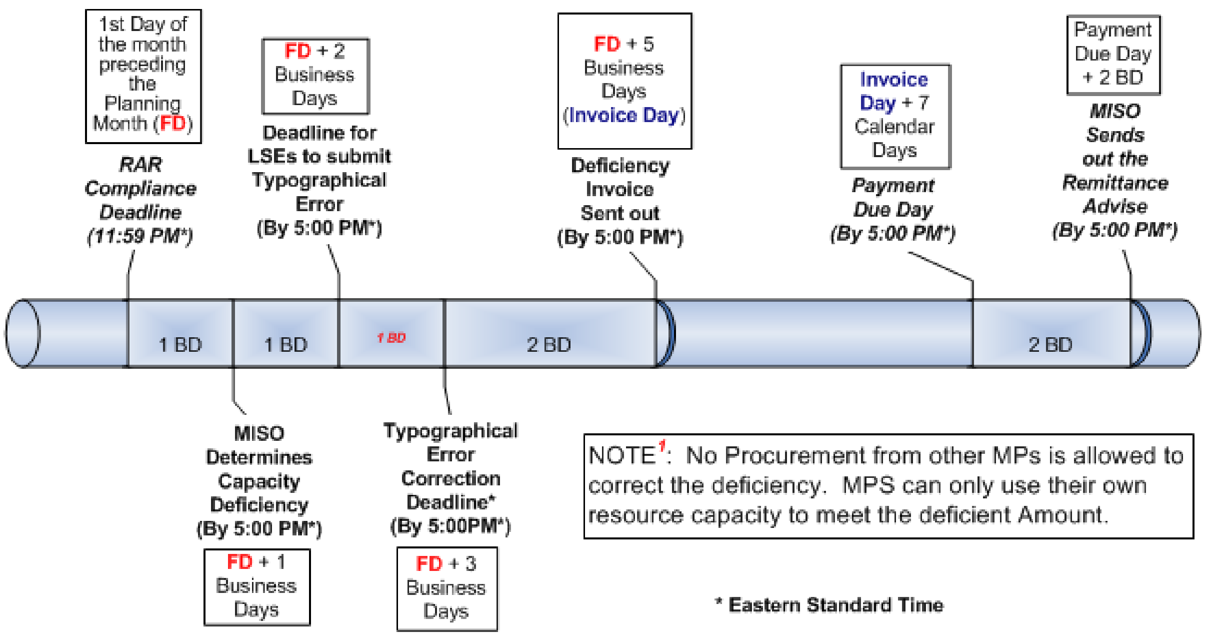
Each LSE shall no later than the first day of the month prior to the Planning Month, update the MECT with revisions to its Resource Plan for the Planning Year and shall demonstrate continued adherence to the RAR standards. LSEs shall remain committed to the required transmission capability to the extent required to ensure deliverability of the Capacity Resources supporting PRCs.

MISO will maintain databases and will report to states upon request the extent to which each LSE has met or has not met the requirements in Section 69.1 of the Tariff during relevant time periods, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

MISO will, at a minimum, conduct the following evaluations: (1) the annual Resource Plan evaluation will be provided in March for the next Planning Year. (2) a pre-compliance evaluation will be conducted one (1) Month prior to the Resource Plan Deadline; (3) on the first Business Day after the Resource Plan Deadline each LSE's Resource Plan will be evaluated to determine if the LSE is deficient for the following Month.

7.3.1 Timeline

Timeline for the Monthly Deficiency Procedures



7.4 Determination of Whether an LSE is Deficient

On the first Business Day after the Resource Plan Deadline, MISO will utilize the MECT to determine if the LSE is deficient for the following Month and will electronically notify the LSE of any deficiency. An LSE will be allowed to correct any errors in the MECT where the LSE has sufficient PRCs in the MECT at the time of the Resource Plan deadline, but has failed to designate those PRCs to meet its PRMR.

If an LSE is deemed deficient but the LSE believes that such a determination due to an error and that the LSE actually has sufficient PRCs, then the LSE shall have the opportunity to utilize

MISO’s dispute resolution procedures to justify why it should not be subject to a Financial Settlement Charge.

7.5 Assessment and Calculation of Deficiency Charges

Prior to imposing a Financial Settlement Charge, MISO will notify an affected LSE of its right to correct typographical errors in the MECT. If an LSE is deemed deficient solely because the LSE has failed to designate sufficient PRCs in the MECT to be used to meet the LSE's PRMR, even though the LSE has adequate PRCs in the MECT that could be designated, then MISO will consider such inaction to designate available PRCs to be a "typographical error" in accordance with Section 69.8.b of the Tariff. In such a situation, MISO will provide such LSE with 24 hours to correct the typographical error in the MECT and to designate the LSE's available PRCs to meet its PRMR before MISO assesses a Financial Settlement Charge to the LSE.

Where an LSE is determined to be capacity deficient through the procedure described in Section 7.4 of this BPM, the LSE will be responsible for the payment of a Financial Settlement Charge via a separate invoice issued by MISO. The amount of the Financial Settlement Charge will be calculated by taking the number of MW-months an LSE is deficient for such month and multiplying that amount by 100% of the appropriate CONE value, depending upon the month in the Planning Year when the deficiency occurs and any prior Capacity deficiencies that the LSE incurred during the Planning Year.

The Financial Settlement Charge for the initial Capacity deficiency during a Planning Year shall be calculated as follows: the product of the number of MW months that an LSE is Capacity deficient during such month times 100% of the CONE value. For subsequent Capacity deficiencies during a given Planning Year, which are equal to or less than the initial Planning Year Capacity deficiency, the Financial Settlement Charge shall be calculated as follows:

(1) a subsequent Capacity deficiency during the months of July or August shall be the product of the number of MW months that an LSE is Capacity deficient during such month times 25% of the CONE value;

(2) a subsequent Capacity deficiency during the month of December, January or February, shall be the product of the number of MW months that an LSE is Capacity deficient during such month times 25% of the CONE value; and

(3) a subsequent Capacity deficiency during September, October, November, March, April, or May, shall be the product of the number of MW months that an LSE is Capacity deficient during such month times 8.3% of the CONE value.

If an LSE has an increase in its Capacity deficiency in subsequent months greater than the maximum of the Capacity deficiencies during the previous months in the Planning Year, the incremental amount above the maximum of the previous months will be assessed a Financial Settlement Charge equal to the product of the incremental number of MW months that an LSE is Capacity deficient during such month times 100% of the CONE value.

7.5.1 Distribution of Financial Settlement Deficiency Revenues

Revenues from Financial Settlement Charges levied upon LSEs that are deficient will be distributed by MISO to LSEs on a *pro rata* basis, based on the MW of monthly peak Demand Forecast of those LSEs that have met or exceeded their RAR in the applicable Planning Reserve Zones ("PRZs") during the Month. For the initial Planning Year, the PRZs will be those zones shown in Attachment FF-3 of the Tariff. LSEs eligible for distribution of FSC revenues will receive the remittance advice letter with details on the distribution two (2) business days after the FSCs are collected.

Capacity deficiencies are determined as the difference, only if it is negative, between the amount of Planning Resources committed for the Planning Month less the Forecast LSE Requirement times one (1) plus the PRM. Capacity deficiency will be evaluated by CPNode but will be determined separately for each PRZ in which the LSE has a load serving obligation. MISO will notify the LSE of the amount of any deficiency. Any LSE deemed Capacity deficient will be liable for the Financial Settlement Charges for the given month.

An LSE is Capacity deficient if the following equation results in a value less than zero after the Resource Plan Deadline:

Σ(Capacity Resources and BTMG committed to load at the CPNode) – {(CPNode forecasted Demand - Σ[CPNode Demand Resources]) X [1 + CPNode PRM in which the LSE serves load]}

7.6 Ongoing Calculation of CONE

For the Planning Year that commenced on June 1, 2009, the monthly CONE was established as $80,000/MW thereafter, MISO will work with the Independent Market Monitor (IMM) to recalculate CONE annually by August 1 of each year, for Planning Years after the initial Planning Year. In calculating the CONE value, the IMM and MISO will consider the following factors:

- physical factors: type of resource, location, costs for fuel
- financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE, MISO will make a filing with the Commission under Federal Power Act Section 205 seeking approval from the Commission for the re-calculated CONE.

The table below contains the CONE values for each Planning Year:

Planning Year	CONE Value $/MW
2009 - 2010	80,000
2010 - 2011	90,000
2011 - 2012	TBD

7.7 Must Offer Requirement and Monitoring

Commencing on March 1, 2010, at a minimum on a monthly basis, MISO will monitor whether the Offers in the Day-Ahead Energy and Operating Reserve Market and first post Day-Ahead RAC process meet the must offer requirements of the Asset Owner of each Capacity Resource that created PRCs. MISO will compare the difference between the Emergency Maximum Limit (MW) or scheduled maximum (MW) offer and the must offer requirement (MW) for each hour of each day. If the Offers for Day Ahead and/or Forward RAC are less than the must offer requirement, then MISO will compare the difference to derates in the MISO Outage Scheduler (CROW) for such resources. Planned outages in the Outage Scheduler (CROW) and Offers at the DA Market close and FRAC close will be used in the must offer monitoring process. Outages, derates and Offers will be captured based on the information provided at both the DA Market close and FRAC close. Exact times for DA Market close and FRAC close are reflected in the Energy and Operating Reserve Markets BPM. MISO will apply a tolerance threshold to all resources based on the Must Offer Requirement reported in the MECT to recognize that data entry errors could occur when providing derate volumes through the MISO Outage Scheduler (CROW). The tolerance threshold will be applied at the CPNode level except for those resources noted otherwise in this BPM. . The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

If the difference including the appropriate threshold is documented in the MISO Outage Scheduler (CROW) as a derate for such hours, then the MP will have passed the must offer monitoring check. If the difference is not documented as a derate or full outage, then the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the MECT portal if they do not pass the monitoring check. If a Market Participant believes there is a discrepancy in their must offer report, the Market Participant can notify MISO in writing of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage. MISO will review the information submitted and notify the Market Participant within seven (7) business days via email of the outcome of the review.

The IMM also has access to the reports published on the MECT portal and may contact Market Participants directly regarding any compliance issues.

7.8 After the Fact Demand Assessments

Forecasted Demand:

LSEs have the option to submit data as outlined in Section 6.5 of this BPM in addition to their forecasted Demand (Section 6.4 of this BPM) in the MECT to provide MISO with standard deviation data and information to normalize the forecasted Demand for weather, price, and retail load shifting. On a monthly basis MISO will review the data submitted by an LSE for the appropriate Month to evaluate the accuracy of the forecasted Demand per CPNode submitted by each LSE for such Month. Since the MECT allows data entry rounded to the nearest tenth of a MW, the assessment is conducted accordingly. While MISO will conduct this assessment for each CPNode, LSEs will only be reported to their applicable state authority/authorities if the LSE has under forecasted on an LSE wide basis.

The Following Planning Month section in the MECT under Assessment for Under-Forecasted Demand will be open for two months following the planning month. Following the closure of the after the fact window MISO will contact the LSE with their under forecast information if under forecasted on an LSE wide basis within 15 calendar days and will request a response from the LSE by the last day of the current month. MISO will send the letters to the applicable state authorities within 15 calendar days of the month following that. The letter will include the response from the LSE

MISO will analyze whether the LSE has Under Forecasted its Demand at a CPNode. An Under-Forecast is the negative difference between the forecasted Demand minus transmission losses plus standard deviation, if provided by the LSE, and measured Demand after adjustment for actual weather conditions, retail Load changes and actual LMPs at each CPNode. The measured demand is the most recently updated meter data reported to MISO at the time of the assessment. If data is available, MISO will normalize the values for weather, price, and/or retail load shift. To be able to make these adjustments, the LSE must provide MISO with the following data for each adjustment due to the weather or LMP or other normalization adjustment variable:

- Definition of the variable used in the forecast
- Actual and forecasted values for each variable
- Associated elasticity for the variable with respect to Demand

The normal variable used in the assumptions needs to be entered into the MECT tool prior to the first day of the month. After the fact variable information must to be entered into the MECT by the last day of the second month following the Planning Month. The methodology employed by the LSE must be credible, replicable, and defensible. For all information entered into the MECT the LSE must be able to provide MISO with supporting documentation if requested. For example, for retail Load changes, the LSE must be able to provide documented evidence of when and how much retail Load increased during the period from the first day of the preceding month of the Planning Month through the Planning Month.

If MISO determines that an LSE Under-Forecasts its Demand, after accounting for any actual weather conditions and other normalization adjustments during such Month, MISO will notify the LSE of the Under-Forecast and request a written response detailing the reasons for the Under-Forecast.

For the time-periods identified below, MISO will inform applicable state authorities of all Under-Forecasts that are statistically significant with respect to an LSE’s total forecasted demand after taking into account weather and other normalizations:

- Under-Forecasts for one (1) Month between June 1 and September 30 of the same calendar year; or,

- Under-Forecasts for three (3) consecutive Months.

"Statistical significance" means rejection of the null hypothesis that the actual Demand falls within the forecasted Demand, plus or minus 1 standard deviation.

An example of the methodology that MISO will utilize to analyze load forecasts is located in Appendix B of this BPM.

MISO and LSE will work together to resolve any deficiencies identified in the load forecasting process. An industry-accepted methodology for load forecasting processes is described below.

A generally accepted step by step approach is described below:

a) A detailed development of the forecasting problem, including well-defined variables (*e.g.*, econometric, time series (state space, time series), end-use, or hybrid);

b) Complete description of the data used in the analysis;

c) Methodology employed and mathematical specification of the approach;

d) Statistical measures of evaluation of fit; and

e) Forecasts employed, including forecasts of driving variables and sources used for each.

For a numerical example please see Appendix B.

8. The Voluntary Capacity Auction

8.1 Purpose of Voluntary Capacity Auction System

The VCA system is a Web based application used by LSEs to make bids to buy APRC or by MPs to make offers to sell APRCs through MISO monthly capacity auctions. The system is also used by the MPs to view their respective auction results and/or to create APRC transactions.

8.2 Intended Audience

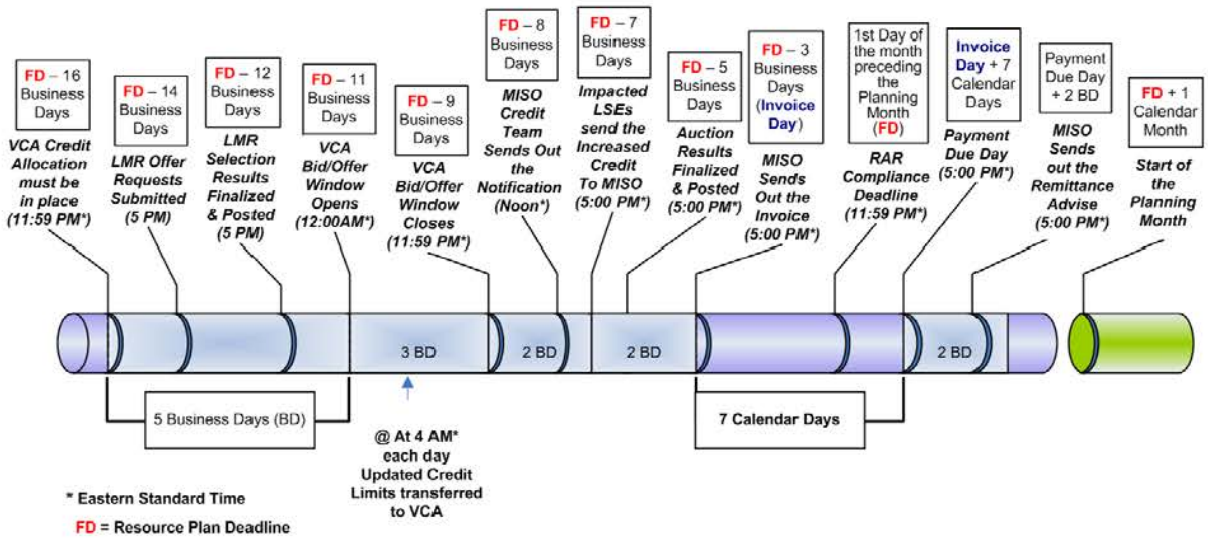
This section is intended for MPs that own APRCs who want to offer such PRC into the VCA and for LSEs who have Planning Reserve Margin Requirements with sufficient Credit to bid for APRCs in the monthly Voluntary Capacity Auction.

8.3 Overview and Timeline

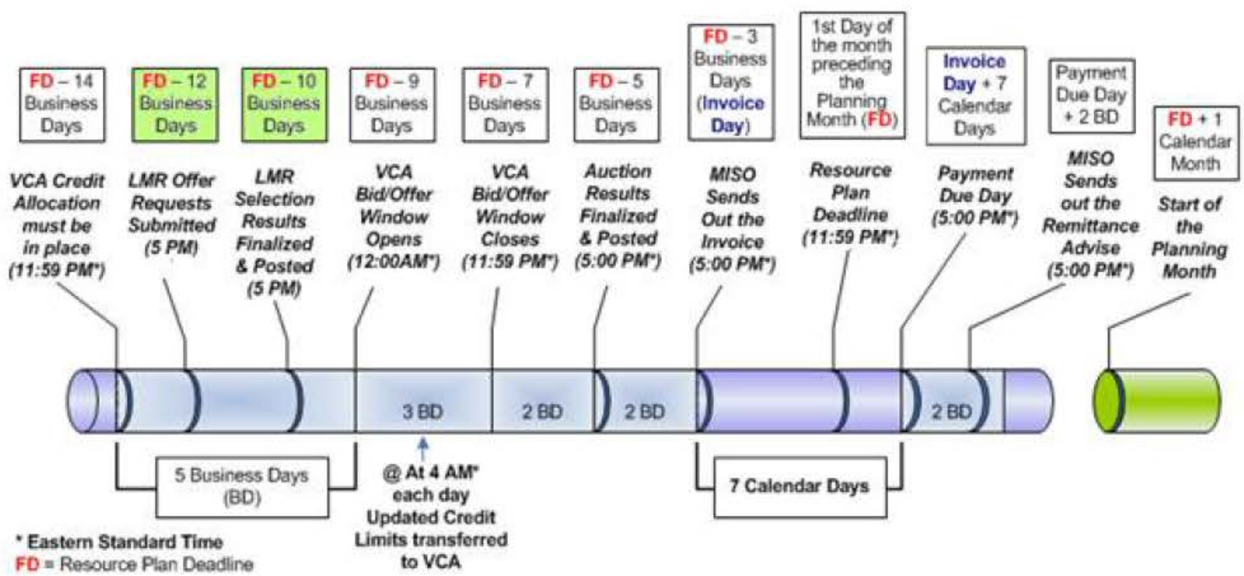
The VCA Settlements follows a calendar month billing cycle. One business day after the auction results are finalized and posted, the VCA system passes the necessary data to the Oracle Financial system of the MISO Finance Department. At that time invoices are generated by the Finance Department and distributed via the MISO Market portal.

The VCA Timeline is documented in the diagram below:

Timeline for the Monthly Voluntary Capacity Auction



Timeline for the Monthly Voluntary Capacity Auction



8.4 Voluntary Capacity Auction Procedures

The purpose of the monthly VCA is to facilitate the procurement of APRCs and to encourage bilateral contracting by LSEs prior to the Resource Plan Deadline, in order to help LSEs fulfill their PRMR. The VCA accomplishes this by providing an optional monthly forum for APRC sellers and APRC buyers to interact in order to buy and sell APRCs. Those LSEs that are interested in acquiring APRCs may participate in the voluntary capacity auction in order to attempt to obtain the necessary APRCs to meet their PRMR. To that end, MISO will conduct a VCA five (5) Business Days prior to the Resource Plan Deadline each Month. LSEs will have the option of submitting bids for APRCs (APRC Bids) and MPs (suppliers) will have the option of submitting offers for APRC (APRC Offers) as described below.

8.4.1 APRC Bids

MPs interested in procuring APRCs through the VCA, must submit their APRC Bids at least nine (9) Business Days prior to the Resource Plan Deadline via the VCA system. In submitting their APRC Bids to MISO, MPs must indicate the quantity of APRCs that the MP is seeking and a corresponding price that the MP is willing to pay for those APRCs on a monotonically decreasing basis, in the form of a downward sloping, stepped down, bid curve consisting of not more than five (5) price/quantity paired segments. MISO's Credit Policy, as expressed in Attachment L of the Tariff, provides that any party taking service under the Tariff must have an approved credit application and must establish a Total Credit Limit with the MISO Credit Department in accordance with The MISO Credit Policy. In accordance with that policy, an MP's APRC Bids may not exceed the share of that MP's Total Credit Limit allocated to the VCA (Credit Limit). MPs will establish their Credit Limit as early as sixteen (16) Business Days prior to the First Day of the month preceding the Planning Month until the end of next five (5) Business Days when VCA Bid/Offer Window is opened. During the VCA Bid/Offer Window period, MPs are not allowed to decrease their Credit Limit.

A participating LSE's RAR Auction Credit Requirement will be calculated as the lesser of $1,000/MW for bids submitted or the output from the following formula:

$$\sum_{p \in P} MPB_p$$

Where:

MPB = The maximum of all price points specified for a given positive RAR Bid, calculated as the MW value specified for the price-point, times the dollar value per megawatt specified for the price-point

P = Set of all positive RAR Bids to be submitted by a given Market Participant during an open RAR Auction bid window.

8.4.2 APRC Offers

Similar to the process for submitting APRC Bids, MPs that choose to participate in the VCA must submit APRC Offers at least seven (7) Business days prior to the Resource Plan Deadline. MPs may only submit APRC Offers that have not been designated via the MECT. MPs may enter into bilateral transactions through MISO's electronic bulletin board to acquire or sell LPRCs and/or EPRCs.

In order to validate and confirm APRC Bids and APRC Offers, APRCs offered into the auction will not be available for other transactions unless the offer is removed by the MP prior to the bid/offer window closing. Once the results of the VCA are posted, APRCs that have not cleared the auction will be made available for other transactions. Prior to running the VCA, MISO will ensure that an MP's APRC Offers do not exceed the available APRCs of that MP for the Planning Month for which they have offered their APRCs into the VCA. In the event that an MP's APRC Offers exceed the available amount of APRCs, the APRC Offer will be rejected and the MP will be invited to submit a new APRC Offer.

APRC Offers must indicate the quantity and price on a monotonically increasing basis, in the form of an upward sloping, stepped up offer curve consisting of not more than five (5) APRC price/quantity paired segments. The APRC Offer price for an APRC may not exceed the CONE as calculated by MISO.

APRC Offers which did not clear in the auction will be available to the MP for other transactions once the results of the auction are posted.

8.4.3 Deliverability of LMRs in the VCA – Interim method

Market Participants (MP) interested in offering their PRCs from LMR in the VCA (LMR Offer) are required to submit their requests via MECT at least three (3) business days prior to the start of the VCA. MPs will indicate which LMRs they are planning to offer in the VCA. If the LMR being offered was previously used to net against the LSE's Demand Forecast, the LMR Offer will increase the LSE's obligation by the full amount of LMR with additional PRM as a result. If an MP chooses to offer less than the full amount of the LMR that was netted, then the LMR must be converted to PRC before the MP can make the request.

Once the LMR Offer requests are received, the MISO Resource Adequacy Department will evaluate the requested LMR offers for the selection process. The results of the evaluation will be posted in MECT no later than 1700 EST one (1) business day prior to the start of the auction. The results will show the list of selected LMR Offers and their maximum amount of allowable offers.

Evaluation Method

Based upon the LSE's simple average historic use of APRCs during the three (3) months prior to the VCA for the Load CP Node being evaluated, the MISO Resource Adequacy Department will first determine the maximum amount of LMR allowed to offer at each Load CP Node. The total amount of LMR Offers into the auction cannot exceed the three (3) months average use of APRCs at the Load CP Node. If LMR Offers at a Load CP Node involve more than one (1) MP, then each MP's allowed offer amount will be determined on a "pro rata basis", based on the amount of MPs' allowed offer at that Load CP Node. (See the Example 1 in Appendix H.) Procedures for LMR Offer in the VCA will be consistent with that of APRC offers described in Section 7.4.2 – "APRC Offers". The LMR Offers (part or all) that were not cleared by the VCA will be added to MPs' Available LPRCs for the appropriate Load CP Zone. If the uncleared LMR Offer from an MP involves more than one (1) Load Zone, then the uncleared portion will be added to the MP's Available LPRCs for the appropriate Load CP zones on a "pro rata basis", based on the amount of LMR Offers submitted from each Load CP Nodes (See Example 2 in Appendix H.)

8.4.4 VCA Monitoring

All participants in the VCA will be subject to the provisions of Module D of the Tariff. MISO will report any suspicion of potential market power abuse to the IMM, including, but not limited to the exercise of physical or economic withholding of Planning Resources. The monitoring procedures that MISO and the IMM will use are documented in the Market Monitoring and Mitigation BPM.

8.5 Clearing Process

8.5.1 Initial Clearing of the VCA

The initial clearing of the VCA will commence with MISO reviewing the APRC Bids and APRC Offers for the applicable Month to determine which APRCs will be cleared through the auction. MISO will use an automated clearing process to make this determination. The clearing process will operate such that APRC Bids will be stacked, starting with the highest priced APRC Bid and continuing in that manner until all received APRC Bids have been compiled. Similarly, APRC Offers will be sorted such that the lowest priced APRC Offer will be first, followed by the next lowest priced APRC Offer until all offered APRC Offers have been included.

MISO will compare the APRC Offers to the APRC Bids to determine the APRCs that clear because the APRC Bids are at or higher than the respective APRC Offers. MISO will identify the quantity in MW-month and the associated price of the highest price APRC Offer that clear the auction, which will become the Auction Clearing Price (ACP) for all APRCs for that particular month. The ACP shall occur where the cost associated with providing the last incremental amount (the marginal APRC Offer) equals the value associated with the marginal APRC bid for the same incremental amount of APRCs. Each MP whose APRC Offer clears in the auction will receive the full ACP for the APRC volume cleared. APRCs acquired through the auction will be transferred to the appropriate MECT account but will not be designated in the MECT.

8.5.2 Potential for Re-Clearing of VCA

The Transmission Provider will re-clear the VCA if after the initial clearing of the VCA the following occurs: i) the auction clearing price exceeds the cap of $1,000/MW and; ii) an LSE's established RAR Auction Credit Allocation is insufficient to cover the updated RAR Auction Credit Exposure as described below:

If the situation as described above were to occur, MISO Credit team will inform the applicable LSEs in writing that they have two business days, from the date of communication, to increase the RAR Auction Credit Allocation to a level that equals or exceeds the updated RAR Auction Credit Exposure. If said LSE does not sufficiently increase the RAR Auction Credit Allocation to meet the request, the LSE's bids will be rejected and MISO will re-clear the VCA absent the rejected bids.

8.5.3 Determination of Voluntary Capacity Auction Clearing Price

MISO will maintain an internal, auditable, non-public information system to allow for the analysis and then acceptance or rejection of APRC Bids and APRC Offers, which will also provide a record of all bids and offers that are made. Once the VCA has been completed, MISO will publicly post information regarding the total amount of APRCs bid and offered into the VCA (*e.g*. 1000 MW) and the total amount of APRCs that cleared the auction, as well as the ACP. Three (3) months following the close of the auction, MISO will post the individual APRC Bids and APRC Offers, while keeping confidential the names of the corresponding MPs that participated in the VCA.

8.6 Settlement

MISO will settle the VCA by charging the ACP for that Planning Month to MPs with cleared APRC Bids and crediting MPs with cleared APRC Offers, based on the ACP that is established for APRCs for the Planning Month. The invoice (charge) will be available in the Market Portal in two (2) business days after the VCA has been cleared. The payment of the charge will be due within seven (7) calendars days after the invoice is published. Two (2) business days after the charges are collected; the MISO Finance group will credit MPs who have cleared the APRC offers during the VCA. Since the amount of cleared APRC Offers must be exactly equal to the amount of APRC Bids cleared (and both the cleared APRC Offers and cleared APRC Bids are both settled at the ACP), the settlement of the auction clearing does not require any uplift or revenue inadequacy adjustment. APRCs not cleared in the VCA may be sold bilaterally. See the timeline diagram for the VCA included above.

9. Testing Procedures and Requirements

9.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix L of this BPM.

9.2 Midwest Reliability Organization - MRO

The MRO Generator Testing Requirements can be found at:

See MRO's website for testing requirements

9.3 Reliability First Corporation - RFC

The Generator Verification Data Reporting standard drafting team is developing an RFC standard on generator verification to be approved by the Board of Directors. Until that standard is approved, each generator owner remains responsible for testing or verifying the capacity ratings of their generators in accordance with its legacy region's requirements. Generator owners in the former MAIN and ECAR regions can find reporting forms below that are available to download and complete. Completed reporting forms can be submitted to Paul Kure (paul.kure@rfirst.org) at the Reliability*First* office. Former MAAC members will continue to submit their generator test/verification data via the PJM eGADS system.

ECAR Generator Forms (DOC) | MAIN Generator Forms (XLS)

The ECAR Generator Testing Requirements can be found on Reliability First's website.

The MAIN Generator Testing Requirements can be found on Reliability First's website. :

The "Draft" RFC Generator Testing Requirements can be found on Reliability First's website.

9.4 SERC Reliability Corporation – SERC

The SERC Generator Testing Requirements can be found on SERC's website.

9.5 North American Electric Reliability Corporation – NERC, MOD 24

The NERC Verification of Generator Gross and Net Real Power Capability Standard, “MOD – 024 – 1 can be found on NERC’s website.

10. Appendices

Appendix A – Planning Reserve Zone Determination

Beyond the Midwest Transmission Expansion Plan (MTEP) planning areas identified in Attachment FF-3 of the Tariff, MISO intends to review the system and determine the extent to which transmission constraints on the system present barriers to the reliable sharing of generation across the market footprint. While more granular zones may be required to model the congestion effects in GE MARS, congestion is a separate issue from whether or not the zones warrant different PRMs. Further analysis with the GE MARS application will be conducted to resolve whether a different Planning Reserve Margin is warranted for different zones.

Any additional zones will be developed from an annual Security Constrained Economic Dispatch (SCED) Locational Marginal Pricing (LMP) simulation of the Market and surrounding equivalent areas. This process is described below:

Step 1: Identify the busses in the annual SCED simulation that realize positive hourly values of Marginal Congestion Component (MCC), and also identify the busses that realize negative MCC values. In the same manner create a second list by restricting the identification of busses to only the months June through August, identifying the busses that realize only positive hourly values or MCC, and the busses that realize only negative MCC values.

Step 2: From the set of busses found in step 1, retain up to 30,000 of the largest positive MCC values, and retain up to 30,000 of the largest negative MCC values. If no congestion occurs on the system, there will be no MCC values; and the system is appropriately represented by one single neutral zone. From the annual set, create a June through August subset.

Step 3: Geographically locate the busses associated with the up to 30,000 most positive MCC values and the busses associated with the up to 30,000 most negative MCC values. When plotted, the locations reveal clusters of same sign MCC busses, which are precursors to LOLE zones. The remaining geographic areas apart from the clusters of same sign MCC busses define a neutral zone. Sort the busses into three groups: busses that have only positive MCC values, busses that have only negative MCC values, and busses that have zero or mixed sign MCC values. An annual version and a June through August version of this plotted information will be developed based on the two sets identified from results from step 2.

Step 4: The annual versus June through August sets of results are reviewed in order to determine which set best reflects the overall congested areas on the system and should be used going forward in step 5. This review is conducted considering the following:

a. Review of commonly realized issues relative to historical congestion or of Narrow Constrained Areas (NCAs) while recognizing that the modeled year may include certain transmission and generation facilities and load patterns that were not reflected in the historical experience. Such review will be conducted with stakeholder participation.

b. The general knowledge about the transmission system and the facility additions that have been planned through the MTEP process.

c. Review use of shorter periods of time, such as one month for example. Consider sorting data by time-of-day or other methods that would result in useful perceptions.

Step 5: Once the decision has been made to use the annual set or the June through August or some other chosen subset of the data found to focus on the most extensive and typically congested conditions set in step 4, the grouping of adjacent clusters with the same sign MCC busses, plus the inclusion of the neutral busses in an otherwise void portion, is used to create a zone which is a contiguous set of busses. Neutral busses may also be acquired to complete the representation for the zone as a reasonable contiguous geographic area determined by factors such as, but not limited to, being in or out of the MISO Market, major bodies of water and dividing properties of the underlying transmission infrastructure. These bus-contiguous zones (based on the precursor information in step 3) qualify as zones to model in an LOLE study when the following conditions are met:

a. The collection of busses forming the zone is within the MISO Market. Clusters outside of the Market may be modeled in the LOLE simulation, however they will not emerge as a zone for PRM determination obligations applicable to LSE's load in the Market.

b. A zone will be sustained for modeling if it contains either greater than 2,000 MW of generation or 2,000 MW of load, however a zone will not emerge as a zone for PRM determination obligations applicable to LSE's load in the Market unless the zone contains a modeled peak load value of no less than 2,000 MW.

Step 6: The positive MCC zones found in step 5 above are the appropriate zones to model and analyze with an LOLE program to determine which of these zones can meet the reliability criteria requirements without relying on transmission ties to the adjacent system. If the LOLE analysis shows that the reliability criteria is met for a zone assuming no benefit from tie line capability, that zone is eliminated and merged into the neutral zone. The remaining zones (from step 5) will undergo the LOLE analysis to determine what reserve level is necessary for the zone to meet the reliability criteria including the benefit of the Effective Import Tie Capability (EITC) into a zone from the balance of the system, which is determined in step 7. PRM is related to where LSE load is located, and PRM will be uniform throughout MISO, unless the GE MARS results indicate that a particular zone cannot be considered part of the larger modeled pool representing MISO.

Step 7: The maximum utilization of transmission ties is the resulting level of MW transfer into a positive MCC zone, or out of a negative MCC zone that can be achieved reliably within the bounds of maintaining security as the system is dispatched on a SCED basis, and can include adjustments warranted in step 7b. Both the EITC into positive MCC zones and the Effective Export Tie Capability (EETC) out of negative MCC zones are measured by summing the simulated flows on transmission ties into or out of the zone utilizing a SCED model described in steps 7a, or 7b as warranted.

a. A forced dispatch scenario of the SCED simulation is used to observe both the EITC into positive MCC zones and the EETC out of negative MCC zones. This scenario incorporates adjusting generator fuel prices upward in positive MCC zones and downward in negative MCC zones so that the resulting power flow on the tie lines will have emulated maximum power flow that can be simultaneously transferred throughout the transmission grid modeled in the simulation.
b. In addition to maximizing utilization of transmission ties as determined by the step 7a SCED simulation, supplemental analysis to further aid in determining the EITC to an area, may also be performed using a Transfer Capability Analysis Tool (TCAT) or other conventional tools such as a power flow model. The TCAT and other types of engineering tools focus on modeling a moment in time calculation versus the extensive hourly calculations provided via the SCED type of analysis. The findings from such analysis may be used to adjust zone boundaries where for example a critical generator moves from one adjacent zone to another, and is shown to reflect less or no load at risk in one zone while not adversely affecting adjacent zones to the extent that load becomes at risk beyond the set criteria. Supporting analysis with a TCAT program or other tools is required if the year being studied is the next current year for implementing PRM levels, and when the EITC determined by the step 7a SCED simulation indicates a transfer capability that is either insufficient for an area to meet LOLE criteria, or achieves the LOLE criteria by only a small margin. A small margin would mean that the import transfer capability needed to achieve the LOLE criteria for a zone is greater than 90% of the EITC found in step 7a for that same zone.

Step 8: All zones found in step 7 to have adequate EITC to meet the reliability criteria to serve load are also merged into the neutral zone. Also, all zones with negative MCC values are merged into the neutral zone. All merged zones then acquire the overall PRM of the new resulting larger composite neutral zone, as determined by an LOLE analysis for the new composite neutral zone.

Step 9: Zones that are found in step 7 to not have adequate transmission tie capability to meet the required critical amount of EITC to meet reliability criteria for the current Planning Year are assigned the PRM obligation equal to the PRM in the merged zones in step 7, however the following will apply:

a. Such Zones are not treated as an integral part of the pool being modeled in GE MARS, because their need for resource support for adjacent zones exceeds the available transmission EITC. Continuing to run the GE MARS application in view of such relationship produces nonsensical results for the adjacent zones that can otherwise be reasonably treated as a pool when disassociated from EITC deficient zones.

b. An amount of load equal to the amount of load at risk in the zone shall be quantified by the study. Such quantification is the end of the study process and indicates that as studied there were insufficient resources in an area to achieve the reliability criteria. The study scope does not go further than identifying the problem. The LOLE study serves to quantify the problem for consideration in long term expansion planning, or as information upon which short term operating measures may be designed to cope with the situation. For example this information can be used to quantify how much firm load would be at risk, or the amount of firm load that would be desirable for conversion to non-firm.

c. Short term operation is defined outside of Module E, and would be in accordance with MISO Abnormal Operating Procedures, RTO-AOP-013-R2, and Transmission Emergencies Procedures, RTO-EOP-004-R5.

Step 10: Zone Planning Reserve Margin Requirements will be allocated to determine each LSE's PRM obligation. The PRMR is the long-term planning requirement for resource adequacy. It is equal to the Forecast LSE Requirement multiplied by one (1) plus the applicable PRM established either by MISO or established by the state having jurisdiction over the applicable LSE. If zones with different PRM obligations result due to insufficient EITC to some zones, either through the steps 1 through 8 or as a result of having a different

PRM assigned according to state regulations, the resulting PRM for each LSE shall be weighted by a calculation that reflects the share of an LSE's load in each zone.

Appendix B – Under Forecasting Assessment Example

Suppose LSE1 provides the following data to MISO on 1 May for the June planning period.

- ✓ forecasted Demand, inclusive of losses (F_{wl}): 1020 MW[1]
- ✓ loss factor used (LF): 20 MW
- ✓ forecasted Demand net of losses (F): F = F_{wl} -LF = 1000 MW
- ✓ Associated estimate of standard deviation (s): 40 MW
- ✓ Weather variable used in this example: Temperature of 80 degrees (choice of weather variable is dependent on the MP's specification. MISO is not advocating or mandating a certain weather variable be used.
- ✓ Estimated weather elasticity (ε_w), significant at the 95% level: 0.025[2]

[1] The numbers provide herein are illustrative only, used for purposes of providing an example for the types of ex post assessments that can occur.

- ✓ No price normalizations submitted[3]
- ✓ Retail load shifting is a possibility
- ✓ Actual weather variable assumed at peak in this example is 85 degrees.

Ex Post Assessment:

Suppose LSE1's actual Demand (A) is 1052MW.

1.) Is there an Under-Forecast inclusive of standard deviation but without any normalization?

Is A – (F + s) > 0?

A – (F + s) = 1052 – (1000 + 40) = 12 > 0

Yes. (If No, no further assessments are required.)

2.) What is LSE1's weather normalized Demand?

In this example we use actual temperature comparison:

(actual temperature – normal temperature) / normal temperature x elasticity

(85-80) / 80 x 0.025 = 0.0015625

Weather normalization amount = 1000 x 0.0015625 = 1.5625

Weather normalized forecast (F_{wn}) = 1000 + 1.5625 = 1001.5625 MW

3.) Is there an Under-Forecast with weather normalizations?

Is A – (F_{wn} + s) > 0?

A – (F_{wn} + s) = 1052 – (1001.56 + 40) = 10.44 > 0

Yes. (If No, no further assessments are required.)

[2] Elasticities are unit less numbers. In this case, $\boldsymbol{\varepsilon_w}$ = percentage change in Demand/ percentage change in Temperature .

[3] Price normalization work similar to weather normalizations, requiring supportable LMP price data and the associated price elasticity.

4.) Was there any retail load shifts (RLS) during May and June prior to the peak in June not accounted for in the forecast?

If Yes, LSE1 must provide documented evidence of when and how much retail Load increased (after accounting for and netting any retail Load lost to competitors) during the period.

Suppose LSE1 submits evidence of increased Load of 15 MW. Then, forecasted Demand adjusted for weather normalization and retail load shifts ($F_{wa\&rls}$) is:

$F_{wa\&rls} = 1001.56 + 40 + 15 = 1056.56$

5.) Is there an Under-Forecast with weather normalizations and accounting for retail Load shifts?

Is $A – (F_{wa\&rls} + s) > 0$?

$A – (F_{wa\&rls} + (s) = 1052 – 1056.56 = -4.56$

No. No further assessments are required.) If Yes, the following two steps as outlined in the BPM apply from the BPM for Resource Adequacy

Appendix C – Generator Testing and XEFORd details (OMC Codes

The following chart lists the GADS Cause Codes applicable to reporting outages to MISO:

GADS Cause Codes Outside Plant Management Control (OMC)

(As of January 1st, 2006)

3600	Switchyard transformers and associated cooling systems – external
3611	Switchyard circuit breakers – external
3612	Switchyard system protection devices – external
3619	Other Switchyard equipment – external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st Substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st Substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels

9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9250	Low Btu coal
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings 0 regulatory agency initiative
9502	Regulatory (nuclear) proceedings and hearings 0 intervener initiated
9504	Regulatory (environmental) proceedings and hearings 0 regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings 0 intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc)
9590	miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-0related factor contributed to the primary cause of the event)

Outside Management Control (OMC) Outages

There are outages from outside sources that result in generating units restricted in generating capabilities or in full outages. Such outages include (but are not limited to) ice storms, hurricanes, tornados, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated this list based on what PJM has adopted and these OMC codes will be the only codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

Appendix D – Registration of DRs

Demand Resource	
Registration Requirements	**Explanation**
Market Participant Legal Name	Enter your Market Participant legal name that you have registered with MISO.
Market Participant Contact Name	Enter the MP contact for this DR resource.
MP Contact Phone Number	Enter the MP contact phone number for this resource.
Market Participant NERC ID	Enter the NERC ID that represents your company's legal name.
Asset Owner of the DR	Enter the name of the entity that owns or has rights to this asset.
Local Balancing Area (LBA)	Enter the name of the LBA where the DR asset is located.
CPNode location of this DR Asset	Enter the CPNode where the DR asset is located.
Identification of DR	Enter a name for the DR to facilitate tracking in the MECT
City/Cities (where the LMR is located)	Enter the city or cities where the DR asset is located.
County/Counties (where the LMR is located)	Enter the county or counties where the DR is located.
State/States (where the LMR is located)	Enter the State or states where the DR is located.
Is this also an Emergency Demand Response Resource (EDR)?	Does this DR participate in the EDR program
If yes, name of the EDR Asset	Enter the registered name of the EDR.
Shut-Down Time (in hours, max of 12)	Enter the time (in hours) required to interrupt load. This value must be 12 hours or less in order to qualify as an LMR.
Maximum Number of Interruptions during the Summer Season (minimum of five (5) times)	Enter the maximum number of times a DR can be interrupted during the Summer Season. This value must be at least 5 in order to qualify as an LMR.
DR Duration (minimum of four (4) hours each occurrence)	Enter the maximum number of hours the DR can maintain its load reduction or firm services level. This value must be at least 4 hours to qualify as an LMR.
Effective Start Date of the DR	Enter the date that the DR will be available to reduce load. Must be available for an entire month in order to be used to meet RAR for a given month.
Effective Stop Date of the DR (optional)	Enter the date that the DR will be unavailable to reduce load.
Can this DR curtail to a firm service level?	Yes or No.
If yes, enter the firm service level (in MWs) that the DR can curtail	If yes, then enter the firm service level that the DR will curtail to and provide the Monthly Demand Reduction

Demand Resource	
Registration Requirements	**Explanation**
to and provide Monthly and Seasonal Demand reduction capability below. If no, provide Monthly and Seasonal Demand reduction capability below	capability.
Monthly Demand reduction capability (24 months for years 1 and 2) (list in MWs coincident with LSE peak monthly demand)	Enter monthly MW values associated with the reduction in load and coincident with the LSE's forecast Demand for each of the next 24 months.
Seasonal Peak Demand reduction capability (16 seasonal, for Summer Season and Winter Season only based upon NERC definitions for years 3 through 10) (list in MWs)	Enter 16 seasonal (Summer and Winter as defined by NERC definitions) MW values associated with the reduction in load and coincident with the LSE's forecast Demand for each season. Seasonal values shall be provided for the seasons beyond the 24 monthly values.
DR Operator Contact (24 x7)	Enter who to contact for deployment of DR. The contact should be available 24 x 7 for commitment by MISO or the LBA.
DR Operator Contact Phone Number (24 x7)	Enter phone number for the 24 x 7 operator.
DR Contact E-mail (24 x 7)	Enter e-mail address for the 24X7 operator.
Any limitation on the DR Participant's ability to reduce demand?	Yes or No.
If yes, describe	Please describe any limitations on a DR not being able to achieve a reduction. (*e.g.*, temperature sensitive, time of day, etc.). If the DR is temperature sensitive analysis, which may include weather elasticity chart.
Is the DR accredited by the state utility commission, past performance data or mock test, or accredited by a third party auditor?	
Please provide supporting documentation including testing procedures with past performance data or mock test results (required by tariff section 69.2.2.1(b)) based on state requirements or 3rd party assessments.	Please provide written documentation from the state, performance data or mock test or 3rd party that indicates approval (as required by section 69.2.2.1 (b) of the Tariff).
What type of load reduction protocol will be applied to this DR	Select the protocol that should be applied. This is used for determination of whether the LMR met its performance

Demand Resource	
Registration Requirements	**Explanation**
to measure response when called? 1. **Maximum Base Load**: A performance evaluation methodology based solely on a Demand Resource's ability to reduce to a specified level of electricity demand, regardless of its electricity consumption or demand at Deployment. 2. **Meter Before / Meter After**: A performance evaluation methodology where electricity consumption or demand over a prescribed period of time prior to Deployment is compared to similar readings during the Sustained Response Period. 3. **Baseline Type-I**: A Baseline performance evaluation methodology based on a Demand Resource's historical interval meter data which may also include other variables such as weather and calendar data. 4. **Baseline Type-II**: A Baseline performance evaluation methodology that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available	obligation.

Demand Resource	
Registration Requirements	**Explanation**
on the entire population. 5. **Other**: Please describe method and provide supporting documentation.	
Have you notified your LBA of the LMR?	Indicate if you have notified the LBA that this DR exists in their area.
Do you have a deployment plan in place with your LBA?	Indicate if you have a deployment plan in place with LBA where this DR is located.

Appendix E – Registration of BTMG

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Market Participant Legal Name	Enter your Market Participant legal name that you have registered with Midwest ISO.
Market Participant NERC ID	Enter the NERC ID that represents your company's legal name.
BTMG Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner of the BTMG	Enter the name of the entity that owns or has rights to this asset.
MISO Local Balancing Area (LBA)	Enter the name of the LBA where this BTMG asset is located.
CPNode location of this BTMG Asset	Enter the CPNode where the BTMG asset is located.
City (where the LMR is located)	Enter the city where the BTMG is located.
County (where the LMR is located)	Enter the county where the BTMG is located.
State (where the LMR is located)	Enter the state where the BTMG is located.
Is this an intermittent resource?	Yes/No
If yes, enter details of intermittent resource	Enter Unit Name, Size, Fuel Type, NRIS, and/or NonAgg IS if applicable.
Effective Start Date of the BTMG	Enter the date that the BTMG will be available to supply energy. Must be available for an entire month in order to be used to meet RAR for a given month.
Effective Stop Date of the BTMG (Optional)	Enter the date that the BTMG will be unavailable to supply energy.
Start up notification time (in hours)	Enter the notification time required to start this BTMG. Needs to be less than 12 hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 or from 0000 to 0000 acceptable)
Monthly BTMG Capacity (ICAP MW) (please list 12 months)	Provide 24 monthly MW levels associated with the installed capacity of the BTMG each month. Monthly values shall be provided for the first two years from the Effective Start Date.
Seasonal Peak BTMG Capacity (ICAP MW) (based on NERC definitions of Summer and Winter)	Provide 16 seasonal (Summer and Winter) MW levels associated with the installed capacity of the BTMG for each season. Seasonal values shall be provided beyond the 2 year monthly window.

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
BTMG Contact Operator (24 x7)	Enter who to contact for deployment of BTMG. The contact should be available 24 x 7 for commitment by the Midwest ISO or LBA.
BTMG Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
BTMG Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Is this an EDR?	Does this BTMG participate in the EDR program.
If yes, name of the EDR Asset	Enter the registered name of the EDR.
Are all necessary permits in place to operate this resource?	Indicate if all permits are in place in order for this resource to operate.
Do you hold all rights necessary to operate this resource?	Indicate if you hold all rights to operate or to the output of the resource.
What type of measurement protocol will be applied to this BTMG to measure response when called on during an EEA level 2 or higher event? 1. **Metering Generator Output**: A performance evaluation methodology, used when a generation asset is located behind the Demand Resource's revenue meter, in which the Demand Reduction Value is based on the output of the generation asset. 2. **Other**: Please describe method and provide supporting documentation.	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during an EEA level 2 or higher.
Have you notified your LBA of the LMR?	Indicate if you have notified the LBA that this DR exists in their area.
Do you have a deployment plan in place with your LBA?	Indicate if you have a deployment plan in place with LBA where this DR is located.

Appendix F – Registration of External Resource

External Resources	
Registration Requirements	**Explanation**
Market Participant Legal Name	Market Participant legal name that you have registered with MISO will be displayed on the registration screen
Market Participant NERC ID	NERC ID that represents your company's legal name.
Resource Description	Detailed description of the resource
Is this External Resource Direct Ownership or via a Power Purchase Agreement (PPA)?	Select Direct Ownership or PPA.
If PPA, is the capacity purchased at Installed Capacity (ICAP) or Unforced Capacity (UCAP) rating?	Select ICAP or UCAP.
If PPA, provide the Monthly MW value of the contract	Enter monthly MW values of contract.
Does this external resource need to have its	Select Yes or No.

External Resources	
Registration Requirements	**Explanation**
capacity increased to account for PRM and XEFORd (Capacity $_{new}$ = Cap$_{sumitted}$ x (1 + PRM) x (1 + XEFORd)) (this is most likely a scenario for Slice of MHEB and WAPA)?	
Does this Resource Submit Availability Data to MISO GADS	Select Yes or No.
GADS Generator Name	Select GADS Generator Name(s) from the list
MISO Local Balancing Area (BA) where the Resource(s) is/are located	Enter Local Balancing Authority (BA) where resource(s) are located.
External Balancing Area (BA) where the Resource(s) is/are located	Enter Regional Entity where external resource(s) is located.
Interface Commercial Pricing Node	Enter interface commercial pricing node where energy will be delivered to the MISO boundary.
MISO Local Balancing Area (LBA)	Select Local Balancing Authority (BA) where resource(s) are located.

External Resources	
Registration Requirements	**Explanation**
Sink Commercial Pricing Node(s)	Enter sink CPNode where energy will sink within the MISO boundary.
Regional Entity (where External Resource is located)	Enter Regional Entity where external resource(s) is located.
Effective Start Date of the External Resource	Enter date that the external resource is available to deliver energy. The external resource must be available for an entire month to qualify as a capacity resource to meet RAR.
Effective Stop Date of the External Resource (Optional)	Enter date that the external resource is no longer available to deliver energy.
Resource Operator Contact (24 x 7)	Enter contact information for who will be operating (dispatching) the external resource. The contact should be available 24 x 7 for commitment and dispatch by MISO or the LBA.
Resource Operator Contact Phone Number (24 x 7)	Enter phone number for the 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter E-mail address for the 24 x 7 operator.
Does this resource meet all qualification requirements for a use limited resource?	Select Yes or No

External Resources	
Registration Requirements	**Explanation**
Have you notified the host (where resource is located) BA of this capacity commitment to MISO?	Select Yes or No
Are you confirming that the capacity being registered to serve the Load in the MISO is not being used as capacity resources in any other RTO/ISO or in another state resource adequacy	Select Yes or No
List Transmission Provider (TP) and OASIS number for firm transmission to MISO border	Enter transmission provider and OASIS number for firm transmission to the MISO border. (External Resource to MISO interface commercial pricing node)
List OASIS and eDNR number for firm transmission on MISO transmission system	Enter OASIS and eDNR number for firm transmission on the MISO transmission system. (MISO interface commercial pricing node to MISO load CPNode)
Have you included or attached a copy of the applicable PPA?	Select Yes or No. (a copy of the PPA must be provided each Planning Year)

External Resources	
Registration Requirements	**Explanation**
Have you satisfied all other requirements applicable to capacity resources: 1. Provide GADS data 2. Available during emergency 3. Generator test information 4. Comply with Must Offer requirements 5. Sustained Commitment to maintain firm transmission from External resource to load	Select Yes or No.
Additional details on how you intend to meet the requirement prior to accreditation	Upload the document as needed
Submitter's Name	Enter the name of the person registering the resource.
Submitter's Email	Enter E-mail address of the person registering the resource.
Submitter's Phone Number	Enter phone number of the person registering the resource.

Appendix G1 – VCA Clearing Examples

In this example, we have 2 buyers (MB1 and MB2) and 2 Suppliers (MS1 and MS2) submitting Bids/Supplies as shown below:

Demand Bid: Submitted by PRC Buyers

	MB1		MB2	
Seg.	Price ($/APRC)	Demand (APRC)	Price ($/APRC)	Demand (APRC)
1	60	10	55	20
2	50	30	40	40
3	30	50	20	60
4	25	70	10	80
5	15	90	5	85

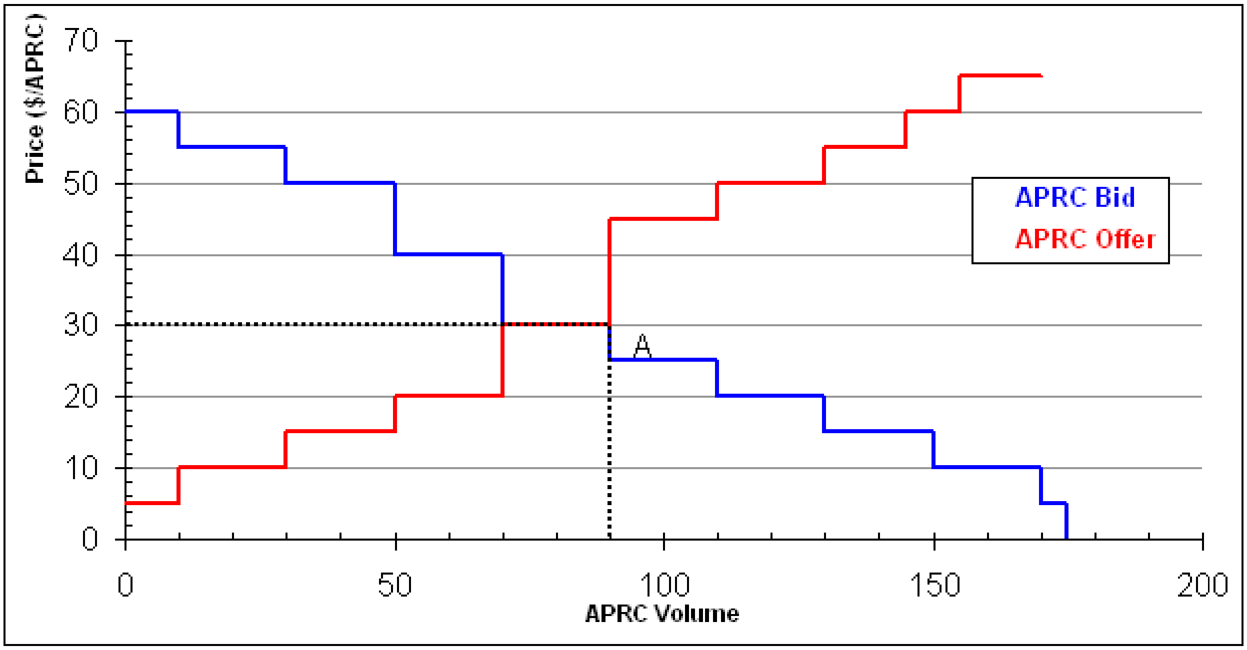
Supply Offer: Submitted by PRC Sellers

	MS1		MS2	
Seg.	Price ($/APRC)	Supply (APRC)	Price ($/APRC)	Supply (APRC)
1	5	10	10	20
2	15	30	20	40
3	30	50	45	60
4	50	70	55	75
5	60	80	65	90

Based on the bids/offers received above, the following table is constructed which shows all APRC Bids stacked from the highest priced APRC Bid to the lowest, and similarly the APRC Offers stacked from lowest priced APRC Offer to the highest:

Demand				Supply			
APRC Buyer	Price ($/APRC)	Cumulative APRC Bid	Range	APRC Seller	Price ($/APRC)	Cumulative APRC Offer	Range
MB 1	60	10	0 to 10^-	MS 1	5	10	0 to 10^-
MB 2	55	30	10 to 30^-	MS 2	10	30	10 to 30^-
MB 1	50	50	30 to 50^-	MS 1	15	50	30 to 50^-
MB 2	40	70	50 to 70^-	MS 2	20	70	50 to 70^-
MB 1	30	90	70 to 90^-	MS 1	30	90	70 to 90^-
MB 1	25	110	90 to 110^-	MS 2	45	110	90 to 110^-
MB 2	20	130	110 to 130^-	MS 1	50	130	110 to 130^-
MB 1	15	150	130 to 150^-	MS 2	55	145	130 to 145^-
MB 2	10	170	150 to 170^-	MS 1	60	155	145 to 155^-
MB 2	5	175	170 to 175^-	MS 2	65	170	155 to 170^-

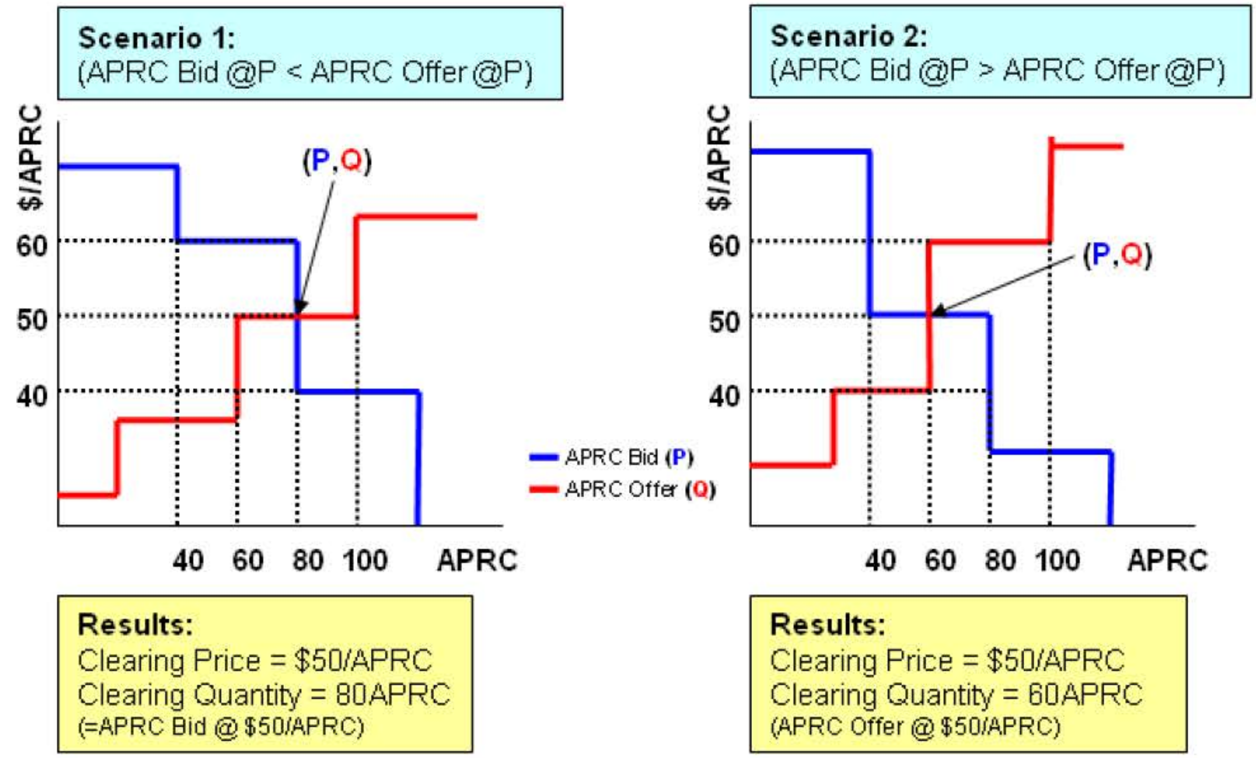
The following is the graphical illustration of the above table. The graph shows that the Clearing Price is determined as the price point at which the bid curve and offer curve intersect.

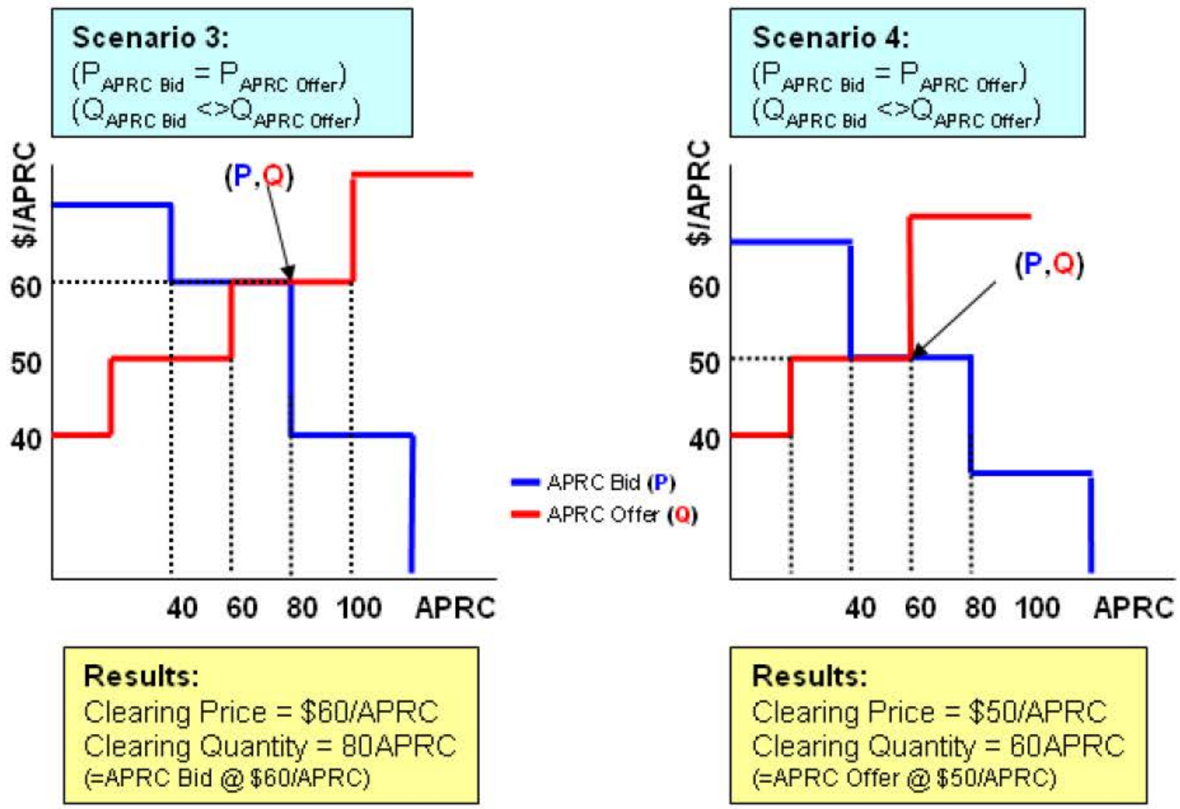


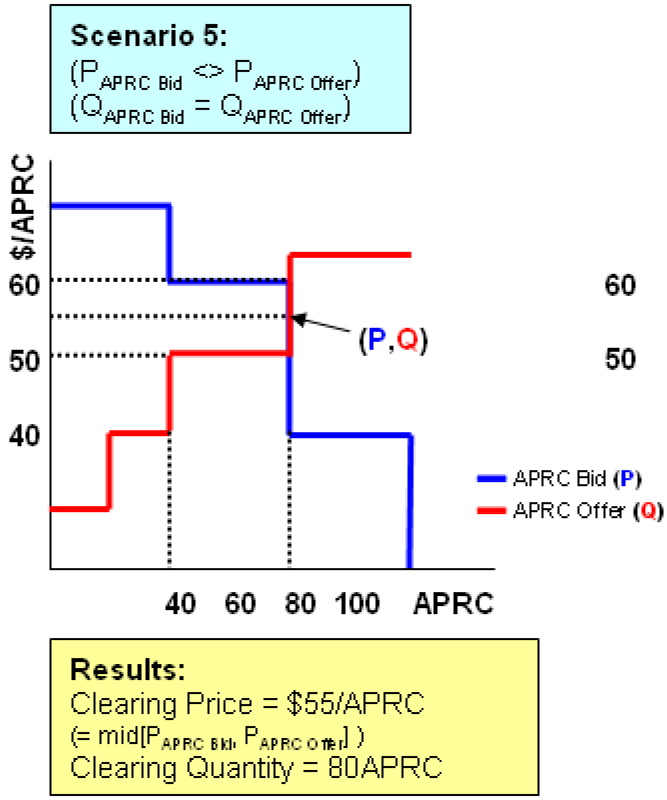
Results: Clearing Price: $30/APRC

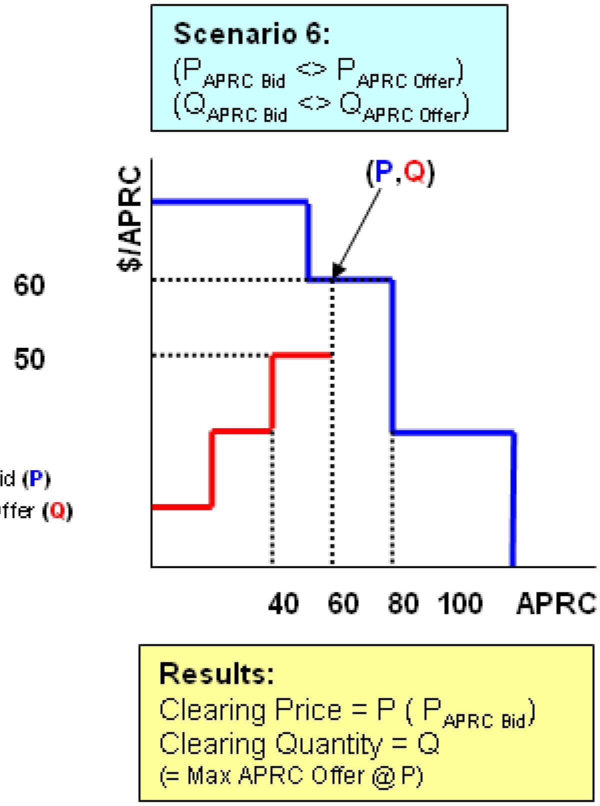
Cleared APRCs: 90 APRC

Various scenarios explaining how the VCA Market Price will be determined are illustrated below:


Scenario 1:
(APRC Bid @P < APRC Offer @P)
$/APRC
(P,Q)
60
50
40
40 60 80 100 APRC
Results:
Clearing Price = $50/APRC
Clearing Quantity = 80APRC
(=APRC Bid @ $50/APRC)
APRC Bid (P)
APRC Offer (Q)
Scenario 2:
(APRC Bid @P > APRC Offer @P)
$/APRC
(P,Q)
60
50
40
40 60 80 100 APRC
Results:
Clearing Price = $50/APRC
Clearing Quantity = 60APRC
(APRC Offer @ $50/APRC)


Scenario 3:
($P_{APRC\ Bid} = P_{APRC\ Offer}$)
($Q_{APRC\ Bid} <> Q_{APRC\ Offer}$)
$/APRC
(P,Q)
60
50
40
40 60 80 100 APRC
Results:
Clearing Price = $60/APRC
Clearing Quantity = 80APRC
(=APRC Bid @ $60/APRC)
APRC Bid (P)
APRC Offer (Q)
Scenario 4:
($P_{APRC\ Bid} = P_{APRC\ Offer}$)
($Q_{APRC\ Bid} <> Q_{APRC\ Offer}$)
$/APRC
(P,Q)
60
50
40
40 60 80 100 APRC
Results:
Clearing Price = $50/APRC
Clearing Quantity = 60APRC
(=APRC Offer @ $50/APRC)





Appendix G2 – LMR Deliverability Evaluation process for VCA participation

Example 1 – Two (2) LMR offers at a single Load CP Zone

<u>LSE:</u>

LSE's Demand Forecast at Load CP Node A = 180 MW

- LSE previously nominated 80 MW of LMR1 used to net against the Demand Forecast (DF) at CP Node A, now chooses to use it as a resource [Note1], offers the entire amount [Note2] (= 80 MW) in the VCA.
- LSE previously nominated 60 MW of LMR2 used to net against the DF at CP Node A, now chooses to use it as a resource, and offers the entire amount (=60 MW) in the VCA.

Note1: LSE nominates the LMR as "Resource" in the <u>Confirm/Reject DR</u> screen of the MECT.

Note2: LSE converts the entire amount of its LMRs into LPRCs.

LSE's Obligation at Load CP Node A assuming Planning Reserve Margin = 4.5%

- LSE's Old Obligation at CP Node A = (180 - 80 - 60) * (1 + 0.045) = 41.8 MW
- LSE's Revised Obligation at CP Node A = 180 * (1 + 0.045) = 188.1 MW

<u>MISO:</u>

➢ MISO determines the 3 months historic use of APRCs at CP Node A = 100 MW

(= Maximum amount of LMR Offers allowed at CP Node A = 100 MW)

1. *<u>LMR Offer Selection</u>*:

- Amount of LMR1's offer selected = 100 * 80 / (80 + 60) = 57.1 MW (Unselected portion of LMR (80 – 57.1 = 22.9 MW) will be added to LMR1's Available LPRC)
- Amount of LMR2's offer selected = 100 * 60 / (80 + 60) = 42.9 MW (Unselected portion of LMR (60 – 42.9 = 17.1 MW) will be added to LMR2's Available LPRC)

2. *<u>VCA Clearing of LMRs</u>*:

Assuming that VCA only clears 30 MW from LMR1's Offer, and 20 MW from LMR2's Offer, the uncleared portion of the LMR Offers will be returned to the LSE in the following manner:

- Added to LMR1's Available LPRC at CP Zone A = 57.1 – 30 = 27.1 MW (LMR1's Total Available LPRC = 22.9 + 27.1 = 50 MW)
- Added to LMR2's Available LPRC at CP Zone A = 42.9 – 20 = 22.9 MW (LMR2's Total Available LPRC = 17.1 + 22.9 = 40 MW)

Example 2 – Two (2) LMR offers at Two (2) different Load CP zones:

<u>LSE:</u>

LSE's Demand Forecast at Load CP Node A = 180 MW

LSE's Demand Forecast at Load CP Node B = 100 MW

0. LSE previously nominated 50 MW of LMR1 used to net against the DF at CP Node A, now chooses to use it as a resource [Note1], offers the entire amount [Note2] (= 50MW) in the VCA.
1. LSE previously nominated 20 MW of LMR2 used to net against the DF at CP Node B, now chooses to use it as a resource, and offers the entire amount (=20 MW) in the VCA.

Note1: LSE nominates the LMR as "Resource" in the Confirm/Reject DR screen of the MECT.

Note2: LSE converts the entire amount of its LMRs into LPRCs.

LSE's Obligation at Load CP Node A an B assuming Planning Reserve Margin = 4.5%

- LSE's Old Obligation at CP Node A = (180 - 50) * (1 + 0.045) = 135.9 MW
- LSE's Revised Obligation at CP Node A = 180 * (1 + 0.045) = 188.1 MW
- LSE's Old Obligation at CP Node B = (100 - 20) * (1 + 0.045) = 83.6 MW
- LSE's Revised Obligation at CP Node B = 100 * (1 + 0.045) = 104.5 MW

MISO:

- 3 months historic use of APRCs at CP Node A = 40 MW

  (= Maximum amount of LMR Offers allowed at CP Node A = 40 MW)
- 3 months historic use of APRCs at CP Node B = 60 MW

  (= Maximum amount of LMR Offers allowed at CP Node B = 60 MW)

1. LMR Offer Selection:

- Amount of LSE's LMR1 Offer at CP Node A selected = Minimum of (Offer, Max Allowed Offer amount) = minimum (50, 40) = 40 MW (Unselected portion of LMR1 Offer (50 – 40 = 10 MW) will be added to LMR1's Available LPRC at CP Zone A
- Amount of LSE's LMR2 Offer at CP Node B selected = Minimum of (Offer, Max Allowed Offer amount) = minimum (20, 60) = 20 MW (All of LMR2 Offer at CP Zone B was selected)

➢ LSE submits the VCA LMR Offer for the amount of 60 MW (= 40 MW from LMR1 and 20MW from LMR2) as a single offer.

2. VCA Clearing:

Assuming that VCA only clears 30 MW from LSE's LMR Offer, uncleared portion of LMR Offers (30 MW) will return to LSE's LMR1 and LMR2 in the following manner:

- Added to LMR1's Available LPRC at CP Zone = 30 * (40 /(40 + 20)) = 20 MW (LMR1's Total Available LPRC = 10 + 20 = 30 MW)
- Added to LMR2's Available LPRC at CP Zone = 30 * (20 /(40 + 20)) =10 MW (LMR2's Total Available LPRC = 0 + 10 MW = 10 MW)

Appendix H – Unforced Capacity (UCAP) Calculations for Planning Resources

The following sets of equations establish how the unforced capacity values (Aggregate UCAP and Local UCAP) are determined for Planning Resources to account for resource performance and availability.

H.1 Planning Resource UCAP calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on the MISO Transmission System

The unforced capacity calculation is based on its type and volume of interconnection service, Generation Verification Test Capacity (GVTC), and forced outage rate ($XEFOR_d$). The following steps are used to calculate Aggregate UCAP and Local UCAP for each Planning Resource.

H.1.1 Planning Year 2011-2012 and Going Forward UCAP Calculation

The following steps are used to calculate Aggregate UCAP and Local UCAP for each Planning Resource.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its Generation Verification Test Capacity (GVTC), or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

The next step is to convert the resultant Total Interconnection ICAP value to unforced capacity value, Total Interconnection UCAP, by applying its forced outage rate ($XEFOR_d$).

A forced outage rate class average is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

The final step is to allocate the Planning Resource's Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to calculate the Aggregate UCAP. The remaining Total Interconnection UCAP will then be allocated to Local UCAP. . If the Planning Resource has provisional interconnection service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

The Aggregate UCAP and Local UCAP represent the capacity in MWs that is eligible to be converted into Planning Resource Credits.

H.2 UCAP calculation for an External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource unforced capacity calculation is based on its Generation Verification Test Capacity (GVTC) and forced outage rate ($XEFOR_d$). The Local UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

A forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

The Local UCAP represents the capacity in MWs that are eligible to be converted into Planning Resource Credits.

H.3 Planning Resource UCAP calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, which does not have a Point of Interconnection on the MISO Transmission System

The unforced capacity calculation is based on its Generation Verification Test Capacity (GVTC) and forced outage rate ($XEFOR_d$) if it does not have a Point of Interconnection to the MISO Transmission System. The Local UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

A forced outage rate class average is used if the Load Modifying Resource (BTMG) has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

The Local UCAP represents the capacity in MWs that are eligible to be converted into Planning Resource Credits.

H.4 UCAP calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

The unforced capacity is determined based on past historical performance and availability data for non-wind resources and through an effective load carrying capability study performed by MISO for Planning Resources fueled by wind. The unforced capacity calculation also considers the type and volume of interconnection service for a Planning Resource that has a Point of Interconnection to the MISO Transmission System.

H.4.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on the MISO Transmission System

The following sets of equation establish how unforced capacity values (Aggregate UCAP and Local UCAP) are determined for Intermittent Generation and Dispatchable Intermittent Resources that has a Point of Interconnection on the MISO Transmission System to account for resource performance and availability.

H.4.1.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the Module E Capacity Tracking Tool.

H.4.1.1.1 Planning Year 2011-2012 and Going Forward UCAP Calculation

MISO calculates a wind farm specific wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind. The wind capacity credit is determined by performing an Effective Load Carry Capability study on an annual basis and using wind farm specific past metered data, reference section 4.5 of the BPM for Resource Adequacy.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its Generation Verification Test Capacity (GVTC), or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to convert the resultant Total Interconnection ICAP value to an unforced capacity value, Total Interconnection UCAP, by applying its CPNode specific wind capacity credit.

The final step is to allocate the Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to Aggregate UCAP. The remaining Total Interconnection UCAP will then be allocated to Local UCAP. If the Planning Resource has provisional interconnections service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

H.4.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.5.2 of this BPM.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its Generation Verification Test Capacity (GVTC), or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO Generation Interconnection Procedures or through a market transition deliverability test.

The final step is to allocate the Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to the Aggregate UCAP. The remaining Total Interconnection UCAP will then be allocated to Local UCAP. If the Planning Resource has provisional interconnections service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

H.4.2 Intermittent Generation and Dispatchable Intermittent Resources that do not have Point of Interconnection on the MISO Transmission System

The following equations apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on the MISO Transmission System. The Local UCAP represents the capacity in MWs that are eligible to be converted into Planning Resource Credits.

H.4.2.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the Module E Capacity Tracking Tool.

H.4.2.1.1 Planning Year 2011-2012 and Going Forward UCAP Calculation

MISO calculates a wind farm specific wind capacity credit for each Planning Resource that is fueled by wind. The wind capacity credit is determined by performing an Effective Load Carry Capability study on an annual basis and using wind farm specific past metered data, reference section 4.5 of the BPM for Resource Adequacy.

H.4.2.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.5.2 of this BPM.

Appendix I - XEFOR$_d$ Calculation

To help better understand how the XEFOR$_d$ value is determined a description of the EFOR$_d$ has been provided below:

The equivalent forced outage rate demand calculation is based on the equation defined in the IEEE Standard No. 762 *"Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity."* This equation is shown below.

$$EFOR_d = \frac{FOH_d + EFDH_d}{FOH_d + SH} \quad x \quad 100\,\%$$

where:

$FOH_d = f_f$ x FOH

$EFDH_d$ = (EFDH – EFDHRS) if reserve shutdown events reported, or

= (f_p x EFDH) if no reserve shutdown events reported.

Please note that the IEEE Standard No. 762 and NERC definitions for EFDH differs slightly from the way MISO's PowerGADS tool calculates EFDH. These differences can be seen below.

IEEE and NERC's definition for EFDH: (Derated Hours * Size of Reduction)/Net Max Capacity

PowerGADS definition for EFDH: (Derated Hours * Size of Reduction)/Net Dependable Capacity

The Size of Reduction is equal to the Net Dependable Capacity minus the Net Available Capacity

f_f = full forced outage factor = (1/r + 1/ T)/(1/r + 1/T +1/D)

- r = average forced outage duration = (FOH)/(# of FO occurrences)

- D = average demand time = (SH + Synch Hours)/(# of unit actual starts)
- T = average reserve shutdown time = (RSH)/(# of unit attempted starts)

FOH = full forced outage hours

SH = service hours

Synch Hours = synchronous hours

RSH = reserve shutdown hours

EFDH = equivalent forced de-rated hours

EFDHRS = equivalent forced de-rated hours during reserve shutdowns

f_p = partial forced outage factor = (SH + Synch Hours/AH)

AH = available hours

Note:

Special cases are evaluated in the following order:

If reserve hours < 1, then f_f =1

Else if (SH + Synch hours) = 0, then f_f = 1

Else if (1/r + 1/T + 1/D) = 0, then f_f = 0

Else if # of FO occurrences = 0 or FOH = 0, then 1/r = 0

Else if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0

Else if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0

Else if (SH+RSH+Synch Hours) = 0, then f_p = 0

Else if ((SH + Synch Hours) + (f_f x FOH)) = 0, then $EFOR_d$ = 0

Example

Raw Data									
Unit	**Capacity(MW)**	**SH**	**RSH**	**AH**	**Actual**	**Attempted**	**EFDH**	**FOH**	**FO**

					Starts	Starts			events
1	55	4,856	2,063	6,918	34	34	146.99	773	12
2	75	4,556	1,963	6,519	31	31	110.51	407	5
3	120	3,942	3,694	7,635	36	36	19.92	504	11
4	153	6,460	516	6,978	17	18	131.03	340	14
5	180	6,904	62	6,968	14	16	35.81	138	12
Totals	**583**	**26,718**	**8,298**	**35,018**	**132**	**135**	**444.26**	**2,162**	**54**

Calculated Intermediate Values								
Unit	**1/r**	**1/T**	**1/D**	**f_f**	**f_f * FOH = FOH_d**	**f_p**	**f_p * EFDH = $EFDH_d$**	**$EFOR_d$**
1	0.0155	0.0165	0.0070	0.8205	634.25	0.7019	103.18	13.43%
2	0.0123	0.0158	0.0068	0.8049	327.61	0.6989	77.23	8.29%
3	0.0218	0.0097	0.0091	0.7756	390.92	0.5163	10.28	9.26%
4	0.0412	0.0329	0.0026	0.9657	328.34	0.9258	121.30	6.62%
5	0.0870	0.2258	0.0020	0.9936	137.11	0.9908	35.48	2.45%
Totals					**1,818.23**		**347.48**	**8.01%**

EFOR$_d$ Calculation for Unit 1:

Synch Hours = 0

$$r = \text{average forced outage duration} = \frac{FOH}{\#\text{ of FO}} = \frac{773}{12} = 64.41667$$

$$T = \text{average reserve shutdown time} = \frac{RSH}{\#\text{ of Attempted Starts}} = \frac{2{,}063}{34} = 60.67647$$

$$D = \text{average demand time} = \frac{SH}{\#\text{ of Actual Starts}} = \frac{4{,}856}{34} = 142.82353$$

$$f_f = \text{full forced outage factor} = \frac{\frac{1}{r}+\frac{1}{T}}{\frac{1}{r}+\frac{1}{T}+\frac{1}{D}} = \frac{(0.0155+0.0165)}{(0.0155+0.0165+0.0070)} = 0.8205$$

$$f_p = \text{partial forced outage factor} = \frac{SH}{AH} = \frac{4{,}856}{6{,}918} = 0.7019$$

$$EFOR_d = \frac{FOH_d + EFDH_d}{SH + FOH_d} \text{ x } 100\% = \frac{(634.25+103.18)}{(4{,}856+634.25)} \text{ x } 100\% = 13.43\%$$

Additional Note: SH, RSH and Synch Hours are reported by the users in the Performance data. The rest of the statistics are calculated by PowerGADS based on Event data submitted by the users.

EFOR$_d$ for each unit is presented in the Generator Outage Rate Program (GORP) report. The statistics used in calculating EFOR$_d$ can be found in the Statistics Report and the Performance Report. The EFOR$_d$ calculation is applied differently for unique instances such as existing and new units. This calculation is based on the historical data from MISO's GADS database. Each unit's EFOR$_d$ value that is used for the Planning Year will be based on either a class average value for that particular unit's size and type or the unit's actual data. A class average value will not be blended with a unit's actual data to determine a 36 month EFOR$_d$ or XEFOR$_d$.

Existing Units or Units with 12 or more consecutive months of actual data: The $EFOR_d$ of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months. Eventually, each unit will have a 36 month $EFOR_d$ based on actual data.

Example: If a unit has 12 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 12 months.

If a unit has 27 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 27 months.
If a unit has 36 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 36 months.

New Units or Units with less than 12 consecutive months of actual data: The $EFOR_d$ of a unit in service less than twelve full calendar months shall be determined by the class average rate for units within the same range of capability and type. A unit will use the class average value until 12 consecutive months of data is obtained and a new planning year has occurred.

Units with Low Service Hours BPM Language

Beginning Planning Year 3 (2011-2012), units with an average of 80 service hours or less per year can have their service hours adjusted if the unit has at least 12 consecutive months of GADS data. The adjusted service hours will be based on 240 service hours (80 service hours x 3 years) or a fraction of 240 if less than 36 consecutive months of GADS data. This adjustment will be performed automatically by MISO staff. The calculation for the adjustment is as follows:

Qualification: $SH \leq (MO/36 * 240)$
SH = Service Hours (actual)
MO = consecutive Months in operation
Adjusted Service Hours, if qualified:

$$\left[\left(\frac{Actual\ Starts}{Attempted\ Starts}\right)\cdot\left(\frac{Months}{36}\cdot 240 - SH\right)\right] + SH = SH'$$

Zero Service Hour Provision:

MPs that have reported zero service hours for any unit in GADS which resulted in a XEFORd of 100% have the option of using a class average EFORd . In order to receive class average EFORd, the MP must perform a one (1) hour test to demonstrate capability. This provision is only applicable to the 2010 - 2011 Planning Year since Planning Year 3 requires all generators to test.

Catastrophic Outage Provision:

Catastrophic outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) Months. MPs that own units that experience a catastrophic outage can select one of the following options for $XEFOR_d$ values used in determining UCAP MW for such units for future Planning Years. MPs must notify the MISO Resource Adequacy Department in writing by sending an email to a member of the Resource Adequacy team within thirty (30) calendar days of the outage if they want to use option 1 below. Otherwise, future UCAP MW will be assigned based on option 2.

- Option 1: Class Average EFORd used for future Planning Year UCAP Determination:

  If this option is selected, the MP must unconvert all PRCs created from such unit for the remainder of the Planning Months that UCAP MW has been qualified prior to the next Monthly Resource Plan Deadline. The MP shall not convert UCAP MW to PRC until the unit has been repaired and qualifies as a Planning Resource for a subsequent Planning Year (including but not limited to performing a GVTC). When the unit returns from the catastrophic outage, it must re-qualify as a Planning Resource which includes but not limited to submitting GADS and GVTC results. The unit will be given a class average

EFORd after its return from the catastrophic outage until there are 12 months of GADS data available for the unit once all qualification requirements have been met.

- Option 2: Unit specific XEFORd used for future Planning Year UCAP determination :

  The MP will be allowed to continue using the resource as a Planning Resource for the Planning Year or Years that the resource has been given UCAP MW as a Planning Resource. The MP can continue to use the PRCs converted from such resources. However, when the unit returns from the outage it must meet all requirements to qualify as a Planning Resource and will be given a XEFORd based on the GADS data submitted for the unit. The catastrophic outage should be documented as a forced outage in the GADS data.

External Resources: Market Participants are responsible for making sure that GADS data is submitted from the External Resources that they are seeking qualification as PRCs. The Market Participant can submit this data to the MISO GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the Midwest Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator then it is the Market Participant’s responsibility to receive and submit this data for the External Resource.

Behind The Meter Generation:

For the initial Planning Year, all BTMG units will receive a class average $EFOR_d$ value based on the unit type and size, unless GADS data that the MP for the BTMG submits to the Midwest ISO demonstrates a higher average $EFOR_d$ value. Those units less than 10 MW that do not submit GADS data will receive the class average. For the initial Planning Year, the class average $EFOR_d$ or actual $EFOR_d$ of the BTMG will be used. The Unforced Capacity calculation is shown in section 7.7.2. Section 4.4.1 Registration of Load Modifying Resources and section 4.5.4 Annual Performance Testing for LMRs provides additional details on the registration and the qualification of a BTMG.

Pooled Class Average Rates: The class average values are only used in place of actual data when such data are not available either due to the unit being new, or without adequate historical performance or operating statistics. These values are calculated from the MISO GADS database based on unit size and type. MISO's $EFOR_d$ classes will be the same as defined by NERC's Generating Unit Statistical Brochure. An example is shown below:

Unit	SH	FOH_d	$EFDH_d$	$EFOR_d$
1	4,000	630	100	15.77%
2	4,500	330	75	8.39%
3	4,000	400	10	9.32%
4	6,500	300	120	6.18%
5	7,000	150	40	2.66%
Totals	**26,000**	**1,810**	**345**	

$$\text{Pooled Average } EFOR_d = \frac{\sum FOH_d + \sum EFDH_d}{\sum SH + \sum FOH_d} = \frac{1{,}810 + 345}{26{,}000 + 1{,}810} \text{ x } 100\% = 7.71\%$$

Note:

There must be a sample size of at least 30 (minimum sample size used by NERC GADS) units to determine a MISO class average. If there are not enough samples, MISO will default to the NERC Class Average for that particular type of unit. MISO and NERC Class average results can be found under the LOLE Study Report on MISO's website.

Responsibility and Timing:

All generating facilities, other than Intermittent Generation and Dispatchable Intermittent Resources, taking part in the MISO market are required to submit unit statistical performance and reliability data to determine the value of the facility as an Unforced Capacity Resource. BTMG less than 10 MW have an option of submitting GADS. Intermittent Generation and Dispatchable Intermittent Resources must provide historical output data to MISO, not GADS data, which will be used by to establish the annual UCAP values. To this end, all participants must report data as defined in the NERC GADS using the MISO GADS tool. Facilities within this system are uniquely identified and their reported data are available for review and use only by the owner/submitter and MISO. Security and confidentiality are strictly kept.

It is the responsibility of each member company to submit to MISO quarterly data by the last day of the month following the applicable quarter.

1st Quarter: Data is due by April 30th

2nd Quarter: Data is due by July 31st

3rd Quarter: Data is due by October 31st

4th Quarter: Data is due by January 31st

All data should be 100% complete and accurate at that time (all data should have passed the level 2 checks). It is the responsibility of MISO to produce an annual unit $EFOR_d$. The unit $EFOR_d$ will be 100% for any month of operation during which the minimum reporting requirements are not met. A timeline is shown below.

The $XEFOR_d$ values for the upcoming Planning Year will be locked down on October 31st of the current Planning Year using the previous 3 years history of GADS data ranging from September through August (e.g., September 2005 through August 2008 for the initial Planning Year).

There are several cases in which multiple GADS units point to one CPNode. In this case, a weighted $EFOR_d$ will be calculated. An example is shown below.

Unit	CPNode Name	Pmax (MW)	EFORd	WEFORd
1	TEST.CP1	100	7.50%	1.50%
2	TEST.CP2	200	6.00%	2.40%
3	TEST.CP3	150	5.50%	1.65%
4	TEST.CP4	125	5.00%	1.25%
Units Aggregated		**500**	**6.00%**	**6.80%**

where WEFORd = (Pmax/Sum of Pmax)*EFORd

Multiple CPNodes that map to one GADS unit will use the same $XEFOR_d$ value for each CPNode.

PowerGADS Lock Release Policy

The long term goal of MISO is to have the data in PowerGADS be in final form. This means that all data should be correct and error free by the time it has passed the Level 2 Validation. MISO has begun to take steps in this direction through development of this policy, although no time table has been set.

MISO's goal is to have accurate data submitted to the PowerGADS tool for generator availability data and GVTC. The MISO GADS Administrator can release locks to correct data errors subject to the following:

- The last day that a lock release will be allowed is 6 months following the date the lock release is being requested. For example, data entered for January 15^{th}, 2009 will only be allowed to be edited up until July 15^{th}, 2009.

- The data errors must be well documented as to why the data needs to be edited and provided to the MISO GADS Administrator. MISO reserves the right to deny a lock release if proper documentation is not provided.

Lock releases are most commonly seen when events cross quarters. MISO will be more lenient toward these types of lock releases.

Appendix J - PowerGADS Access

New Companies to GADS

New Companies need to inform one of the MISO GADS data administrators that they wish to add their units to the PowerGADS database and one of the administrators will contact NERC and get a NERC Utility Code. Once a Utility Code is assigned to a company, the company can then assign their units unit codes based on the descriptions below. Both the Utility Code and Unit Code are needed for identifying the unit in the PowerGADS database.

New Users with New or External Units to Be Added

New users wishing to gain access to PowerGADS need to take the following actions (assuming Utility Codes and Unit Codes have been established).

1. Contact one of the MISO GADS data administrators with the unit(s) they wish to add.
2. The administrator will add the unit(s) once some basic information on the unit(s) is collected from the user.
3. After the units are populated in PowerGADS the administrator will contact the user who should then contact their company's Local Security Administrator (LSA). The Local Security Administrator will log on to the Midwest Market Portal and create a username. The LSA will then assign access to the user by checking the boxes next to the units that the user should have access to in PowerGADS. There are 2 levels of access privileges: submit and view. Submit access level is for submitting GADS data, and view access level is for reading the submitted GADS data only. Typically, at a given company one or more GADS data submitters are assigned the "submit" role and other interested staff members are assigned the "view" role.
4. Once this is complete an automated update occurs four times a day (7AM, 1PM, 7PM, and 1AM EDT). This update needs to occur before the user will actually have access to PowerGADS through the Midwest Market Portal and only then will the units will be assigned for submitting/viewing the data.

New Users with Existing Units

Follow Steps 3 and 4

Unit Code Descriptions

Fossil (Steam) 100 - 199

(Use 600-649 if additional numbers are needed)

Nuclear 200 - 299

Combustion Turbines (Gas Turbines or Jet Engines) 300 - 399

(Use 700-799 if additional numbers are needed)

Diesel Engines 400 - 499

Hydro/Pumped Storage Units 500 - 599

(Use 900-999 if additional numbers are needed)

Fluidized Bed Combustion Units 650 - 699

Miscellaneous Units (Multi-Boiler/Multi-Turbine, 800 - 899

Geothermal, Combined Cycle Block, etc.)

Information Needed For a New Unit:

Name

Utility Code – Assigned by NERC

Unit Code – Assigned by the company

Short Name

NERC Unit Type

Primary Fuel

Summer Season Max Capacity

Winter Season Max Capacity

Summer Season Installed Capacity

Winter Season Installed Capacity

The GADS Administrator can be contact via the email address gads@midwestios.org.

Appendix K - Reporting GADs Data

Planning Resources, with the exception of DR, DRR, Intermittent Generation and Dispatchable Intermittent Resources, are required to submit unit statistical performance and reliability data. Owners/submitters must report data as defined in the NERC GADS using the MISO GADS tool. Planning Resources greater than or equal to 10 MW are required to submit unit statistical performance and reliability data. Owners/submitters must report data as defined in the NERC GADS using the MISO GADS tool. Facilities within this system are uniquely identified and their reported data are available for review and use only by the owner/submitter and MISO. Security and confidentiality are strictly kept.

It is the responsibility of each Planning Resource owner to submit to MISO monthly data by the last day of the month following the last month of a quarter. All data should be 100% complete and accurate at that time (all data should have passed the level 2 checks). It is the responsibility of MISO to produce an annual unit $EFOR_d$ and MISO will determine how to produce an annual unit $EFOR_d$ for DRR for Planning Years after the initial Planning Year. The unit $EFOR_d$ will be 100% for any month of operation during which the minimum reporting requirements are not met.

The MISO Power GADS User Manual and The MISO GADS tool can be found on the Midwest Market Portal.

Appendix L - MISO Generator Testing Requirements

All Generation Resources, External Resources, Demand Response Resources backed by Behind-The-Meter Generation (BTMG) and BTMG that intend to qualify as or being used as a Planning Resources are required to perform a real power test or provide past operational data that meets these requirements to determine its Generation Verification Test Capacity (GVTC) and submit its GVTC to the MISO PowerGADS.

If a Planning Resource fails to perform a real power test during the testing period and report the test information to the MISO PowerGADS by the reporting deadline, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero (0) UCAP MWs for the upcoming Planning Year.

L.1 Generation Verification Test Capacity (GVTC)

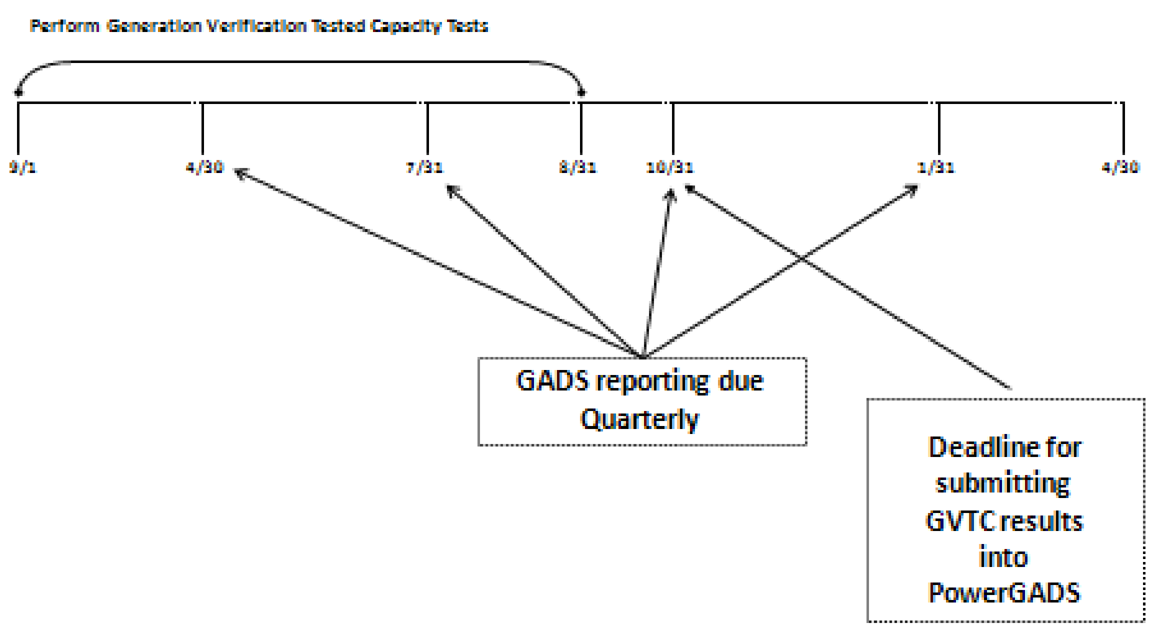
The maximum Energy output (MW) that a Generation Resource, External Resource, Demand Response Resource backed by behind the meter generation, or Behind the Meter Generation (BTMG) can sustain over the specified period of time, if there are no equipment, operating, or regulatory restrictions, minus any Capacity utilized for the units station service power.

L.2 When to Perform and Submit a Generation Verification Test Capacity

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data shall be between September 1st and August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
- A real power test is required when returning from a “mothballed” state, and then submit the GVTC.

- A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E) or being qualified as a Planning Resource for the first time.
    - The GVTC for a new BTMG is due at the time a Market Participant registers its new BTMG in the MECT, must be submitted at least 60 days prior to the first Planning Month that the BTMG is effective in the Module E Capacity Tracking Tool.

Key Deliverables Timeline



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L.3 Adjustment to establish the GVTC

The GVTC shall be temperature corrected to the average temperature of the date and times of MISO coincident summer peak, measured at or near the generator's location, for the last 5 years. MISO publishes the date and time of the past 5 annual coincident Summer Peaks. When local weather records are not available at the plant site the values shall be determined from the best data available (i.e., local weather service, local airports, river authority, etc.)

The adjustments required to establish the GVTC of a unit include, as appropriate for each electric generating technology, ambient temperature, humidity, condensing water temperature and availability, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

L.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in The MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in The MISO GADs lasted a minimum of 90 consecutive days prior to the test data and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact the MISO Resource Adequacy Department for a review of its request.

L.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

L.5 GVTC Real Power Test Requirements

L.5.1 Thermal Steam and Nuclear

The Generation Verification Test Capacity (GVTC) capability will be validated for each unit type for a period of not less than two (2) continuous hours and will be the average of the two (2) hours.

Generating units GVTC as affected by the turbine exhaust pressure will be corrected to the past five years (or if a generating unit has not been in operation for five years or more, then as many years as the unit has been in operation) average daily maximum circulating water temperature measured at the date and time of the MISO Summer Peak. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of the MISO Summer Peak.

Steam conditions will correspond to operating standards established by the generator owner for the unit or plant.

Capability of nuclear units will be determined taking into consideration the fuel management program and any restrictions imposed by regulatory agencies.

L.5.2 Combined-cycle units

The gross capability and net continuous GVTC will be validated for a period of not less than two (2) continuous hours and will be the average of the two (2) hours that result in the highest GVTC.

Generating unit GVTC as affected by the turbine exhaust pressure will be corrected to the past five years (or if a generating unit has not been in operation for five years or more, then as many years as the unit has been in operation) average daily maximum circulating water temperature measured at the date and time of the MISO Summer Peak, and the ambient air temperature and humidity conditions experienced at the unit location at the time of the MISO Summer Peak. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of the MISO Summer Peak given humidity conditions experienced at the unit location at the time of the MISO Summer Peak

GVTC of a unit shall be reported for the unit as a whole, as well as for the individual combustion turbine(s) and the steam turbine(s).

Steam conditions will correspond to the operating standard established by the Generator Owner.

The unit shall be operated with the regularly available type and quality of fuel.

The determination of the GVTC of a combined-cycle unit will depend on the structure of the complete unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this reporting manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion turbine(s) and steam components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

L.5.3 Combustion Turbine, Internal Combustion, and Diesel Units

The gross capability and continuous GVTC will be validated for a period of not less than one (1) hour.

Ambient temperature and humidity conditions to be used for adjusting the measured test output shall be the average for the past five years of the maximum temperature and humidity occurring the day of the MISO system summer maximum peak. Where inlet cooling is used to reduce turbine inlet air temperature; the temperature at the discharge of the Inlet coolers shall be the basis for ambient temperature adjustment.

Unit shall be operated with regularly available type and quality of fuel.

For a facility that consists of multiple units, auxiliary load for a shared auxiliary power system shall be allocated to the individual units to compute unit net capability.

L.5.4 Hydroelectric Units – Pumped storage and Reservoir

The gross capability and continuous GVTC will be validated for a period of not less than one (1) hour.

The GVTC established for hydroelectric plants shall recognize the head available giving proper consideration to operating restriction and ambient conditions such as forecasted reservoir levels or water flow conditions during the summer period and environmental and regulatory restrictions. Hydroelectric units with water related operating restrictions will be corrected to the past five year median conditions.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

Reporting

The following information shall be reported to the MISO GADS as appropriate. Please consult the MISO Net Capability Verification Test User Manual for more details with respect to the fields shown below.

CARD	Must be "90"
Utility	Required
Unit	Required
Year	Required
Period	Must be "S" for Summer
Test Index	Must be a "1"
REVISIONCODE	Must be "0" for initial upload, "R" to Revise, or "D" to Delete
Corrected Net	Leave Blank
Claimed Installed	Leave Blank
Difference	Leave Blank
Unit Type	Optional. If entered should be CT, ST, DS, HD, NU, CC, FB or PS
Test Start Date	Required
Test End Date	Required
Gross MW	Required
Station Service	Required
Process Load Served	Required
Net Test Capability	Required
Reactive Generation MVAR	Optional
Total Power MVA	Leave Blank
Power Factor	Leave Blank
Dry Air Temperature Observed	Required for certain unit types
Dry Air Temperature Rated	Required for certain unit types
Air Temperature Correction	Required
Relative Humidity Observed	Required for certain unit types
Relative Humidity Rated	Required for certain unit types
Relative Humidity Correction	Required
Cooling Water Temperature Observed	Required for certain unit types
Cooling Water Temperature Rated	Required for certain unit types
Cooling Water Temperature Correction	Required
STANDARD	Must be "MISO"

Reporting is accomplished through the MISO PowerGADS reporting system as described in the MISO Net Capability Verification Test User Manual, which is located on the MISO website under Planning > Resource Adequacy (Module E) > PowerGADS documentation.

MISO

Controlled Document Approval/Termination Form

Instructions: All Controlled Documents submitted to RIM staff must be accompanied with a Document Approval/Termination Form. Complete the Document Description section, print the form and use for obtaining signatures. Completed form may be sent to RIM staff through interoffice mail or scanned and sent to RIM staff via email. Questions concerning this form should be sent to ControlledDocuments@misoenergy.org.

Document Description			
Document Title	**Resource Adequacy Business Practice Manual**	**Document Number**	BPM-011-r9
Document Type (Check One)	☐Policy (PL) ☐Procedure (OP) ☒BPM	**Document Effective Date**	04/15/2012
Document Level (Check One)	☐Corporate ☐Multi-Departmental ☒Departmental	**Legal/Regulatory/ SSAE 16 Reference** (Check all that apply)	☐Tariff ☐NERC ☐SSAE 16 ☐Federal/State
Publish to	☒Internet (Provide Web location) (www.misoenergy.org/Library/Pages/Library.aspx)	**Document Status**	☒Approval ☐Termination
Access Level (Check One)	☐ Confidential ☐ Protected ☒ Public	Provided notice to Process, Controls & Compliance ☐	

Approver Signatures			
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Owner's Manager	[signature]	Manager	4/16/2012

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