Manual No. 011

Business Practice Manual

RESOURCE ADEQUACY

Disclaimer

This document is prepared for informational purposes only to support the development application of enhancements to MISO's Resource Adequacy construct. Thus the provisions of the Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) of the Midwest Independent Transmission System Operator, Inc. (MISO), Tariff and the services provided under the Tariff. MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be used by MISO to update this document and communicate key processes, system, and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff.

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's 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

Doc- Number	Reason for Issue	Revised by:	Effective Date
BPM-011-r13	Updated LRZ map, timeline, and added catastrophic outage provisions	C. Clark	JAN-01-2014
BPM-011-r12	Annual review and updated to reflect Tariff orders	C. Clark	AUG-01-2013
BPM-011-r11	Updated to reflect Module E-1-1 Tariff	C. Clark	OCT-01-2012
BPM-011-r10	Updated GVTC language for Hydro and ROR.	C. Clark	SEP-28-2012
BPM-011-r9	Annual Review completed and Updated Registration tables and added new section for qualifying PPAs.	C. Clark	APR-15-2012
BPM-011-r8	MISO Rebranding Changes JUL-19-2011	G. Krebsbach	JUN-13-2011
BPM-011-r8	Annual Review and added Dispatchable Intermittent Resource, minor clarifications	C. Clark	JUN-13-2011
BPM-011-r7	Updated UCAP calculations for plan year 2011/2012, undated Must-offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications	M. Heraeus / C. Clark	Dec-1-2010
BPM-011-r6	Corrected errors and added "Must-Offer" language and Units with Low Service Hours	M. Heraeus / C. Clark	JUN-1-2010
BPM-011-r5	Corrected errors and inadvertent omissions	M. Heraeus	MAR-3-2010
BPM-011-r4	Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011	K. Larson	DEC-21-2009
TP-BPM-003-r3	Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1.	T. Hillman	JUN-01-2009
TP-BPM-003-r2	Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements	T. Hillman	JUN-01-2009
TP-BPM-003-r1	Revised to reflect Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.	J Moser	JAN-06-2009
TP-BPM-003	Updated template	J. Moser	APR-01-2008
N/A	Section 3.2.1 Determination of Requirements – Non-valid statements were removed. Section 3.2.3 Default Requirements – Minor revisions were made for clarification. Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR "must offer" compliance was removed.		DEC-12-2007

	Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification. Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification. Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted. Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR "must offer" compliance was removed. Section 5.5 Financial Transmission Rights – This section was deleted. Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions. Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890. Section 6.1.4 Hubbing Transactions – This section was deleted. Section 8 Data Requirements – Entire section updated to reflect FERC order 890		

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1. Introduction

This introduction to the Midcontinent Transmission System Operator (MISO) Business Practice Manual for Resource Adequacy Requirements includes basic information about this and the other MISO BPMs. Section 1.1 of this Introduction provides information about MISO's Business Practice Manuals (BPMs). Section 1.2 is an introduction to this Business Practice Manual document. Section 1.3 identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this document. Bracketed entries [xx.xx] provide references to MISO's Tariff.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, and business 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 Manual Document

This *Resource Adequacy Business Practice Manual* document describes MISO's and other entities' roles and responsibilities related to maintaining 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.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines and standards in order to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- 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 Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?
- What are the deliverability requirements for Planning Resources?
- 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 the changes to Module E-1 of the Tariff?
- What are the procedures for participating in the annual and Transitional Planning Resource Auctions?
- What are the settlement provisions for the annual and Transitional Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

1.3 References

Other reference information related to this document includes:

- MISO BPMs
- MISO's 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
- LOLE Study Reports
- 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 needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy 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, resources committed thru the Resource Adequacy Requirements have a capacity 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
- Load Forecast Uncertainty

2.1 Planning Reserve Margin Requirement Overview

Each LSEs total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Forecasted Coincident 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) which will include distribution losses. An LSE's PRMR is described in Section 3.1 of this BPM.

2.2 Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency 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 resources 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. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource. A Market Participant (MP) can use Capacity Resources up to their UCAP values to comply with their Resource Adequacy Requirements.
- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during all types of emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO will determine annual Unforced Capacity (UCAP) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each Planning Year.

2.3 Resource Adequacy Requirements Overview

Planning Resources that clear in an annual or Transitional Planning Resource Auction (TPRA) or designated in a Fixed Resource Adequacy Plan (FRAP) will be obligated to provide capacity the entire Planning Year. LSEs that serve Load during the Planning Year will be obligated to pay for capacity from such Planning Resources pursuant to the relevant Auction Clearing Price (ACP) for the LRZ where the Load is located, unless the Planning Resource was designated in a FRAP. Resource Adequacy is achieved if an LSE has at least as many Zonal Resource Credits (ZRCs) as its Coincident Peak Demand (CPD) forecast plus its PRM and transmission losses.

In the event that an LSE fails to achieve Resource Adequacy for a Planning Year and chooses to pay the Capacity Deficiency Charge, the charge will be paid to MISO who will distribute it among LSEs in the applicable LRZ that did achieve Resource Adequacy. The Capacity Deficiency Charge is based on 2.748 times applicable Cost of New Entry (CONE) for the LRZ where the LSE's load is located.

2.4 Settlements/Performance Requirements Overview

The Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be fixed for the Planning Year and they will be settled based upon the Planning Resource Auction (PRA) clearing price for an LSE's Load, unless covered by a Fixed Resource Adequacy Plan (FRAP). Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable annual and Transitional PRA included on their daily settlements statements for all loads and Planning Resources cleared in an annual or Transitional PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA, or were used in a FRAP, or that were netted against a Coincident Peak Demand forecast will have a performance obligation to be available during system emergencies.

3. Establishing Planning Reserve Margin Requirement

3.1 Overview

The Planning Reserve Margin Requirement (PRMR) is the number of ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load.

When the LSE meets this requirement, they have demonstrated that they have acquired enough capacity to meet their Coincident Peak Demand forecast (CPD forecast) minus netted Planning Resources, plus transmission losses, plus the Planning Reserve Margin.

The PRMR is expressed in the following equation per Asset Owner and Local Balancing Authority (LBA):

$$PRMR = [(CPDf - DR_{Net} - EER_{Net} - FRP + FRS) \times (1 + TL\%_{LBA})] \times Max([1 + PRM_{RTO}], [{}^{LCR_{LRZ}}/_{CPDf_{LRZ}}])$$

Where:

PRMR = Planning Reserve Margin Requirement per Asset Owner and LBA.
CPDf= Coincident Peak Demand forecast per LBA
CPDF $_{LRZ}$ = Sum of Coincident Peak Demand forecast in the LRZ
DR_{Net}= Netted Demand Resource
EER_{Net}= Netted Energy Efficiency Resource
FRP = Full Responsibility Purchase
FRS = Full Responsibility Sale
$TL\%_{LBA}$= Transmission Loss Percentage of LBA for which the CPDf and/FRS is attributed to
PRM $_{RTO}$= Planning Reserve Margin in Unforced Capacity
LCR $_{LRZ}$= CPDf $_{LRZ}$ less DR $_{Net}$ less EER $_{Net}$ times LRR per MW less CIL $_{LRZ}$

3.1.1 Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity would perform functions on behalf of the applicable LSE including but not limited to submitting the LSE's forecasted CPD forecast or share of CPD forecast.

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 comply with any part of the Resource Adequacy Requirements 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 entity will provide.

3.1.2 Validation of Firm Transmission Service for Load

Each LSE shall document as described in Module B – Transmission Service BPM to MISO that the LSE has obtained sufficient firm Transmission Service for the entire Planning year 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 Behind-the-Meter Generation (BTMGs), Demand Resources (DRs) and Energy Efficiency Resources (EERs), and does not use the MISO Transmission System to serve such Demand.

3.2 Demand and Energy Forecasts

MISO collects a variety of forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them.

Demand and Energy that is not subject to retail choice switching should be reported by the respective LSE. Demand and Energy that is subject to retail choice switching should be reported by the respective Electric Distribution Company (EDC). Additionally, for demand and energy that is subject to retail choice switching, each LSE is responsible for reporting their share of the EDC's forecast.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.1 Non-Coincident Peak Demand and Energy for Load Forecasts

Non-coincident peak demand and energy for load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-coincident peak demand forecast and FERC's form 714 for the energy for load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective standards documents, defer to the latter.

The non-coincident peak demand and energy for load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:

Summer: June through November
Winter: December through May

For seasonal reporting of the non-coincident peak demand forecast the single highest peak hour during the season should be reported in MW. For energy for load forecasts, the summation of each month's energy for load (GWh) should be reported.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.2 Coincident Peak Demand Forecast

The Coincident Peak Demand forecast (CPD forecast) is used to determine each LSE's Planning Reserve Margin Requirement. The CPD forecast shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing in detail the desired approach to be used by LSEs in preparing the CPD forecast, the information required in each annual filing, and the process used in reviewing the CPD forecast can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper

The CPD forecast must be provided by the Asset Owner and the LBA. Providing the CPD forecast by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the applicable Transmission Losses. Transmission Losses will be reported on the Market Portal by MISO for each by LBA, for the hours of MISO's monthly peaks. When S55 data becomes available for June, July, and August, MISO will provide the monthly values.

The CPD forecast must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecast is reported differently in non-retail choice and retail choice areas as described in the following subsections.

3.2.3 Forecast Reporting

LSEs with demand and energy that is not subject to retail choice switching are required to provide MISO with demand and energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The CPD forecast must be reported for each Asset Owner by LBA.

LSEs with demand and energy that is subject to retail choice switching are not required to provide MISO with demand and energy forecasts. Electric Distribution Companies are responsible for submitting forecasts in areas that have demand and energy that is subject to retail choice switching. Additionally, LSEs are required to work with the applicable EDC in order to report their share of the EDC's forecasts.

Electric Distribution Companies (EDC) are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area that provides MISO with an annual peak forecasted Demand coincident with MISO's annual peak must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs using the preferred default method to track and settle PRA load obligations associated with retail customers switching between LSEs, must provide both MISO and the respective LSEs with each retail customer's peak load contribution ("PLC"), excluding transmission losses, in the EDC's service territory by no later than 11:59 p.m. December 15th each year for the following Planning Year.

For EDCs that lack data necessary to use the preferred default peak load contribution methodology and for which MISO has not provided the necessary peak load contribution ("PLC") from historical data, a daily peak load default methodology will be used to track and settle PRA load obligations associated with retail customers switching between LSEs. This methodology requires that the EDC must provide both MISO and each of the respective LSEs with the LSE's historic share of the EDC's Coincident Peak Demand, by no later than 11:59 p.m. December 15th each year for the following Planning Year.

All new EDCs are required to work with the MISO Customer Service department (register@misoenergy.org,), to set up access to the MECT tool and the relationships between the EDC and the LSEs in the EDC area. The MISO Customer Service team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the Retail Choice program are required to provide the name of the Electric Distribution Company (EDC) where the commercial pricing node is located.

3.2.3.1 Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any PRMR from demand left unclaimed by LSEs in the EDC service territory. The Transmission Provider will work with POLR and EDC to ensure that POLR will serve any remaining demand that is not allocated to LSE's.

3.2.4 Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the demand and energy attributed to those wholesale customers in their demand and energy forecasts by November 1st prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

Case 1: LSE knows the entity that will serve the wholesale customer next Planning Year

In this case the existing LSE is not responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

Case 2: LSE does not know who will serve the wholesale customer next Planning Year

In this case the existing LSE is responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to work to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the demand from the old LSE to the new LSE prior to the Planning Resource Auction.

3.2.5 Review of CPD forecast

Starting November 1st, MISO will begin reviewing all forecasts and supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether or not the forecast methodology adequately and reasonably forecasts peak demand, energy, and/or demand reduction capability of the submitting entity. LSEs will be able to view the status (approved or pending review) of their CPD forecast in the MECT. The forecast review process will be completed no later than March 1st of each year prior to the annual PRA. MISO will develop the required forecast for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity of other Market Participants that do not submit a CPD forecast and supporting documentation by the November 1st deadline.

3.3 Netting of Planning Resources from and LSE CPD forecast

The following types of Planning Resources qualify for netting: Demand Resources (DR) and Energy Efficiency Resources (EER).

LSEs may request that their DR or EER be netted through the registration process from their CPD forecast prior to MISO applying Transmission Losses and PRM to establish PRMR. For example, if an LSE submits a CPD forecast of 110MW in the MECT with Demand and/or Energy Efficiency Resources of 10MW then the MECT will calculate PRMR based on the reduced CPD forecast of 100 MW.

3.4 Full Responsibility Transactions

Full responsibility transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of a FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of demand. As a result, the PRMR calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for demand that is not subject to retail choice switching.

The FRS results in an increase in demand and FRP results in a decrease in demand. This can be interpreted as the purchaser paying the seller to take on demand and its associated PRMR. This transfer of demand results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS 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 MISO's Region, sellers are responsible for all of that LSE's PRMR associated with the sale

  Example:

  Asset Owner MM1:
  CPDf = 10 MW
  PRM = 6.2%
  Transmission Loss % = 2%
  Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
  MM1's PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

  Asset Owner SS2:
  CPDf = 20 MW
  PRM = 6.2%
  Transmission Loss % = 2%
  Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
  SS2's PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

Asset Owner BB3:
CPDf = 50 MW
PRM = 6.2%
Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3's PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon ACP 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 CPD information for the transferred Demand into the MECT. A MP with an FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. 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 capacity payments 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.

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 remains with the original LSE (purchaser).

In accordance with the following formula found in Section 69A.2 of the Tariff, the PRM for the LRZ in which the load resides will be applied to the load regardless of which LSE or MP has the reserve obligation.

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 capacity obligations shift. This must be done prior to the opening PRA window and the settlement will be between LSEs for all FRP/FRS transactions. The PRMR should not be a negative number as a result of the FRT.

3.5 Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process and the process used by MISO to establish the Planning Reserve Margin (PRM) for the MISO Planning Year. A MISO Planning Year runs from June 1 through May 31 of the following year.

3.5.1 Determination of PRM

MISO will perform a technical analysis on an annual basis to establish the PRM and Local Reliability Requirement for Local Resource Zones for the MISO Region, recognizing internal transmission limitations, and will publish the results by November 1st preceding the applicable Planning Year. The analysis includes calculating the driving parameters for determining the Local Clearing Requirement (LCR) in each Zone. Those drivers are Local Reliability Requirement (LRR), the Capacity Import Limit (CIL) and the Capacity Export Limit (CEL).

The LOLE study 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 ("LMR") and EE Resources, load forecast uncertainty, and the Transmission System's import and export capability with external systems. 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 software is determined on an ICAP basis. This $PRMR_{ICAP}$ value is the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the UCAP ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total UCAP rated MW needed, or the $PRMP_{UCAP}$

MISO will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

Previous LOLE studies were based on the LSE forecasts that were Non-coincident with the MISO system peak. Based on LSE forecast at time of MISO peak under the new construct starting in PY 2013-2014, the Planning Reserve Margins that would have been determined for past Planning Years are shown in the table below:

	Coincident Load Based[1] (UCAP)	MISO System wide Forced Outage Rate (XEFORd)			Coincident Load Based (ICAP)
Planning Year (2009-2010)	7.89 %	6.51%			15.40%
Planning Year (2010-2011)	7.74 %	6.64%			15.40%
Planning Year (2011-2012)	8.76 %	7.36%			16.10%
Planning Year (2012-2013)	8.80%	6.77%			16.7%
Planning Year (2013-2014)[1]	6.2%	6.46%			14.2%

[1] Applicable to Forecast LSE Requirement at time of MISO peak

See MISO's website for current and previous LOLE Study reports.

3.5.2 LOLE Analysis

MISO will determine the appropriate PRM for the applicable Planning Year based upon the probabilistic analysis of being able to reliably serve MISO's Coincident Peak Demand. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations. MISO will annually calculate the PRM such that the LOLE is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined using the LOLE analysis by either adding Coincident Peak Demand or removing Planning Resources until a 0.1 day per year solution is reached. MISO will also determine the Local Resource Requirement for each zone consistent with the LOLE achieving 0.1 day per year. The minimum amount of capacity above Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system wide PRM and the Local Reliability Requirement (LRR) for each Local Resource Zone.

3.5.3 Loss of Load Expectation (LOLE) Working Group

MISO has established an Unforced Capacity requirement based on the LOLE analysis conducted by 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 the PRM and LRR's to MISO.

3.5.4 Probabilistic Analysis LOLE Study

The probabilistic study will use the General Electric's Multi-Area Reliability Simulation (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 3. 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 XEFORd 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 XEFORd and EFORd metrics are more fully described below. The zones to be modeled in the MARS application are discussed in Section 5.2 Local Resource Zones.

Although the compliance rating for individual generators will be based on the XEFORd metric, the LOLE study also will account for additional system wide outages beyond the outage causes captured in the XEFORd metric. The XEFORd 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 rate 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, losses of transmission outlet lines are considered as OMC relative to a unit's operation.

OMC Codes approved by stakeholders for use in the MISO LOLE study are listed in Appendix B.

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.

3.5.5 State authority to set PRM

The only entity other than MISO that may establish a PRM is a state regulatory body regarding those regulated entities under their jurisdiction. If a state regulatory body establishes a minimum PRM for the LSEs under their jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in such state. If a state regulatory body establishes a PRM that is higher than the MISO established PRM, the affected LSEs must meet the state set PRM. Similarly, if a state regulatory body establishes a PRM that is lower than the MISO established PRM, then the affected LSEs must 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-1. 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 PRMR.

4. Qualifying and Quantifying Planning Resources

4.1 Overview

MISO has worked with its stakeholders in order to build consensus regarding the processes required to qualify Planning Resources. This section identifies the qualification requirements for each type of Planning Resource.

All Planning 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 will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the UCAP value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs

Planning Resources consist of Capacity Resources and Load Modifying Resources; Capacity Resources consist of Generation Resources, External Resources, and Demand Response Resources. Load Modifying Resource consist of Behind the Meter Generation and Demand Resources.

Generation Resources and Demand Response Resources backed by behind the meter generation 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 H of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources and Demand Response Resources backed by behind the meter generation that have not provided at least one year of historical performance data will have their UCAP calculated for them after they are listed in MISO's Commercial Model provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA they are physically located in. The following Table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

	Planning Resource				
	Capacity Resource		Load Modifying Resource		
	Generation and External	Demand Response Resources	BTMG	Demand Resource	Energy Efficiency
Capacity Verification [1]	X	X	X	X	X
Must offer [1]	X[3]	X[3]			
GADS Data Entry	X		X[2]		
Must Respond to Emergency Operating Procedures	X	X	X	X	

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

3 – Resources that have either cleared in the PRA or are used as part of a FRAP.

4.2 Capacity Resources

4.2.1 Non-Intermittent Generation Resources

4.2.1.1 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 MISO's Region. The deliverability of Generation Resources to Network Load within MISO's 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 or by demonstrating firm transmission service is in place between the Generation Resource and Network Load. The Deliverability Test Results are provided on MISO's public website at the following location: > Planning > Generator Interconnection > Generation Deliverability Workbook.
- Generation Resources that do not pass the deliverability test may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Generation Resources 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)) or new to MISO must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal.
- Generation Resources less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information.
- 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.

- Generation Resources that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resources that are committed through a Planning Resource Auction cannot retire, mothball, or suspend a resource unless another resource is replaced.
- Generation Resources must demonstrate capability on an annual basis as described below.
    - All Generation Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31st in order to qualify as a Planning Resource. The test shall be performed between September 1st and August 31 of the prior Planning Year and corrected to the average temperature of the date and times of MISO's coincident Summer peak, measured at or near the Generation Resource's location, for the last 5 years, or provide past operational data that meets these requirements to determine its GVTC and submit its GVTC data to MISO's 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 during, or past operational data provided for the test period of September 1st through 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 a revised GVTC should be submitted to MISO no later than March 1st prior to the Planning Year. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a "mothballed" state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).

- The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1st prior to the Planning Year. See Appendix J for links to MISO's GVTC Manual and processes.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in *Net Capability Verification Test User Manual*

4.2.1.2 Non-Intermittent Generation Resources – 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 $XEFOR_d$ value of such Generation Resource as described in Appendix H-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 values than units with below average availability.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4 of the RAR BPM.

4.2.1.3 Non-Intermittent Generation Resource – Must-Offer Performance Requirements

As described in detail in Section 6.1 , an MP that owns a Capacity Resource with ZRCs that clear in an annual or Transitional PRA or identified in a Fixed Resource Adequacy Plan (FRAP) must submit the full operable capacity of the Resource, but not less than the ICAP equivalent of the cleared or FRAP ZRCs, and make an Offer into the Day-Ahead Energy market and the first post Day-Ahead Reliability Assessment Commitment (RAC), for every hour of every day, except to the extent that the Capacity Resource is unavailable due to a full or partial forced scheduled outage. Outages and derates must 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 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.

4.2.2 Intermittent Generation and Dispatchable Intermittent Resources

4.2.2.1 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 MISO's Region. The deliverability of Intermittent Generation and Dispatchable Intermittent Resources to Network Load within MISO's 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, or by demonstrating from transmission service that is in place between the Generation Resource and Network Load. The Deliverability Test Results are provided on MISO's public website at the following location: Planning > Generator Interconnection > Generation Deliverability Workbook.
- Intermittent Generation and Dispatchable Intermittent Resources that do not pass the deliverability test may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Intermittent Generation and Dispatchable Intermittent Resources that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resources that are committed through a Planning Resource Auction cannot retire, mothball, or suspend a resource unless another resource is replaced.

- Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent consecutive 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.
- Intermittent Generation and Dispatchable Intermittent Resources not powered by wind which do not have a minimum of 30 consecutive days of historical data from June, July, or August for the hours of 1500-1700 EST prior to the Planning Year, will be granted a class average $EFOR_d$ based on their unit type and size. In the event that a class average $EFOR_d$ does not exist, the MP shall provide at least 30 consecutive days of operating data for the resource prior to participating in any PRAs.

4.2.2.2 Intermittent Resource Generation - UCAP Determination

The Unforced Capacity for a Capacity Resource that is Intermittent Generation and Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of interconnection service. Intermittent Resources that are powered solely by wind, Intermittent Generation and Dispatchable Intermittent Resources are not required to report generator availability data (GADs) and will be assigned a XEFORd 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).

4.2.2.3 Wind Capacity Credit

MISO uses historical wind availability information to calculate Effective Load Carry Capacity (ELCC) to determine a wind capacity credit. MISO's Wind Capacity Credit Report by the LOLEWG reports the wind capacity results for each Planning Year. Appendix A explains the methodology for calculating wind capacity credit. See MISO's website for previous LOLE studies, and starting with the 2013-2014 Planning Year the wind capacity is in a standalone report from the LOLE report which sets the Planning Reserve Margin (PRM).

4.2.2.3.1 Wind Capacity Credit Calculation

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 MW for the MISO system is allocated to each wind farm based on its capacity value at each of MISO's top 8 highest coincident peaks that occurred during the Summer. The Wind Capacity Credit Report includes analysis and results. This calculation is done on a CPNode basis for wind farms that are registered in MISO's Commercial Model, and on a wind farm basis as submitted through the 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 thereafter metered data will be used in order 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%.

Planning Year	Total System Wind Capacity Credit
2012-2013	14.7%
2013-2014	13.3%

4.2.2.4 Intermittent Generation and Dispatchable Intermittent Resources – Non-wind

For Run of River Hydro, the median hourly integrated net output from the most recent three (3) years up to the most recent fifteen (15) years for hours ending 1500-1700 EST for all days of the Summer (June, July, August) shall be used. If 15 years of historic data is not available for this period when the 15 year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15 year requirement is met.

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

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 for hours 1500-1700 EST for the most recent Summer months (June, July, and August). For non-wind powered Intermittent Generation and Dispatchable Intermittent Resources Market Participants

will need to supply this historical data to MISO by October 31 of each year in order to have their 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 for the prior Summer with a minimum of 30 consecutive days, in order to have their 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 as if all units had been on line. For units that experience reduced output due to reasons outside of management control data from these periods may be excluded from the calculation of UCAP. MISO will consider reasons outside management control based on the OMC codes entered in GADS for resources that report data. 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. This notification is due by March 1st prior to the Planning Year.

UCAP options for units with derates prior to the GVTC test date are further explained in Appendix J.4.

4.2.2.5 Intermittent Resource Generation and Dispatchable Intermittent Resources – Must Offer

As described in detail in Section 6.1, an MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan or ZRCs which clear in an annual or Transitional PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unavailable due to a full or partial scheduled outage

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 cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by $(1 - XEFOR_d)$ of the Capacity Resource. Conversely, for wind resources it is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. 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. For non-wind Intermittent Resource not modeled in the Commercial Model, the ICAP will be the name plate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by DA close and Forward Reliability Assessment Commitment (FRAC) close of the DA Market close, and 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. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the Installed Capacity as the must-offer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

Format instructions for DA Reliability Forecasts are located at www.misoenergy.org under Related Documents>Market Procedures Documents and Technical Manuals>Registration>Reference Documents> Resource Forecast Data Submittal for Reliability Guide.

https://www.misoenergy.org/StakeholderCenter/MarketParticipants/Pages/MarketParticipants.aspx

A header row should be included at the beginning of the file in the format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO's Outage Scheduler (CROW). The must-offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only; and the thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

4.2.3 Use Limited Resources

4.2.3.1 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 MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates capability and submit the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.

- Use Limited Resources must be deliverable to Load within MISO's Region. The deliverability of Use Limited Resources to Network Load within MISO's 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 MISO's 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 do not pass the deliverability test may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- 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 it is greater than or equal to 10 MW based on GVTC, then it must submit GADS prior to being approved as a Capacity Resource.
- Use Limited Resources that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resources that are committed through a Planning Resource Auction cannot retire, mothball, or suspend a resource unless another resource is replaced.
- 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.

- MISO will qualify a resource classified as a Diversity Contract provided the resource meets all of the requirements as an External Resource and the Diversity Contract includes a one MW of summer for one MW of non-summer capacity swap, in order to participate in the Planning Resource Auction (PRA).
- Use Limited Resources must demonstrate capability on an annual basis.
- MISO has developed generator-testing standards.
    - All Use Limited Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to 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 shall be corrected to the average temperature of the date and times of MISO's coincident Summer peak, measured at or near the generator's location, for the last 5 years, or the operator shall provide past operational data that meets these requirements to determine its and submit its GVTC data to MISO's 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 BTMG that qualified as Planning Resources for the current Planning Year, shall submit their GVTC no later than October 31st of the prior Planning Year in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed, or past operational data must be provided during the test period 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 the revised GVTC data should be submitted to MISO by March 1st. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a "mothballed" state and the owner of the unit must submit GVTC data to MISO.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or if not qualified as a Planning Resource under Module E-1), or after being qualified as a Planning Resource for the first time.

- The GVTC for a new Use Limited Resource that is an External Resource is due before a Market Participant registers its new Use Limited Resource in the MECT, and the GVTC data must be submitted by March 1st prior to the Planning Year. For new Use Limited Resources internal to MISO, the GVTC data should be submitted no later than March 1st prior to the Planning Year.
- See Appendix J for links to MISO's GVTC Manual and processes.
- Reporting is accomplished through MISO's PowerGADS reporting system, as described in MISO's PowerGADS User's Net Capability Verification Test User Manual. The Asset Owner must submit its test results no later than October 31 of each year.

4.2.3.2 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 H of the RA BPM.

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 Use Limited 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.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4.

4.2.3.3 Use Limited Resources Must-Offer Requirement

As described in detail in Section 6.1 , an MP that commits a Capacity Resource that has ZRCs which clear in an annual or Transitional Planning Resource Auction or used in a Fixed Resource Adequacy Plan must submit the full operable capacity of the Resource, but not less than the ICAP value of ZRCs which either clear the annual or Transitional Planning Resource Auction or used in a Fixed Resource Adequacy Plan, in the Day-Ahead Energy Market and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage.

A Use Limited Resource must-offer or Self-schedule into the Day-Ahead Market for at least four (4) continuous hours daily across MISO's peak (including weekends) in such a way as to enable MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO's peak period will be based on the forecast published one day prior to the operating day 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.

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 the corresponding date.

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

4.2.4 External Resources

4.2.4.1 , 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. Power Purchase Agreements with varying monthly amounts will have their UCAP value calculated according to the lowest monthly value indicated in the contract

the MP shall notify MISO if the External Resource being registered is an Intermittent Generation or Use Limited Resource. External Resources that are also Intermittent Generation must meet all requirements in section 4.2.2. External Resources that are also Use Limited Resources must meet all requirements in section 4.2.3 and be approved by a member of the Resource Adequacy team.

An MP will submit the completed applicable registration form for existing resources via the MECT by February 1st prior to the Planning Year. New External Resource registrations or existing registrations with increased capacity are to be completed in the MECT by March 1st prior to the Planning Year. Existing registrations with increased capacity are still required to submit the original GVTC by October 31st prior to the Planning Year. 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 that External Resources are not being utilized for capacity purposes by such entities. The reason 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 and 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 MISO's Region, and that;

- Firm Transmission Service has been obtained within MISO to deliver at least the ICAP amount of the Capacity Resource seeking to be qualified from the External Resource(s) to the CPNode within MISO. The CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO's 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.
    - Firm Delivery external to MISO may either be Firm Transmission Service on external transmission provider(s) from the External Resource to the border of MISO or Network Resource Interconnection Service under Attachment X
- External Resources may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- 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 that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resource that have are committed through a Planning Resource Auction cannot retire, mothball, or suspend a resource unless another resource is replaced.
- External Resources greater than or equal to 10 MW based on GVTC must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal. Generation. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs nor does it apply to Intermittent Resources or Intermittent Generation.

- External Resources will be recognized in the LRZ zone where the firm transmission service within MISO sinks. Existing External Resources with firm and/or GFA rights to load will be treated as a zonal resource for that load's LRZ zone subject to Grandmother Hedge if it existed on or prior to July 20, 2011.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS 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 $XEFOR_d$ 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.

o Planning Year Testing:
  - All External Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's 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 MISO's 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 GVTC and submit its GVTC data to MISO's 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 data 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 must be provided during the test period 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 to MISO by March 1st. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a "mothballed" state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time, and must be submitted to MISO no later than March 1st prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT, and must be submitted by March 1st prior to the upcoming Planning Year.
- See Appendix J of this BPM for links to MISO's GVTC Manual and processes.

o Reporting

- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Net Capability Verification Test User Manual, which is located on MISO's website under Planning > Resource Adequacy> Related Documents> PowerGADS Documentation> Power GADS GVTC User Manual.
- 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 MISO then this transaction should be represented in the MECT as a ZRC transaction. If the PPA involves External Resources, once such External Resources are registered and accredited, the associated UCAP MWs may be converted to ZRCs in accordance with the procedures in Section 4.4.
- A PPA must be valid for the entire Planning Year if being used as a Planning Resource. PPAs that do not cover the entire Planning Year will not qualify as a Planning Resource under Module E.
- In order for a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.

4.2.4.2 Submission of new External Resources Registrations

A Market Participant must register their new External Resource via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. In order to guarantee new Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. 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 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 within 15 days after the registration form was submitted as to 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.

4.2.4.3 Termination of resources Accredited as External Resources

Because External Resources need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.4.4 Amendments to Accredited External Resource Registration Data

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March1st if the original registration was submitted by the deadline.

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 either an increase or decrease in its MW capability, then the Market Participant shall amend registration information in the Registration screen by March 1st prior to a Planning Year in order for MISO to determine whether the resource still qualifies as an External Resource.

4.2.4.5 Renewal of External Resource for Subsequent Planning Years

Each External Resource must be reviewed for accreditation as an External Resource on an annual basis. Renewal of External Resources must be requested by February 1st prior to the Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an External Resource. MISO will notify the Market Participant within 15 days after the renewed registration form 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.

4.2.4.6 Review of Power Purchase Agreements

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 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered "conforming". 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 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 their agreements will need to follow the procedures applicable to the planning period for which such External Resource is intended to be relied upon to meet Capacity requirements. This includes the

provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.4 in order to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered "non-conforming" and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;
f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
(h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Midwest ISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

4.2.4.7 External Resources – UCAP Determination

External Resources will be accredited at the Capacity Resource's Unforced Capacity based on GVTC value(s), transmission service, and $EFOR_d$ values of such External Resources based on the methodology documented in Appendix H of the RAR BPM. MISO will determine UCAP values for External Resources that are Intermittent Generation as described in Section 4.2.2. External Resources, from PPAs, with varying monthly Capacity values will be credited with lowest monthly Capacity value of the contract.

4.2.4.8 UCAP Determination – Full Requirements PPA

Market Participants may register External Resources to model a full requirements power purchase agreements with a counterparty. This designation will be made in the MECT tool on the External Resource registration. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource's UCAP and Must Offer calculations beginning with the 2014-2015 Planning Year.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left(\frac{ICAP_i \; x \; (1 + PRM_{LRZ}) \; x \; (1 + TL_{LBA})}{(1 - \; XEFORd_i)} \right)$$

Where:
$ICAP_{adjustedi}$: PPA Pct x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
PRM_{LRZ}: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in.
TL_{LBA}: Transmission Losses for the LBA that the External Resource will be serving load in.

4.2.4.9 External Resources – Must Offer Obligation

As described in detail in Section 6.1, the maximum must offer requirement applies to the registered Capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan or clear in either an annual or Transitional PRA s must submit the full operable capacity of the Resource, but not less than the ICAP value of registered Capacity and make an Offer into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage. The must-offer requirement applies to the Installed Capacity (ICAP) of an External Resource, and not the UCAP rating. Installed Capacity refers to the amount of ZRCs divided by (1-XEFORd) of the Capacity Resource. The must offer requirement will be capped at the resource's ICAP value.

An MP that has ZRCs from External Resource(s) that are either indicated in a Fixed Resource Adequacy Plan or clear in an annual or Transitional Planning Resource Auction establishes a Must-Offer requirement. Offers in the Day-Ahead Energy Market can only be Normal Energy type with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post 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 has either identified ZRCs from a FRAP or cleared ZRCs in an annual or Transitional Planning Resource Auction from External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator via System Data Exchange (SDX) or CROW. External Resources must be available to schedule Energy into MISO's Region during emergencies if needed by MISO. EOP-002 includes a mechanism to schedule all External Resources into MISO's 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 of the Planning Resource must be entered in the value field of the MISC section exactly as it appears in the approved registration in the MECT, Outage Scheduler (CROW) or SDX, except that the name must be in all caps. The NERC IDC name in the External Resource registration should be provided in the correct format in order for MISO to retrieve outage information from the SDX.

External Resources that are Use Limited Resources must follow the Day-Ahead must-offer requirements for Use Limited Resources as documented in section 4.2.3.2 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 MISO's Outage Scheduler (CROW), NERC SDX and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation.

4.2.5 DRR Type I and Type II – Qualification Requirements

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. Verification of DRR Type I and Type II capability will be in accordance with the guidelines established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.

- DRRs that do not pass the deliverability test may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- New DRR Type I and Type II Resources must submit GVTC, and if greater than or equal to 10 MW based on GVTC, then these Resources must submit GADS prior to being approved as a Capacity Resource.
- DRR Type I and Type II that are less than 10 MW based upon type and volume interconnection service and 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.
- All DRR Type I and II backed by a generator are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31st, in order to qualify as a Planning or Load Modifying Resource.
- DRR Type I or II Resources that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resources that are committed through a Planning Resource Auction cannot retire, mothball, or suspend a DRR unless another resource is replaced.

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 data 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 must be provided during the test period between September 1st and August 31st prior to the upcoming Planning Year shall be used.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC data to MISO by March 1st prior to the Planning Year. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a "mothballed" state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to operational status after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time must be submitted by March 1st prior to the Planning Year.
- The GVTC data for a new Demand Response Resource is due to MISO at the time a Market Participant registers the resource in the Commercial Model and before the Market Participant elects to register the resource in the MECT. See Appendix J for links to MISO GVTC Manual and processes.
    - Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Net Capability Verification Test User Manual

4.2.5.1 DRR Type I and Type II – UCAP Determination

MISO will determine the UCAP value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and $XEFOR_d$ values of such BTMG. 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 be used to calculate the forced outage rate.

A $XEFOR_d$ value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4.

4.2.5.2 DRR TYPE I AND TYPE II – Must Offer

As described in detail in Section 6.1, an MP that commits a Generation Resource's UCAP MW must submit the full operable capacity of the Resource, but not less than the ICAP value of ZRCs cleared and/or used in a Fixed Resource Adequacy Plan, into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage.

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 ZRCs cleared in an annual or Transitional PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – $XEFOR_d$) of the Capacity Resource.

4.2.6 Load Modifying Resource Obligations and Penalties

Load Modifying Resources (LMRs) consist of approved 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.

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 Setpoint Instructions. An LMR that relies solely on a generator to reduce load or as a fallback for load control or interruption must register as a BTMG.

LMR differ from Capacity Resource in that they do not have a must offer requirement, however they must be available for use as registered as defined in this BPM during all types of Emergency events (including both capacity and transmission events) declared by MISO unless unavailable as a result of maintenance requirements or for reasons of Force Majeure. LMRs notify MISO of their availability through the MCS. The availability update should be specific to the LMR that is listed in MCS. The MCS users guide is available for detailed information see MCS User's Guide. LMRs that are registered as other type of resources should adjust their availability in MCS according to the LMR obligation less the max offer submitted for those resources. If the LMR is already deployed or on any type of outage, the availability should be adjusted based on the LMR obligation less the LMR MW deployed or any outages.

If an Emergency is declared by MISO, MISO will create obligation instructions based on the availability information in MCS. The LBA and the MP/Asset Owner will receive a notification of the obligation instructions via MCS message. The MP/Asset Owner will need to acknowledge the obligation and the availability of the LMR(s) being used to meet the obligation instruction should be updated in MCS to reflect the MW amount in the specified time(s). This update and acknowledgement should be done within one hour of receiving the obligation instruction from MISO. Also, the MPs that registered the LMR with MISO should submit to MISO within one business day the LMR Resource Name used in MECT registration, MP that registered LMR, Asset Owner, LBA, MW, Date of Emergency, and Hours Ending with MW values, to radequacy@misoenergy.org for the LMRs used in an Emergency. Only one file per MP should be submitted and should contain all of the LMRs that were used to meet the obligation instructions sent by MISO. The file should be in a csv format according to the following format:

Market Participant Name	NERC id	Resource Name of LMR	LBA	Asset Owner	Date of Emergency	HE1	HE2	HE3	HE4
ABC COMPANY	ABC	ABC LMR	ABC	ABC	7/31/20XX	10	10	10	10

LMRs that report availability in MCS that is less than the obligation required in the MECT may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declares an Emergency. MISO may also request for documentation for LMRs in which the availability in MCS is less than the obligation for non-Emergency events. Documentation should be sent to radequacy@misoenergy.org and metered data should be uploaded in the DR Tool. Metered data and documentation should be provided within 53 days of the Emergency event or as requested by MISO.

LMR will be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period or the resource has reached its registered number of deployments). MISO's Emergency Operations Manuals, RTO-EOP-002 and RTO-EOP-004 include the procedures on 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 that have converted UCAP to ZRCs are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert its associated UCAP may also register the resource as an LMR. In this case, the UCAP converted under the LMR designation would follow the respective LMR requirements and likewise the UCAP converted, if any, that are assigned to the DRR would carry the must offer requirement. DRR offered MWs will always be dispatched ahead of LMRs. Also, the combined UCAP converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned value of the singular resource.

Performance evaluation of the LMR will not include restrictions placed on the resource as a result of the resource being deployed as a DRR, so this evaluation must be taken into account when considering this option. For example, if a DRR can only perform for four hours and requires a four hour down period before a second deployment, it would at risk of failing to perform as an LMR if needed during the down period.

An LMR is not required to be a Network Resource. A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 regardless of whether it qualifies as an LMR under Module E-1. Also, dual registration as an EDR and an LMR is acceptable. In the case of a dual LMR / EDR registration, the resource will be dispatched as an EDR when there is a pending EDR offer (EDR offers are made on a daily basis). While the resource is dispatched as an EDR, it maintains its LMR obligations and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered.

Accredited LMRs that have been converted to ZRCs must be available as outlined above for use in the event of an Emergency declared by MISO. A Market Participant that has cleared ZRCs in the PRA from an approved LMR or netted approved DRs against its Coincident Peak Demand forecast will be subject to the penalties described in Section 69A.3.9 of the Tariff if the 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 as directed by MISO or the LBA. Such LSE shall be assessed the costs that were otherwise incurred to replace the energy deficiency at the time the LMR was dispatched.

The target level of Load reduction for a DR will take into account the specified firm service level it specified at registration. However, MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. Survey responses prior to an Emergency event will also be considered when evaluating whether target levels of generation increase or Load reduction have been met.

The operators of LMRs that properly report to MISO and to the LBA that an LMR is unavailable in the MCS or the LMR does not respond to the Transmission Provider's dispatch instruction 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 amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) at the time the request for interruption is made. Likewise, for certain LMRs that are temperature dependent (*e.g.*, 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 a DR is called upon to reduce Load or BTMG is called upon to increase generation.

4.2.7 BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Registering BTMG through the MECT BTMG registration screen according to the process documented in Section 4.3.2.1.
- 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 for 5 emergency events.

- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times during the Summer season when called on by MISO or the LBA for emergency event 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 if located in the same LRZ).
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. 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 4.2.2.
- For wind resources being registered as BTMG, the following information is required:
    - Resources with at least one year of metered values would submit metered values in MWs for all Hours in the test period.
    - Resources with less than one year of metered values would receive class average for the Initial Planning Year.
- New BTMG resources must submit GVTC and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being registered as a LMR.
- The $XEFOR_d$ 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.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Demonstrating capability for non-intermittent BTMG on an annual basis as described below.
- BTMGs that have been retired, mothballed, or suspended will no longer qualify as a Planning Resource. Planning Resources that are committed through a Planning Resource Auction cannot retire, mothball, or suspend a resource unless another resource is replaced.

- All BTMGs being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's 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 prior to the Planning Year. The BTMG GVTC will be corrected to the average temperature of the date and times of MISO's 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 GVTC and submit its GVTC data to MISO's 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 that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31st in order to qualify as a Planning Resource for 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 data.
    - The real power test shall be performed or past operational data must be provided during the test period between 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 submittal of the results of the GVTC to MISO via the PowerGADS system.
    - A real power test is required when any returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time.
- The GVTC for a new BTMG with increased capability is due before a Market Participant registers it in the MECT, and must be submitted by March 1st prior to the Planning Year that the BTMG is effective in the Module E-1 Capacity Tracking Tool.

- The GVTC for an existing BTMG with increased capability is due by March 1st if the original GVTC was submitted by the October 31st deadline and the registered in the MECT by February 1st.
- See Appendix J for links to MISO GVTC Manual and processes.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Net Capability Verification Test User Manual, which is located on MISO's website.

4.2.7.1 Submission of New BTMG Registrations

A MP will register its new BTMG via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. The registering entity must be a MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. 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 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.

4.2.7.2 Termination of BTMG Accredited as LMR

Because BTMGs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.7.3 Amendments to Accredited BTMG Registration Data

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation or has either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1st prior to a Planning Year in order for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1st.

If Market Participant wishes to retire, suspend or mothball a BTMG, the MP must replace retired or mothballed resources that either cleared in the Planning Resource Auction or were identified in a Fixed Resource Adequacy Plan (FRAP) via the MECT. MPs must notify Resource Adequacy at least (7) Business Days prior to replacing any resources. The ZRCs which are being replaced must be in the same Local Resource Zone as the BTMG being retired, suspended, or mothballed and such ZRCs may not be used elsewhere to satisfy obligations unless the BTMG was partially used. Only the remaining ZRCs of a BTMG that was partially used, can be used to help meet the performance requirements of the original BTMG cleared in the PRA, or used in a FRAP.

4.2.7.4 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 by February 1st prior to the Planning Year. NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3.2., 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 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, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.7.5 Behind the Meter Generation (BTMG)– UCAP Determination

The UCAP value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, 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.

BTMG that are intermittent wind resource will have their UCAP determined consistent with the methodology described the MISO Wind Capacity Credit Report.

UCAP MW options for units with derates prior to the GVTC test date are further explained in Appendix J.4 of the RAR BPM.

4.2.7.6 BTMG Deliverability

BTMG must be deliverable to Load located within MISO's Region using one of the following:

- BTMG that is located in the same LBA as the LSE's CPD forecast that is being used to offset the same LSE's PRMR in the same LBA.
- Market Participant 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 MISO's OASIS.
- Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
- The load is a network customer and the BTMG has been determined to be aggregate deliverable by acquiring Network Resource Interconnection Service or as determined by the Market Transition Deliverability test provided that the BTMG is interconnected to MISO's Transmission System.

4.2.7.7 Measurement and Verification of BTMG

See Attachment TT of the Tariff

4.2.8 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 process documented in Section 4.3.3.1.
- Registering the reduction capability of the DR, excluding transmission losses and consistent with conditions at MISO's Coincident Peak.

- 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 a 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 the first (5) times during the Summer season when called on by MISO or the LBA for Emergency purposes during the Planning Year.
- Confirming that the Market Participant has the authority to reduce demand using the DR.
- Documenting in the MECT the DR's 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 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, then 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
    - For the 2013-2014 Planning Year, test, performance data, third party audit or other documentation supporting the registered MW should be from June 1, 2012 to March 1, 2013. Beginning in Planning Year 2014-2015 and thereafter, test, performance data, third party audit or documentation supporting the MW being registered should be from September 1 to August 31st immediately preceding the applicable Planning Year. Results should be submitted to MISO by October 31st.

- Documenting in the MECT 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 69A.3.9 of the Tariff. 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 69A.3.5 of the Tariff.

4.2.8.1 Demand Resource Registration Process

DR can be registered to be used to net against an LSE's Demand forecast, or to be used as a resource to receive UCAP MW that can be converted to ZRCs. 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 ZRCs may not also be netted from the LSE's forecasted Demand. MISO will subtract accredited DR from an LSE's CPD forecast if the LSE chooses the "netting" option during registration.

4.2.8.2 Submission of new DR Registrations

A MP may register new DR via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. In order to guarantee new Planning Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. 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, should 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 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 form 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.

4.2.8.3 Termination of Demand Resource Accredited as LMR

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.8.4 Amendments to Accredited DR Registration Data

The Market Participant can amend the registration for a DR for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The MP may 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 amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit amended registration information in the Registration screen by March 1st prior to the Planning Year in order for MISO to determine whether the resource still qualifies as an LMR.

If a Market Participant wishes to discontinue a DR that either was identified in a Fixed Resource Adequacy Plan, netted against an LSE's Coincident Peak Forecast or cleared in the Planning Resource Auction during the Planning Year, the Market Participant must replace the DR with a resource in the same LRZ via the MECT. The MP should notify Resource Adequacy at least 7) Business Days prior to replacing the DR. The ZRCs which are being replaced must be in same Local Resource Zone as the DR being discontinued and may not be used elsewhere to satisfy obligations unless the DR was partially used. Only the remaining ZRCs of a DR partially used can be used help meet the performance requirements of the original DR cleared in the PRA or used in a FRAP.

4.2.8.5 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 by February 1st prior to the Planning Year. 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 form 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.

4.2.8.6 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, past performance, or mock test.

MISO will determine through the registration process whether the BTMG or DR qualifies as an LMR. The resource may also qualify as an EDR under Schedule 30 regardless of whether it qualifies as an LMR. Dual registration as an EDR and an LMR is acceptable. Once the LMR and its MWs are entered into the MECT and accredited by MISO, then the MP that registered the LMR can elect to convert all or part of the LMR's accredited MWs into ZRCs.

4.2.8.7 Demand Resource Deliverability

The owner of the ZRCs may not use DR as part of a FRAP, offer into the PRA, or net against a Coincident Peak Demand forecast if the DR is outside the LRZ where the DR physically resides.

4.2.8.8 Measurement and Verification of Demand Resource

See Attachment TT of the Tariff.

4.2.9 Energy Efficiency Resources

Energy Efficiency (EE) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecast used for the Planning Resource Auction for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric energy consumption due to existing EE programs that is reflected in the CPDf cannot also be qualified as an EE Resource.

All of the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for the Planning Year. The Nominated EE Value is the expected average demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days from June 1 through August 31, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource no later than 30 days prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource no later than 30 days prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report prior to a subsequent Planning Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to measure PRA commitment compliance during the Planning Year. Details regarding PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE Value that is used to measure PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in PRAs or used in a FRAP for that Planning Year and three subsequent Planning Years. For example, an Energy Efficiency resource installed and qualified prior to June 1, 2013, could participate in the PRA or be used in a FRAP for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the Energy Efficiency resource registers and meets the qualification requirements for each Planning Year. After four years, the Energy Efficiency resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the demand forecast.

4.2.9.1 Energy Efficiency Resource – M&V

See Attachment UU of the Tariff

4.3 Confirmation and Conversion of UCAP MW

To create a ZRC, a MP must confirm the UCAP MW and then convert UCAP MW from each qualified Planning Resource to ZRC through the MECT UCAP/ZRC conversion screen. A ZRC represents 1 MW-day of qualified Unforced Capacity from a Planning Resource for a specific Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. All types of Planning Resources are tracked in the MECT, which tracks Module E-1 resources used for compliance against an LSE's obligations.

When ZRCs are converted from UCAP by the Planning Resource owner, the ZRCs are populated in that MP's available ZRC account. MISO will keep track of how many ZRCs the MP has created, and how many remaining UCAP MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the specific Planning Resources that they were created from in order to assist with establishing clearing requirements, the auction clearing process and market mitigation monitoring.

4.4 ZRC Transactions

4.4.1 Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the ZRC Transactions' tab in the MECT. Both the 'Buyer' and 'Seller' are required to account for a ZRC transaction in the MECT, the "Seller" is required to submit the transaction in the MECT, and the "Buyer" is required to confirm the transaction reported.. Once the transaction has been submitted and confirmed by both parties the ZRC transaction volumes will be subtracted from the seller's available ZRC account and added to the buyer's available ZRC account. The MECT allows transactions based on type of ZRCs.

4.4.2 Conversion of ZRCs to UCAP MW

An owner of ZRCs that also owns Planning Resources from which any ZRCs have been converted, may convert uncleared ZRCs from the same resource or any other resource in the same LRZ back to UCAP MW via the MECT UCAP/ZRC conversion screen if the resources have not cleared in a Planning Resource Auction or used in a FRAP.

The conversion of ZRCs may be directed to any specified resource provided that: (a) the resource previously was used to create ZRCs; and (b) that the increase in remaining UCAP MW from the conversion, when added to the currently remaining UCAP MW eligible for conversion to ZRCs, does not exceed the maximum UCAP MW for the resource.

5. Resource Adequacy Requirements

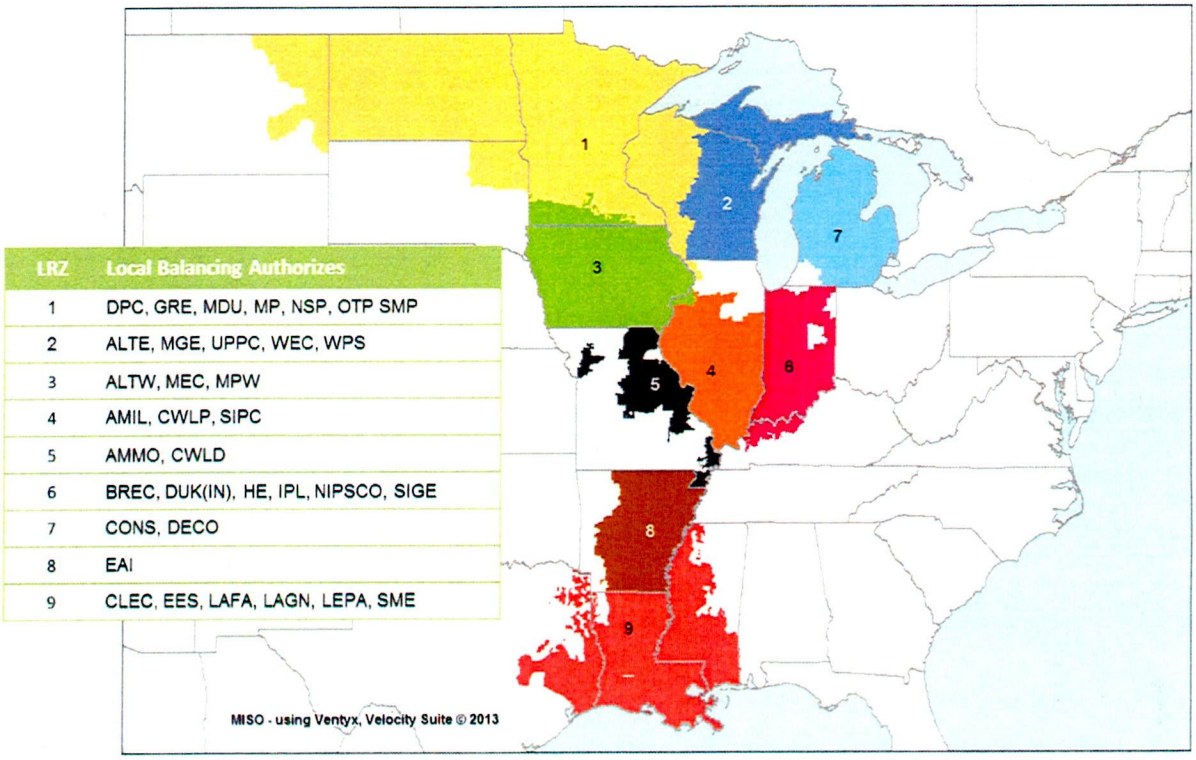
5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resources Zone (LRZ) to meet the MISO footprint's Planning Reserve Margin Requirement (PRMR). An LSE can meet its PRMR by any of the following ways:

(1) Self-scheduling
(2) Fixed Resource Adequacy Plan (FRAP)
(3) Participating in the Planning Resource Auction (PRA)
(4) Paying the Capacity Deficiency Charge (CDC)

5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of the Local Resource Zones no later than September 1st of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region, based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV, may change the configuration of the LRZs due to changes in system topology or configuration. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA.

5.2.1.1 Calculation of Transfer Limits of the Local Resource Zone

MISO will determine the CEL and CIL for a LRZ for a Planning Year using the following process:

- Use the Planning Year MISO Transmission Expansion Plan (MTEP) reliability model
- Model MTEP Appendix A facilities, considering facility in service dates
- All in service Planning Resources; and Planning Resources in the Generator Interconnection Queue with a signed Interconnection Agreement and an in-service date in the relevant Planning Year
- Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category A (N-0) and Category B (N-1) contingencies

- Model generation-to-generation transfers
- Calculate FCTTC for each LRZ to and from the balance of LRZ using a One to all for export; and an All to one for import)

The outcome of this process will identify a CEL and CIL for each of the LRZs. MISO will publish the CEL and CIL for each LRZ by November 1st preceding the applicable Planning Year, or at least thirty (30) calendar days prior to a Transitional Planning Resource Auction (TPRA).

5.2.1.2 Establishment of Local Reliability Requirement

Each LRZ's Local Reliability Requirement (LRR) is the amount of UCAP MWs required to yield a 0.1-day-per-year LOLE, without assistance from resources outside the respective zone at the load level for the LRZ at the time of the MISO system peak. The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

The LRR will be established using the following iterative process:

- Use the LOLE model in MARS to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and physical resources from the PRM Analysis.
- The LOLE model will be run through multiple iterations successively adding resources until the LRZ achieves the 1 day in 10 years LOLE criteria with no external ties.
    - A Load Forecast Uncertainty (LFU) factor will be applied for each Zone. The initial iteration of the LOLE model will assume 0 MW of resources within the LRZ, and then, starting with the largest Unforced Capacity rated resource located in the LRZ, MISO will sequentially add additional resources (or fractions thereof) in descending order of MW of Unforced Capacity located in the LRZ until the LOLE is 0.1 day per year for the LRZ.

- If the LRZ does not have sufficient resources located in the LRZ to achieve the LOLE of 0.1 day per year, then additional proxy resources (of typical size and typical $EFOR_d$ for the particular LRZ) will be added until the LRZ would achieve the LOLE of 0.1 day per year. A fraction of the final proxy resource will be added to achieve exactly the LOLE of 0.1 day per year for the LRZ.

The formula for the LRZ's LRR is as follows:

LRR_{z1} = (Largest Unforced Capacity rated $resource_{z1}$ + 2nd Largest Unforced Capacity rated $resource_{z1}$ + 3rd largest Unforced Capacity rated $resource_{z1}$ + Nth largest Unforced Capacity rated resource or fraction thereof, including if necessary, any proxy resources) such that the $LOLE_{z1}$ = 0.1 day per year

The per-unit LRR values are annually calculated by the MISO Policy and Economic Studies Department (PES) and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit LRR values are multiplied by the total zonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) inclusive of Transmission losses to calculate each Local Resources Zone's Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

5.2.1.3 Establishment of Local Clearing Requirement

The final step in calculating an LRZ's LCR is to account for the external transmission ties by reducing the LRR by the capacity import limit determined in accordance with Section 3.3.3.2. The formula for determining the LCR is as follows:

$LCR_{z1} = LRR_{z1} - \text{Capacity Import Limit}_{z1}$

MISO will publish the LCR determinations by November 1st prior to the upcoming Planning Year.

5.3 Fixed Resource Adequacy Plan (FRAP)

The FRAP will identify resources that an LSE has ownership or contractual rights that will be relied upon to meet the LSE's Planning Reserve Margin Requirement and its share of the Local Clearing Requirement (LCR) in each LRZ where the LSE has Load. The FRAP plan must be submitted via the MECT by the 7th business day of March prior to each Planning Year, and each Planning Resource must meet the qualification requirements identified in Section 4 of this Business Practice Manual document if seeking to be part of the LSE's FRAP. MISO will review the FRAP and notify the LSE of any issues by March 15th. LSEs will have until the PRA offer window closes to resolve any issues identified by MISO.

An LSE can designate its ZRCs in the FRAP up to the LSEs PRMR. ZRCs designated in the FRAP will be identified in the MECT. The ZRCs from these Planning Resources will be deducted from the available ZRC balance of that Planning Resource in the MECT. Any portion of an LSE's PRMR not covered by the FRAP can be purchased through the PRA.

5.3.1 LSE's Local Clearing Requirement for LSE's Using a FRAP

LSEs that chose to use the FRAP to meet their Resource Adequacy Requirements must designate a sufficient volume of resources located in the same LRZ as the LSE's PRMR to meet its pro rata share of the LRZs total LCR. LSE's share of the LRZ's LCR is it's pro rata share of the sum of the zone's Coincident Peak Forecast multiplied by the total zonal LCR. The following formula is used to determine each LSEs Fixed Resource Adequacy Plan LCR requirements:

LSE FRAP LCR = (LSE CPDF/LRZ CPDF) * zonal LCR

5.4 Hedges

5.4.1 Grandmother Agreements (GMA)

A GMA is a financial hedge against LRZ Auction Clearing Prices (ACPs) differentials. GMA's for existing capacity agreements hold LSEs harmless from price separation as a result of adding locational requirements to the Resource Adequacy provisions. GMAs for existing LSEs will be allowed for Planning Years 2013-2014 and 2014-2015. For New LSEs, GMAs will be allowed for their transitional Planning Year and the next two full Planning Years. GMAs will be granted for a Planning Resource that clears in the Planning Resource Auction or Transitional Planning Resource Auction.

The following criteria are required for GMA approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year
- Contract must be executed and in place on or before July 20, 2011
- For existing LSEs, GMAs will expire at the end of the contract term, unit ownership change, unit retirement date, or by May 31, 2015, whichever is first
- For New LSEs, GMAs will expire at the end of the contract term, unit ownership change, unit retirement date, or after the first two full Planning Years following integration with MISO, whichever is first
- Register GMA in MECT by November 1st prior to each Planning Year. Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Local Resource Zone, and TSR /eDNR (electronic Designated Network Resource) number. Once the UCAP MW for Planning Resources is converted to ZRCs, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Local Resource Zone, and TSR/eDNR number information only. Updates will need to be completed by February 1st prior to each Planning Year.
- A separate GMA registration is required for each Planning Resource and LRZ of load.
  - One Planning Resource in a registration can only select one LRZ.
- Transmission Requirements for GMAs need to meet one of the following three:
  - NRIS (aggregate deliverable plus eDNR) or;
  - NRIS Local or NITS (Network Designated TSR plus eDNR) or;
  - Firm Point to Point for NRIS Local or ERIS;
- The MW in GMA registrations should not exceed the LSE's PRMR, contract amount, ZRCs, and transmission reservation.

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as Grandmother Agreements, provided that the agreements otherwise satisfy the criteria.

Intra-zonal capacity transactions that become inter-zonal capacity transactions as a result of future revision to the LRZ boundaries during the two-year transition period will be eligible for the Grandmother Agreement hedge.

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the Grandmother Hedge provided that the GMA criteria is satisfied.

Firm resources that meet Grandmother Hedge criteria may be included as part of a FRAP or offered into the annual auction. An LSE requesting a Grandmother Hedge will need to register and include documentation via the MECT by November 1st prior to the Planning Year to demonstrate their eligibility.

Historical Contract Eligibility for GMA

Although APRCs will cease to exist as of May 31, 2013, they can prequalify as GMAs as follows:

- Submit executed contract between MP requesting GMA and seller of APRCs requesting a GMA
- MISO will calculate annual UCAP MW of Planning Resources
- Market Participants will need to convert UCAP MW to Zonal Resource Credits (ZRC)
    - Zonal Resource Credits will have unit and LRZ specific identifiers
- As Market Participants transact ZRCs to fulfill contracts that meet criteria for hedge, MISO will be able to determine source of ZRCs to apply "Grandmothering" financial hedge to auction results
    - ZRCs transacted to fulfill existing contracts will need to have unit identifiers from aggregate deliverable generators
- Based on ZRCs transacted, MISO will work with the MP that qualified the GMA to determine which LRZ the Planning Resource is located
- LSEs with APRCs contracts must provide their Network Contract number as the TSR in addition to eDNR number which lists the Planning Resource being selected in the GMA registration. The eDNR can be provided in the comments field of the registration or as an attached document in the GMA registration.

If Load is located in an LRZ with a higher ACP than the LRZ where the Resource is located, Load will pay an amount equal to the difference in the ACPs between the LRZs, times the amount of the unhedged Load if a Grandmother Hedge does not exist. After the two year transition period for Grandmother Agreements concludes, the zonal deliverability benefit shall be distributed by the Transmission Provider such that ZDC Hedges are funded first, and then any excess credits are distributed in accordance with the Module E-1 Tariff.

5.4.2 Zonal Deliverability Charge and Hedge

An LSE submitting a FRAP may be subject to a ZDC. The ZDC is the difference between the ACP in the LRZ where the LSE has PRMR obligation and the ACP in the LRZ where the LSE Planning Resources are located times the volume of Planning Resources in the LRZ where their resources are located. LSE can obtain a ZDC hedge as described herein as a financial protection from zonal price differences. Excess revenues collected from the PRA will be used to fund GMAs and ZDC hedges, and zonal deliverability benefit in this order.

Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a hedge. Also, any cost shared upgrades would not be eligible for a hedge. The participant that funds the upgrades and submits the Transmission Service request is the participant who is eligible for the hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1st prior to the Planning Year to demonstrate eligibility. ZDC hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

5.5 Planning Resource Auction (PRA)

5.5.1 Timing of Auctions

The annual PRA will be conducted beginning in April, which is approximately two months before the beginning of the associated Planning Year. Any Transitional PRA will be conducted prior to the New LSE's integration date.

5.5.2 Amount of Capacity Cleared in Each Auction

The annual Planning Resource Auction shall clear the ZRC offers in order to satisfy 100% of the PRMR for each existing LSE, less the amount of PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a FRAP, in each LRZ up to the total volume of offered ZRCs.

Transitional Planning Resource Auctions shall clear ZRC offers in order to satisfy 100% of the PRMR for each New LSE, less the amount of PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a FRAP, in each LRZ up to the total volume of offered ZRCs.

5.5.3 Conduct of the PRA

The annual and Transitional PRA shall be a sealed bid auction, which will determine the Auction Clearing Price (ACP) for each Local Resource Zone modeled in that Auction. The Auction shall determine the outcome of all Planning Resource offers accepted during the qualification process and submitted during the auction.

Step 1: Compilation of Offers

Offers for the Auction must be submitted in the MECT's Submit Offer screen during the Auction window period. The offer window for the auction will be opened during the last three business days in the month of March prior to the start of the new Planning Year. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of a FRAP.

MISO shall compile all of the offers, as follows: The MP acting on behalf of any Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of ZRCs that the MP would commit to provide from the Resource in the associated modeled Local Resource Zone during the Planning Year. An offer shall be defined by the submission of up to five such pairs, each having a strictly greater price than the previous price in the submittal. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for price. Each offer is separately evaluated.

Step 2: Determination of the Outcome

- MISO shall use the ZRC offers to determine the aggregate supply curves for each MISO modeled Local Resource Zone. MISO will use the offers in conjunction with the import and export constraints, local clearing requirements, and other inputs to determine the least cost set of resources that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the LRZ and not the size of the plant (i.e. LRZ needs 50 MW, but Market Participant has a 100 MW plant only 50 MW will clear). At any non-zero clearing price, pro-rate clearing from tied bids will be applied. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Inadequate Supply

While the auction will endeavor to select ZRC offers sufficient to meet the requirements of each LRZ, it is possible that sufficient resources are not available. In such cases, the auction will clear all offered resources in the LRZ at the price approved by FERC and the LRZ would be short of Planning Resources for the Planning Year.

5.5.4 Market Monitoring

All participation by resource providers is subject to the market power mitigation rules described in Module D of MISO's Open Access Transmission Tariff.

5.5.5 Local Reliability Requirement

Local Reliability Requirements for each LRZ will be determined by MISO through engineering studies based on the 0.1 days per year loss of load expectation criteria for each LRZ in isolation. From this initially determined value (the Local Reliability Requirement) will be subtracted the import capability of the LRZ from the rest of MISO's system, resulting in the LCR value. Further details on the LCR can be found in the LOLE study. MISO will provide the LCR to LSEs by November 1st prior to the upcoming Planning Year.

5.5.6 Target Reliability Value

The resultant target reliability value for each LRZ will be the greater of the system-wide value based on MISO's PRM or the local clearing requirement value. The sum of these LRZ target reliability values will be the system's target reliability value, that is, the amount of UCAP MW that must be obtained, if available, from the Auction.

5.5.7 Resource Offers

Any ZRCs that were not used in the FRAP or sold to other MPs can be offered for the PRA during the Auction window period. The following business rules are applied to the PRA Offers:

- Offer cannot be changed or withdrawn after the Auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.
- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each zone is annual Zonal CONE divided by 365
- Transmission Provider will clear offers based on the needs of the LRZ and not the size of the plant (i.e. LRZ needs 50 MW, but Market Participant has a 100 MW plant only; 50 MW will clear).
- Offers will be submitted via the MECT while the Auction window is opened.
- At any non-zero clearing price, pro-rate clearing from tied bids will be applied.
- At a zero-clearing price, all zero-price and price-taking offers will be accepted.
- Only non-negative offers are accepted.

Self-Scheduling

LSEs that "self-schedule" ZRCs by submitting offers into the PRA for the associated ZRCs with a price of $0.00 will always clear the Auction.

5.5.8 Auction Results Posting

MISO Resource Adequacy team will post the summary of the annual PRA results on its website Ten (10) Business Days after the Auction window is closed and any Transitional PRA Five (5) Business Days after the Auction window is closed. The summary includes PRMR, Netted DR/EER, Adjusted PRMR, Total Offer + FRAP, Offer Cleared + FRAP, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, and Deficient Amount by Local Resource Zone, and Total Offer Cleared Amount for the system.

Three (3) months following the completion of any PRA, MISO will post the results of the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

Resource Adequacy Settlement

Transmission Provider will settle the annual and any Transitional Planning Resource Auction using the following steps:

1. Determine the zonal Auction Clearing Prices for Resources and Loads within each LRZ;
2. Provide Grandmother Agreement credits equal to the zonal Auction Clearing Price differential to Load subject to Grandmother Agreements.
3. Provide Zonal Delivery Charge Hedge credits equal to the zonal Auction Clearing Price differential to Zonal Delivery Charge Hedge Load amounts.
4. Provide zonal delivery benefit credits to all remaining load in the LRZ.

The zonal delivery benefit credit is determined as follows:

a. Determine the remaining payments due to Resources providing service to the remaining Load in the LRZ;
b. Divide (a) by the remaining Load (Load without GMA and/or ZDC hedge) in the LRZ;
c. Subtract (b) from the Auction Clearing Price to determine the zonal delivery benefit

Settlement calculations for the PRA will be conducted on a daily basis and the results will be shown under the S14 Settlements statement. Please refer to the Market Settlements BPM for further details. There are four (4) charge types under the PRA Settlement:

- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's FRAP will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when a LSE clears more ZRC in the PRA than its PRMR. The LSEs that converted UCAP MW to ZRCs will receive the auction clearing price for the entire Planning Year for those ZRCs that cleared in the PRA.

5.6 Retail and Wholesale Load

Both the Retail and Wholesale Load switching between LSEs can be tracked through the MECT Application after the start of the new planning year. As a result of load switching, the PRMR of the LSEs involved in the load switching will change. However, the EDC's total area demand will not change due to Retail Load switching. Similarly, wholesale load transaction will not change the total MISO PRMR.

Retail Load Switching

By January 15th 11:59 p.m. EST prior to start of the new Planning Year, both the Electric Distribution Company (EDC) and LSEs will confirm the LSEs' share of the EDC's area Coincident Peak Forecast (i.e. PLC); and submitted in the MECT by the LSE. The LSE's PRMR under the Retail Choice program will be initially determined based on the PLC; however, an LSEs' PRMR will change during the Planning year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

5.6.1 Non-Retail Load Switching

For the case of the wholesale Load switching, the amount of the PRMR transacted via the wholesale load transaction process will transfer the PRMR of the current LSE to the new LSE starting with the effective date specified in the Wholesale transaction. The transaction must be confirmed in the MECT before the start of the effective date.

5.6.2 Default Method

The preferred default method is based on the PLC value of each retail customer, which is based on the customer's demand at the time of the Transmission Provider's peak demand during the Summer prior to the Planning Year. The aggregate PLCs will be set equal to the forecast provided by the EDC. Specific methods used by the EDC to calculate each customer's PLC must be provided to both MISO and LSEs no later than December 15th on the year prior to the upcoming Planning Year. Then LSEs will have until January 15th to verify the EDC provided data and submit the aggregated total in the MECT.

In the event that no data is available to use for the default method described above, a "daily peak load" default methodology will be used. The daily capacity charges relating to the PRMR will be allocated based on the historical share of the Summer peak load from the previous Planning Year.

5.6.3 Retail Load Switching under the Default Method

The Retail Load screen in the MECT is provided for EDCs in Retail Choice states utilizing the Default Method to track the LSE's day-to-day migration of loads at the Asset Owner (AO) level.

Using the daily retail load switching information in the MECT, MISO Settlements calculates the LSE's new PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

For LSEs using the backup Default Method, their load switching will be determined based on the daily Load served by each LSE within the EDC's area for the peak hour of the Transmission Provider's region which the EDC submitted to the MISO's Settlements system.

The backup Default Method will be employed until the permanent solution is in place.

The daily retail load switching information includes:

- Name of the EDC Zone
- Name of the LRZ
- Effective Date of Retail load switching
- Name of AO(s)
- AO's new Retail MW (with granularity of thousandths of a MW)

5.6.4 Wholesale Load Switching

Wholesale Load obligation can be switched from one LSE to another using the Wholesale transaction screen in the MECT during the Planning Year. When wholesale Load switching occurs, the daily capacity charges of wholesale Load will be transferred from the current LSE to the new LSE. The PRMR for affected LSEs will be decreased or increased, as appropriate, by the amount of the wholesale load plus the PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Planning Year enter a wholesale Load switching contract representing PRMR in the MECT.

5.6.5 Distribution of Capacity Deficiency Charges Revenues

The Transmission Provider will impose a capacity deficiency charge on an LSE that has not demonstrated, at the close of the Planning Resource Auction, to the Transmission Provider, through the MECT, that it has arranged sufficient zonal capacity resources to meets its PRMR. The annual capacity deficiency charge will be calculated as follows: The CONE value for the LRZ where the LSE has not arranged through the MECT sufficient ZRCs will be multiplied by 2.748 times the number of Zonal Resource Credits that the LSE is deficient. The capacity deficiency charge will be assessed to a capacity deficient LSE on the first business day after the results of the Planning Resource Auction have been published.

b. Distribution of Capacity Charge Revenues: Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to LSEs in the capacity deficient LRZ on a *pro rata* basis, based upon MW of annual peak load of LSEs that have met their RAR during the Planning Year. If the LRZ where the LSE incurred Capacity Deficiency Charges failed to meet its LCR, then Capacity Deficiency Charge revenues will be allocated solely to LSEs that have met their RAR in the applicable LRZ. Otherwise, Capacity Deficiency Charge revenues will be allocated to all LSEs that have met their RAR in the Transmission Provider footprint.

5.6.6 Settlements of Wholesale and Retail Switching

All confirmed load switching Information submitted by the Settlements deadline (per Market Settlements BPM) will be transferred to Market Settlements for the settlements calculation purpose.

An LSE's PRMR will change based on the information submitted in the MECT for both Wholesale Load Switching, Retail Load Switching for the Default Method and Retail Load Switching determined by the Settlements team for the backup Default Method.

MISO will calculate the new charges and credits by applying the Auction Clearing Price (ACP) for the applicable LRZ to the new daily PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE's PRMR will change if Retail Load switching information in the MECT or daily load data for Settlements is resubmitted per the Settlement's rerun process (i.e. S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

6. Performance Requirements

6.1 Must Offer Requirement and Monitoring

The must offer requirement applies to any Market Participant who registers a Capacity Resource and that an LSE uses to meet their PRMR. The must offer requirement applies to all Capacity Resources that either are used in a FRAP or clear in a Planning Resource Auction. The must offer volume is calculated by dividing the amount of ZRCs by (1 – XEFORd) of the Capacity Resource except for wind units which is based on cleared ZRCs or ZRCs used in a Fixed Resource Adequacy Plan (FRAP) divided by wind capacity credit.

On a daily basis, MISO will monitor whether the Offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market and first post Day-Ahead RAC process meet the must-offer requirements for the amount of Installed Capacity. MISO will compare the difference between the Emergency default 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 first post Day-Ahead RAC are less than the must-offer requirement, then MISO will compare the difference to derates in MISO's Outage Scheduler (CROW) for such resources. Outages, derates and Offers will be captured based on the information provided at both the DA Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM. MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT under ZRC Available Balance. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO's Outage Scheduler (CROW). They do not relieve the MP of the obligation to meet the must-offer requirement for the tolerance threshold volume 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

Offered MW (Emergency Max) > = must offer requirement less Threshold (excluding Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO).

If the amount of the derate in CROW plus the appropriate threshold is greater than or equal to the above mentioned difference including the appropriate threshold as 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 monitoring check. MISO will notify MPs through a report published on the MECT portal of their must offer status. If a Market Participant believes there is a discrepancy in their must-offer report, the Market Participant can notify MISO via email to Resource Adequacy personnel 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 on any compliance issues.

6.2 Ongoing Calculation of CONE and Net CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each Local Resource Zone annually by September 1 of each year, for the following Planning Year.

In calculating zonal CONE values, 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 for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE.

The table below contains the CONE values for each LRZ for Planning Year 2013-2014:

ZONE	CONE
LRZ 1	$ 98,810
LRZ 2	$ 98,380
LRZ 3	$ 97,650
LRZ 4	$ 99,940
LRZ 5	$102,320
LRZ 6	$ 99,860
LRZ 7	$ 99,310

6.3 Replacement Resources

Any Market Participant with a Planning Resource that either cleared in a Planning Resource Auction or was identified in a FRAP who plan to de-commit (retire, mothball, other) the Planning Resource during the Planning Year must be replaced with ZRCs from a Planning Resource located in the same Local Resource Zone as the Planning Resource that is being de-committed. Planning Resources that are used for replacement purposes should be done at least 7 days prior to effective date of replacement. Replacement of resources can be done only with ZRCs that have not cleared in an annual or Transitional PRA, indicated in a FRAP, or netted in a Coincident Peak Demand forecast. The ZRCs can be from the Market Participant's own Planning Resources or from another Market Participant as long the Planning Resources are in the same LRZ and have not been used to meet Module E requirements. New resources can be used if registered, qualified and approved by MISO by the due dates for annual and Transitional PRAs.

For DR and EER that are netted against a CPD forecast, the Market Participant must replace the ZRCs by using the following methods:

- Replacing with an equivalent volume of netted DR or EER in the same LRZ; or
- Replacing with the ZRC equivalent of the de-committed amount (accounting for Transmission Losses and PRM) from non-netted Planning Resources located in the same LRZ.

For Planning Resources that are not netted or from a diversity contract, the Market Participant must replace the ZRCs by replacing them with an equivalent volume of ZRCs from Planning Resources located in the same LRZ.

For External Resources that are diversity contracts, the Market Participant must replace the ZRCs by using the following methods:

- Replacing with an equivalent volume of ZRCs from a Planning Resource in the same LRZ; or
- Replacing with an equivalent volume of ZRCs from an External Resource that is a diversity contract that is at least as available for the same duration during the Planning Year as the resource being de-committed.

6.4 LMR performance

6.4.1 BTMG Performance

When a BTMG that either is used in a FRAP or cleared in a PRA 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) applicable Revenue Sufficiency Guarantee ("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) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the RSG First Pass Distribution rate for the applicable Hour.

The revenues from charges resulting from BTMGs 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 BTMG not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The BTMG will be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period; or the resource has reached its registered maximum number of deployments).

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 MISO to increase generation, except for a validated circumstance of maintenance requirements, for reasons of Force Majeure or other acceptable reasons defined in the tariff or this BPM, the LSE that has cleared ZRCs of ZRCs used in a FRAP from an accredited BTMG in the PRA will be subject to the penalties described herein (if that BTMG 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 to receive ACP payments for the current Planning Year and for the next Planning Year.

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.

6.4.2 DR Performance

If a DR that either is used in a FRAP, netted against Coincident Peak Demand forecast or cleared in the PRA fails to perform during an Emergency when called on to reduce Demand by MISO or the LBA, penalties will be 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) applicable 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) 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) actual Load reduction; and (2) the RSG First Pass Distribution rate for the applicable Hour.

The revenues from charges resulting from DRs 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 unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR will be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period; or the resource has reached its registered maximum number of deployments).

In the event the same DR 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; , except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the LSE that either used ZRCS in a FRAP, cleared ZRCs in the PRA from an accredited DR, or netted accredited DRs against its Demand forecast, will be subject to the penalties described herein (if that DR 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 to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s) unless the DR is unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM.

7. Integration of New LSEs

This section serves as a guide for those new Load Serving Entities ("the new LSEs") integrating into MISO's region between the time the MISO has completed the annual Planning Resource Auction and the next Planning Year starts. Once the integration date is set the MISO Resource Adequacy (RA) team will work with both existing and new LSEs to ensure that the newly integrating LSEs to the MISO Region has sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin (PRMR). To meet the Planning Reserve Margin Requirement (PRMR) for the newly integrating MISO region, MISO will conduct the Transitional Planning Resource Auction (PRA). The RA process involves the following four sections as described in the RA BPM sections shown in the parenthesis:

1. Establishing Planning Reserve Margin Requirement (Section 2.1)
2. Qualifying Resources (Section 2.2)
3. Resource Adequacy Requirements (Section 2.3)
4. Settlements/Performance Requirements (Section 2.4)

N new LSEs are encouraged to become familiar with the Resource Adequacy Business Practice Manual for a better understanding of its primary responsibilities and obligations. The new LSEs primary responsibilities and obligations include the following:

1. Qualifying Planning Resources (Section 4) – All Capacity Resources, Load Modifying Resources, and External Resources must be submitted to MISO for their review and approval before they can be used to meet Resource Adequacy Requirements. The owner's of the Planning Resources are required to provide the following data items in the MECT by:

    - Submitting Generator Real Power Verification Testing (GVTC) results for Capacity Resources (Section 4.2) by following the GVTC Testing Requirements described in Appendix J
    - Submitting the LMR and External Resource registrations
        - Netting of Planning Resources (Section 3.3)
        - Non-Intermittent Generation Resources (Section 4.2.1)
        - Intermittent Generation and Dispatchable Intermittent Resources (Section 4.2.2)
        - Use Limited Resources – Qualification Requirements (Section 4.2.3)
        - External Resources - Qualification Requirements (Section 4.2.4)
        - BTMG (Section 4.3.2)
        - Demand Resource (Section 4.3.3)

    - Energy Efficiency Resources (Section 4.3.4)
- Confirmation and Conversion of UCAP MW (Section 4.4)
- Conversion of ZRCs to UCAP MW (Section 4.5.2)
- Submit ZRC Transactions (Section 4.5.1)
- Submit Grandmother Agreements (GMA) (Section 5.4.1)
- Submit Zonal Deliverability Charge and Hedge(Section 5.4.2)
- Submit Resource Offer – (Section 5.5.7)
- Submit Fixed Resource Adequacy Plan (FRAP) (Section 5.3)

2. Establishing Planning Reserve Margin Requirement (Section 3):
    - Submit Coincident Peak Demand Forecast (Section 3.2)
        - Non-Retail Choice (Section 3.2.1)
        - Retail Choice (Section 3.2.2)
    - Full Responsibility Transactions (Section 3.4)
    - Submit Wholesale Load Transaction(Section 5.6)

MISO will have the following primary responsibilities for the new LSEs:

1. Define new Local Resource Zone and their associated zonal Parameters including:
    - Calculate Zonal CONE,
    - Determine Import/Export Limit,
    - LOLE Analysis (Section 3.5.2)
    - Calculate Local Reliability Requirement (Section 5.5.5)
    - Define new Local Resource Zones (Section 5.2)
    - Ongoing Calculation of CONE and Net CONE (Section 6.2)

2. Calculate Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Planning Reserve Margin (Section 3.5.1)
    - Review of CPDF (Section 3.2.3)

3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Publish Auction Results (Section 5.5.8)

The MISO RA team will coordinate the proper timing of the data collection effort with the new LSEs for the successful completion of the Transitional (PRA). The Transitional PRA will ensure that the sufficient Planning Resources are procured to meet the Planning Resource Margin Requirement (PRMR) of the newly integrating MISO region for the remaining Planning Year.

The RA Timeline for the annual PRA is shown in Appendix K. MISO will determine the RA timeline for the Transitional PRA that are unique to each Integration, and will publish it in the Resource Adequacy Planning Page under the Planning Section of the MISO Internet. The RA timeline for the Transitional PRA will be reviewed at the Supply Adequacy Working Group prior to publishing in the MISO Internet.

8. Testing Procedures and Requirements

8.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J will apply for Planning Years (2011-2012) and beyond.

9. Appendices

Appendix A – Wind Capacity Credit

The basic goal is to estimate the reliable output of wind as a percentage of the installed capacity, for the MISO System and by CPnode. This involves the following data.

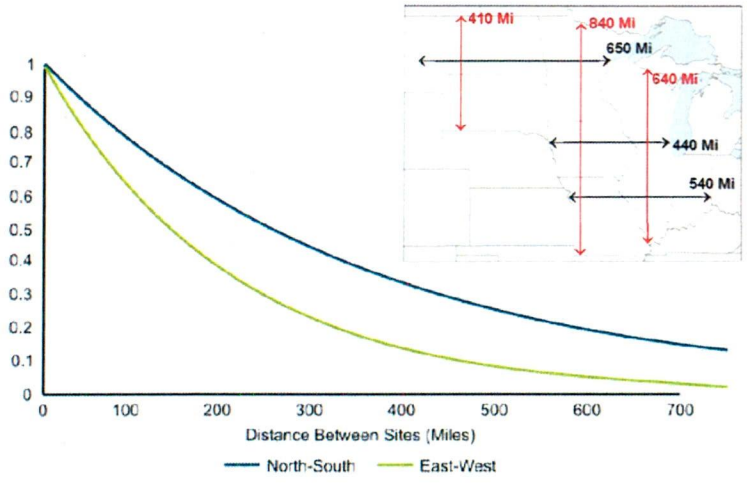
Driving Data for Wind Capacity Credit

- The hourly load and the hourly wind output for 8,760 hours. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system wide Effective Load Carrying Capacity (ELCC) of the wind resources.
- MISO tracks the hourly wind output for the top 8 daily peak hours, by MISO total and individual wind CPnodes. The system wide and CPnode data is used to allocate the system wide Effective Load Carrying Capacity (ELCC) among individual CPnodes.
- MISO tracks the hourly amounts by which individual wind CPnodes are dispatched downward as part of the Dispatchable Intermittent Resources (DIR) activity. Similarly, MISO estimates the MW that CPnodes may have been curtailed.

Since 2009 MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO process as developed and vetted through the MISO stakeholder community consists of a two-step method. The first-step utilizes a probabilistic approach to calculate the MISO system-wide Effective Load Carrying Capability (ELCC) value for all wind resources in the MISO footprint. The second-step employs a deterministic approach using specific information about the location of each wind resource 'period metric' to allocate the single system-wide ELCC value across all wind CPnodes in the MISO system, to determine a wind capacity credit for each wind node.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. So for each upcoming planning year the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the ever increasing integration of new resources into the system. The sections of this write-up and current results illustrated here are broken down to describe the details of the two-step method adopted by MISO for determining wind capacity credit for the 2012 planning year.

Wind Output Correlation vs. Distance Between Wind Sites



Step-1: MISO System-Wide Wind ELCC Study
Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the "Less than 1 Day in 10 Years" criteria for LOLE. This measure is often expressed as 0.1 days/year, as that is often the time period (1 year) over which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one "with" and one "without" the resource. Inherently, the case "with" the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 3 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case "With" and "Without" the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) LOLE criteria.

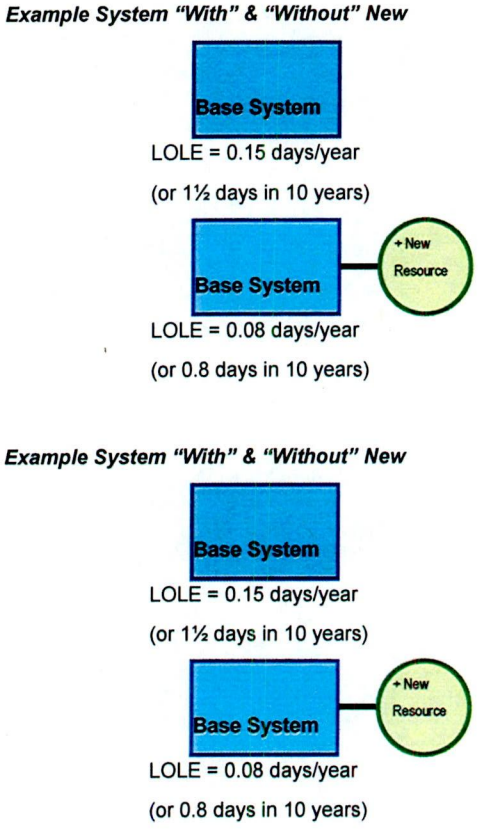


Figure 3 Example System "With" and "Without" New Resource

With each case being at the same reliability level, as shown in Fig. 4, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 – -200) for the new resource in this example. Sometimes this number is divided by the nameplate rating of the new resource and then expressed in percentage (%) form. The new resource in the ELCC example Fig. 4 has an ELCC of 30% of the resource nameplate.

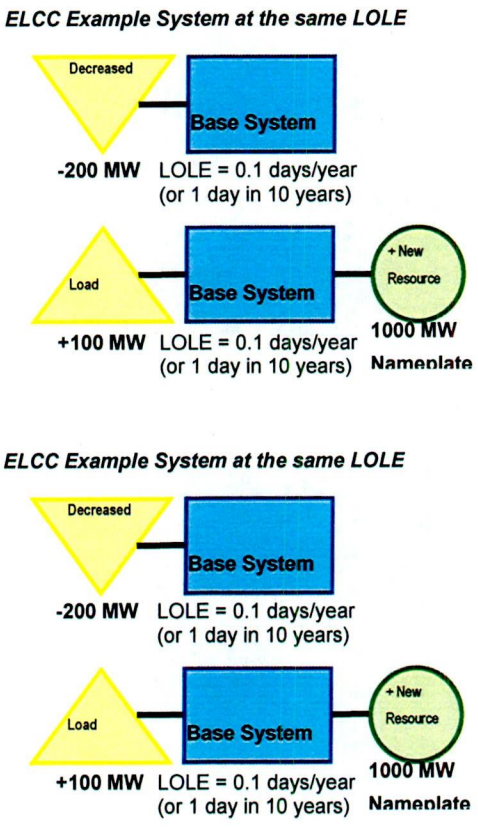


Figure 4 ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 4 was utilized as the analytical approach for the determination of the system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied there were two types of cases analyzed, ones with and ones without the wind resources. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. Using ELCC is the preferred method of calculation for determining the capacity value of wind [2].

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology MISO uses the Multi-Area Reliability Simulation (MARS) program by GE Energy to calculate LOLE values with and without the wind resource modeled. This model consisted of three major inputs:

Generator Forced Outage Rates (FOR)
Actual Historic Hourly Load Values
Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These FOR are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system as well as the capacity throughout the country.

To incorporate historical information the actual 2005-2011 historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic ELCC values for the wind generation in the MISO on a system-wide basis. The last two columns in Table I illustrate the ELCC results for the 7-years of MISO historic data.

MISO System Wide ELCC Results

MISO calculated ELCC percentage results for historic years 2005 through 2011 and at multiple scenarios of penetration levels, corresponding to 10 GW, 20 GW and 30 GW of installed wind capacity. This creates an ELCC penetration characteristic for each year, as illustrated by the different curves in Fig. 5. The initial left most data point for each curve is at the lowest penetration point on each characteristic curve and represents the actual annual ELCC for that year; and the values are shown in the right column in Table I. The values along each year's characteristic curve at the higher penetration levels reflect what that year's wind resource would have as an ELCC if more capacity had been installed in that year, over the same MISO footprint. The high end 30 GW level of penetration is an estimate of the amount of wind generation that could result in MISO, as the Load Serving Entities (LSE) collectively meet renewable resource mandates of the various MISO States

The end of a 2nd Quarter is the convention used to set the capacity going into the next planning year. The penetration level at the end of the 2nd Quarter 2011 was 9.7%. Specifically as a percentage, the 2011 penetration level is the 2nd Quarter 9,996 MW in column-4 of Table 1 divided by the 102,804 MW peak load in column-1. The vertical line in Fig. 5 illustrates where the most recent historical 9.7% penetration level intersects each year's ELCC characteristic curve. The average of these seven intersect values is the 14.7% system wide ELCC assigned for the upcoming planning year 2012.

TABLE 1 MISO Historical Wind ELCC Values

Year	MISO Peak Load (MW)	Registered Wind Max Capacity (MW)	Historical Wind Penetration (%)	System-Wide ELCC (MW)	System-Wide ELCC (%)
2005	109,473	908	0.8%	152	16.7%
2006	113,095	1,251	1.1%	495	39.6%
2007	101,800	2,065	2.0%	57	2.8%
2008	96,321	3,086	3.2%	395	12.8%
2009	94,185	5,636	6.0%	173	3.1%
2010	107,171	8,179	7.6%	1,548	18.9%
2011	102,804	9,996	9.7%	3,007	30.1%

The ELCC characteristic of each year can be represented by a trend line equation that has an R^2 coefficient of no less than 0.9996. This is the basis for achieving accuracy with sparse or few years of data. Alternative attempts to directly find a composite suitable single-trend-line curve to represent the aggregate 28 ELCC characteristic points of all seven years, met with poor R^2 coefficients in the range of 0.04 to 0.11.

Step-2: Wind Capacity Credit by CPnode Calculation

Deterministic Analytical Technique

Since there are many wind CPnodes throughout the MISO system (143 in 2011), a deterministic approach involving an historic-period metric is used to allocate the single system-wide ELCC value of wind to all the registered wind CPnodes. While evaluation of all CPnodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPnode locations, because in the MISO market the location relates to deliverability due to possible congestion on the transmission system. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance is a valuable input in determining the tradeoffs between constructing wind facilities in high capacity factor locations, that in the case of the MISO are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The system-wide wind ELCC value of 14.7% times the 2011 installed registered wind capacity of 9,996 MW results in 1,469 MW of system-wide capacity. The 1,469 MW is then allocated to the 143 different CPnodes in the MISO system. The historic output has been tracked for each wind CPnode over the top 8 daily peak hours for each year 2005 through 2011. The average capacity factor for each CPnode during all 56 (8-hours x 7-years) historical daily peak hours is called the "$PKmetric_{CPnode}$" for that CPnode. The capacity factor over those 56 hours and the installed capacity at each CPnode, are the basis for allocating the 1,469 MW of capacity to the 143 CPnodes. MISO has developed business practice Manual for the handling of new wind CPnodes that do not have historic output data and for CPnodes with less than 7-years of data.

Tracking the top 8 daily peak hours in a year is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $PKmetric_{CPnode}$ over multiple years.

Wind CPnode Equations

Registered Maximum (RMax) is the MISO market term for the installed capacity of a resource. The relationship of the wind capacity rating to a CPnode's installed capacity value and Capacity Credit percent is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPnode n}} = \text{RMax}_{\text{CPnode n}} \times (\text{Capacity Credit \%})_{\text{CPnode n}}$$

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$$(\text{Wind Capacity Rating})_{\text{CPnode n}} = \text{RMax}_{\text{CPnode n}} \times (\text{Capacity Credit \%})_{\text{CPnode n}} \quad (1)$$

Where $\text{RMax}_{\text{CPnode n}}$ = Registered Maximum installed capacity of the wind facility at the CPnode n. The right most term in (1), the $(\text{Capacity Credit \%})_{\text{CPnode n}}$ can be replaced by the expression (2):

$$K \times (\text{PKmetric}_{\text{CPnode n}}\%)$$

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$$K \times (\text{PKmetric}_{\text{CPnode n}}\%) \quad (2)$$

Where "K" for Year 2011 was found by obtaining the PKmetric at each CPnode over the 7 year period, and solving expression (3):

$$K = \frac{\text{ELCC}}{\sum_{1}^{143} \text{RMax}_{\text{CPnode n}} \times \text{PKmetric}_{\text{CPnode n}}} \quad (3)$$

This results in the sum of the MW ratings calculated for the CPnodes equal to the system wide ELCC 1,479 MW. The values in (3) are:

ELCC = 1,469 MW

$\sum \text{RMax}_{\text{CPnode n}} \times \text{PKmetric}_{\text{CPnode n}}$ = 1,803 MW

Therefore: K = 0.8148 = 1,469 / 1,803

Wind CPnode Capacity Credit Results & Examples

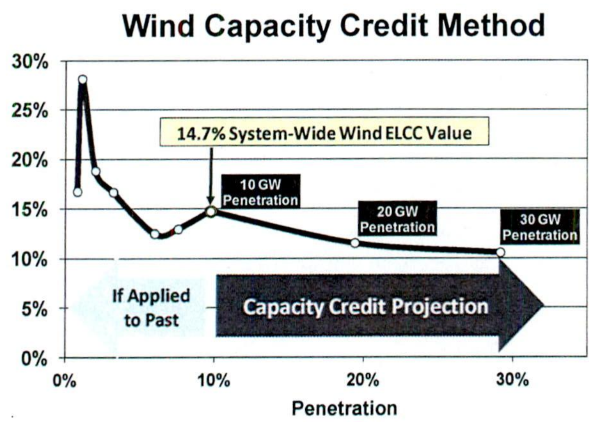
The individual PKmetric's$_{CPnode}$ of the CPnodes ranged from zero to 39.9%. The individual Capacity Credit percent for CPnodes therefore ranged from zero to 32.5%, by applying expression (2)

Example 1) For the best performing CPnode through 2011 data, the 39.89% PKmetric drives the capacity credit equal to:

- 32.5% = 39.9% x 0.8148, and therefore 32.5% times that CPnode's RMax would equal the Unforced Capacity (UCAP) rating for the best performing CPnode.
- Example 2) For the CPnode nearest the nominal 14.7% capacity credit through 2011 data, the 18.2% PKmetric drives the capacity credit equal to:
- 14.8% = 18.2% x 0.8148, and therefore 14.8% times that CPnode's RMax would equal the UCAP rating for that CPnode.

The MISO capacity credit method uses actual historical power output as a basis for setting the capacity rating of wind resources. While, MISO is currently limited to applying seven years of historical power outputs from the wind resources; by applying the developed ELCC and merging techniques the results are converging and are reflective as if one had more years of historical data available for the process. Fig. 9 illustrates the method over a range of limited data results. The left most point on the x-axis is the system wide result while utilizing only one year of data, the second point represents having two years of historical data available for the process. Progressively, the seventh point illustrates where MISO is currently at with seven years of data, and a projection sensitive to penetration is shown. As data from each new successive year becomes available, the subsequent capacity credit for successive years is expected to stabilize, and be more exclusively driven by penetration.

While the process discussed here represents a consistent and repeatable way to calculate the MISO market needs, MISO will continue to track and consider adjustments that may be required to deal with further aspects of common mode failure of wind generation. The MISO believes that the capacity credit for wind will be near 10% as the system approaches 25,000 to 30,000 MW of installed wind generation.


Wind Capacity Credit Method
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15%
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14.7% System-Wide Wind ELCC Value
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If Applied to Past
Capacity Credit Projection
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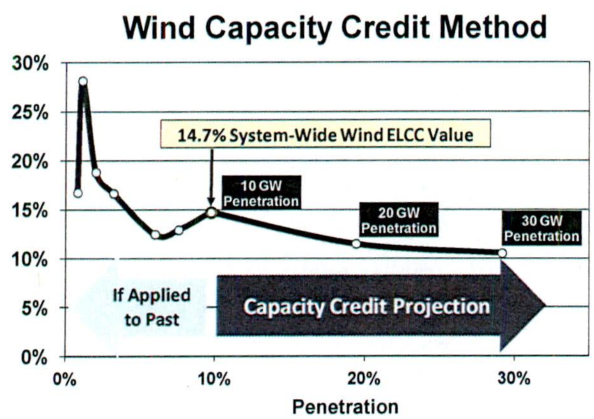
Penetration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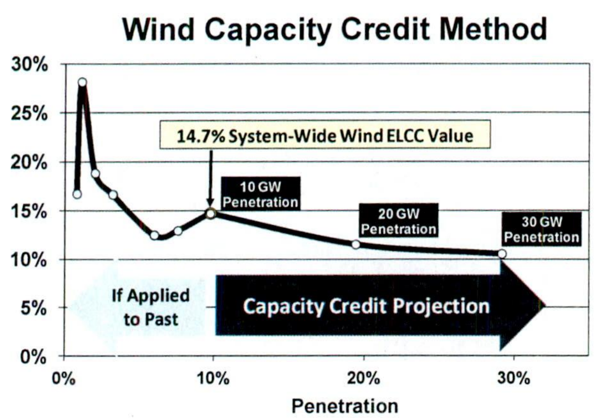
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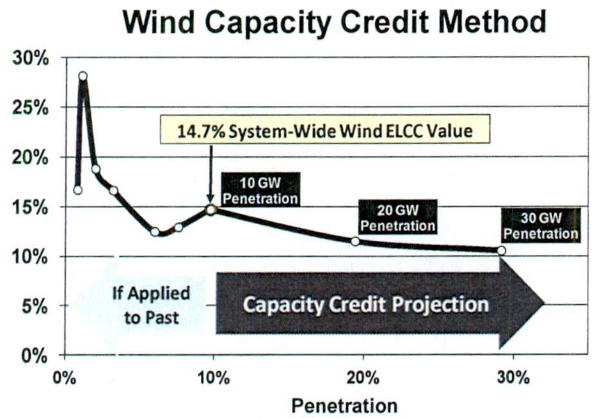
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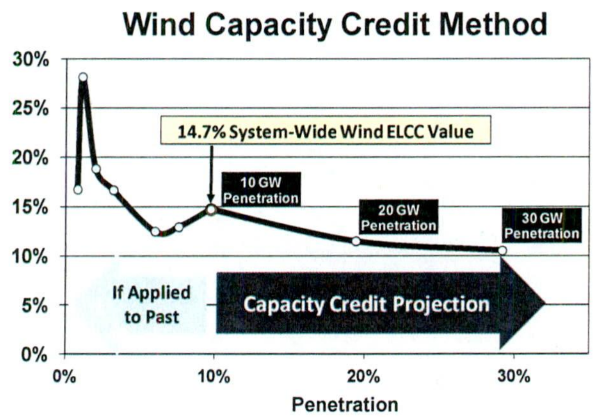
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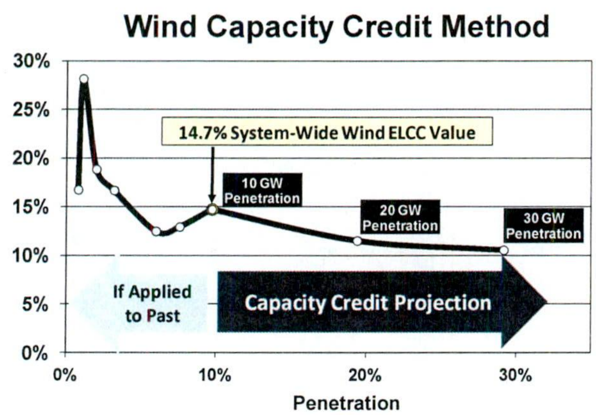
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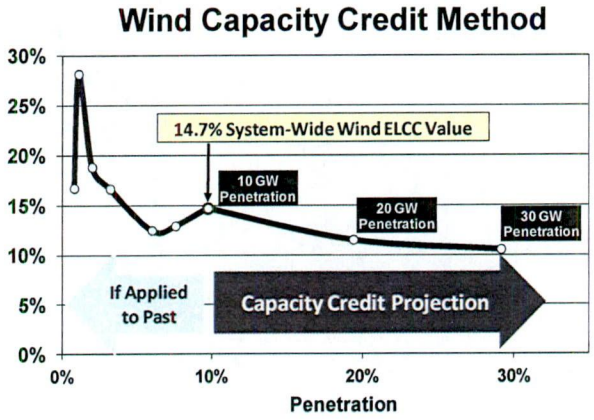


Figure 9 Applying Capacity Credit Method Starting with 2005 data

References

[1] Garver, L.L.; , "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on , vol.PAS-85, no.8, pp.910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; , "Capacity Value of Wind Power," Power Systems, IEEE Transactions on , vol.26, no.2, pp.564-572, May 2011

Appendix B – Generator Testing and XEFORd details (OMC Codes)

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.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

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-related factor contributed to the primary cause of the event)

Appendix C – Registration of Energy Efficiency Resources

Energy Efficiency Resource	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your Energy Efficiency Resource.
Energy Efficiency Resource Name	Enter Name of the Energy Efficiency Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this Energy Efficiency Resource is located
Local Balancing Area (LBA)	Select the LBA where this Energy Efficiency Resource is located.
Load Zone CPNode	Enter the CPNode where the Energy Efficiency Resource is located.
Program Information	Indicate if this is a new program or previously registered program
Program Inception Year	Select year program began
Program Name	Name of program that is being registered
Energy Efficiency Available at MISO Peak	Enter MW value of program at MISO Peak
Demand Reduction/Allocation	Enter MW value of program being netted and/or used as a Planning Resource
Capability Added Each Plan Year	Enter MW difference in program from the Inception Year
Accreditation	Attach supporting documentation
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix D – Registration of DRs

Demand Resource (DR)	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your DR.
DR Name	Enter Name of the DR.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this DR is located
Local Balancing Area (LBA)	Select the LBA where this DR asset is located.
Load Zone CPNode	Enter the CPNode where the DR asset is located.
Retail Choice	Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer
Aggregate Retail Customer (ARC)	Check box if Resource registered as an ARC
Registered DRR	Indicate if this resource is registered as a DRR
DRR CPNode	Select the name of the DRR CPNode that is registered
Demand Reduction Capability at MISO's Peak	Indicate MW being registered at MISO's Peak
Demand Reduction Capability Net/Resource Allocation	Indicate percentage to net against Coincident Peak Demand and amount requesting to be used as a Planning Resource. Total Allocation should equal to 100%.
Accreditation	Attach supporting documentation
NERC Reporting	Provide 24 monthly MW levels associated with the installed capacity of the DR each month. Monthly values shall be provided for the first two years from the Effective Start Date. Provide 16 seasonal (Summer and Winter) MW levels associated with the installed capacity of the DR for

	each season. Seasonal values shall be provided beyond the 2 year monthly window.
City (where the LMR is located)	Enter the city where the DR is located.
County (where the LMR is located)	Enter the county where the DR is located.
State (where the LMR is located)	Enter the state where the DR is located.
Load Control Method	Select if load is direct control or interruptible load
EDR?	Check box if DR registered as an EDR
Emergency Demand Resource	Select the registered name of the EDR.
Curtail to Peak Firm Service Level	Check box if DR can curtail to firm service level
Monthly peak firm service levels	Enter monthly firm service level values if applicable
Plan Year Interruptions and Run Time	Select maximum number of events DR can be used and number of run hours
M&V protocol to be applied to this DR	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. If other selected, please describe in box.
Notification details	Enter the notification time required for this DR. Notification time cannot be more than 12 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of DR. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Have you notified your LBA?	Indicate if you have contacted your LBA of this LMR located in their area

Is a deployment plan in place with the LBA?	Indicate if you have a deployment plan in place with the LBA where the resource is located?
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix E – BTMG registration

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your btmg.
BTMG Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this btmg is located
Local Balancing Area (LBA)	Select the LBA where this BTMG asset is located.
Load Zone CPNode	Enter the CPNode where the BTMG asset is located.
GADS Generator/ Intermittent Resource	Check box if the BTMG is an Intermittent Resource
GADS Generator	Select the name of the GADS Generator(s)
Accreditation	Attach supporting documentation
NERC Reporting	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. 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.
Plan Year Interruptions and Run Time	Select maximum number of events BTMG can be used and number of run hours
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.

EDR?	Check box if BTMG registered as an EDR
Emergency Demand Resource	Select the registered name of the EDR.
M&V protocol to be applied to this BTMG	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. If other selected, please describe in box.
Start up notification time details (in hours)	Enter the notification time required to start this BTMG. Needs to be no more than 12 hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
Do you hold all permits in place necessary to operate this resource?	Indicate if all permits are in place in order for this resource to operate.
Do you hold all rights in place necessary to operate this resource?	Indicate if all rights are in place in order to operate this resource.
Have you notified your LBA?	Indicate if you have contacted your LBA of this LMR located in their area
Is a deployment plan in place with the LBA?	Indicate if you have a deployment plan in place with the LBA where the resource is located?
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix F – External Resources

External Resources	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your External Resource.
EXTERNAL RESOURCE Name	Enter Name of the EXTERNAL RESOURCE.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this External Resource is located
Local Balancing Area (LBA)	Select the LBA where this EXTERNAL RESOURCE asset is located.
Sink Load Zone CPNode	Enter the CPNode where the EXTERNAL RESOURCE asset is located.
Direct Ownership or PPA	Indicate if the External Resource is Directly Owned or PPA
Direct Ownership	Enter MW value the Market Participant can register
GADS Generator	Select name of GADS Generator and input percentage if PPA otherwise select name of GADS generator
IDC Name	Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement.
GADS registered capacity increased	Indicate if this resource needs to have its capacity increased by PRM and XEFORd
Unit Type	Select Unit Type
Fuel Type	Select Fuel Type
Description	Provide Description of Unit Type and Fuel Type
Unit Size	Select Unit Size
External Balance Authority where Resource(s) are located	Enter Balancing Authority where Resource(s) are located
Interface CPNode	Select Interface CPNode

NERC Regional Entity	Select NERC Regional Entity
Description	Provide description of NERC Regional Entity
Use Limited Qualification	Indicate if this Resource meets the Use Limited Qualification
Firm transmission to MISO border	Input effective date and OASIS reservation number and select Transmission Provider
Firm transmission within MISO	Input effective date, OASIS and eDNR number
Have you notified the host BA?	Indicate if you have contacted your host BA of this registration.
Is this External Resource only be used as a Capacity Resource in MISO?	Indicate if you have a certified that this External Resource is only being used as a Capacity Resource for MISO.
Is this External Resource available the entire Planning Year?	Indicate if this External Resource is available for the entire Planning Year.
Have all other requirements been met?	Indicate if all other requirements have been met.
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of External Resource. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

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

The following sets of equations establish how the Unforced Capacity values (NRIS UCAP and ERIS 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 MISO's Transmission System

The Unforced Capacity calculation is based on its type and volume of interconnection service, GVTC, and forced outage rate ($XEFOR_d$). The following steps are used to calculate NRIS UCAP and ERIS UCAP for each Planning Resource.

H.1.1 Planning Year UCAP Calculation

The following steps are used to calculate NRIS UCAP and ERIS 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 GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

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.

$$Total\ Interconnection\ UCAP = Total\ Interconnection\ ICAP \times (1 - XEFOR_d)$$

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 NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. . 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).

$$\text{NRIS UCAP} = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRIS \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$\text{ERIS UCAP} = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

The NRIS UCAP and ERIS UCAP represent the capacity in MWs that is eligible to be converted into Zonal 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 GVTC and forced outage rate ($XEFOR_d$). The ERIS UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

$$ERIS\ UCAP = GVTC \times (1 - XEFOR_d)$$

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 ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal 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 MISO's Transmission System

The Unforced Capacity calculation is based on its GVTC and forced outage rate ($XEFOR_d$) if it does not have a Point of Interconnection to MISO's Transmission System. The ERIS UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

$$ERIS\ UCAP = GVTC \times (1 - XEFOR_d)$$

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 ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal 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 at 80% confidence level 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 MISO's Transmission System.

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

The following sets of equation establish how Unforced Capacity values (NRIS UCAP and ERIS UCAP) are determined for Intermittent Generation and Dispatchable Intermittent Resources that has a Point of Interconnection on MISO's 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-1 Capacity Tracking Tool.

H.4.1.1.1 Planning Year UCAP Calculation for Wind Farms

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 GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

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.

$$Total\ Interconnection\ UCAP = Total\ Interconnetion\ ICAP \times (Wind\ Capacity\ Credit_{CPNode})$$

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 NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. 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).

$$\text{NRIS UCAP} = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRIS \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$\text{ERIS UCAP} = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

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 4.2.2 .

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 GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ UCAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

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 NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. 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).

$$NRIS\ UCAP = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRI \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$ERIS\ UCAP = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

H.4.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following equations apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal 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-1 Capacity Tracking Tool.

H.4.2.1.1 Planning Year 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.

$$ERIS\ UCAP = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

( )

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 4.2.2 .

$$\text{ERIS} = GVTC$$

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.

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

where:

$FOH_d = f_f \times FOH$

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

$= (f_p \times EFDH)$ if no reserve shutdown events reported.

Please note that the IEEE Standard No. 762 and NERC definitions for EFDH differ 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 Starts**	**Attempted Starts**	**EFDH**	**FOH**	**FO 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**		**346.18**	**8.01%**

$EFOR_d$ Calculation for Unit 1:

Synch Hours = 0

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

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

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

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

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

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

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

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

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

External Resources: Market Participants are responsible for making sure that GADS data is submitted from the External Resources that they are seeking qualification as ZRCs. The Market

Participant can submit this data to MISO's 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 MISO 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.

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 MISO's GADS database based on unit size and type. MISO's EFORd classes will be the same as defined by NERC's Generating Unit Statistical Brochure.

- Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous Months, which is not the result of a planned maintenance outage.
- MP will have to notify MISO RA team in writing within 75 days of the Catastrophic Outage occurring that includes description of Catastrophic Outage, date of outage, etc.
- Under annual construct, if MP chooses not to replace Planning Resource that suffers a Catastrophic Outage the XEFORd will be based on GADs submitted
- If MP chooses to replace the Planning Resource of a unit that suffers a Catastrophic Outage, the EFORd will be based on class average when the unit returns
    - Resource replacement is completed within 75 days of catastrophic outage or date of notification to RA team whichever comes first
    - Resource replacement must be from Planning Resources in the same Local Resource Zone
    - Once unit returns from Catastrophic Outage, the Planning Resource qualification requirements still apply

Appendix J – GVTC Testing Requirements

All Generation Resources, External Resources, Demand Response Resources backed by behind-the-meter generation 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 GVTC and submits its GVTC data to MISO's PowerGADS.

If a Planning Resource fails to perform a real power test during the testing period and report the test information to MISO's 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.

J.1 Generation Verification Test Capacity (GVTC)

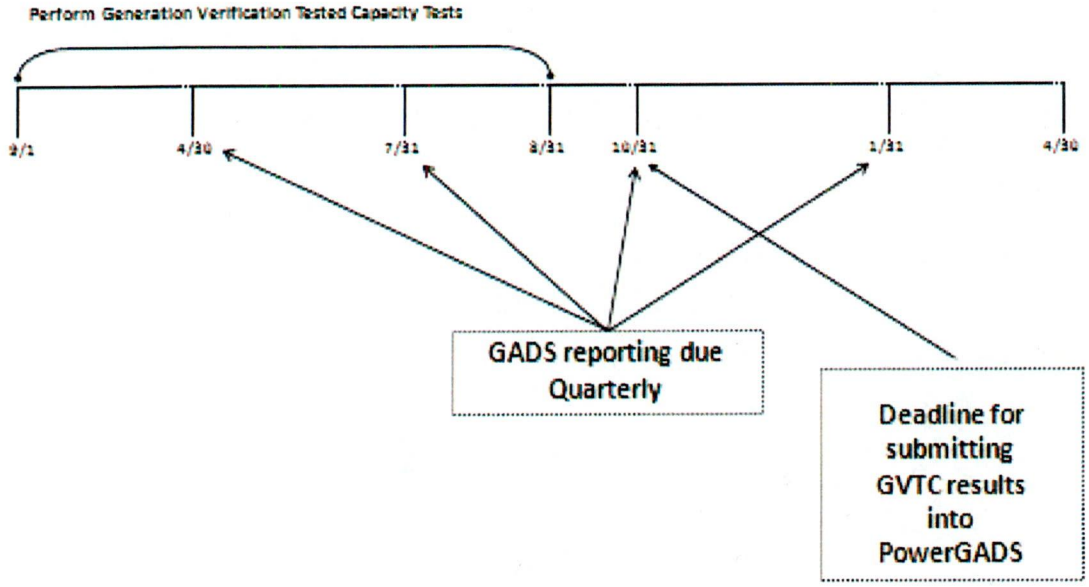
The maximum Energy output (MW) that a Generation Resource, External Resource, Demand Response Resource backed by behind the meter generation, or Behind the Meter Generation (BTMG) can sustain over the specified period of time, if there are no equipment, operating, or regulatory restrictions, minus any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

J.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 must be provided during the test period 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-1) or being qualified as a Planning Resource for the first time

Key Deliverables Timeline



J.3 Adjustment to establish the GVTC

The GVTC shall be temperature corrected to the average temperature of the date and times of MISO's 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.

J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in 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 MISO's Resource Adequacy Department for a review of its request.

J.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.

J.5 GVTC Real Power Test Requirements

J.5.1 Thermal Steam and Nuclear

The 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 MISO's 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 MISO's 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.

J.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 MISO's Summer Peak, and the ambient air temperature and humidity conditions experienced at the unit location at the time of MISO's 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 MISO's Summer Peak given humidity conditions experienced at the unit location at the time of MISO's 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.

J.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 MISO's 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.

J.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 environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The historic median head shall be determined as the median of all head measurements for hours ending 1500-1700 EST for all days of the Summer (June, July, August) from the most recent five (5) years up to the most recent fifteen (15) years for Reservoir Hydro and Pumped Storage. If 15 years of historic data is not available for this period when the 15 year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15 year requirement is met.

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

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 MISO's GADS as appropriate. Please consult MISO's *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 MISO's PowerGADS reporting system as described in MISO's *Net Capability Verification Test User Manual*.

Appendix K – Resource Adequacy Timeline

Month	Day	Process	Responsible entity
Sep	1st	MECT available for data submission	MISO
Sep	1st	Annual Cost of New Entry for 7 LRZs filing due to FERC	MISO
Oct	31st	Generation Verification Test Capacity/demand reduction capability data /Generator Availability Data due for those resources required to report GADS Updated historical performance submittal due for hours 1500-1700 in June, July, and August for Intermittent Generation and non-wind DIRs that do not report into GADS and do not submit GVTC	Resource Owner
Nov	1st	Coincident Peak Demand forecast by LSE/EDC , Non-Coincident Peak, and energy forecast values by LSE due	LSE, EDC
Nov	1st	Publish LRZs, CIL, CEL, and LRR	MISO
Nov	1st	Evidence for new GMA/Zonal Deliverability Charge hedges due	LSE
Dec	1st	Unforced Capacity values are published by MISO	MISO
Dec	15th	Peak Load Contribution submissions by EDC due (EDC will send the details of the PLCs to both the respective LSEs and the MISO for their review)	EDCS in Retail Choice
Dec	1st Bus. day	Transmission losses by Local Balancing Authority are posted by MISO	MISO
Jan	15th	LSEs submit the Retail Choice PLC in the MECT	LSEs in Retail Choice
Feb	1st	Loss of Load Expectation study begins for next Planning Year	MISO
Feb	1st	Existing Load Modifying Resource/Energy Efficiency/ External Resource registrations due for prompt Planning Year	LMR Owner
Feb	16th	Submit data for facility –specific reference level(s) to IMM due 45 days prior to the close of the PRA (optional)	Gen. Owner
Mar	1st	IMM publicly posts Reference Level for Planning Resources generic data 30 days prior to the close of the PRA	IMM*
Mar	1st	New Load Modifying Resource/Energy Efficiency Resource/ External Registrations due for prompt Planning Year	LMR Owner

Mar	1st	Generator Verification Test Capacity/Generator Availability Data for new resources or resources with increased capacity prompt Planning Year	LMR Owner
Mar	1st	MISO to complete its Coincident Peak Demand forecast review process	MISO
Mar	1st	Grandmother Agreement and Zonal Deliverability Charge hedge information posted by MISO	MISO
Mar	7th Bus. day	Fixed Resource Adequacy Plan due by LSE	LSE
Mar	15th	Fixed Resource Adequacy Plan review completed by MISO.	MISO/LSE
Mar	25th	Provide facility-specific Planning Resource Level (s) to MP data 5 days prior to the close of the Auction	IMM
Mar	Last 3 Bus. days	Planning Resource Auction offer window is opened	MISO
Apr	1st 5 Bus. Days	Iterations of auction runs with the adjusted CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding.	MISO/IMM
Apr	5th Bus. day	Planning Resource Auction results posted	MISO
Apr	6th Bus. Day	Assess the Capacity Deficiency Charge	MISO
Apr	11th Bus. day	MISO sends out the Capacity Deficiency Charge	MISO
Apr	11th Bus. days + 7	Capacity Deficiency Charge payment due	MISO
Apr	11th Bus. days + 7 + 2 Bus. days	Capacity Deficiency Charge payments made to MPs	MISO
Jun	1st	New Planning Year starts	All
Jun	1st	First day of the Integration	All

Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak from the previous calendar year.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour.

The Local Balancing Authority (LBA) Transmission Loss percentage calculated by the Transmission Provider will apply to the LSE's applicable LBA Coincident Peak Demand forecast to determine the LSE transmission losses. PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Appendix M – Auction Formulation

Planning Resource Auction Software Formulations

Disclaimer

This document is prepared for informational purposes only to support the application of the Midwest Independent Transmission System Operator, Inc. (MISO) Tariff provisions relating to Resource Adequacy Requirements. MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff.

Purpose of this document

MISO's Resource Adequacy Enhancement construct provides LSEs in MISO footprint an ability to procure planning resources through an annual Planning Resource Auction (PRA). An AIMMS based Auction Clearing Tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization objective function that is used for clearing the PRA and explains how zonal Auction Clearing Prices would be calculated.

[1] AIMMS ("Advanced Interactive Multidimensional Modeling System") is an intergrated modeling system that supports modeling and solving large-scale optimization problems.

Notations

Set Z = {All zones in the market}

Set G = {All resources in the market}

Set G_k = {All resources in zone k}

PRM = Planning Reserve Margin

$PRMR_k$ = Planning Reserve Margin Requirement for Zone k

$CPDF$= Coincident Peak Forecasted Demand

CIL_k = Capacity Import Limit for zone k

CEL_k = Capacity Export Limit for zone k

LCR_k = Local Clearing Requirement for zone k

$ZReq_k$ = Total capacity requirement for loads in zone k

$$ZReq_k = \max\{PRMR_k, LCR_k\}$$

$$PRMR_k = CPDF_k \times (1 + PRM)$$

$OfferPrice_i$ = The offer price for resource i

Note: In this document, a resource can offer only one price. Multiple price segments are treated as multiple resources.

$OfferMW_i$ = Offered MW value for resource i.

$MWCleared_i$ = Cleared MW value for resource i.

$P1_k, P2_k$ = Penalty prices for shortage

$SSlack_k, ZSlack_k$ = Slack variables representing capacity shortage, nonnegative

$ZACP_k$ = Auction Clearing Price for Zone k

$CONE$ = Cost of new entry

Objective Function

The auction is cleared by solving the following optimization problem. The objective function is expressed with the following mathematical terms:

Minimize $f =$

$$\sum_{i=1}^{m} OfferPrice_i \times MWCleared_i + \sum_{k=1}^{Z} (P1_k \times SSlack_k + P2_k \times ZSlack_k)$$

The slack variables are used to make sure the LP is feasible. The penalty prices are set to be a little higher than CONE values.

Constraints:

C1) $MWCleared_i \leq OfferMW_i$

C2) $MWCleared_i \geq 0$

C3) $\sum_{i \in G} MWCleared_i + \sum_{k=1}^{Z} SSlack_k = \sum_{k=1}^{Z} ZReq_k - \varepsilon_0$

This is the system demand constraint, its shadow price is referred as *SPsys.*

ε_0 is nonnegative and would be less than 0.001.

If ε_0 equals zero, the shadow price *SPsys* may not be unique at certain situations.

A small positive ε_0 would ensure *SPsys* is unique.

C4) $\sum_{i \in G_k} MWCleared_i + SSlack_k \geq ZReq_k - CIL_k - \varepsilon_k$

Each zone has a minimal clearing constraint with corresponding shadow price $SPmin_k$.

ε_k is nonnegative and would be less than 0.001.

C5) $\sum_{i \in G_k} MWCleared_i + SSlack_k \leq ZReq_k + CEL_k + \varepsilon_k$

Each zone has a maximal clearing constraint with corresponding shadow price $SPmax_k$

Again, the purpose of ε_k is to guarantee a unique shadow price $SPmax_k$.

C6) $\sum_{i \in G_k} MWCleared_i + ZSlack_k \geq LCR_k - \varepsilon_k$

The corresponding shadow price is referred as $SPlcr_k$.

C7) $SSlack_k \leq \max(0,\ ZReq_k - \sum_{i \in G_k} MWCleared_i)$

Zonal Prices

The clearing price for each zone k ($ZACP_k$) would be equal to the minimum of the CONE value and the sum of the shadow prices
$SPsys,\ SPmin_k, SPmax_k, and\ SPlcr_k$ for the LP problem.

$$ZACP_k = \min(CONE_k, SPsys + SPmin_k + SPmax_k + SPlcr_k)$$

Capacity Market Settlement Examples

High Level Clearing Constraints

- Input
  - PRM, Load Forecast, LRR, CIL_z, CEL_z
  - $LCR_z = LCR_z - CIL_z$
  - $PRMR_z = (1 + PRM) * \text{Load Forecast}_z$
  - $LRR_z \geq PRMR_z \rightarrow LCR_z = \geq PRMR_z - CIL_z$
  - $ZReq_z = \max\{LCR_z, PRMR_z\}$
  - $CONE_z$: maye different for each zone
- Objective
  - $\sum_{i=1}^{m} OfferPrice\ i \times MWCleared i + \sum_{z=1}^{z} (CONEz \times SSLACKz + CONEz \times ZSLACKk)$
- Market wide and zonal constraints and shadow prices

$\sum_z \{ZClear_z + SSlack_z\} \geq \sum_z ZReq_z - \varepsilon_o$ ($\alpha_{mkt} \geq 0$) (1)
$ZClear_z + SSlack_z \leq ZReq_z - CEL_z$ ($\alpha_{max,z} \leq 0$) (2)
$ZClear_z + SSlack_z \geq ZReq_z - CIL_z - \varepsilon_k$ ($\alpha_{min2,z} \geq 0$) (3)
$ZClear_z + ZSlack_z \geq LCR_z - \varepsilon_k$ ($\alpha_{min1,z} \geq 0$) (4)

- For export zones, check and resolve to make sure $SSlack_z \leq ZReq_z - ZClear_z$
- Clearing Price

- Market-wide: MACP = α_{mkt}
- Zonal: ZACP = $\alpha_{mkt} + \alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z}$ = MACP + + $\alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z}$
- When both (30 and (4) are violated, $ZACP_z$ may be higher than $CONE_z$. If so, then cap $ZACP_z$ at $CONE_z$.

- Initial Settlement
  - Gen revenue: $\sum_z (ZACPz * ZClearz))$
  - Load Payment: $\sum_z (ZACPz * ZReqz))$

FRAP and GMA

- Before the auction, the engineers should have checked the FRAP and GMA data to ensure they are consistent with CIL and CEL;
- All FRAP Gen will be treated as $0 offer and participate the auction clearing;
- All GMA Gen will have an offer and will participate the auction with the offered price;
- After the auction clearing, it will go through all GMAs:
  - If $ACP_{GMA,Gen} \leq ACP_{GMA,load}$, the GMA will be honored and will be excluded from the auction settlement based on ZACP
  - If $ACP_{GMA,Gen} > ACP_{GMA,load}$, the GMA will be not be honored. It will be settled based on ZACP.
- This may cause $\{GMA_{zgen\_to\_exld}-FRAP_{exgne\_to\_zld}\}>CEL_z$ or $\{GMA_{exgen\_to\_zld}-FRAP_{zgen\_to\_exld}\}>PRMP_z - LCR_z$. When this happens, we may pay more to resources than charge from load. The auction clearing engine will check each zone and identify potential issues. If any problem is identified, we will report it and go back to step 1) for proper adjustment of FRAP, CIL and/or CEL to re-run the auction clearing.
- If there is any human error, we may have FRAP in conflict with CIL and/CEL. The engine will not be able to clear all FRAP in this scenario. The engine should report the issue so that FRAP, CIL and/or CEL can be properly adjusted.
- Input validation
  - $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone should be no more than $ZReq_z-LCR_z$: $FRAP_{exgen\_to\_zld} \leq ZReq_z-LCR_z$
  - There is no limitation on $FRAP_{zgen\_to\_exld}$ from generators in zone z to load outside.
    - When there is limitation on CEL_z, $FRAP_{zgen\_to\_exld}$ may not always be cleared from the auction process. However, it will all be treated as cleared at $0 afterwards. In this case, the export binding zone price must be $0.
  - GMA $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone will always be no more than $PRMR_z-LCR_z$: $GMA_{exgen\_to\_zld} \leq ZReq_z-LCR_z$
  - CEL_z will be set so that $GMA_{zgen\_to\_exld}$ from generators can be cleared: $GMA_{zgen\_to\_exld} \leq CEL_z$
- Warning messages from clearing engine for inputs with:
  - $FRAP_{exgen\_to\_zld} > ZReq_z-LCR_z$

- $FRAP_{zgen\_to\_exld} > CEL_z$
- $GMA_{exgen\_to\_zld} > ZReq_z - LCR_z$
- $GMA_{zgen\_to\_exld} > CEL_z$

- After clearing, GMA and FRAP met the following conditions will be excluded from the auction settlement
  - **The same amount of FRAP Gen or load is excluded if $ACP_{FRAP,Gen} > ACP_{FRAP,load}$**
  - **GMA is honored and excluded if $ACP_{GMA,Gen} < ACP_{GMA,load.}$**
- For GMA and FRAP that are settled outside market (TrGMA, TrFRAP), MISO may have negative revenue if the following conditions are met. Hence the clearing engine will issue ERROR messages when:
  - $TrGMA_{zgen\_to\_exld} - TrFRAP_{exgen\_to\_zld} > CEL_z$
  - $TrGMA_{exgen\_to\_zld} - TrFRAP_{zgen\_to\_exld} > ZReq_z - LCR_z$
  - $TrFRAP_{zgen\_to\_exld} - TrGMA_{exgen\_to\_zld} > CEL_z$
  - $TrFRAP_{exgen\_to\_zld} - TrGMA_{zgen\_to\_exld} > ZReq_z - LCR_z$

Settlement Issue Under no Scarcity

- Imbalance under zonal binding

$$\sum_z \{ZACP_z * (ZClear_z - ZReq_z)$$
$$= \{MACP * \sum_z (ZClear_z - ZReq_z)\} + \sum_z \{(\alpha_{min1,z} + \alpha_{min2,z}) * (ZClear_z - ZReq_z)\} + \sum_z \{\alpha_{max,z} * (ZClear_z - ZReq_z)\}$$

  - $\{MACP * \sum_z (ZClear_z - PRMR_z)\} = 0$ because

1) If $MACP = \alpha_{mkt} > 0$, then (1) is binding. Hence $\sum_z (ZClear_z - ZReq_z)\} = 0$ if $MACP = \alpha_{mkt} > 0$.

2) If (1) is not binding, i.e. $\sum_z ZClear_z > \sum_z ZReq_z$, then $MACP = \alpha_{mkt} = 0$.

Define $\alpha_{min,z} = \alpha_{min1,z} + \alpha_{min2,z}$

- $\{\alpha_{min,z} * (ZClear_z - ZReq_z)\} < 0$ when
- (3) and/or (4) is binding, i.e. $ZClear_z = LCR_z$ → Import binding $ZACP_z > MACP$
- $\alpha_{min,z} > 0$, $\{\alpha_{min,z} * (ZClear_z - ZReq_z)\} = \alpha_{min,z} * (LCR_z - ZReq_z) \leq 0$
- $\{\alpha_{max} * (ZClear_z - ZReq_z)\} < 0$ when
- (2) is binding, i.e. $ZClear_z = ZReq_z + CEL_z$ → Export binding $ZACP_z < MACP$
- $\alpha_{max,z} < 0$, $\{\alpha_{max,z} * (ZClear_z - ZReq_z)\} = \alpha_{max,z} * CEL_z \leq 0$

Allocation of Imbalance Fund for Import Binding Zones

- For import binding zone
  - Zone with $ZACP_z - MACP = \alpha_{min,z} > 0$

– Imbalance amount

$\{\alpha_{min,z} *(ZClear_z-ZReq_z)\}=\alpha_{min,z}* \{ LCR_z -ZReq_z\}$

$= \alpha_{min,z} *(LCR_z-ZReq_z)\leq 0$

– This amount should be refunded to load in the zone because the extra load is served by cheaper generation outside

➔Refunding dollar (calculated as part of zone z benefit):

$$\alpha_{min,z} *\{(ZReq_z - TrGMA_{load\ in\ z} - TrFRAP_{load\ in\ z}) - (ZClear_z - TrGMA_{gen\ in\ z} - TrFRAP_{gen\ in\ z})\}$$

This also covers $Zslack_z > 0$ and $Sslack_z = 0$

➔Amount of load in the zone eligible for refunding:

$ZReq_z - (TrGMA_{load\ in\ z})-(TrFRAP_{load\ in\ z})$ (where $TrFRAP_{load\ in\ z}$ should most likely be 0)

(Note, may also be allocated to FRAP and GMA per tariff)

- For export binding zone
  - Zone with $ZACP_z$-MACP= $\alpha_{max,z} < 0$
  - Imbalance amount

$\{\alpha_{max,z} *(ZClear_z-ZReq_z)\}=\alpha_{max,z}* CEL_z < 0$

– This amount should be refunded to load outside the zone because excess load outside is served by cheaper generation from export binding zones

➔For imbalance from export binding zone z1, refunding dollar:

$$-\alpha_{max,z1}* \{(ZClear_{z1} - TrGMA_{gen\ in\ z1} - TrFRAP_{gen\ in\ z1}) -(ZReq_{z1} - TrGMA_{load\ in\ z1}- TrFRAP_{load\ in\ z1})\}$$

➔ It is distributed to load in non export binding zones based on the following logic (calculated as part of zone z benefit):

1) For non-binding zones: $LZ_z=\min\{CEL_z-(ZClear_z-ZReq_z), CIL_z, ZReq_z-LCR_z\}$
2) For each import binding zone, calculate: $LZ_z=ZReq_z-LCR_z$
3) Distribute the imbalance amount proportionally based on LZ_z

➔Amount of load in the zone eligible for refunding:

$ZReq_z - (TrGMA_{load\ in\ z})-(TrFRAP_{load\ in\ z})$

(Note, may also be allocated to FRAP per tariff)

Refund under Scarcity ($Sslack_z>0$)

- With zonal CONE and cap ZACP at its CONE, the allocation is more complicated

- If MACP<min(CONEz), all scarcity is considered zonal.
  - $ZACP_z$*$Sslack_z$ is refund to the zone. (if $Zslack_z$ and $Sslack_z$ are both non-zero, price capping will remove the impact from $Zslack_z$)
  - If MACP≥min(CONEz),
  - Zonal scarce (min($Zslack_z$, $Sslack_z$)>0)

  $ZACP_z$*min($Zslack_z$, $Sslack_z$) refund to the zone

  - Market-wide constraint can be violated for zonal or market-wide scarcities.
    - Allocate "$\sum_z${$ZACP_z$*[Sslackz -min(Zslackz, Sslackz)]} the same ways as the benefit from export zones, i.e. For non-binding zones based on LZz=min{CELz-(ZClearz-ZReqz), CILz, ZReqz –LCRz} and for import binding zone based on $LZ_z=ZReq_z-LCR_z$.

Amount of load in the zone eligible for refunding:

$ZReq_z$- ($TrGMA_{load\ in\ z}$)-($TrFRAP_{load\ in\ z}$)

(Note, may also be allocated to FRAP per tariff)

Additional Post Processing and Notes on Scarcity Pricing

- After clearing the first time, if in the same zone there are multiple offers with prices equal to the $ZACP_z$, the second run will ensure those offers are cleared proportional to their offered MW
- After that, all $0 offers are cleared

Note:

- When there is system shortage, even if all zones meet their local requirements (max(ZReq-CIL,LCR)), the engine has to allocate the system shortage to each zone so that it can solve with different CONE price. The engine allocates the shortage to zones with the lowest CONE first. Each zone is allocated with no more than ZReq-Zclear, i.e. build new resources up to ZReq. For all the zones allocated with shortage, it will solve at its CONE price. All other zones will take the highest CONE of the zone with shortage allocated if nothing else binding.
- It is equivalent to have a system wide demand curve formed as from the lowest CONE to the highest CONE. However, the width of each price segment depends on the solution, i.e. ZReq-ZClear.

Appendix N – Demand and Energy Forecast Characteristics

Forecast Criteria	Coincident Peak Demand forecast	Non-coincident Peak Demand forecast	energy for load
Includes Demand Served by Energy Efficiency Planning Resources	Yes	No	
Includes Demand Served by Demand Resources	Yes	No	
Includes Demand Served by BTMG Planning Resources	Yes	No	
Includes Demand Served by Non-Planning Resources	Yes	No	
Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR	No	Yes	
Includes Demand Served by Controllable demand resources (NERC definition)	Yes	No	
Includes Demand Served by Demand Side Management	Yes	Yes	
Includes Transmission Losses	No	Yes	
Coincident with MISO's Peak	Yes	No	
Non-coincident	No	Yes	
Demand reported at Physical LBA Location	Yes	Yes	
Include Demand Pseudo-Tied Out of MISO BA and Subject to other RAR	No	Yes	
Include Demand from Power Plant Station or Auxiliary Needs	No	No	