Manual No. 002

Business Practices Manual

Energy and Operating Reserve Markets

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Revision History

Doc Number	Description	Author	Effective Date
BPM-002-r19	Annual review completed. This revision contains updates for Coordinated Transaction Scheduling (CTS) between MISO and PJM. It also includes various correction of provisions that are no longer in practice.	P. Addepalle M. Kandukuri A. Hartman	OCT-15-2018
BPM-002-r18	Annual review completed. This revision contains updates from MISO's internal Tariff review and implementation of some Emergency pricing enhancements, Change of RGD references to GBAO per Operation reorganization. It also includes various corrections of provisions that are no longer in practice; Updated Pricing logic; Updated attachment D and corrected typographical errors.	P. Addepalle, A. Hartman, S. Li B. Borissov	SEP-23-2017
BPM-002-r17	Address changes in DA/FRAC Market Timing related to FERC order 809	Y. Jiang	NOV-05-2016
BPM-002-r16	Annual Review completed. Reflect changes associated with Emergency and LMR pricing and Real Time Offer Override Enhancement and expand on Day Ahead market extension and reopening; added details on Ramp Up/Down impact on SCED algorithm; revised Demand Response max contribution to SPIN and off line supplemental; added guidance on registration of Regulation, Spin and Supplemental qualified resources	R. Merring	OCT-01-2016
BPM-002-r15	Annual Review completed. This revision describes changes to accommodate MISO's implementation of Ramp Capability Product, a new Ancillary Service. This update also includes clarifications on Bi-Directional EAR, the transition to webTrans and load modeling procedures.	K. Spontak	MAR-17-2016
BPM-002-r14	Annual Review completed. This revision describes changes to accommodate MISO's implementation of the Extended LMP process, Demand Response Enhancement process, Bi-Direction EAR process, the Sub-Regional Power Balance Constraint, control mode response based on behavior for Real Time ancillary services, behavior for partial generation resources associated with external schedules, the switch in Day Ahead from Nodal Power Balance to Global Power Balance and the update to weighting factors for ARR Zones compared to load zones.	K. Spontak J. Li C. Wang K. Trotter P. Caro-Ochoa S. Duggirala R. Merring	MAR-01-2015
BPM-002-r13	This revision describes changes to accommodate MISO's compliance to FERC Order 755 regarding Regulation Mileage, and changes to accommodate Transmission Constraint Demand Curve Tariff	M. Keyser A. Hartman Y. Ma K. Spontak	FEB-04-2014

	changes. It also includes various corrections and language improvements. Annual review completed.		
BPM-002-r12	This revision describes changes for the Look-Ahead commitment process, changes to accommodate FERC Order 719 and 745 (on Demand Response and Aggregators of Retail Customers), changes for Reg+Spin Demand Curves, and changes to eliminate gaming opportunities from the Day-Ahead market and other forward processes. Also, validations that exist in the Market Portal (MUI) are described, descriptions of how transmission constraint marginal value limits are determined, and various corrections and language improvements are included. Annual review completed.	M. Keyser	FEB-06-2013
BPM-002-r11	This revision describes Reserve Procurement changes, new rules for Resource Supplemental Reserve Testing and Capping, inclusion of notification deadline language, and various corrections and language improvements, including corrections to MCP formulations for the inclusion of Demand Response Resource Type I clearing Spinning Reserves.	M. Keyser	JAN-13--2012
BPM-002-r10	This revision contains changes to accommodate Dispatchable Intermittent Resources. In addition, details about the Real-Time Congestion Management Procedure has been added; various clean-up and grammar edits have been made; MISO rebranding included.	M. Keyser A. Hartman	JUN-29-2011
BPM-002-r9	This revision contains the following changes: timing changes associated with moving the Day-Ahead clearing forward by one hour; references to dispatch bands have been removed; Quick-Start Resource language has been added and clarified; Outage language has been updated for clarity, and to accommodate the new Outage Scheduling application; various clean-up and grammar edits have been made.	M. Keyser A. Hartman	OCT-21-2010
BPM-002-r8	This revision contains constraint details for DA and RAC Ramp Capability Constraints. Several corrections are made to other areas, including DRRI's clearing Spinning Reserves.	M. Keyser	JUL-07-2010
BPM-002-r7	This revision contains changes to accommodate clearing of Spinning Reserves on DRR-Type I Resources	M. Keyser	MAR-11-2010
BPM-002-r6	This revision contains clerical changes only, to reflect the change in identification of this document, from "MO-BPM-001-rxxx" to "BPM-002-rxxx". Also, the Issue Date has been removed from this Revision History.	M. Keyser	JAN-12-2010

BPM-002-r5	This primary reason for this revision is to incorporate Stored Energy Resources, a new resource type. During this revision, other corrections and language improvements were made. Noteworthy changes are to the table of contents and references; all links have been corrected. Also, changes have been made to the language regarding the clearing and deployment of Regulating Reserves, to increase precision. Editing Note: For ease of reading, each Attachment being published along with this r5 revision is being named "r5", even if no changes have been made to that Attachment.	M. Keyser	OCT-27-2009
BPM-002-r4	This revision updates pricing sections to more accurately reflect Market rules. In addition, several other minor corrections have been made as well.	B. Borissov	OCT-02-2009
BPM-002-r3	This revision removes references to the DNR Regulation Must-Offer requirement that existed during the first 180 days of the market. It also describes new rules regarding Interchange Scheduling	M. Keyser	JAN-06-2009
BPM-002-r2	This revision reflects changes to align the document with the final as-built design of the Energy and Operating Reserves Market to the extent possible at the time of edit. Typographical and grammatical corrections have also been made.	M. Keyser	JAN-06-2009
BPM-002-r1	This new Energy and Operating Reserve Market BPM was created by combining the current Energy Markets BPM and Energy Markets Instruments BPM and then revising this combined BPM to reflect the September 14, 2007 filing, subsequent September 19, 2007 Errata filing and March 26, 2008 30-Day Compliance Filing of the Open Access Transmission and Energy Markets Tariff for the MISO, Inc. (EMT) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and integration of proposed changes to the Balancing Authority Agreement.	M. Tackett	JAN-06-2009

Contents

List of Attachments

Attachment A – Market Optimization Techniques – (provided in separate document)

Attachment B – Day-Ahead Energy and Operating Reserve Market Software Formulations and Business Logic – (provided in separate document)

Attachment C – Reliability Assessment Commitment Software Formulations and Business Logic – (provided in separate document)

Attachment D – Real-Time Energy and Operating Reserve Market Software Formulations and Business Logic – (provided in separate document)

List of Exhibits:

1. Introduction

This introduction to the *Business Practices Manual ("BPM") for Energy and Operating Reserve Markets* includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs in general. The second section (Section 1.2) is an introduction to this BPM in particular. The third section (Section 1.30) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provision of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

1.2 Purpose of this Business Practices Manual

This BPM for *Energy and Operating Reserve Markets* covers the rules, design, and operational elements of MISO's Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Market. MISO uses simultaneously co-optimized Security Constrained Unit Commitment ("SCUC"), Security Constrained Economic Dispatch ("SCED") and SCED-Pricing algorithms to clear and dispatch the Energy and Operating Reserve Markets. To understand how these algorithms perform their optimization function, a series of Attachments have been developed to assist in the understanding of some basic optimization concepts and the optimization formulations used within the applicable algorithms as follows:

- Attachment A to the BPM for *Energy and Operating Reserve Markets* outlines some basic optimization concepts and provides a high level description of the SCED and SCUC algorithms that are utilized by MISO to achieve its objectives;
- Attachment B provides additional detail regarding how the Day-Ahead Energy and Operating Reserve Market SCUC, SCED and SCED-Pricing algorithms were formulated and the business logic that is applied to clear the Day-Ahead Energy and Operating Reserve Market;
- Attachment C provides additional detail regarding how the SCUC algorithms were formulated for use in the multi-day RAC, forward RAC and intra-day RAC processes;
- Attachment D provides additional detail regarding how the SCED and SCED-Pricing algorithms were formulated for use in the Real-Time operating hour to calculate Dispatch Targets for Energy and Operating Reserve; and

This BPM conforms and complies with MISO’s Tariff, the reliability standards, policies, principles and guidelines of the North American Electric Reliability Corporation (“NERC”), also known as the Electric Reliability Organization (“ERO”), operating policies, and the applicable Regional Entities, and is designed to facilitate administration of efficient Energy and Operating Reserve Markets.

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

- What are the roles of MISO and the Market Participants (“MPs”) in the Energy and Operating Reserve Markets?
- What are the basic concepts that one needs to know to interact with the Energy and Operating Reserve Markets?
- What MP activities must be performed to engage in the Energy and Operating Reserve Markets?

1.3 References

Other reference information related to this BPM includes:

- Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (referred to as “T.O. Agreement” or “TOA”)
- BPM-001 Market Registration BPM
- BPM-004 FTR-ARR BPM
- BPM-005 Market Settlements BPM
- BPM-007 Physical Scheduling BPM
- BPM-008 Outage Operations BPM
- BPM-009 Market Monitoring and Mitigation Business Practice Manual
- BPM-010 Network and Commercial Models BPM
- BPM-011 Resource Adequacy BPM
- BPM-025 Forecast Engineering BPM
- BPM-026 Demand Response BPM
- BPM-030 Pseudo-Tie BPM
- Market User Interface – Participant XML Specification
- MS-OP-031 Post Operating Processor Calculation Guide in the Market Settlements BPM
- Tariff for Midcontinent Independent System Operator, Inc.
- Coordination Policy Manual

2. Energy and Operating Reserve Markets Overview

This section presents a high level description of the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The intent is to explain the basics, including the following:

- Energy and Operating Reserve Markets operation and Settlements
- Roles and Responsibilities of the entities that interact with the Energy and Operating Reserve Markets
- Market models and terminology
- Day-Ahead and Real-Time computer system components
- Market operation tools

2.1 Energy and Operating Reserve Markets Operation and Settlements

MISO operates two Energy and Operating Reserve Markets:

- ***Day-Ahead Energy and Operating Reserve Market*** – The Day-Ahead Energy and Operating Reserve Market is a forward market in which Energy and Operating Reserve are cleared on a simultaneously co-optimized basis for each hour of the next Operating Day using Security-Constrained Unit Commitment ("SCUC"), Security-Constrained Economic Dispatch ("SCED") and SCED-Pricing computer programs to satisfy the Energy demand Bids and Operating Reserve requirements of the Day-Ahead Energy and Operating Reserve Market. The results of the Day-Ahead Energy and Operating Reserve Market clearing include hourly Ex Ante and Ex Post LMP values for Energy demand and supply, hourly Ex Ante and Ex Post Market Clearing Price ("MCP") values for Regulating Reserve, Spinning Reserve, Supplemental Reserve supply, Up Ramp Capability and Down Ramp Capability and hourly Energy demand schedules, hourly Energy supply schedules for each Resource, hourly Regulating Reserve, Spinning Reserve and Supplemental Reserve supply, hourly Up Ramp Capability and Down Ramp Capability schedules for each qualified Resource. See Section 7 of this BPM for details of the Day-Ahead Energy and Operating Reserve Market.
- ***Real-Time Energy and Operating Reserve Market*** – The Real-Time Energy and Operating Reserve Market is a market in which Energy and Operating Reserve are cleared on a simultaneously co-optimized basis every five minutes using Security-Constrained Economic Dispatch ("SCED") computer programs to satisfy the forecasted Energy demand and Operating Reserve requirements of the Real-Time Energy and Operating Reserve Market based on actual system operating conditions,

as described by MISO's State Estimator. The results of the Real-Time Energy and Operating Reserve Market clearing include five-minute Ex Ante LMPs for Energy demand and supply, five-minute Ex Ante MCP values for Regulating Reserve, Spinning Reserve, Supplemental Reserve supply, and Up Ramp Capability and Down Ramp Capability, five-minute Dispatch Targets for each Resource for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve, and clearing results for Up Ramp Capability and Down Ramp Capability. The Real-Time Energy and Operating Reserve Market dispatch is supported by a Reliability Assessment Commitment ("RAC") process to ensure sufficient capacity is on line to meet Real-Time operating conditions. See Section 6 of this BPM for details of the RAC processes and Section 8 of this BPM for details of the Real-Time Energy and Operating Reserve Market.

These Energy and Operating Reserve Markets operate in a coordinated sequence as summarized by the process/event overview timeline in Exhibit 2-1.

Separate accounting Settlements are performed for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. See the BPM for *Market Settlements* for a detailed description.

LMP and MCP price calculations are described in detail in Section 5 of this BPM.

Real Time Ex Post Prices are calculated as part of Real Time Market Closure Activities as described in detail in Section 9 of this BPM.

Exhibit 2-1: Energy and Operating Reserve Markets – Timeline Overview

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Real-Time Energy and Operating Reserve Market RAC Pre Day-Ahead (See Section 6)		
OD-7 @ 0000	OD-1 @ 2400	RAC Pre Day-Ahead Time Frame
Day-Ahead Energy and Operating Reserve Market Activities (See Section 7)		
OD-7 @ 0000	OD-1 @ 1030 EPT	Prepare for Day-Ahead Energy and Operating Reserve Market
	OD-1 @ 1030 EPT	Close Day-Ahead Energy and Operating Reserve Market
	OD-1 @ 1330 EPT	Post the Day-Ahead Energy and Operating Reserve Market Awards Results and Ex-Ante LMPs and MCPs
OD-1 @ 1330 EPT	OD-1 @ 1630 EPT	Post the Day-Ahead Energy and Operating Reserve Market Ex-Post LMPs and MCPs
Real-Time Energy and Operating Reserve Market RAC Post Day-Ahead (See Section 6)		
OD-1 @ 1330EPT	OD-1 @ 1430 EPT	Revise Offers for RAC Post Day-Ahead (with knowledge of Day-Ahead Energy and Operating Reserve Market results)
	OD-1 @ 1800EPT	Perform Post Day-Ahead RAC Process
OD-1 @ 1800 EPT	OD @ 0000	Notify Start-Up/Shut-Downs from Post Day-Ahead RAC Process
Real-Time Energy and Operating Reserve Market RAC Intraday (See Section 6)		
OD-1@ 2000	OD @ 2400	RAC Intraday Time Frame
Real-Time Energy and Operating Reserve Market Activities (See Section 8)		
OD-1 @ 2330	OD @ RT	Real-Time Energy and Operating Reserve Market Time Frame
	OD @ OH-30min	Close Real-Time Energy and Operating Reserve Market 30 minutes Prior to Top of Each OH
	OD @ RT-5min (Every 5 minutes)	Send UDS Dispatch Targets and post results
	OD @ RT-Continuous	Send Setpoint Instructions approximately every 4 seconds.
Energy Markets Closure Activities (See Section 9)		
OD = Operating Day OH = Operating Hour (00 to 23) RT = Real-Time (target time for UDS Dispatch Targets) RAC = Reliability Assessment Commitment	UDS = Unit Dispatch System Note: All times are in EST unless noted otherwise.	

2.2 Market Modeling Terminology

This section describes the models and terminology that MISO utilizes to coordinate the electric power system ("Network Model") with the Energy and Operating Reserve Markets ("Commercial Model"). Model coordination is crucial to the Settlement process so that credits and charges are accurately allocated to the MPs. The following subsections provide an overview of market modeling. See the BPM for *Network and Commercial Models* for a detailed description.

2.2.1 Network Model

The Network Model is a representation of the actual Transmission System within the MISO Balancing Authority Area, including all connection points modeled for generation and Load and including representations of other transmission systems within the Eastern Interconnection. This model has many purposes, including the analysis of the anticipated impact of physical Energy flow across the Transmission System.

2.2.2 Commercial Model

The Commercial Model differs from the Network Model in that it describes the financial market relationships of the MPs and Asset Owners ("AOs"), and the commercial relationships among the elements of the Network Model. The hierarchy of relationships is as follows:

- MP Level
- AO Level
- Commercial Pricing Node ("CPNode") Level
- Elemental Pricing Node ("EPNode") Level

2.2.3 Elemental Pricing Nodes

The EPNode is the finest level of granularity in the Commercial Model. EPNodes represent selected single Buses in the Transmission System Network Model. EPNodes generally include all Buses where Energy is injected and/or withdrawn from the Transmissions System, as well as other commercially significant buses. MISO calculates the Ex Ante and Ex Post LMP of supplying and consuming Energy at each EPNode. Ex Ante and Ex Post MCPs are calculated directly at the CPNode level.

2.2.4 Aggregated Pricing Nodes

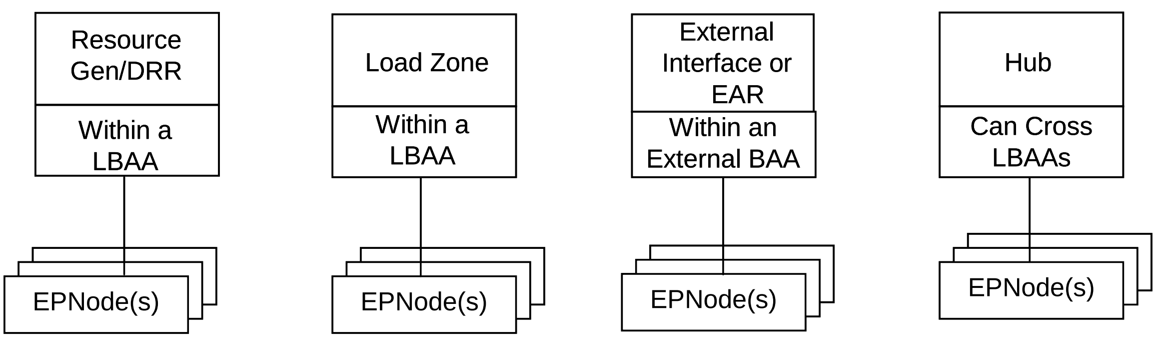
The Aggregated Pricing Node ("APNode") represents an aggregation of two or more EPNodes using predetermined weighting factors. For each APNode, the relationship of EPNodes to APNodes determines how Energy and Operating Reserve at the APNode level are allocated at the EPNode level and/or how prices at the EPNode level are weighted at the APNode level. This nodal relationship is maintained in MISO's Asset Registration System.

2.2.5 Commercial Pricing Nodes

The CPNode represents the next hierarchical level in the Commercial Model and consists of a single EPNode or APNode (i.e., an aggregation of one or more EPNodes). Energy supply and demand is financially settled at the CPNode level based on the appropriate CPNode LMP (Hourly Ex Post Day-Ahead or Hourly Ex Post Real Time) and CPNode energy injection or withdrawal level. Operating Reserve supply is financially settled at the Resource CPNode level based on the appropriate CPNode MCPs (Ex Post Day-Ahead MCPs or Ex Post Real Time MCPs). All LMPs and MCPs will be made available to the public.

There are four types of CPNodes: Resource, Load Zone, Hub, and Interface. Exhibit 2-2 illustrates the relationship between EPNodes and CPNodes.

Exhibit 2-2: CPNode Types



BAA = Balancing Authority Area
LBAA = Local Balancing Authority Area
DRR = Demand Response Resource Types I & II
EAR = External Asynchronous Resource

A Resource CPNode will be based on a single EPNode if the Resource output is injected at a single Bus or an APNode if the Resource output is injected at multiple Buses. For example, a Generation Resource with a single Generator or a Demand Response Resource - Type II hosted by a single Load on the Transmission System would contain a CPNode comprised of the single EPNode where the Generation Resource or Demand Response Resource - Type II injects energy. On the other hand, a Combined Cycle Resource with multiple Generators connected to different electrical Buses or a Demand Response Resource - Type I representing an AC Compressor Control demand-side management program spread across many Loads could be represented by an APNode. Under this situation, the APNode weighting factors would be determined by the MP when the asset is registered and would need to be based on how the total energy injection from the Resource would be distributed among the multiple injection points to which the Resource connects.

A Load Zone CPNode will be based on a single EPNode if the Load Zone represents Load at a single Bus or an APNode if the Load Zone represents Load at multiple Buses. For Load Zone CPNodes that are APNodes, the weighting factors are generally based on actual Load measurements. For the Day-Ahead and Real-Time Markets, a common set of weighting factors are used for all 24 hours of the operating day and are based on the average of the 24 hourly State Estimator Loads associated with the day seven days prior to the Operating Day. On Quarterly Model updates, State Estimator Loads consistent with the new model may not be available, therefore, the weighting factors may be derived off line and applied for the first seven days after a new model is effective

A Hub CPNode can be based on a single EPNode, but will almost always be based on an APNode. The weighting factors for most Hubs are fixed and determined in advance and are not based on energy injection and/or withdrawal levels at the associated EPNodes.

ARR Zones administered as Hub CPNodes are an exception to this practice. The weighting factors of EPNodes comprising an APNode representing an ARR Zone are calculated in the same manner as those of EPNodes comprising a Load Zone. For ARR Zone CPNodes that are APNodes, the weighting factors are generally based on actual Load measurements. For the Day-Ahead and Real-Time Markets, a common set of weighting factors is used for all 24 hours of the Operating Day and are based on the average of the 24 hourly State Estimator Loads associated with the day seven days prior to the Operating Day.

An Interface CPNode can be based on a single EPNode or an APNode. MISO will determine the weighting factors for an Interface CPNode at the time the Network Model is updated. An Interface CPNode is established for each external Balancing Authority. The EPNodes and associated weighting factors are established to simulate as accurately as possible the sourcing or sinking of an Interchange Schedule within the associated external Balancing Authority based on the physical Resources within such Balancing Authority. In many cases, external Interface Buses represent an aggregation of the Resources within the external Balancing Authority that are most likely to move up or down to accommodate an Interchange Schedule to or from the MISO Balancing Authority.

EPNodes may be allocated by percent of ownership to more than one CPNode, provided that the total allocation equals 100 percent. CPNodes that represent Resources and Loads are referred to as assets and all of these types of Assets must be completely assigned (i.e., 100%) to an AO.

2.2.6 Asset Owners

The AO is the next higher hierarchical level in the Commercial Model and typically, but not necessarily, represents a company. A company may choose to be registered as more than one AO. Within the Commercial Model, AOs can own any combination of generation, Load, and/or FTR assets across any number of Local Balancing Authority Areas ("LBAAs"). All AOs must each be represented by an MP.

MISO calculates charges and produces market Settlements statements for each AO. Each Settlement statement provides the billing determinants for each transaction, along with the AO's total financial obligation resulting from its transactions.

2.2.7 Market Participants

The MP is the highest hierarchical level in the Commercial Model and is the entity in the Commercial Model that is financially obligated to MISO for market Settlements. A single MP represents one or more AOs. A single MP may authorize other entities such as a Scheduling Agent (SA) to act in the MISO Energy and Operating Reserve Markets on its behalf. The MP remains financially responsible for market Settlements. MPs receive Settlement summaries and invoices from MISO for Energy and Operating Reserve Markets activities executed by the MPs' or entities authorized by the MP. See the BPM for *Market Settlements* for detailed information.

2.3 Roles and Responsibilities

Roles and responsibilities are described for the following entities:

- MISO
- MPs
- Transmission Owners/Operators
- Generation Owners/Operators
- Load-Serving Entities ("LSEs")
- Market Support Services Providers
- Local Balancing Authorities ("LBAs")
- Independent Market Monitor ("IMM")

2.3.1 MISO

MISO provides all market services for Energy, Operating Reserve and Transmission Service in accordance with the terms of the Tariff, the BPMs, and related agreements. This includes operation and Settlement of the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market.

MISO administers the Energy and Operating Reserve Markets through performance of the following processes:

1) **Reserve Zone Configuration and Operating Reserve Requirements (see Section 3):**
   - Identify and/or modify Reserve Zones on a quarterly basis consistent with updates of the Network Model
   - Calculate minimum Zonal Operating Reserve Requirements on daily basis and post such Requirements 2 days prior to the applicable Operating Day.
   - Calculate Market-Wide Operating Reserve Requirements on daily basis and post such Requirements 2 days prior to the applicable Operating Day.
2) **Multi-Day Reliability Assessment and Commitment ("MDRAC") (see Section 6):**
   - Accumulate information to assess system reliability for the next three to seven days, including gathering data for analyses, identifying potential problems, and determining if sufficient capacity is available to meet Energy and Operating Reserve requirements.
   - Commit, if necessary, Generation Resources, Demand Response Resources – Type II and Demand Response Resources - Type I with Start-Up Notification Time + Start-Up Time greater than 24 hours for a future Operating Day.
3) **Day-Ahead Energy and Operating Reserve Market (see Section 7):**
   - Acquire Day-Ahead data, including transmission outages, generation outages, and Day-Ahead Bids and Offers **(see Section 4)**.
   - Confirm Day-Ahead Interchange Schedules.
   - Clear the Day-Ahead Energy and Operating Reserve Market by committing and dispatching Day-Ahead supply, including consideration of Start-Up, No-Load, Energy Offer, Regulating Reserve Offer, Spinning Reserve Offer (or On-Line Supplemental Reserve Offer if not Spin Qualified), Off-Line Supplemental Reserve Offer (if a Quick-Start Resource) and Ramp Capability for Generation Resources and DRRs-Type II; consideration of Energy Offer,

Regulating Reserve Offer, Spinning Reserve Offer (or On-Line Supplemental Reserve Offer if not Spin Qualified), and Ramp Capability for External Asynchronous Resources ("EARS"); consideration of Shut-Down Offers, Hourly Curtailment Offers, Energy Offers, Spinning Reserve Offers and Supplemental Reserve Offers for DRRs-Type I; and consideration of Regulating Reserve Offer for Stored Energy Resources ("SERs"), against Day-Ahead demand and Operating Reserve requirements.

- Calculate Day Ahead Ex Ante LMPs, Ex Post LMPs, Ex Ante MCPs and Ex Post MCPs **(see Section 5)**
- Review Day-Ahead Energy and Operating Reserve Market results.
- Publish data for Day-Ahead Energy and Operating Reserve Market results (e.g., schedule, commitment, Load, Ex Ante LMP, Ex Post LMP, Ex Ante MCP and Ex Post MCP).
- Perform Day-Ahead Energy and Operating Reserve Market Settlement.

4) Day-Ahead Reliability Assessment and Commitment (DARAC) (see Section 6):

- Following the posting of Day-Ahead Energy and Operating Reserve Market results, accumulate information to assess system reliability for the next Operating Day, including gathering data for analyses, identifying potential problems, and determining if sufficient capacity is available to meet Energy and Operating Reserve requirements.
- Commit additional Resources not previously committed during the Day-Ahead Energy and Operating Reserve Market process, if necessary, to meet forecast Load and Operating Reserve requirements for the next Operating Day based on Start-Up Offers, No-Load Offers, Energy Offers, Regulating Reserve Offers, Spinning Reserve Offers (or On-Line Supplemental Reserve Offers if not Spin Qualified), Off-Line Supplemental Reserve Offers (if a Quick-Start Resource), and Ramp Capability for Generation Resources and DRRs-Type II; consideration of Energy Offer, Regulating Reserve Offers, Spinning Reserve Offers (or On-Line Supplemental Reserve Offers if not Spin Qualified), and Ramp Capability for External Asynchronous Resources; consideration of Shut-Down Offers, Hourly Curtailment Offers, Spinning Reserve Offers and Supplemental Reserve Offers for DRRs-Type I; and Regulating Reserve Offers for Stored Energy Resources. Both EAR and SER Resources are considered to be committed, if available, during this process.
- Recommend, if necessary, Resource candidates to supply Regulating Reserve.

- Recommend, if necessary, the release of the emergency high range or emergency low range on specific Resources should it be necessary to ensure power balance and satisfy Operating Reserve requirements.
- Identify Quick-Start Resources selected to supply Supplemental Reserve.

5) Intra-Day Reliability Assessment and Commitment (IRAC) (see Section 6):

- Continue to accumulate information to assess system reliability during the Operating Day, including gathering data for analyses, identifying potential problems, and determining if sufficient capacity is available to meet Energy and Operating Reserve requirements.
- Commit additional Resources not previously committed during the Day-Ahead Energy and Operating Reserve Market process, Day-Ahead RAC process or previous Intra-Day RAC process if necessary, to meet forecast Load and Operating Reserve requirements for the remainder of the Operating Day based on Start-Up Offers, No-Load Offers, Energy Offers, Regulating Reserve Offers, Spinning Reserve Offers (or On-Line Supplemental Reserve Offers if not Spin Qualified), Off-Line Supplemental Reserve Offers (if a Quick Start Resource) and Ramp Capability for Generation Resources and DRRs-Type II and Shut-Down Offers, Hourly Curtailment Offers, Spinning Reserve Offers and Supplemental Reserve Offers for DRRs-Type I. External Asynchronous Resources, if available and not previously selected during the Day-Ahead Energy and Operating Reserve Market process or prior RAC processes, are also considered in this step based on their Energy Offers, Regulating Reserve Offers, Spinning Reserve Offers, Supplemental Reserve Offers and Ramp Capability.[1] SERs, if available and not previously selected during the Day-Ahead Energy and Operating Reserve Market process or prior RAC processes, are also considered in this step based on their Regulating Reserve Offers.
- Recommend, if necessary, Resource candidates to supply Regulating Reserve for the commitment period.
- Recommend, if necessary, the release of the emergency high range or the emergency low range on specific Resources should it be necessary to ensure power balance and satisfy Operating Reserve requirements.

[1] Only if not Spin Qualified

- Identify Quick-Start Resources selected to supply Supplemental Reserve and/or DRRs-Type I selected to supply Contingency Reserve.

6) Real-Time Energy and Operating Reserve Market (see Section 8):

- Update minimum Zonal and Market-Wide Operating Reserve Requirements, if required due to a change in system conditions from Day-Ahead that would adversely impact system reliability.
- Acquire Real-Time Energy and Operating Reserve Market Offers **(see Section 4)**.
- Acquire most recent RAC data (e.g. operating plan).
- Confirm Real-Time Interchange Schedules and Real-Time Resource Offer data.
- Acquire current system conditions, including: Binding Transmission Constraints (limits, actual flows and sensitivity factors) and actual generation.
- Calculate 5-minute Load Forecast.
- Operate and clear the Real-Time Energy and Operating Reserve Market and determine Ex Ante LMPs, Ex Ante MCPs, cleared Energy, cleared Operating Reserve and Dispatch Targets.
- Send Dispatch Targets to Market Participants with Generation Resources, DRRs-Type II, Stored Energy Resources and External Asynchronous Resources every five minutes.
- Send Setpoint Instructions to Market Participants with Generation Resources, Demand Response Resources - Type II, Stored Energy Resources and External Asynchronous Resources every four seconds.
- Calculate and publish preliminary Ex Post LMPs and MCPs.
- Review Real-Time Energy and Operating Reserve Market results.
- Schedule and payback Inadvertent Interchange.
- Initiate Emergency procedures, as needed.
- Calculate and publish final Hourly Ex Post LMPs and MCPs.
- Perform Real-Time Energy and Operating Reserve Market Settlement.

2.3.2 Market Participants

MPs are entities that are qualified, pursuant to criteria and procedures established by MISO, to perform the following actions:

1) **Day-Ahead Energy and Operating Reserve Market:**
   - Submit Interchange Schedules to MISO.
   - Submit Demand Bids to purchase Energy and/or submit Offers, including Self-Schedules, to sell Energy and Operating Reserve.
   - Submit Day-Ahead Financial Schedules to MISO by 1200 hours Eastern Standard Time ("EST") up to six days following the Operating Day (OD+6).
   - Submit Virtual Supply Offers and Virtual Demand Bids.
2) **Real-Time Energy and Operating Reserve Market:**
   - Submit Offers for any of the RAC processes (beginning at OD-7).
   - Submit Interchange Schedules to MISO.
   - Submit new or modified Offers, including Self-Schedules, to supply Energy and Operating Reserve no later than 30 minutes prior to the Operating Hour.
   - Submit Real-Time Financial Schedules by 1200 EST up to six days following the Operating Day (OD+6).

2.3.3 Transmission Operators

A Transmission Owner is a member of MISO that has (in whole or in part) transferred functional responsibilities of its transmission facilities classified as transmission and covered under the Tariff and TOA. Those facilities make up MISO's Transmission System. Transmission Operators perform the following actions on behalf of Transmission Owners:

1) **Prior to the Operating Day:**
   - Receive and/or develop transmission maintenance requirements and plans for Transmission Owners.
   - Define operating limits, develop contingency plans, and monitor operations of the transmission facilities under the Transmission Operator's control and as directed by MISO.
   - Provide operating information to MISO.
   - Determine amounts required and arrange for Other Ancillary Services from Generation Owners to ensure reactive supply and voltage control (e.g., from Generation Resources) in coordination with the LBAs and MISO.
   - Update transmission facility ratings.

2) **During the Operating Day:**
   - Operate or direct the operations of the Transmission System within equipment and facility ratings established by the Transmission Owners and Generation Owners, and system ratings established by MISO.
   - Deploy reactive Resources from Transmission Owners and Generation Owners Other Ancillary Services to maintain acceptable voltage profiles and direct Distribution Providers to maintain voltages within limits.
   - Provide Real-Time operations information to MISO.
   - Notify Generation Owners and other affected entities of Transmission System problems (e.g., voltage limitations or equipment overloads that may affect Generator operations).
   - Request MISO actions to mitigate equipment overloads for facilities not monitored by MISO.
   - Coordinate Load Shedding with, or as directed by, MISO and direct Distribution Providers to shed Load.

2.3.4 Generation Owners/Operators

A Generation Owner is an entity that owns, or leases with rights equivalent to ownership, facilities for generation of Energy and provision of Operating Reserve that are located within or are used to supply Energy and Operating Reserve in the MISO market footprint. Generation Resources within the Market Footprint must be represented by an MP. Generator Operators perform the following actions:

1) **Prior to the Operating Day:**
   - Submit maintenance schedules.
   - Submit operational parameters and facility limitations (e.g., long lead time units).
2) **During the Operating Day:**
   - Respond to dispatch and control directives or signals.
   - Respond to reactive supply and voltage control directives.
   - Respond to Start-Up and Shut-Down directives.

2.3.5 Load-Serving Entities

LSEs are any parties taking Transmission Service on behalf of wholesale or retail power customers, that have undertaken an obligation to provide or obtain Energy and/or Operating Reserves for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System.

An LSE must either qualify as an MP, or arrange with an MP to be served through the Energy and Operating Reserve Markets. LSEs perform the following actions:

1) **Prior to the Operating Day:**
    - Coordinate with their LBA in the development of Load Forecasts (hourly for 7 days out) that the LBA submits to MISO.
2) **During the Operating Day:**
    - Respond to MISO interruptible Load and Load Shedding directives either directly or through their LBA.

2.3.6 Aggregators of Retail Customers ("ARCs")

ARCs are any parties that have contracted to provide load interruption services or behind the meter generation to the Energy and Operating Reserve Markets with one or more retail or wholesale customers whose load they have not undertaken an obligation to provide or obtain Energy and/or Operating Reserves for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System.

An ARC must either qualify as an MP, or arrange with an MP to be served through the Energy and Operating Reserve Markets. ARCs perform the following actions:

1) **Prior to the Operating Day:**
    - Submit Maintenance Schedules
    - Submit operational parameters and facility limitations (e.g., long lead time Resources)
2) **During the Operating Day:**
    - Respond to dispatch and control directives or signals
    - Respond to Start-Up and Shut-Down directives

2.3.7 Market Support Services Providers

There are three types of market support services providers:

- ***Scheduling Agent ("SA")*** – an agent designated by an MP to physically exchange market information, such as submitting Bilateral Transactions, Bids, and Offers or receiving market data and notifications from MISO on the MP's behalf.
- ***Meter Data and Management Agent ("MDMA")*** – an entity that is designated by an MP to manage and conduct the metering function.
- ***Billing Agent*** – an entity that may be designated by an MP to receive bills and/or make payments on behalf of the MP.

Market support services providers do not need to be qualified as MPs as long as the MPs they represent remain financially liable to MISO for all the activities that the market support services providers perform. The market support services providers are required to act in accordance with the provisions of the Tariff. However, the MP's responsibilities and liabilities to MISO cannot be transferred to market support service providers.

2.3.8 Local Balancing Authorities

Local Balancing Authority responsibilities are specified in the Amended Balancing Authority Agreement.

2.3.9 Independent Market Monitor

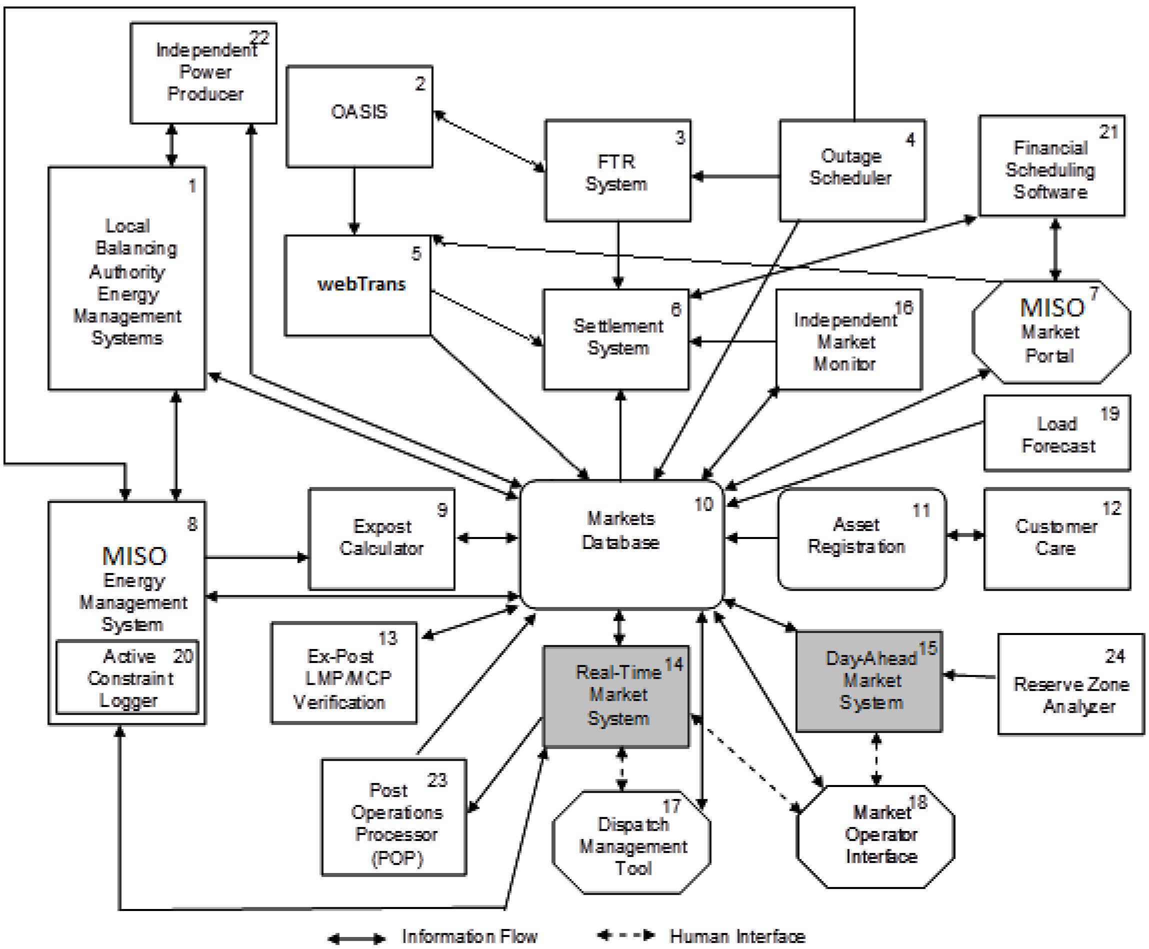
MISO uses the services of its IMM to provide for the independent, impartial, and effective monitoring and reporting on the MISO Energy and Operating Reserve Markets as a whole. In addition, the IMM provides the means for MISO to mitigate the market effects of any conduct that would distort competitive outcomes in the Energy and Operating Reserve Markets. For further information on the IMM, please see the BPM for *Market Monitoring and Mitigation*.

2.4 Energy and Operating Reserve Markets System Components

The Day-Ahead and Real-Time Energy and Operating Reserve Markets ("DART") system consists of software, servers, and related applications used to support the operation of the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

Exhibit 2-3 depicts the major components of this system.

Exhibit 2-3: DART Components Overview



The following components are shown in

Exhibit 2-3:

1) ***LBA/MP Energy Management Systems*** – The LBA and MP EMSs that are within the Market Footprint provide SCADA via ICCP, and the MISO EMS and MP EMSs that are within the Market Footprint provide Dispatch Targets, to Resources that are dispatched by MISO. MISO also sends Resource Dispatch Targets to LBAs.
2) ***Open Access Same-Time Information System ("OASIS")*** – Used to manage Transmission Service reservations that may be used to schedule Interchange Transactions. Reservations for Firm Transmission Service may also be accompanied by an FTR request via the OASIS.
3) ***FTR System*** – Maintains records of FTR Holders, allocates new FTRs, and conducts auctions.

4) ***Outage Scheduler*** – The system that tracks the status of transmission and generation outages and their expected return to service.
5) **webTrans –** The system for entering and disseminating Interchange Schedule information. Interchange Schedules are submitted to webTrans via NERC E-Tag.
6) ***Settlement System*** – Calculates the MP charges and credits for the Day-Ahead Energy and Operating Reserve Market, the Real-Time Energy and Operating Reserve Market, and the FTR Market.
7) ***MISO Market User Interface ("MUI"), also known as the Market Portal*** – The internet portal by which MP information is entered via input/output displays and data templates[2].
8) ***MISO Energy Management System*** ("EMS") – consists of the power system network analysis functions (including the State Estimator and Contingency Analysis) that are used by MISO Operators to maintain reliable power system operations and the AGC system.
9) ***Real Time Ex-Post Calculator*** – Calculates five-minute Ex-Post LMPs and MCPs based on the same input data and SCED-Pricing algorithm used to clear the Real-Time Energy and Operating Reserve Market.
10) ***Markets Database*** – The Markets Database is the central repository of all market-related data and coordinates market component communications.
11) ***Asset Registration*** – The system for the storing of authorized MP information relevant to participation in the MISO markets.
12) ***Customer Care*** – Customer services and the MISO response to market inquiries.
13) ***Ex- Post LMP/MCP Verification*** – Verification and correction of Ex-Post Calculator results.
14) ***Real-Time Market System*** – Provides Dispatch Targets for a near-term forecast of operating conditions for the Real-Time Energy and Operating Reserve Market, using a simultaneously co-optimized SCED algorithm. For the Real-Time Energy and Operating Reserve Market, the SCED algorithm is executed on a five-minute periodic basis to produce a security constrained co-optimized economic dispatch and Operating Reserve clearing and determines Ex-Ante LMPs and Ex-Ante MCPs based on the current system conditions, the actively managed transmission

[2] For more information regarding querying and submitting Market data to the MUI, please see the *Market User Interface – Participant XML Specification*

constraints, the Sub-Regional Power Balance Constraint and the forecast system conditions. The SCED algorithm is not used in RAC.

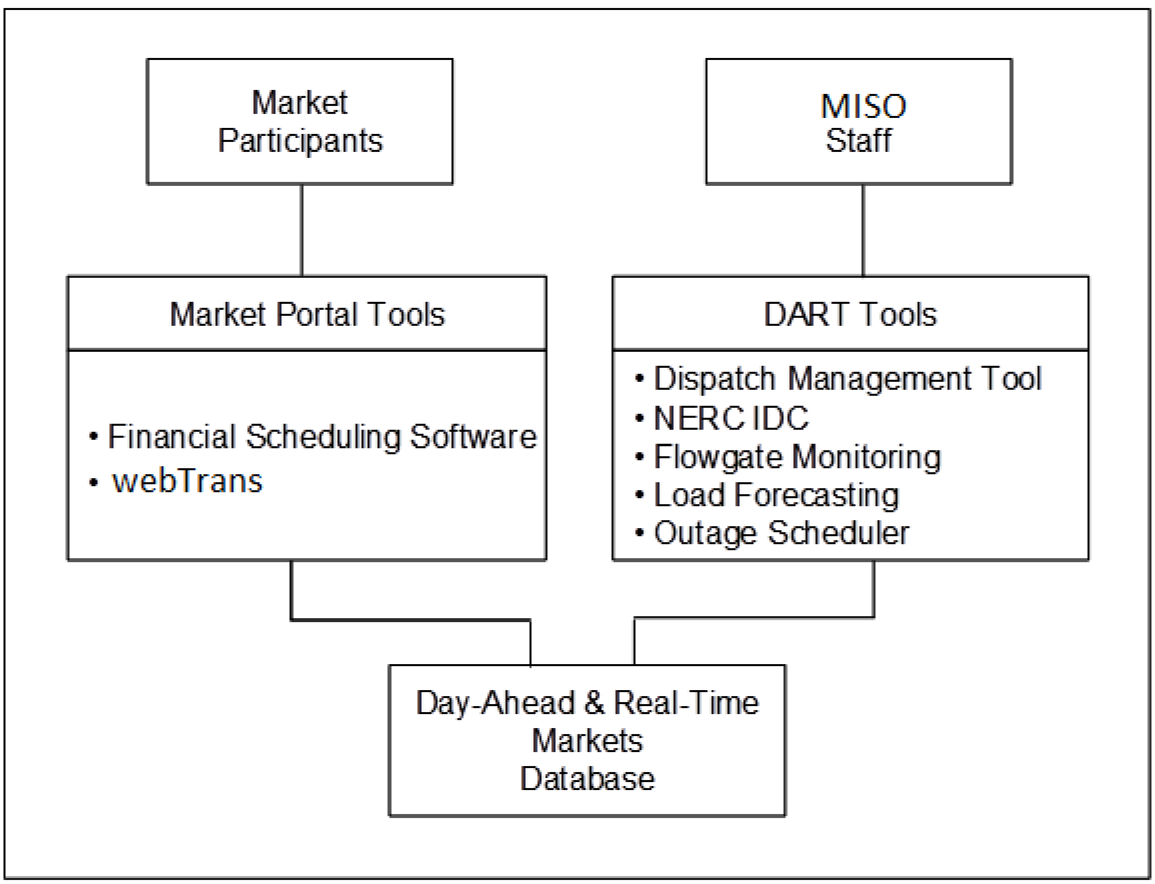
15) ***Day-Ahead Market System*** – Provides SCUC commitments, SCED schedules and SCED-Pricing prices, based on MP submitted Offers and Bids and forecast Operating Reserve requirements. The following applications are executed for each hour:
    - ***Resource Scheduling and Commitment ("RSC")*** – A SCUC which performs generation commitment for the 24-hour period.
    - ***Scheduling, Pricing and Dispatch ("SPD")*** – A SCED that uses the Network Model to perform dispatch for 24 hours and determines Ex Ante LMPs and Ex Ante MCPs.
    - ***Simultaneous Feasibility Test ("SFT")*** – Performs contingency analysis for each hour to evaluate network security of a set of injections and withdrawals under a range of contingent scenarios.
    - ***Day Ahead Locational Marginal Price ("DALMP")*** – A SCED, specifically SCED-Pricing, that uses the Network Model to perform dispatch for 24 hours and determines Ex Post LMPs and Ex Post MCPs.
16) ***Independent Market Monitor ("IMM")*** – Provides the independent observation of market activities to detect market rule violations and the influence of market power.
17) ***Energy Market Displays ("EMD")*** – Allows the Operator to make changes to the planned operation of specific Resources,
18) to view the inputs and outputs of the market system, and to make input parameter adjustments.
19) ***Load Forecast*** – Provides short-term Load forecast over the next hour for the Real-Time Energy and Operating Reserve Market dispatch and provides 24 hour Load forecast values for rolling seven days for use in the RAC for the Real-Time Energy and Operating Reserve Market.
20) ***Active Constraint Logger*** – Records and logs transmission constraints that are "actively" being controlled and impacting the dispatch solution produced by UDS in the Real-Time Energy and Operating Reserve Market.
21) ***Financial Scheduling Software ("finSched")*** – Used by MPs to enter Financial Schedules.
22) ***Independent Power Producer ("IPP")*** – A Generation Resource that operates within an LBA and that submits MW/Price Offers into the Energy and Operating Reserve Markets, independently of any other Generation Resource(s) within the LBA.

23) ***Post Operation Processor ("POP")*** – Calculates hourly MCPs and cleared Operating Reserve MW for use in the hourly Settlements in the Real-Time Energy and Operating Reserve Market.

2.5 Market Operations Tools

Many software tools are required for the operation of the Day-Ahead and Real-Time Energy and Operating Reserve Markets. These tools, listed as part of the system components described under Section 2.4, can be categorized as illustrated by Exhibit 2-4, which distinguishes between those tools designed for MP interaction and those tools designed primarily for MISO staff interaction.

Exhibit 2-4: Market Operations Tools



The following software tools are available to assist MISO with the management of the Energy and Operating Reserve Markets and interactions with MPs, and are described in this subsection:

- Financial Scheduling Software (“finSched”)
- Physical Scheduling Software (“webTrans”)
- MISO Market Portal

2.5.1 Financial Scheduling Software

The finSched MUI application provides MPs with the ability to create Financial Schedules that transfer the financial responsibility for Energy, but not the physical flow of Energy. A Financial Schedule identifies the parties, Source Point, Delivery Point, Sink Point, and Energy schedules. The Source/Delivery/Sink Points can be any CPNode. The following MP capabilities and functionalities are incorporated in finSched:

- Define contracts between two parties who are each MPs in the Energy and Operating Reserve Markets. The contracts permit parties to create schedules, which transfer financial responsibility between parties.
- Define MW schedules for periods of time consistent with the contracts that are defined between the parties.
- Define financial transfers within and across MISO’s Market Footprint.
- Acknowledge/accept the contracts and schedules entered by the counterparty.
- Provide the MPs with web and XML methods to schedule Financial Schedules. Those MPs with a programmatic interface receive notification from finSched of schedules that are pending their approval.
- Provide financial schedule reports to MPs via web browser and XML programmatic interface.
- Enter and confirm Financial Schedules (by both parties to the agreement) by 1200 EST on the sixth day after the Operating Day (OD+6).

See Section 4.1.3 of this BPM for a description of Financial Schedules.

2.5.2 Physical Scheduling Software (webTrans)

OATI’s webTrans processes and tracks the Interchange Schedules that enter, exit, pass through or exist within MISO’s market footprint. In general, webTrans is used to process Interchange Schedules with external entities and validate transactions against rules explained in BPM-007.

2.5.3 MISO Market Portal

MPs may submit Bilateral Transactions, Resource Offers, Demand Bids, and Virtual Transactions into the Energy and Operating Reserve Markets through MISO's Market Portal. The Market Portal also serves as the focal point for posting unrestricted (public) information and private information to authorized MPs.

3. Energy and Operating Reserve Market Requirements and Product Description

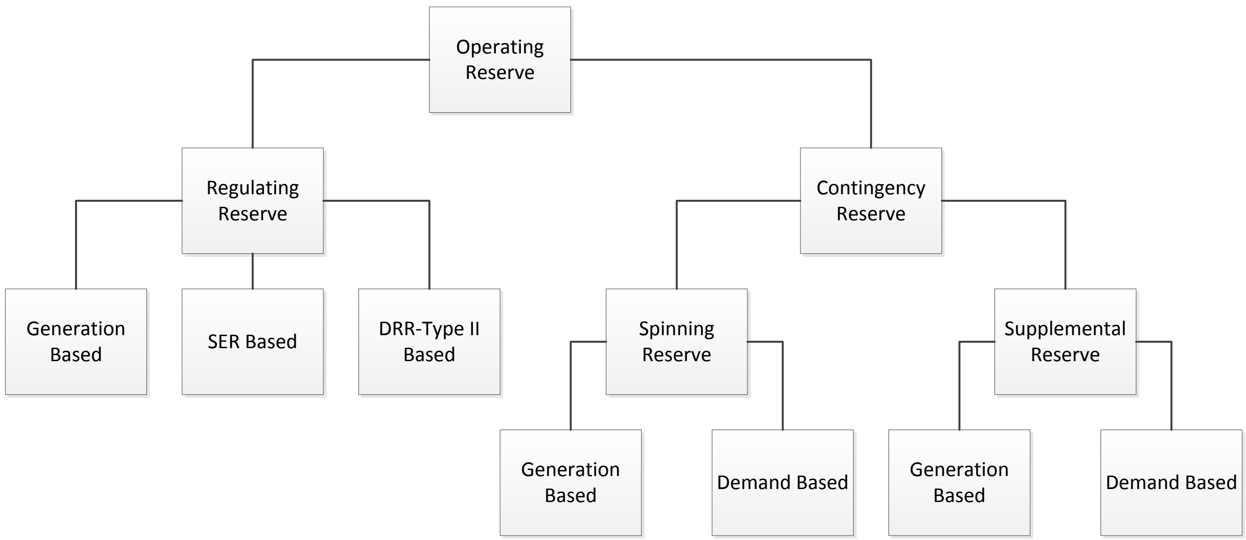
The following five products are traded in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets to meet the MISO Energy and Operating Reserve Market requirements:

- Locational Energy;
- Regulating Reserve;
- Spinning Reserve;
- Supplemental Reserve;
- Ramp Capability.

Locational Energy is a commodity that is both purchased and sold by MPs to meet Energy requirements. Day-Ahead Energy requirements are based upon Demand Bids, Virtual Demand Bids and Export Schedules. Real-Time Energy requirements are based upon actual real-time metered deviations from Day-Ahead Energy requirements. Regulating Reserve, Spinning Reserve and Supplemental Reserve represent Ancillary Services procured to meet MISO Operating Reserve requirements to ensure reliable operation of the MISO Balancing Authority. The three Operating Reserve products are related through the Operating Reserve Hierarchy (See

Exhibit 2-5). Ramp Capability is used to reduce the occurrence of energy and reserve scarcity by reserving ramping capacity for future load variations and uncertainty. Ramp Capability does not fit within the hierarchy of Operating Reserves for the purpose of product substitution.

Exhibit 2-5: Operating Reserve Product Hierarchy



Based on the Operating Reserve Hierarchy, Operating Reserve is comprised of Regulating Reserve and Contingency Reserve; Regulating Reserve is comprised of Generation-based, DRR-Type II based and SER-based Regulating Reserve; Contingency Reserve is comprised of Generation-based and Demand-based Spinning Reserve and Generation-based and Demand-based Supplemental Reserve. This Section describes the Operating Reserve products and the methods used by MISO to calculate the Market-Wide and Zonal Regulating Reserve Requirements. The Market-Wide Operating Reserve Requirement is always equal to the sum of the Market-Wide Regulating Reserve Requirement and the Market-Wide Contingency Reserve Requirement.

3.1 Regulating Reserve Product and Requirements

The Regulating Reserve product and the methods used by MISO to set the Market-Wide and Zonal Regulating Reserve Requirements are described in the following subsections.

3.1.1 Regulating Reserve Product Description

Regulating Reserve products cleared in either the Day-Ahead or Real-Time Energy and Operating Reserve Market to meet either the Zonal or Market-Wide Regulating Reserve Requirements must meet the following criteria:

- All cleared Regulating Reserve products must be fully deployable in both the regulation-up and regulation-down directions within the Regulation Response Time. MISO will determine automatically the maximum amount of Regulating Reserve that is fully deployable from a specific Resource within the Regulation Response Time based on active ramp rates and/or the clearing of other products on the Resource.

- The Regulation Response Time may be reviewed and adjusted if it is determined by MISO that the current setting is not providing acceptable reliability compliance at a reasonable cost.
- All Regulating Reserve products must be supplied by Regulation Qualified Resources, where Regulation Qualified Resources are Resources that are registered as such, meet the requirements outlined in Section 4.2 of this BPM for Regulation Qualified Resources and have their hourly Regulation Qualified Flag set to "True" for the Operating Hour in question.
- The amount of Regulating Reserve product that can be economically cleared on Stored Energy Resources is limited to be less than or equal to the Market-Wide Regulating Reserve Requirement. This could result in price separation between the SER-based Regulating Reserve product and the non-SER-based Regulating Reserve product. If an amount of Regulating Reserve greater than the Market-Wide Regulating Reserve Requirement is Self-Scheduled or offered with price zero by SERs, then the amount of Regulating Reserve cleared on SERs will be greater than the Market-Wide Regulating Reserve Requirement; however, this Regulating Reserve will not be eligible to substitute for other Operating Reserve products.

3.1.2 Market-Wide Regulating Reserve Requirements

MISO sets the Market-Wide Regulating Reserve Requirements based upon the follow criteria:

- The MISO Market-Wide Regulating Reserve Requirement will be established and posted for each hour of the Operating Day no later than 48 hours prior to the Operating Day. These hourly requirements will apply to both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The MISO Market-Wide Regulating Reserve Requirement may be adjusted for the Real-Time Energy and Operating Reserve Market if necessary due to an Emergency operating condition.
- The hourly Market-Wide Regulating Reserve Requirements will be reviewed daily to ensure acceptable compliance levels with Electric Reliability Organization standards and applicable Regional Entity standards related to control performance. Acceptable compliance levels are performance levels that meet reliability standards at a reasonable cost. Market-Wide Regulating Reserve Requirements will be set to comply with Electric Reliability Organization Standards related to control performance. Should these standards be modified, replaced or terminated, or should additional standards related to control performance be adopted, the method used to

set the hourly Market-Wide Regulating Reserve Requirements will be updated accordingly.

3.2 Contingency Reserve Product and Requirements

The Contingency Reserve product and the methods used by MISO to set the Market-Wide and Zonal Contingency Reserve Requirements are described in the following subsections.

3.2.1 Contingency Reserve Product Requirements

Contingency Reserve products cleared in either the Day-Ahead or Real-Time Energy and Operating Reserve Market to meet either the Zonal or Market-Wide Contingency Reserve Requirements must meet the following criteria:

- All cleared Contingency Reserve must be fully deployable within the Contingency Reserve Deployment Period. MISO will determine automatically the maximum amount of Contingency Reserve that is fully deployable from a specific Resource within the Contingency Reserve Deployment Period based on active ramp rates and/or the clearing of other products on the Resource.
- The Contingency Reserve Deployment Period will be governed by Reliability standards, but in no case will be set greater than 10.0 minutes. Based on Electric Reliability Organization ("ERO") Standard BAL 002-0, a Balancing Authority has 15.0 minutes (the Disturbance Recovery Period) to return its Area Control Error to the lesser of zero or the pre-disturbance Area Control Error level. MISO currently allows five minutes to notify Resources to deploy Contingency Reserve after the occurrence of a disturbance which requires a Contingency Reserve Deployment Instruction. Therefore, MISO will set the Contingency Reserve Deployment Period at 10.0 minutes, which is the difference between the Disturbance Recovery Period (15.0 minutes) and the notification time (5.0 minutes).
- Contingency Reserve will be comprised of Spinning Reserve and Supplemental Reserve. Spinning Reserve is Contingency Reserve supplied from Spin Qualified Resources whereas Supplemental Reserve is Contingency Reserve supplied from Supplemental Qualified Resources that are not Spin Qualified Resources. However, it is important to note that Spin Qualified Resources may supply Supplemental Reserve through product substitution.

3.2.2 Market-Wide Contingency Reserve Requirements

MISO sets the Market-Wide Contingency Reserve Requirements based upon the following criteria:

- The MISO Market-Wide Contingency Reserve requirement will be established and posted for each hour of the Operating Day no later than 48 hours prior to the Operating Day and will generally be the same value in each hour[3]. These hourly requirements will apply to both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The MISO Market-Wide Contingency Reserve Requirement may be adjusted anytime following the posting of the requirements 48 hours prior to the Operating Day if necessary due to changing reliability requirements, such as loss of most severe system contingency and MISO, in such cases, will post the revised requirements as quickly as possible.
- The hourly MISO Market-Wide Contingency Reserve Requirement will be set equal to the most restrictive requirement mandated by Electric Reliability Organization standards, applicable Regional Entity standards or applicable Contingency Reserve Sharing Agreement requirement allocations. In no case will the hourly MISO Market-Wide Contingency Reserve Requirement be set less than the largest single supply contingency (Resource or transmission). Currently, Electric Reliability Organization Standard BAL-002 indicates that, *"Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability".* The MISO Market-Wide Contingency Reserve requirement may be adjusted after the close of the Day-Ahead Energy and Operating Reserve Market for the Real-Time Energy and Operating Reserve Market if one or more events result in a different requirement level.
- The hourly Market-Wide Spinning Reserve requirement will be equal to the greater of i) the most restrictive frequency responsive Contingency Reserve requirement, expressed in MW or as a percent of Contingency Reserve, specified by Electric Reliability Organization standards, applicable Regional Reliability Organization standards and/or applicable Contingency Reserve Sharing Agreements or ii) the

[3] The Market-Wide Contingency Reserve Requirement may change in some hours during the Operating Day based upon changes to the most severe system contingency.

most restrictive spinning reserve requirement, expressed in MW or as a percent of Contingency Reserve, specified by Electric Reliability Organization standards, applicable Regional Reliability Organization standards and/or applicable Contingency Reserve Sharing Group agreements.

- Electric Reliability Organization Standard BAL-002 indicates that, following a supply contingency, a Balancing Authority or Reserve Sharing Group must restore their Contingency Reserve within the Contingency Reserve Restoration Period, which is defined in the standard as the 90 minute period following the end of the Disturbance Recovery Period. After the Contingency Reserve Restoration Period expires, the Real-Time Energy and Operating Reserve Market will restore the Market-Wide Contingency Reserve Requirement back to its pre-disturbance level. However, should there be capacity available to clear additional Market-Wide Contingency Reserve, the Real-Time Energy and Operating Reserve Market will clear additional Market-Wide Contingency Reserve up to the pre-disturbance Market-Wide Contingency Reserve requirement prior to the end of the Contingency Reserve Restoration Period.

3.3 Reserve Zone Establishment and Zonal Operating Reserve Requirements

MISO establishes and reconfigures Reserve Zone boundaries and sets the minimum Operating Reserve requirements for each Reserve Zone based upon the follow methodology:

3.3.1 Method to Establish Reserve Zones

One or more Reserve Zones will be established to ensure Regulating Reserve and Contingency Reserve are dispersed in a manner that prevents adverse operating conditions that affect the reliability of the Transmission System. Reserve Zone Configuration Studies will be performed, as described below, on a quarterly basis, in conjunction with the update of the Network Model, except as provided for under Section 3.3.1.1. Reserve Zone Configuration Studies establish the number of Reserve Zones and the assignment of Resource, Load and/or Interface Elemental Pricing Nodes to specific Reserve Zones concurrent with the update of the Network Model until the next scheduled update of the Network Model and results will be available to Market Participants electronically through downloadable files no less than seven (7) days prior to the date on which the new or reconfigured Resource Zones take effect, except as provided for under Section 3.3.1.1. It is important to note that due to the physical characteristics of Stored Energy Resources, the Regulating Reserve cleared on Stored Energy Resources is ineligible to satisfy Zonal Regulating Reserve Requirements.

In performing Reserve Zone Configuration Studies, MISO applies the following process to establish the Reserve Zones and assign Resource, Load and/or Interface Elemental Pricing Nodes to specific Reserve Zones:

- Utilizing a Network Model representation within the Reserve Zone study software for the target study period, identify all transmission constraints that could occur through Resource re-dispatch. Transmission constraint identification will include consideration of projected system demands and planned generation and transmission outages for the period;
- This list of transmission constraints is then screened to limit the applicable transmission constraints to only those that will have a significant impact on the Reserve Zone determination based on projected system demands and planned generation and transmission outages for the period;
- Once a final set of transmission constraints is identified, Resource, Load, and/or Interface Elemental Pricing Nodes are grouped based on similar impact on all of the remaining transmission constraints. The groups of Resource, Load and Interface Elemental Pricing Nodes represent the Reserve Zones. Multiple Resources and/or Loads normally connected at the same Elemental Pricing Nodes will all be included within a single Reserve Zone.
- Lastly, all remaining Resource, Load and Interface Elemental Pricing Nodes not assigned specifically through the Reserve Zone Configuration Study are assigned to a separate Reserve Zone that represents the remaining part of the system and the minimum Contingency Reserve requirement of this Reserve Zone is always equal to zero (0) MW. The minimum Regulating Reserve requirement for this Reserve Zone may be greater than zero as determined under Section 3.3.2.

3.3.1.1 Reserve Zone Reconfiguration

MISO may adjust the number of Reserve Zones and/or the assignment of Resource, Load and/or Interface Elemental Pricing Nodes to specific Reserve Zones as required if:

- A condition or event occurs, including, but not limited to, an unplanned transmission facility outage, a Generator Forced Outage, or an event of Force Majeure, as defined in Section 10.1 of the Tariff;
- Such condition or event results in an adverse reliability condition that cannot be resolved through operating procedures;
- Such condition or event has a projected duration of two or more Operating Days and;

- MISO determines such adjustment is necessary to ensure the reliability of the Transmission System.

The duration of any Reserve Zone adjustment will coincide with the duration of the condition or event, or until the next quarterly Reserve Zone Configuration Study update, whichever is less. MISO will publish a notice on OASIS identifying the reasons for any such Reserve Zone adjustment, and the expected duration. MISO will not implement an adjustment to a Reserve Zone without a minimum of a forty-eight (48) hour notice prior to the Operating Day for which the Reserve Zone adjustment will apply.

3.3.2 Method to Establish Minimum Zonal Operating Reserve Requirements

MISO identifies the minimum Zonal Operating Reserve Requirements through Reserve Zone Requirements Studies performed on a daily basis, the results of which are posted no later than 48 hours prior to each Operating Day. Reserve Zone Requirements Studies determine (i) the hourly Zonal Regulating Reserve Requirements for each Reserve Zone, (ii) the hourly Zonal Contingency Reserve Requirements for each Reserve Zone, and (iii) the hourly Zonal Spinning Reserve Requirements for each Reserve Zone.

In performing Reserve Zone Requirements Studies, MISO applies the following process to establish the minimum Operating Reserve requirements for each Reserve Zone:

- MISO tests each Reserve Zone established or reconfigured through the Reserve Zone Configuration Study by simulating the loss of each Resource inside the Reserve Zone and importing from the Resources with the highest impact on the transmission constraints identified in the Reserve Zone Configuration Study until a constraint limit is reached or the lost Resource is fully replaced. This step is repeated for each Resource in each Reserve Zone;
- The minimum Operating Reserve requirement is the largest difference between the Resource MW lost and the resulting import capability, but not less than the minimum Regulating Reserve requirements set forth below if applicable, and not greater than the total available Operating Reserve within the Reserve Zone following the loss of the largest Resource within the Reserve Zone;
- The minimum Regulating Reserve requirement for a Reserve Zone is equal to twenty-five (25) percent of the product of the Market-Wide Regulating Reserve Requirement and the ratio of the sum of the Maximum Regulation Capability of Resources within the Reserve Zone to the sum of the Maximum Regulation Capability of all Regulation Qualified Resources. If the resulting Regulating Reserve

Requirement for a Reserve Zone is less than ten (10) MW, the Regulating Reserve Requirement for that Reserve Zone is equal to zero (0) MW;

- The minimum Contingency Reserve requirement for a Reserve Zone is equal to the minimum Operating Reserve requirement of the Reserve Zone less the Regulating Reserve requirement of the Reserve Zone but not less than zero (0) MW. If the minimum Contingency Reserve requirement for a Reserve Zone is calculated to be less than ten (10) MW, the Contingency Reserve requirement for that Reserve Zone is equal to zero (0) MW;
- The minimum Spinning Reserve Requirement for a specific Reserve Zone is equal to twenty-five (25) percent of the product of the minimum Contingency Reserve requirement for that Reserve Zone and the ratio of the Market-Wide Spinning Reserve Requirement to the Market-Wide Contingency Reserve Requirement. If the resulting Spinning Reserve Requirement for a Reserve Zone be less than ten (10) MW, the Spinning Reserve Requirement for that Reserve Zone is equal to zero (0) MW; and
- The minimum Supplemental Reserve requirement for a specific Reserve Zone is equal to the minimum Contingency Reserve Requirement for the Reserve Zone less the minimum Spinning Reserve Requirement for the Reserve Zone.

3.4 Ramp Capability Product

The Ramp Capability product is described in the following subsections.

3.4.1 Ramp Capability Product Description

The Ramp Capability Product is cleared in the Day-Ahead or Real-Time Energy and Operating Reserve Markets to reserve ramp capability to respond to net load variations and includes the following features:

- The Up Ramp Capability and Down Ramp Capability requirements are designed to model both the expected net energy demand change and additional uncertain variation across all market processes and across different system operational conditions at a system level (zonal values will be calculated).
- The contribution of a resource to the ramp capability constraint is limited by its operating limits and its ramp rate over the modeled deployment time. No MP offer price is needed. MPs will be able to indicate their offered dispatch status as either “Economic” or “Not Participating”.
- Ramp capability is not explicitly “deployed.” Rather Ramp Capability prepositions resources so that adequate ramp is available in subsequent dispatch intervals. Ramp

Capability Requirement Demand Curve will enforce this constraint as a soft constraint. Cleared amounts will be reduced if the cost of violation is lower than the cost of economically dispatching energy to meet the Ramp Capability Requirement. The ramp capability product demand curves allow for relaxation for the ramp requirements at a relatively low cost when the resource ramping capability needs to be used in the current interval dispatch.

- Zonal ramp capability requirements are not required since post-deployment constraints ensure that the cleared ramp capability is deliverable to the load without violating transmission constraints after deployments. Although zonal requirements are not decided by the market clearing process and not a direct input, there may be pricing differences as determined by the post-deployment transmission constraints.
- Demand curves for the Up Ramp Capability and Down Ramp Capability products are defined which represent the value for the ramp capability service and provide a mechanism for limiting the clearing of ramp capability and the associated impact on prices when ramp capability is in short supply, e.g., when maintaining the ramp capability is infeasible or unduly expensive. Refer to the MISO Tariff Schedule 28 for more information about the ramp capability demand curve.
- The ramp capability constraints are added to the simultaneous co-optimization of the existing energy and Ancillary Services. The modeled costs include the re-dispatch opportunity cost associated with providing the ramp capability and the existing products and the demand curves for Up and Down Ramp Capabilities. When the ramp capability is “deployed” as energy dispatch during a subsequent Real-Time Dispatch, the simultaneous co-optimization of all products will select the most economical resources to respond with changes in energy output and to fulfill operating reserve and ramp capability requirements.

3.4.2 Ramp Capability Requirements

MISO sets the System-Wide Up and Down Ramp Capability Requirements based upon the following components:

- Net Load Uncertainty is a calculated value based on load forecast error, wind generation forecast errors and dispatchable resources not following set points. This calculated value is fixed for the up and down directions and applies to all case types for all intervals in the Day Ahead and Real Time Markets.
- Net Load Change is a calculated value based on load forecast change, wind generation change and NSI change. The Real-Time Market uses a deploy time

window of 10 minutes. The Day-Ahead Market and other forward processes scale the 10 minute window used in real-time to a deploy time window of one hour.

3.5 Load Forecasting

This subsection describes how MISO develops Load Forecasts for use in the Real-Time Energy and Operating Reserve Market.

3.5.1 High Level Description of Load

MISO needs a forecast of Load for the following purposes:

- The RAC process performed each day for the next several days and also for any RAC process performed current day for future hours of that day
- The LAC process performed for the rolling future hours
- The Real-Time 5-minute dispatch

The values that the Load Forecast represents for each of these purposes are the same and conceptually can be defined as follows:

- ***MISO Forecast Load:*** The Load (including losses) within the telemetered boundary of the MISO LBA members. This includes any Load served "Behind-the-Meter" where the Load and Generation Resources are explicitly modeled in the Network Model for reliability purposes. Load served by generation that MISO has not explicitly modeled in the Network Model is excluded[4].

MISO needs this Load to be at LBA granularity. The definition for the LBA forecast Load is as follows:

- ***Local Balancing Authority Forecast Load:*** The Load (including losses) within the telemetered boundary of a MISO LBA member. This includes any Load served Behind-the-Meter where the Load and generation are explicitly modeled in the Network Model for reliability purposes. Load served by generation that MISO has not explicitly modeled in the Network Model is excluded.

[4] Note that MISO uses ICCP Load data from its members to assist in producing the 5-minute Load Forecast. To be consistent with this definition, the ICCP Load value received from the LBAs should include Load served by generation behind the meter where the generation is included in the MISO Network Model. The forecast Load received from LBAs should also include this Load served by generation behind the meter where the generation is included in the Network Model. Load associated with a DRR-Type I should be submitted on a net basis (i.e., a host DRR-Type I Load of 50 MW that has a DRR-Type I Targeted Demand Reduction Level of 20 MW, should submit a 30 MW Load Forecast for hours in which the DRR-Type I is committed, assuming the load reduction actually occurs).

In addition, note that it is the telemetered boundary of the LBA, as determined by the real-time values included in the LBA's Actual Net Interchange that determines the LBA forecast Load.

For market Settlement purposes, MISO market Load is similar to MISO forecast load with the exception that Load served by Behind-the-Meter Generation Resources but explicitly modeled in the Network Model is excluded (i.e. Load is settled on a net metered basis) and the output of DRRs-Type I and DRRs-Type II is included as part of market Load. The definition of MISO market Load is as follows:

- ***MISO Market Load:*** The Load (including actual losses) within the telemetered boundary of the MISO LBA members. Load served by Generation Resources that MISO has not explicitly modeled in the Network Model or is explicitly modeled for reliability but commercially considered as Behind-the-Meter is not included in this Load. MISO market Load is the sum of the LBA market Load values at any point in time.

Hence, the definition for the LBA market Load is as follows:

- ***Local Balancing Authority Market Load:*** The Load (including actual losses) within the telemetered boundary of a MISO LBA member. Load served by Generation Resources that MISO has not explicitly modeled in the Network Model, or is explicitly modeled for reliability but commercially considered as Behind-the-Meter, is not included in this Load

3.5.2 Use of Load Forecast

3.5.2.1 Reliability Assessment Commitment

The goal of the RAC processes is to ensure that enough generation capacity is scheduled on-line to meet the Load and Operating Reserve requirements in the MISO BA. It is very important that this Load Forecast is as accurate as possible. A low Load Forecast has the potential of resulting in a capacity insufficiency, resulting in the need for Emergency procedures. On the other hand, a high Load Forecast could result in too much generation being committed by MISO, with the potential for uplift of commitment costs.

3.5.2.2 MP Estimation of Operating Reserve Obligations

The hourly mid-term MISO Balancing Authority Area Load Forecast developed for use in RAC is available to MPs through the MUI. Additionally, MISO provides percent of Load values for each Reserve Zone that represent the percentage of the MISO Balancing Authority Area Load Forecast that resides within each Reserve Zone (the sum of all Reserve Zone percentages will be 100%). MPs can use this Load Forecast and Reserve Zone percentage data to estimate their Operating Reserve obligation on both a market-wide and zonal basis. A Market Participant will only need to estimate obligations on a zonal basis if the MP believes that a particular minimum Reserve Zone requirement will bind as illustrated in the following example.

Assume MISO posts the MISO BA Spinning Reserve requirement and Supplemental Reserve requirement, which is equal to 640 MW and 960 MW respectively, and a MISO Balancing Authority Load Forecast for Hour 15 of 70,000 MWh, 48 hours prior to the Operating Day to which the Contingency Reserve requirement applies. There are three Reserve Zones defined and Reserve Zone 4 is the remaining system Zone and Reserve Zone assumptions are defined in Exhibit 2-6 as follows:

Exhibit 2-6: Contingency Reserve Obligation Example

Reserve Zone	Minimum Contingency Reserve Requirement[5]	Minimum Spinning Reserve Requirement[6]	Minimum Supplemental Reserve Requirement[7]	Reserve Zone System Load Percentage	Reserve Zone Load[8] (Hour 15)
Zone 1	150	15	135	15%	10,500
Zone 2	250	25	225	10%	7,000
Zone 3	200	20	180	10%	7,000
Zone 4 (Remaining system)	0	0	0	65%	45,500

Further assume that MP1 has 2,500 MWh of Load located within Reserve Zone 1. If no Reserve Zones are binding (i.e., the amount of Contingency Reserve cleared within each Reserve Zone

[5] Determined by the Reserve Zone Requirements Study.

[6] The Spinning Reserve minimum requirement is equal to 25% of the minimum Contingency Reserve requirement multiplied by (640 / (640 +960)).

[7] The minimum Supplemental Reserve requirement is equal to the minimum Contingency Reserve requirement minus the minimum Spinning Reserve requirement.

[8] Reserve Zone Load Forecast equals Reserve Zone percentage multiplied by MISO BA Load Forecast of 70000 MWh.

exceeds the minimum requirement, thus causing no MCP separation), then MP1's Spinning Reserve and Supplemental Reserve obligations could be estimated as follows:

- MP1 Spinning Reserve obligation estimate = 640 MW * (2,500 MWh / 70,000 MWh) = 23 MW
- MP1 Supplemental Reserve obligation estimate = 960 MW * (2,500 MWh / 70,000 MWh) = 34 MW

MP1 would then have the option of Self-Scheduling 23 MW of Spinning Reserve and 34 MW of Supplemental Reserve from qualified Resources located anywhere within the MISO Balancing Authority Area to meet these obligations, as opposed to purchasing these obligations directly from the Energy and Operating Reserve Markets. In this case, if MP1 Self-Scheduled its entire obligation, a perfect hedge would be created since there is no MCP separation between Reserve Zones, assuming that the actual Load consumption in real-time was exactly equal to the forecast amounts in Hour 15.

If Reserve Zone 1 is binding (i.e., the amount of Contingency Reserve cleared in Reserve Zone 1 is exactly equal to minimum Contingency Reserve requirement and the Spinning Reserve and Supplemental Reserve MCP is greater than the minimum of remaining Reserve Zone MCPs), then MP1's Spinning Reserve and Supplemental Reserve obligations could be estimated as follows:

- MP1 Spinning Reserve obligation estimate = 15 MW * (2,500 MWh / 10,500 MWh) = 4 MW
- MP1 Supplemental Reserve obligation estimate = 135 MW * (2500 MWh / 10,500 MWh) = 32 MW

Again, MP1 would then have the option of Self-Scheduling 4 MW of Spinning Reserve and 32 MW of Supplemental Reserve from qualified Resources located anywhere within the MISO Balancing Authority Area to meet these obligations, as opposed to purchasing these obligations directly from the Energy and Operating Reserve Markets. In this case, however, if MP1 Self-Scheduled its entire obligation, a perfect hedge would not be created since there will be MCP separation between Reserve Zone 1 and the remaining Reserve Zone. MP1 will need to consider that if these obligations are Self-Scheduled on qualified Resources located outside of Reserve Zone 1, that these Self-Schedules may receive an MCP that is less than the MCP that Load located within Reserve Zone 1 will pay and adjust its Self-Schedules accordingly. MP1 would also have the option of purchasing these obligations directly from the Energy and Operating Reserve Markets.

3.5.2.3 Real-Time 5-Minute Dispatch

During the Real-Time 5-minute dispatch process, a MISO developed Load Forecast is developed and used on a 5-minute basis. The SCED will have as inputs this forecast Load for a 5-minute target period and all Interchange Schedules into or out of MISO at that same point in time[9].

To the extent that the actual MISO BA Load in Real-Time is different than the MISO BA 5-minute Load Forecast target, Regulation Capability in the MISO BA will make up for the difference, in response to AGC.

3.5.3 Source of Load Forecast

3.5.3.1 Reliability Assessment Commitment

For the RAC process, MISO requests that the LBA(s) provide a Load Forecast consistent with the above LBA Load Forecast definition at an hourly granularity for the next 7 days to MISO by the Day-Ahead Energy and Operating Reserve Market Offer deadline. MISO also produces a 7-day hourly forecast for the MISO BA. MISO requires MPs serving Load in an LBA to supply a forecast of their Load values to the LBA for the Load served by the MP if the LBA needs the data to develop the LBA forecast.

MISO will continuously evaluate which of these two sources of input produce the most accurate result and will utilize the most accurate source of this data for its RAC processes.

3.5.3.2 Look-Ahead Commitment and Real-Time 5-Minute Dispatch

MISO produces a Short Term Load Forecast (“STLF”) for the MISO BA at a 5-minute granularity for multiple hours into the future, on a rolling basis. LBAs do not provide a forecast for this Real-Time dispatch process. The SCED, as well as the Look-Ahead Commitment (“LAC”) process, utilize these 5-minute forecast Load targets during the dispatch process.[10] The STLF algorithm utilizes the real-time ICCP Load submitted by MISO LBAs and regression modeling.
See the *BPM-025 for Forecast Engineering* for a detailed description of STLF.

3.5.3.3 Pumped Storage Load

[9] For schedules that have been tagged as Dynamic Schedules, the estimated value submitted is used in the dispatch algorithm.

[10] The one exception to this is for non-conforming Loads, which is discussed in more detail below.

Load at a pumped storage facility when operating in pumping mode should be included in the Load Forecast supplied by the LBA for the RAC processes. ICCP values for the load and Generator should be sent to MISO. The Load measurement would be a positive value and the Generator measurement would be "zero" when pumping and vice versa when generating. During Real-Time, Load served by the pumped storage facility can be handled in the same manner as described below under non-conforming Loads. Although not required, it may provide more accuracy for submitting demand Bids in the Day-Ahead Energy and Operating Reserve Market if the pumped storage "Loads" are separated from larger Load Zones of conforming Loads. That will provide more control to Bid in zero Load at that location for expected generating times and specific Load amounts at expected pumping times. Load at pumping facilities may also qualify as a DRR-Type I or a DRR-Type II.

MPs may use all or any combination of the following options to participate in the Energy and Operating Reserve Markets:

- ***Bilateral Transactions*** – For both physical and financial agreements.
- ***Resource Offers*** – For the sale of Energy and Operating Reserve from Generation Resources, Demand Response Resources-Type I ("DRRs-Type I"), Demand Response Resources-Type II ("DRRs-Type II") and External Asynchronous Resources ("EAR"), or for the sale of Regulating Reserve from Stored Energy Resources, as price takers (via Self-Schedules, up to Self-Schedule MW level) or at variable prices.
- ***Demand Bids*** – For the purchase of Energy in the Day-Ahead Energy Market only, at market prices or at "not-to-exceed" prices at Load Zone Commercial Pricing Nodes ("CPNodes").
- ***Virtual Transactions*** – Offers to supply Energy or Bids to purchase Energy at any CPNode in the Day-Ahead Energy and Operating Market only and that are not related to any physical Resource or Load asset.

Exhibit 0-1 provides an overall summary of these options, which market they are applicable to and which software tools are used by MPs to initiate Offer and Bid submittal.

Exhibit 0-1: Market Participation Options

Options	**Day-Ahead Energy and Operating Reserve Market Interface**	**Real-Time Energy and Operating Reserve Market Interface**
Interchange Schedules ▪ Fixed (Normal / Dynamic) ▪ Up to TUC (Normal) (Day-Ahead Energy and Operating Reserve Market Only) ▪ Dispatchable (Normal) (Day-Ahead Energy and Operating Reserve Market Only)	/ E-Tag	/ E-Tag
Financial Schedules ▪ Fixed ▪ Pseudo-Tie ▪ Grandfathered Agreement	Market Portal ▪ finSched ▪ N/A ▪ finSched	Market Portal ▪ finSched ▪ finSched ▪ N/A
Generation Resource Offer	Market Portal	Market Portal
External Asynchronous Resource Offer	Market Portal	Market Portal
Demand Response Resource Type I (“DRR-Type I”) Offer	Market Portal	Market Portal
Demand Response Resource Type II (“DRR-Type II”) Offer	Market Portal	Market Portal
Stored Energy Resource Offer	Market Portal	Market Portal
Demand Bid	Market Portal	N/A
Virtual Supply Offer	Market Portal	N/A
Virtual Demand Bid	Market Portal	N/A
TUC = Transmission Usage Charge N/A = Not allowed finSched = Financial Scheduling Software		

The following subsections describe each of these four options in more detail.

4.1 Bilateral Transactions

Bilateral Transactions are contracts between parties for the transfer of Energy and financial responsibility for Energy from suppliers to consumers.

See the *BPM-007 for Physical Scheduling* for a detailed description of Bilateral Transactions.

4.1.1 Interchange Schedules

4.1.1.1 Interchange Schedule

An Interchange Schedule is submitted via a NERC E-Tag by an MP representing withdrawals and injections at specified locations. See the BPM-007 for Physical Scheduling for a detailed description of Interchange Schedules.

4.1.1.2 Import Schedule

If the Source Point is external to the MISO market footprint and the Sink Point is not, the Interchange Schedule is an Import Schedule.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Spot In Market Product.

4.1.1.3 Export Schedule

If the Sink Point is external to the MISO market footprint and the Source Point is not, the Interchange Schedule is an Export Schedule.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Spot In Market Product.

4.1.1.4 Through Schedule

If the Source Point and Sink Point are both external to the MISO Market Footprint, the Interchange Schedule is a Through Schedule.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Spot In Market Product.

4.1.1.5 Within Schedule

If the Source Point and Sink Point are internal to the MISO market footprint, the Interchange Schedule is a Within Schedule.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Spot In Market Product.

4.1.1.6 GFA Schedule

If the Source Point and Sink Point are internal to the MISO Market Footprint, the schedule is a GFA Schedule. GFA Schedules do not require confirmed reservations of Network Integration Transmission Service because the Transmission Service is provided according to the terms of a Grandfathered Agreement. Grandfathered Carve Outs will be physically scheduled within the Market Footprint GFA Schedule

4.1.2 Interchange Schedule Types

When creating an E-Tag for Interchange Schedules, each MP must select an Energy type, a transaction type, and a market type.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.2.1 Fixed Interchange Schedules

Fixed Interchange Schedules are physical transactions that do not specify a Bid or Offer ($/MWh).

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.2.2 Dispatchable Interchange Schedules

Dispatchable Interchange Schedules are physical transactions that specify a Bid or Offer ($/MWh).

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.2.3 Up-to-TUC Interchange Schedules

Up-to-TUC Interchange Schedules are physical transactions created via NERC E-Tag that specify a willingness to pay the TUC (in $/MWh) represented by a maximum amount beyond which the MP agrees to be curtailed.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.2.4 Dynamic Interchange Schedules Associated with External Asynchronous Resources ("EARs")

Fixed Dynamic Interchange Schedules associated with External Asynchronous Resources (EAR) are special types of schedules that are submitted at an EAR Resource CPNode (the Source Point).

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.2.5 Grandfathered Carve Out Transactions

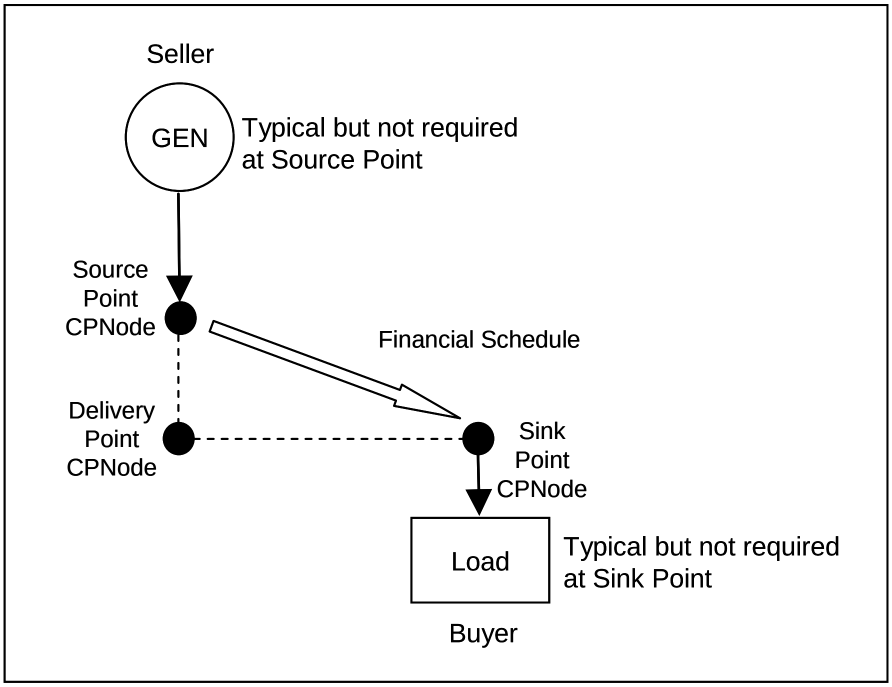
The Federal Energy Regulatory Commission determined that certain Grandfathered transactions would be carved out of the MISO market.

See the *BPM-007 for Physical Scheduling* for a detailed description of the Interchange Schedule Types.

4.1.3 Financial Schedules

Financial Schedules, also known as Financial Bilateral Transactions ("FBTs"), provide MPs with the ability to transfer the financial responsibility for Energy (not the physical flow of Energy) between buyers and sellers for the transfer of Energy within and across the Market Footprint. OASIS reservations are not required for Financial Schedules. Financial Schedules are defined in terms of three points in the Commercial Model as illustrated in Exhibit 0-2.

Exhibit 0-2: Financial Schedule – Definition



4.1.3.1 Rules for Financial Schedules

A Financial Schedule is a financial transaction in which the Source Point, the Sink Point, and the Delivery Point are any CPNodes within the Commercial Model, including Hubs and External Interfaces. Financial Schedules must be submitted through the finSched and may be submitted up to seven days prior to the Operating Day (OD-7), and must be submitted and approved prior to 1200 EST of the sixth day after the Operating Day (OD+6). FBTs must include the following information:

- The Contract Name for the Financial Schedule.
- Identification of the AOs included in the Financial Schedule.
- The CPNodes identified as the Source Point, the Sink Point, and the Delivery Point.
  - The Day-Ahead or Real-Time Energy and Operating Reserve Market for which the Financial Schedule is to be settled, using either the Day-Ahead Ex Post LMPs or Ex Post Real-Time LMPs.
- The scheduled volume in MWh for each hour of the Financial Schedule, using a granularity of tenths of MWh.
- Whether the Financial Schedule is a Financial Schedule for Deviations (by use of the “RSG Deviations Contract” checkbox) Financial Schedules for Deviations must be

submitted at least four hours prior to a given Market Hour (OH-4); submittals made less than four hours prior to a market hour will be rejected.

4.1.3.2 Types of Financial Bilateral Transactions

There are three types of Financial Schedules:

- ***Fixed*** – Fixed Financial Schedules are for a fixed number of MW and may be submitted in either the Day-Ahead or Real-Time Energy and Operating Reserve Markets. These transactions do not roll over from the Day-Ahead to the Real-Time Energy and Operating Reserve Markets.
- ***Pseudo-Tie*** – These Financial Schedules apply to the Real-Time Energy and Operating Reserve Market only as described by Exhibit 1-3.
- ***Grandfathered Agreement*** – These Financial Schedules apply to the Day-Ahead Energy Market only as described by Exhibit 1-4.

Exhibit 1-3: Pseudo-Ties (Real-Time Financial Schedules)

Attaining BA/LBA →	**External BA**	**MISO LBA**	**MISO LBA**
Native BA/LBA →	**MISO LBA**	**External BA**	**MISO LBA**
Load Pseudo-Tie	**Load in Native LBA:** Attaining BA is registered only for Congestion and Loss charges in MISO.	**Load in Native BA:** Pseudo-tie is assigned to Load Zone in Attaining LBA. Attaining LBA must have appropriate transmission service arrangements with Native BA.	**Load in Native LBA:** Pseudo-tie is assigned to Load Zone in Attaining LBA.
Generation Pseudo Tie: (Note: Resource partial Pseudo Tie is represented as two units in the Network Model)	**Generation in Native LBA:** All pseudo-tie units inside MISO must be registered and claimed by AOs. Pseudo-tie units transferred out of MISO are responsible for Congestion and Loss charges in MISO.	**Generation in Native BA:** Pseudo-tie unit transferred into MISO must be claimed by an AO. Pseudo-tie units not transferred into MISO do not need to be registered.	**Generation in Native LBA:** Both pseudo-tie units must be claimed by AOs.
Default AO	Attaining BA/LBA	Attaining BA/LBA	Attaining BA/LBA
Commercial Pricing Node for Pseudo Tie	External Interface CPNode and Pseudo Gen/Load CPNode for Congestion and Loss Charges	Internal Gen/Load CPNode	Attaining LBA's designated CPNode
Financial Schedule: via finSched	Financially Responsible AO is Buyer and Seller.	Financially Responsible AO is Buyer and Seller.	Financially Responsible AO is Buyer and Seller.

Note 1: Native BA means the BA within which the "pseudo" Load or generation is physically located.

Note 2: Attaining BA means the BA that is "sending" MW to the "pseudo" Load or is "receiving" MW from the "pseudo" generation.

Note 3: Pseudo-Tie MW values are calculated by the State Estimator and can be updated up until 1200 EST (OD+1).

Note 4: See Attachments A, B, and C of the *BPM for Network and Commercial Models* for further information.

Exhibit 1-4: Grandfathered Agreements (Day-Ahead Financial Schedules)

GFA Options →	Tariff Option A	Tariff Option B	Tariff Option C
Financial Transmission Right ("FTR")	FTR is held by GFA Responsible Entity	No FTR	No FTR
Cost of Congestion	GFA Responsible Entity is charged	GFA Responsible Entity is credited/charged	GFA Responsible Entity is charged
Cost of Losses	GFA Responsible Entity is charged	GFA Responsible Entity is credited/charged based on difference between Marginal Losses and System Losses	GFA Responsible Entity is charged
Excess Marginal Losses Pool Revenue	GFA Responsible Entity receives share	No share	GFA Responsible Entity receives share
FTR Administrative Costs	GFA Responsible Entity is charged	GFA Responsible Entity is charged	No Charge
Source Point	Any CPNode	Any CPNode	Any CPNode
Delivery Point	Any CPNode	Any CPNode	Any CPNode
Sink Point	Any CPNode	Any CPNode	Any CPNode
Note 1: DRRs are not valid CPNodes for GFA finScheds.			

4.1.3.3 Day-Ahead Transmission Usage Charges for Financial Schedules

MISO collects a Transmission Usage Charge ("TUC") (separated into congestion and loss components for surplus distribution) for all Day-Ahead Financial Schedules. The TUCs for the seller are calculated as the product of (i) the amount of Energy scheduled, in MWh, and (ii) the Day-Ahead Ex Post LMP at the Delivery Point CPNode minus the Day-Ahead Ex Post LMP at the Source Point CPNode. The TUCs for the buyer on the Day-Ahead FBT are calculated as the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Ex Post Day-Ahead LMP at the Sink Point CPNode minus the Day-Ahead Ex Post LMP at the CPNode for the specified Delivery Point.

4.1.3.4 Real-Time Transmission Usage Charges for Financial Schedules

MISO collects a TUC (separated into congestion and loss components for surplus distribution) for all Financial Schedules designated to be settled in the Real-Time Energy and Operating Reserve Market. The TUCs for the seller are calculated as the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Real-Time Ex Post LMP at the Delivery Point CPNode minus the Real-Time Ex Post LMP at the Source Point CPNode. The TUCs for the buyer are calculated as the product of: (i) the amount of Energy scheduled, in MWh, and (ii) the Real-Time

Ex Post LMP at the Sink Point minus the Real-Time Ex Post LMP at the specified Delivery Point.

4.2 Resource Offer Requirements

Resource Offers are submitted by MPs at Resource CPNodes for the purpose of selling Energy and Operating Reserve into the Day-Ahead and Real-Time Energy and Operating Reserve Markets and can be submitted for all types of Resources. The following are the types of Resources for which MPs may submit Offers: Generation Resources (including Jointly-Owned Generation Resources, Combined Cycle Resources, Cross Compound Resources, External Pseudo-Tied Generation Resources, Energy Limited Resources and Intermittent Resources), DRRs-Type I, DRRs-Type II, External Asynchronous Resources, and Stored Energy Resources. DRR-Type II Offer requirements are identical to Generation Resource Offer requirements and thus are combined under Section 4.2.3. Resource qualifications to provide Operating Reserve and Offer parameters are discussed for each Resource category (with Generation Resource and DRR-Type II combined) in the following Subsections.

4.2.1 Resource Qualifications and Eligibility to Provide Operating Reserve

The following subsections describe the requirements that must be met by any Resource in order to be qualified to submit Operating Reserve Offers for use in the Energy and Operating Reserve Markets. Error Exhibit 1-5 provides an Operating Reserve eligibility summary for Resources that are qualified to provide Operating Reserve and Ramp Capability.

Exhibit 1-5: Resource Eligibility Summary for Provision of Operating Reserve and Ramp Capability

Resource	Day-Ahead and Real-Time			
	Regulating Reserve	Spinning Reserve	Supplemental Reserve	Ramp Capability
Committed or on-line Generation Resources	✓	✓	✓	✓
Committed or on-line Generation Resources with Fixed Dynamic Schedule	✓*	✓*	✓*	✓*
Committed or on-line Demand Response Resources - Type II	✓	✓	✓	✓
Available External Asynchronous Resources	✓	✓	✓	✓
Available Stored Energy Resources	✓			
Available off-line or uncommitted Quick-Start Resources			✓	
Uncommitted Demand Response Resources - Type I		✓	✓	

* For a synchronized Generation Resource associated with a Fixed Dynamic Schedule to remain eligible, it must maintain an Hourly Economic Minimum Limit equal to or greater than the Dynamic Interchange Schedule cap limit associated with the resource and an Hourly Economic Maximum Limit greater than the Hourly Economic Minimum Limit.

4.2.1.1 Regulation Qualified Resource Requirements

Any Resource that meets the following criteria will be considered a Regulation Qualified Resource and may submit Offers for Regulating Reserve for use in the Energy and Operating Reserve Markets. All Regulation Qualified Resources must:

- be registered as an Regulation Qualified Resource asset in MISO Energy and Operating Reserve Markets;
- have the appropriate control equipment installed to be capable of providing Regulation Service;
- be capable of supplying Regulation Service in either the up or down direction within the Regulation Response Time;
- be capable of supplying Regulation Service for a continuous duration of 60 minutes;
- be capable of automatically responding to and mitigating frequency deviations via a speed governor or similar device;

- be capable of receiving and responding to automatic control signals on a 4 second periodicity, and providing telemetered output data that can be scanned every 2 seconds;
- if an External Asynchronous Resource, maintain firm point to point transmission service external to MISO in an amount equal to the Hourly Emergency Maximum limit of the External Asynchronous Resource for Imports into MISO, and an amount equal to the Hourly Emergency Minimum limit of the External Asynchronous Resource for Exports out of MISO;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into or out of the MISO Balancing Authority Area;
- if an external Resource, the entire Generation Resource or Stored Energy Resource must be Pseudo-tied into the MISO Balancing Authority Area, and must remain Pseudo-tied into the MISO Balancing Authority Area until the next Network Model update; and
- if a DRR-Type II, be physically located within the Market Footprint.

4.2.1.1.1 Day-Ahead Resource Eligibility

Regulation Qualified Resources that are eligible to provide Regulation Service in the Day-Ahead Energy and Operating Reserve Market are:

- Committed Generation Resources;
- Committed DRRs-Type II; and
- Available External Asynchronous Resources and Stored Energy Resources;

that have their hourly Regulation Qualified Resource availability flags set to “True”.

4.2.1.1.2 Real-Time Resource Eligibility

Regulation Qualified Resources that are eligible to provide Regulation Service in the Real-Time Energy and Operating Reserve Market are:

- synchronized Generation Resources;
- synchronized DRRs-Type II; and

available External Asynchronous Resources and Stored Energy Resources;

that have their hourly Regulation Qualified Resource availability flags set to “True”.

4.2.1.2 Spin Qualified Resource Requirements

Any Regulation Qualified Resource, other than a Stored Energy Resource, is also to be registered as a Spin Qualified Resource. Regulating Reserves may be cleared and substituted for Spinning Reserves on any Regulation Qualified and committed resource if it is economically efficient to do so. Resources that meet the following criteria are considered Spin Qualified Resources and may submit Offers for Spinning Reserve for use in the Energy and Operating Reserve Markets. All Spin Qualified Resources must:

- be registered as a Spin Qualified Resource asset in the MISO Energy and Operating Reserve Markets;
- be capable of automatically responding to and mitigating frequency deviations if required by Applicable Reliability Standards[11];
- be capable of deploying 100% of their cleared Spinning Reserve (including any Spinning Reserve cleared to meet Supplemental Reserve Requirements) within the Contingency Reserve Deployment Period;
- be capable of deploying 100% of their cleared Spinning Reserve for a continuous duration of 60 minutes or the maximum duration specified by Applicable Reliability Standards;
- be capable of providing telemetered output data that can be scanned every 10 seconds (except for DRRs-Type I, which must be capable of providing meter-before/meter-after data as described in the BPM for *Demand Response*);
- if an External Asynchronous Resource, maintain firm point to point transmission service external to MISO in an amount equal to the Hourly Emergency Maximum limit of the External Asynchronous Resource for Imports into MISO, and an amount equal to the Hourly Emergency Minimum limit of the External Asynchronous Resource for Exports out of MISO;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into or out of the MISO Balancing Authority Area;
- if an External Resource, the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area, and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update; and
- if a DRR-Type I or DRR-Type II, be physically located within the Market Footprint.

[11] Current standards do not require Spinning Reserve to be frequency responsive.

4.2.1.2.1 Day-Ahead Resource Eligibility

Spin Qualified Resources that are eligible to provide Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market are:

- Committed Generation Resources;
- Uncommitted DRRs-Type I with a Contingency Reserve Status of "online";
- Committed DRRs-Type II; and
- Available External Asynchronous Resources;

that have their hourly Spin Qualified Resources availability flags set to "True".

4.2.1.2.2 Real-Time Resource Eligibility

Spin Qualified Resources that are eligible to provide Spinning Reserve in the Real-Time Energy and Operating Reserve Market are:

- Synchronized Generation Resources;
- Uncommitted DRRs-Type I with a Contingency Reserve Status of "online";
- Synchronized DRRs-Type II; and
- Available External Asynchronous Resources;

that have their hourly Spin Qualified Resources availability flags set to "True".

4.2.1.3 Supplemental Qualified Resource Requirements

Any Regulation or Spin Qualified Resource is also to be registered as a Supplemental Qualified Resource. MISO may clear Regulating Reserves to substitute for Spinning or on-line Supplemental Reserves when it is economically efficient to do so. Only Resources registered as Quick Start will be eligible to clear as off-line Supplemental. The following requirements apply specifically to Resources that do not qualify as Spin Qualified Resources but are capable of providing Supplemental Reserve, with the exception that Demand Response Resources – Type I can offer Supplemental Reserves if qualified as Spin Qualified Resources. All Supplemental Qualified Resources must:

- be registered as an Supplemental Qualified Resource asset in the MISO Energy and Operating Reserve Markets;
- have a Minimum Run Time (or Minimum Interruption Time for DRRs-Type I) less than or equal to three hours if a Quick-Start Resource[12];

[12] The Quick-Start Resource designation is made and can be modified during the Asset Registration process.

- be capable of deploying 100% of their cleared Supplemental Reserve within the Contingency Reserve Deployment Period;
- be capable of deploying 100% of their cleared Supplemental Reserve for a continuous duration of 60 minutes or the maximum duration specified by Applicable Reliability Standards;
- be capable of providing telemetered output data that can be scanned every 10 seconds (except for DRRs-Type I which must be capable of providing meter-before/meter-after data as described in the BPM for *Demand Response*);
- if an External Asynchronous Resource, maintain firm point to point Transmission Service external to MISO in an amount equal to the Hourly Emergency Maximum limit of the External Asynchronous Resource for Imports into MISO and an amount equal to the Hourly Emergency Minimum limit of the External Asynchronous Resource for Exports out of MISO;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into or out of the MISO Balancing Authority Area;
- if an external Resource, the entire Generation Resource must be pseudo-tied into the MISO Balancing Authority Area, and must remain pseudo-tied into the MISO Balancing Authority Area until the next Network Model update; and
- if a DRR-Type I or DRR-Type II, be physically located within the Market Footprint.

Note: Offers for offline Quick Start Supplemental Qualified Resources should reflect what the Resource is expected to obtain within the Contingency Reserve Deployment Period, barring any mechanical problems or other extenuating circumstances encountered during the start up of the resource, while recognizing that these issues do occur.

4.2.1.3.1 Day-Ahead Resource Eligibility

Supplemental Qualified Resources that are not Spin Qualified Resources that are eligible to provide Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market are:

- uncommitted Quick-Start Resources (Only for offline Supplemental);
- committed Generation Resources;
- uncommitted DRRs-Type I with a Contingency Reserve Status of “offline";
- committed DRRs-Type II; and
- available External Asynchronous Resources;

that have their hourly Supplemental Qualified Resource availability flags set to “True”.

4.2.1.3.2 Real-Time Resource Eligibility

Supplemental Qualified Resources that are not Spin Qualified Resources that are eligible to provide Supplemental Reserve in the Real-Time Energy and Operating Reserve Market are:

- uncommitted Quick-Start Resources (Only for offline Supplemental);
- synchronized Generation Resources;
- uncommitted DRRs-Type I with a Contingency Reserve Status of "offline";;
- synchronized DRRs-Type II; and
- available External Asynchronous Resources;

that have their hourly Supplemental Qualified Resource availability flags set to "True".

4.2.1.4 Ramp Capability Resource Requirements

Resources that are qualified for energy offer will have the Ramp Capability Dispatch Status offer parameter. Valid options for ramp capability dispatch status are "Economic" or "Not Participating" with the default status of "Economic." For DRR-Type I and Stored Energy Resources ("SERs"), the default dispatch status will be "Not Participating".

4.2.1.4.1 Day-Ahead Resource Eligibility

Resources that are eligible to provide Ramp Capability in the Day-Ahead Energy and Operating Reserve Market are:

- committed Generation Resources;
- committed DRRs-Type II; and
- available External Asynchronous Resources

4.2.1.4.2 Real-Time Resource Eligibility

Resources that are eligible to provide Ramp Capability in the Real-Time Energy and Operating Reserve Market are:

- synchronized Generation Resources;
- synchronized DRRs-Type II; and
- available External Asynchronous Resources

4.2.2 Scheduling Resource Outages

The Outage Scheduler status of Generation Resources, DRRs – Type II, and Stored Energy Resources is used, along with applicable offer information, to determine market availability in both the Day Ahead and Real Time Markets. In normal operating conditions, if a Generation Resource or Stored Energy Resource is listed in Outage Scheduler with an outage type of "Out of Service", the resource will be considered unavailable. Generation Resources or Stored

Energy Resources listed in Outage Scheduler with an outage type of “Economy” or “Deration” are considered as available. Further detailed Outage Scheduler information can be found in Section 6.1.6 below, as well as the BPM for *Outage Operations*.

4.2.3 Generation Resources and DRRs-Type II Offer Requirements

The following Subsection describes the economic and operational Offer data for Generation Resources and DRRs-Type II and how these data are used in commitment and dispatch decisions.

4.2.3.1 Offer Information Summary

Generation Resource and DRR-Type II Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

Exhibit 1-6 and Exhibit 1-7 identify the data that may be included in a Generation Resource or DRR-Type II Offer and the markets in which they apply.

Exhibit 1-6: Generation Resource and DRR-Type II Economic Data Summary

Generation and DRR-Type II Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Economic Offer Data				
Energy Offer Curve	MW, $/MWh	Hourly	Hourly	
No-Load Offer	$/hr	Hourly	Hourly	4
Regulating Reserve Capacity Offer	$/MWh	Hourly	Hourly	1
Regulating Reserve Mileage Offer	$/MW	Hourly	Hourly	1
Spinning Reserve Offer	$/MWh	Hourly	Hourly	1
On-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	1,2
Off-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	3
Hot Start-Up Offer	$	Daily	Daily	4
Intermediate Start-Up Offer	$	Daily	Daily	4
Cold Start-Up Offer	$	Daily	Daily	4
Self-Scheduled Regulation	MW	Hourly	Hourly*	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly*	1
Self-Scheduled On-Line Supplemental Reserve	MW	Hourly	Hourly*	1,2
Self-Scheduled Off-Line Supplemental Reserve	MW	Hourly	Hourly*	3
Self-Scheduled Energy	MW	Hourly	Hourly*	

Note 1: If qualified
Note 2: If not Spin Qualified
Note 3: Quick-Start Resources only
Note 4: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets
Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval

Exhibit 1-7: Generation Resource and DRR-Type II Operating Parameter Data Summary

Generation and DRR-Type II Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Commitment Operating Parameter Offer Data				
Hot Notification Time	hh:mm	Hourly	Hourly*	
Hot Start-Up Time	hh:mm	Hourly	Hourly	
Hot to Intermediate Time	hh:mm	Daily	Daily	
Intermediate Notification Time	hh:mm	Hourly	Hourly	
Intermediate Start-Up Time	hh:mm	Hourly	Hourly	
Hot to Cold Time	hh:mm	Daily	Daily	
Cold Notification Time	hh:mm	Hourly	Hourly	
Cold Start-Up Time	hh:mm	Hourly	Hourly	
Maximum Daily Starts	Integer	Daily	Daily	
Maximum Daily Energy	MWh	Daily	Daily	
Minimum Run Time	hh:mm	Daily	Daily	
Maximum Run Time	hh:mm	Daily	Daily	
Minimum Down Time	hh:mm	Daily	Daily	
Commitment Status	Select	Hourly	Hourly	1
Maximum Daily Regulation Up Deployment	MWh	NA	Daily	9
Maximum Daily Regulation Down Deployment	MWh	NA	Daily	9
Maximum Daily Contingency Reserve Deployment	MWh	NA	Daily	9
Dispatch Operating Parameter Offer Data				
Hourly Economic Minimum Limit	MW	Hourly	Hourly*	1
Hourly Economic Maximum Limit	MW	Hourly	Hourly*	1,5
Hourly Regulation Minimum Limit	MW	Hourly	Hourly*	1,6
Hourly Regulation Maximum Limit	MW	Hourly	Hourly*	1,6
Hourly Emergency Minimum Limit	MW	Hourly	Hourly*	1
Hourly Emergency Maximum Limit	MW	Hourly	Hourly*	1,5
Maximum Off-Line Response Limit	MW	Hourly	Hourly*	1,4,6,8
Energy Dispatch Status	Select	Hourly	Hourly*	1
Regulating Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
Spinning Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
On-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
Off-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly*	1,4,6
Hourly Single-Directional-Down Ramp Rate	MW/min	N/A	Hourly*	1,3
Hourly Single-Directional-Up Ramp Rate	MW/min	N/A	Hourly*	1,3
Hourly Bi-Directional Ramp Rate	MW/min	N/A	Hourly*	1,3
Hourly Ramp Rate	MW/min	Hourly	Hourly	1,2,3
Single-Directional-Down Ramp Rate Curve	MW/min	N/A	Hourly	3
Single-Directional-Up Ramp Rate Curve	MW/min	N/A	Hourly	3
Bi-Directional Ramp Rate Curve	MW/min	N/A	Hourly	3
Combined Cycle Status	Select	Daily	Daily	
Forecast Maximum Limit	MW	N/A	Rolling 5-Min	7
Ramp Capability Dispatch Status	Select	Hourly	Hourly*	

Note 1: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets
Note 2: Hourly Ramp Rate is used in Day-Ahead and RAC
Note 3: Ramp Rates may be submitted by MPs at any time and remain fixed until changed by MPs
Note 4: Only applicable to Quick-Start Resources
Note 5: Not applicable to Dispatchable Intermittent Resources in the Real-Time Market
Note 6: Not applicable to Dispatchable Intermittent Resources
Note 7: Only applicable to Dispatchable Intermittent Resources
Note 8: Participant-limited to the level achieved during last deployment or test of Offline Supplemental Reserves issued by MISO
Note 9: Only applicable to DRR-Type II Resources in Real-Time Market
Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval.

MISO maintains a Day-Ahead Schedule Offer[13] and a Real-Time Schedule Offer[14] for each Generation Resource and DRR-Type II. These Offers are standing Offers and maintained for each market independently of the other. Updates to Generation Resource and DRR-Type II Offers may be designated as updating the Day-Ahead Schedule Offer only, the Real-Time Schedule Offer only, or both.

The following two Subsections describe the Economic Offer Data and the Commitment and Dispatch Operating Data Offer Parameters specified in Exhibit 1-6 and Exhibit 1-7 in more detail.

4.2.3.2 Economic Offer Data

The economic Offer data parameters for Generation Resources and DRRs-Type II as identified in Exhibit 1-6 in more detail below.

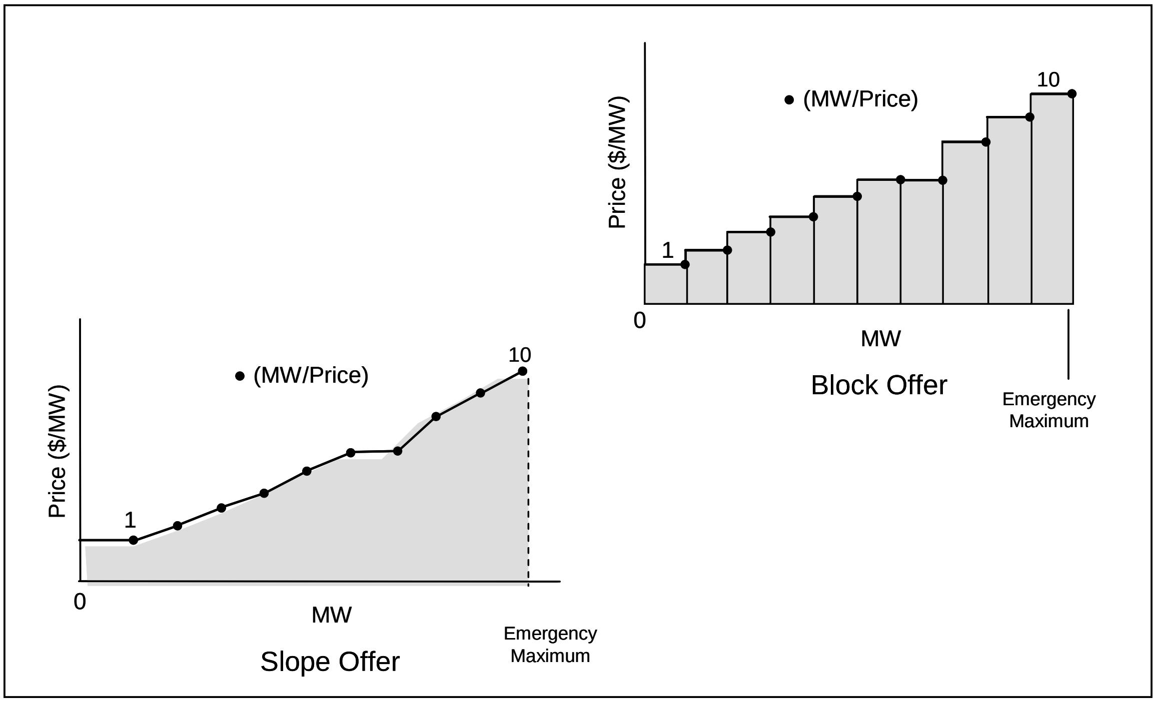
4.2.3.2.1 Energy Offer Curves (MW/Price Pairs)

Energy Offer MW/Price pairs are submitted as part of the Day-Ahead Schedule Offer, Real-Time Schedule Offer, or both. Up to ten MW/Price pairs may be submitted for each hour of the day for the Day-Ahead Energy and Operating Reserve Market and for the Real-Time Energy and Operating Reserve Market. Exhibit 1-8 illustrates the Energy Offer options.

[13] An Offer submitted for use in the Day-Ahead Energy and Operating Reserve Market clearing.

[14] An Offer submitted for use in any RAC process and for use in the Real-Time Energy and Operating Reserve Market clearing within the Operating Hour.

Exhibit 1-8: Types of Energy Offers



The MP may designate whether the MW/Price pairs are considered as a slope or block Offer. The MW values are accepted to the 10th of a MW and the Offer values from -$500 to $1,000. The MW/Price pairs must be monotonically increasing for price and strictly increasing for MW (e.g., 40 MW @ $2.00, 50 MW @ $2.00 are accepted; 40 MW @ $2.00 and 40 MW at $2.50 are not accepted due to the non-increasing MW values; and 40 MW @ $2.00, 50 MW @ $1.50 is not accepted due to the decreasing prices).

There is no connection between the MW/Price pairs for the Day-Ahead and Real-Time Energy and Operating Reserve Markets (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market;. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. Designating the Offer MW/Price pairs as “slope” designates to the dispatch and commitment tools to interpolate a curve from the first MW point to the last MW point submitted. MPs must submit Offer MW/Price pairs for the entire operating range of the Resource up to and including the Hourly Emergency Maximum Limit. If Offer MW/Price pairs are not submitted for any hour for either market, then the values are treated as the quantity zero (0). Generation Resource and DRR-Type II Offer MW/Price pairs are not cumulative, meaning if an MP submits an Offer MW/Price pair of 100 MW at $30 and 200 MW at $40 and the market clears at $40, the Resource clears 200 total MW.

4.2.3.2.2 Regulating Reserve Offers

Generation Resources and DRRs-Type II that are Regulation Qualified Resources may submit Regulating Reserve Offers in two parts: a Regulating Capacity Offer in $/MWh, and a Regulating Mileage Offer, in $/MW (of mileage), for use in the Energy and Operating Reserve Markets. A Regulating Reserve Offer consists of the summation of a Resource's Regulating Capacity Offer and the Resource's Regulating Mileage Offer multiplied by a deployment factor (i.e., Regulating Reserve Offer = Capacity Offer + factor*Mileage Offer). The Regulation Deployment Factor is updated for each calendar Operating Month, based on analysis performed for a one month period ending on the fifteenth of the month prior to the Operating Month. The factor is determined by first calculating the average ratio of deployed Regulating Mileage to cleared Regulating Capacity, averaged across all Resources providing Regulation, for each Dispatch Interval. This average is then multiplied by 12 to convert from average deployments per interval to average deployments per hour. The allowed range for Regulating Reserve Offers is currently -$500.00 to $500.00/MW. As with the Energy Offer Curves, there is no connection between the Regulating Reserve Offers for the Day-Ahead and Real-Time Energy and Operating Reserve Markets (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. If Regulating Reserve Capacity or Mileage prices are not submitted for any hour for either market, then the values are treated as the quantity zero (0).

DRRs-Type II may submit up to three MW/Price pairs for its Regulating Capacity Offer. Similar to Energy Offer Curves, the MP may designate whether the Regulation Offer MW/Price pairs are considered as a slope or block Offer. The MW values are accepted to the 10th of a MW and the Offer values from -$500 to $500. The MW/Price pairs must be monotonically increasing for price and strictly increasing for MW.

4.2.3.2.3 Contingency Reserve Offers

Generation Resources and DRRs-Type II that are Spin Qualified Resources may submit Contingency Reserve Offers in $/MW for use in the Energy and Operating Reserve Markets. The allowed range for Contingency Reserve Offers is currently -$100.00 to $100.00/MW. Generation Resources and DRRs-Type II that are Supplemental Qualified Resources but are not Spin Qualified Resources may submit Supplemental Reserve Offers in $/MW for use in the Energy and Operating Reserve Markets. The allowed range for Supplemental Reserve Offers is currently -$100.00 to $100.00/MW. As with the Energy Offer Curves, there is no connection between the Regulating Reserve, Spinning Reserve or Supplemental Reserve Offers for the Day-Ahead and Real-Time Energy and Operating Reserve Markets (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market;. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. If Operating Reserve Offer prices are not submitted for any hour for either market, then the values are treated as the quantity zero (0).

DRRs-Type II may submit up to three MW/Price pairs for its Contingency Reserve Offers. Similar to Energy Offer Curves, the MP may designate whether the Contingency Reserve Offer MW/Price pairs are considered as a slope or block Offer. The MW values are accepted to the 10th of a MW and the Offer values from -$100 to $100. The MW/Price pairs must be monotonically increasing for price and strictly increasing for MW.

4.2.3.2.4 Start-Up Offers and No-Load Offers

The Cold Start-Up Offer, Intermediate Start-Up Offer and Hot Start-Up Offer may be submitted as part of the default Offer and then overridden on a daily basis for both Day-Ahead and Real-Time Schedule Offers. The No-Load Offer may be submitted as part of the default Offer and then overridden on an hourly basis for both Day-Ahead and Real-Time Schedule Offers. The Start-Up Offer and No-Load Offer are used in conjunction with Energy Offer Curves, Operating Reserve Offers and the Commitment and Dispatch Operating Parameters Offer data in the commitment and dispatch tools to determine the optimum commitment for the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market to meet the Energy and Operating Reserve requirements. The Real-Time Energy and Operating Reserve Market Start-Up Offers and No-Load Offers may be modified at any time prior to 1430 EPT (OD-1) for consideration in the pre Day-Ahead RAC. The Start-Up Offers may be only one value for each type of Start-Up for the day whereas the No-Load Offers may vary for each hour of the day. If a Resource was started more than once per day during the commitment, each start would be considered separately.

4.2.3.3 Commitment Operating Parameter Offer Data

The Resource Offer parameters shown in Exhibit 1-7 associated with the starts, run time, and down time used in Day-Ahead Energy and Operating Reserve Market and RAC commitment and dispatch decisions are described in Exhibit 1-9.

Exhibit 1-9: Generation Resource and DRR-Type II Commitment Offer Parameters

Parameter	Validation	Use
Condition Times	The Hot to Cold Time and the Hot to Intermediate Time can only be submitted as part of the Day-Ahead and Real-Time Schedule Offer. The times are submitted in hh:mm format. The time prior to the Hot to Intermediate Time is considered as Hot.	The Hot to Cold Time and the Hot to Intermediate time are used in evaluating commitment in the Day-Ahead Energy and Operating Reserve Market commitment and the Real-Time Energy and Operating Reserve Market RAC. These parameters determine the Start-Up costs as a function of the unit state.
Start-Up Notification Times	The cold Start-Up Notification Time, intermediate Start-Up Notification Time and hot Start-Up Notification Time parameters are submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in hh:mm format. These values must be less than or equal to 23:59.	The notification times are used in evaluating the commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. These parameters, in conjunction with the associated Start-Up Times establish the time required to start the unit from the applicable unit state of hot, intermediate, or cold.
Start Times	The cold Start-Up Time, intermediate Start-Up Time, and hot Start-Up Time parameters are submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in hh:mm format.	The cold Start-Up Time, intermediate Start-Up Time, and hot Start-Up Time are used in evaluating commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. These parameters, in conjunction with the associated Notification Times establish the time required to start the unit from the applicable unit state of hot, intermediate, or cold.
Minimum Run Time	The Minimum Run Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.	MISO scheduled commitments in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market are for at least as many consecutive hours as specified by Minimum Run Time. Commitment times may be for greater than the Minimum Run Time if a Resource is economic for additional hours.

Parameter	Validation	Use
Minimum Down Time	The Minimum Down Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.	The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market commitments respect the Minimum Down Time in determining when a unit is available for Start-Up.
Maximum Run Time	The Maximum Run Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.	The Maximum Run time restricts the number of hours a unit can be run during the Day-Ahead Energy and Operating Reserve Market or during a study period for the Real-Time Energy and Operating Reserve Market.
Maximum Daily Starts	The Maximum Daily Starts are submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in integer number of times.	The Maximum Daily Starts are the maximum number of times a unit may receive a Start-Up per day during the Day-Ahead Energy and Operating Reserve Market or during a study period of the Real-Time Energy and Operating Reserve Market.
Maximum Daily Energy	The Maximum Daily Energy is submitted as part of the Day-Ahead and Real-Time Schedule Offer, in MWh.	The Maximum Daily Energy is the maximum MWh a Resource is able to supply over a 24 hour period during the Day-Ahead Energy and Operating Reserve Market or during a study period of the Real-Time Energy and Operating Reserve Market.
Maximum Daily Regulation Up Deployment	The Maximum Daily Regulation Up Deployment is submitted as part of the Real-Time Schedule Offer, in MWh, and is only applicable to DRR-Type II resources.	The Maximum Daily Regulation Up Deployment is the maximum MWh a Resource is able to deploy as Regulation Up over a 24 hour Operating Day in the Real-Time Energy and Operating Reserve Market.
Maximum Daily Regulation Down Deployment	The Maximum Daily Regulation Down Deployment is submitted as part of the Real-Time Schedule Offer, in MWh, and is only applicable to DRR-Type II resources.	The Maximum Daily Regulation Down Deployment is the maximum MWh a Resource is able to deploy as Regulation Down over a 24 hour Operating Day in the Real-Time Energy and Operating Reserve Market.
Maximum Daily Contingency Reserve Deployment	The Maximum Daily Contingency Reserve Deployment is submitted as part of the Real-Time Schedule Offer, in MWh, and is only applicable to DRR-Type II resources.	The Maximum Daily Contingency Reserve Deployment is the maximum MWh of Contingency Reserves a Resource is able to deploy as Contingency Reserve over a 24 hour Operating Day of the Real-Time Energy and Operating Reserve Market.

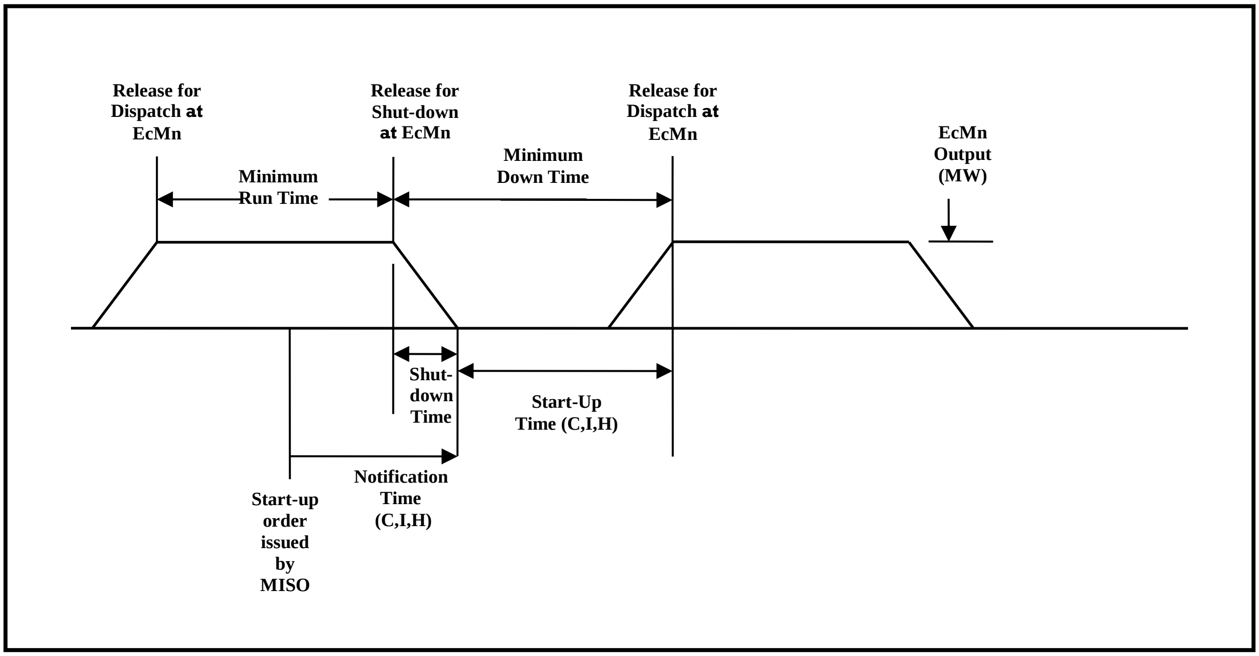
Further explanation of specific Resource parameters used for commitment purposes are provided below along with a graphical representation of how they tie together as depicted in

Exhibit 1-10:

- ***Start-Up Notification Time*** – The amount of notification time required by a Generation Resource prior to the initiation of start-up procedures or the amount of notification time required for a DRR - Type II prior to the initiation of demand reduction procedures. The minimum time required prior to receiving an order from MISO to initiate start-up procedures. Three different Start-Up Notification Times (hot, intermediate, and cold) can be submitted to allow the MP to reflect the difference in the length of time for each condition. For an off-line Quick Start Resource with cleared Contingency Reserve, the Notification Time is assumed to be zero for Contingency Reserve deployment purposes. Submitted notification times cannot exceed 23 hours, 59 minutes.
- ***Start-Up Time*** – The number of hours required to start a Generating Resource or DRR Type - II and synchronize with the MISO Region to Hourly Economic Minimum Limit consistent with the Applicable Reliability Standards. Three different Start-Up Times (hot, intermediate, and cold) can be submitted to allow the MP to reflect the difference in the length of time for each condition. For an off-line Quick Start Resource with cleared Contingency Reserve, the Start-Up Time is assumed to be zero for Contingency Reserve deployment purposes.
- ***Minimum Run Time*** – The minimum number of hours of operation at or above Hourly Economic Minimum Limit that the Resource owner requires MISO to recognize when committing the Resource. The Minimum Run Time applies from the point where the Resource is scheduled to be released for dispatch to MISO from Hourly Economic Minimum Limit to the point where MISO releases the Resource for shut down from Hourly Economic Minimum Limit. MPs should exclude the Start-Up Time and Shut-Down Time (as defined in

- Exhibit 1-10) from the Minimum Run Time to ensure the software recognizes the constraints described by all of the Resource parameters on cycling the Resource in the commitment process. Resources clearing in the DAM or committed in the RAC will have schedules for consecutive hours that are equal to or greater than the Minimum Run Time. For a Quick Start Resource with cleared Contingency Reserve, the Minimum Run Time must be 3 hours or less.
- ***Minimum Down Time*** – The minimum number of hours that the Resource owner requires between the time the Resource is released for shutdown by MISO and the time the Resource is scheduled to be released for dispatch to MISO. MPs should include the Shut-Down Time and the Start-Up Time (as defined in Exhibit 4-9) in the Minimum Down Time to ensure the software recognizes the constraints described by all of the Resource parameters on cycling the Resource in the commitment process. Resources clearing in the DAM or committed in the RAC will have schedules that do not violate the Minimum Down Time.

Exhibit 1-10: Generation Resource & DRR-Type II Operation Timeline



4.2.3.4 Dispatch Operating Parameter Offer Data

The Resource Offer parameters shown in Exhibit 1-7 associated with the Generation Resource and DRR-Type II dispatch used in Day-Ahead Energy and Operating Reserve Market and within the Operating Hour in the Real-Time Energy and Operating Reserve Market are described in the following Subsections.

4.2.3.4.1 Dispatch Limits and Ramp Rates

There are three sets of overall operating limits that can be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer data: Hourly Economic Minimum and Maximum Limits, Hourly Regulation Minimum and Maximum Limits and Hourly Emergency Minimum and Maximum Limits.[15] The Hourly Emergency Maximum Limit must be greater than or equal to the Hourly Economic Maximum Limit, which must be greater than or equal to the Hourly Regulation Maximum Limit, which must be greater than or equal to the Hourly Regulation Minimum Limit, which must be greater than or equal to the Hourly Economic Minimum Limit which must be greater than or equal to the Hourly Emergency Minimum Limit. A DRR-Type II may submit

[15] Dispatchable Intermittent Resources do not submit Hourly Economic, Regulation, or Emergency Maximum Limits as part of the Real-Time Schedule Offer data. See Section 4.2.3.4.2 for more information on DIR Forecast Maximum Limit.

dispatch limits less than zero and cover a negative operating range to reflect an associated load when not providing demand response. Additionally, there are three ramp rate options that can be submitted.

Exhibit 1-11 portrays the relationship between the normal and emergency dispatch limits and normal and Regulation limits.

Exhibit 1-11: Dispatch Limits

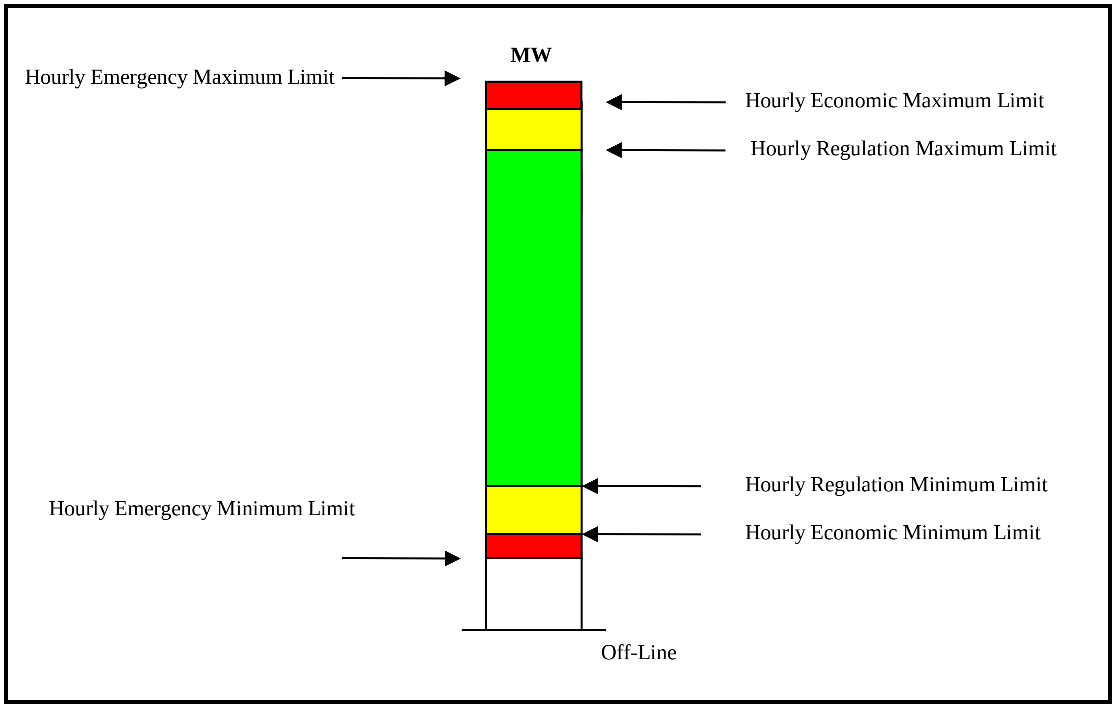


Exhibit 1-12 describes the use and validation of each of the ramp rates and limits.

Exhibit 1-12: Overall Ramp Rate and Limit Use

Limit	Validation	Use
Hourly Bi-Directional Ramp Rate or Bi-Directional Ramp Rate Curve	An Hourly Bi-Directional Ramp Rate may be submitted as part of the Real-Time Schedule Offer to override the default value. A Bi-Directional Ramp Rate Curve may also be submitted as part of the Real-Time Schedule Offer. If the Curve is submitted, it will always override the Hourly value.	The Hourly Bi-Directional Ramp Rate or the Bi-Directional Ramp Rate Curve is only applicable for use in real-time and will apply to Resources scheduled to potentially provide Regulating Reserve to limit the change in Energy Dispatch Target and/or limit the total amount of Operating Reserve that can be cleared on the Resource.
Hourly Single-Directional-Up Ramp-Up or Single-Directional-Up Ramp-Rate Curve	An Hourly Single-Directional-Up Ramp Rate may be submitted as part of the Real-Time Schedule Offer to override the default value. A Single-Directional-Up Ramp Rate Curve may also be submitted as part of the Real-Time Schedule Offer. If the Curve is submitted, it will always override the Hourly value.	The Hourly Single-Directional-Up Ramp Rate or the Single-Directional-Up Ramp Rate Curve is only applicable for use in Real-Time and will apply only to Resources not scheduled to potentially provide Regulating Reserve to limit the change in Energy Dispatch Target in the current Dispatch Interval in the up direction, and/or limit the total amount of Operating Reserve that can be cleared on the Resource. Values submitted for The Hourly Single-Directional-Up Ramp Rate or Single-Directional-Up Ramp Rate Curve must be greater than or equal to the values submitted for the Hourly Bi-Directional Ramp Rate or Bi-Directional Ramp Rate Curve.
Hourly Single-Directional-Down Ramp or Single-Directional-Down Ramp Rate Curve	An Hourly Single-Directional-Down Ramp Rate may be submitted as part of the Real-Time Schedule Offer to override the default value. A Single-Directional-Down Ramp Rate may also be submitted as part of the Real-Time Schedule Offer. If the Curve is submitted, it will always override the Hourly value.	The Hourly Single-Directional-Down Ramp Rate or Single-Directional-Down Ramp Rate Curve is only applicable for use in Real-Time and will apply only to Resources not scheduled to potentially provide Regulating Reserve to limit the change in Energy Dispatch Target in the current Dispatch Interval in the down direction Values submitted for The Hourly Single-Directional-Down Ramp Rate or Single-Directional-Down Ramp Rate Curve must be greater than or equal to the values submitted for the Hourly Single-Directional-Up Ramp Rate or Single-Directional-Up Ramp Rate Curve.
Hourly Ramp Rate	The Hourly Ramp Rate may be submitted as part of the Day-Ahead and Real-Time Schedule Offer to override the default value.	The Hourly Ramp Rate is used in the Day-Ahead Energy and Operating Reserve Market and all RAC processes but not within the Operating Hour.
Hourly Economic Minimum Limit	The Hourly Economic Minimum Limit may be submitted to override the default Offer, for both the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Economic Minimum Limit designates the minimum Energy available, in MW, from the Resource under non-Emergency conditions. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Overall Economic Minimum Limit affects both commitment and dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Energy and Operating Reserve Market dispatch is from

Limit	Validation	Use
		Hourly Economic Minimum Limit to Hourly Economic Maximum Limit under normal conditions.
Hourly Economic Maximum Limit	The Hourly Economic Maximum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Economic Maximum Limit designates the maximum Energy available, in MW, from the Resource under non-Emergency conditions. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Overall Economic Maximum Limit affects both commitment and dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Energy and Operating Reserve Market dispatch is from Hourly Economic Minimum Limit to Hourly Economic Maximum Limit under normal conditions
Hourly Regulation Minimum Limit	The Hourly Regulation Minimum Limit may be submitted to override the default offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Minimum Limit designates the minimum operating level, in MW, at which the Resource can operate while scheduled to potentially provide Regulating Reserves. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Hourly Regulation Minimum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.
Hourly Regulation Maximum Limit	The Hourly Regulation Maximum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Maximum Limit designates the maximum operating level, in MW, at which the Resource can operate while scheduled to potentially provide Regulating Reserves. This value may vary from hour to hour through submission in the Day-ahead Offer and Real-Time Schedule Offer. The Hourly Regulation Maximum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Market.
Hourly Emergency Minimum Limit	The Hourly Emergency Minimum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Emergency Minimum Limit designates the lowest level of energy, in MW, the Resource can produce and maintain a stable level of operation under Emergency conditions.
Hourly Emergency Maximum Limit	The Emergency Maximum may be submitted to override the Default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Emergency Maximum Limit designates the highest level of Energy, in MW, the Resource can produce and maintain a stable level of operation under Emergency conditions.

4.2.3.4.2 DIR Forecast Maximum Limit

Since they are fuel-forecast dependent, Dispatchable Intermittent Resources ("DIRs") do not offer Hourly Regulation, Economic, or Emergency Maximum Limits to the Real-Time Energy and Operating Reserve Markets. Instead, each DIR submits a forecast of its maximum capability in Real-Time, via the MUI.

The participant-generated forecast is submitted on a rolling basis for a single DIR CPNode. The time-points of the data being submitted should align with each of the next twelve UDS interval times: (that is, they should end in 00, 05, 10, 15, 20, 25, 30, 35, 40, 45, 50, or 55). The earliest forecast point being submitted must be less than ten minutes beyond the time at which the data is submitted. For example, if a forecast is being submitted at time 11:27, then the earliest forecast point in the submittal must be either 11:30 or 11:35. If the earliest forecast point in the submittal is 11:40, then the submittal will not be accepted. Requiring the first forecast time to be less than ten minutes from the submittal time ensures that each UDS interval will have an updated forecast for that interval. The forecast submittal allows for submission of at least one and no more than twelve time-quantity pairs per submission. It is important to submit *more than two* data pairs with each forecast submittal. If only two forecast data points are provided with each submittal, it is possible for each submitted forecast to be received too late for MISO to utilize in the five-minute dispatch cycle. Each participant should make a determination of how frequently to submit twelve-part forecasts, given the nature of the fuel-forecast of their DIR. Forecast submissions should be made more frequently than every twenty minutes, since a forecast received more than 30 minutes prior to the UDS interval end-time will not be used, as shown below in the hierarchy for determining the Forecast Maximum Limit[16]:

- Operator Override, as provided by the DIR Resource Asset Owner will be used as the Forecast Maximum Limit;
- If no override is in place, then the Real-Time capability forecast as provided by the DIR Asset Owner, will be used as the Forecast Maximum Limit;
- If the Real-Time capability forecast submitted by the DIR Asset Owner is not provided, or is submitted to the MUI more than 30 minutes prior to the UDS interval end-time, or the value submitted is larger than the Resource's DIR Feasibility limit

[16] For more information regarding the submission of the participant-forecast, please see the *Market User Interface – Participant XML Specification*

times a technical margin, then the Real-Time capability forecast generated by MISO will be used as the Forecast Maximum Limit[17];

- If the Real-Time capability forecast generated by MISO is not provided, or is generated more than 30 minutes prior to the UDS interval end-time, or the value is larger than the Resource's DIR Feasibility limit times a technical margin, then the most recent State Estimated output for the DIR will be used as the Forecast Maximum Limit.

It is expected that a participant-forecast submittal frequency of two and a half to five minutes will be sufficient to adequately capture the changing fuel-forecast of a DIR.

The DIR Feasibility limit described above is submitted by each DIR Asset Owner during the quarterly model process, and is used to validate the quality of each submitted forecast. It is a measure of the maximum potential capability of the DIR at the CP-Node level, taking into account any incremental increases in Resource capability that may take place over the course of a quarterly model. By incorporating a check against this feasibility limit, a faulty submission larger than the feasible maximum will be discarded. MISO will increase each submitted feasibility limit by a small percentage, referred to as the technical margin in the description above, to ensure that only faulty data submissions are discarded in this way. For example: if a Resource with a DIR Feasibility Limit of 100MW submits a forecast of 102MW, the forecast will not be rejected. But if the Resource submits a forecast of 130MW, the forecast will be rejected.

MISO does not generate a Real-Time capability forecast for non-wind DIR Resources. For non-wind DIRs that do not submit a capability limit to be used as the Forecast Maximum Limit, the most recent State Estimated output for the DIR will be used as the Forecast Maximum Limit.

The Real-Time capability forecast generated by MISO is available to the Asset Owner of each wind-fueled DIR and/or Intermittent Resource, via the MUI. The capability forecast is provided to allow each DIR Asset Owner the information necessary to determine whether or not to submit a Real-Time capability forecast, and to allow owners of Intermittent Resources to gauge MISO's capability forecast when considering a transition to Dispatchable Intermittent Resource. For

[17] An option exists, that, when enabled, causes the forecast generated by MISO to be influenced by the State Estimated resource output. That is, if the option is enabled, then the greater of state estimated output and MISO's forecast will be used. This option ONLY affects intervals if activated, and ONLY when the MISO forecast is to be used, and not intervals when the participant-provided forecast is to be used.

more information on accessing the MISO Real-Time forecast, please see the *Market User Interface – Participant XML Specification.*

4.2.3.4.3 Intermittent Resource and DIR Day-Ahead Forecast

For reliability purposes, and in accordance with the Tariff, each Intermittent Resource and Dispatchable Intermittent Resource must submit to the Transmission Provider a Day-Ahead Forecast of its intended output for the next day. The Day-Ahead forecast is not financially binding on the Resource.

MISO provides a non-financially binding DIR and Intermittent Resource Reliability Forecast submittal process through which Asset Owners can submit forecasts of the expected output of their Intermittent Resources and/or DIRs. Day-Ahead Forecasts are communicated to MISO via the MUI, by accessing the “Submit IR Forecast” submittal. Day-Ahead Forecast data must be submitted by 1700EST on the day prior to each Operating Day. For technical information regarding the Day-Ahead reliability forecast, please see the *Market User Interface – Participant XML Specification.*

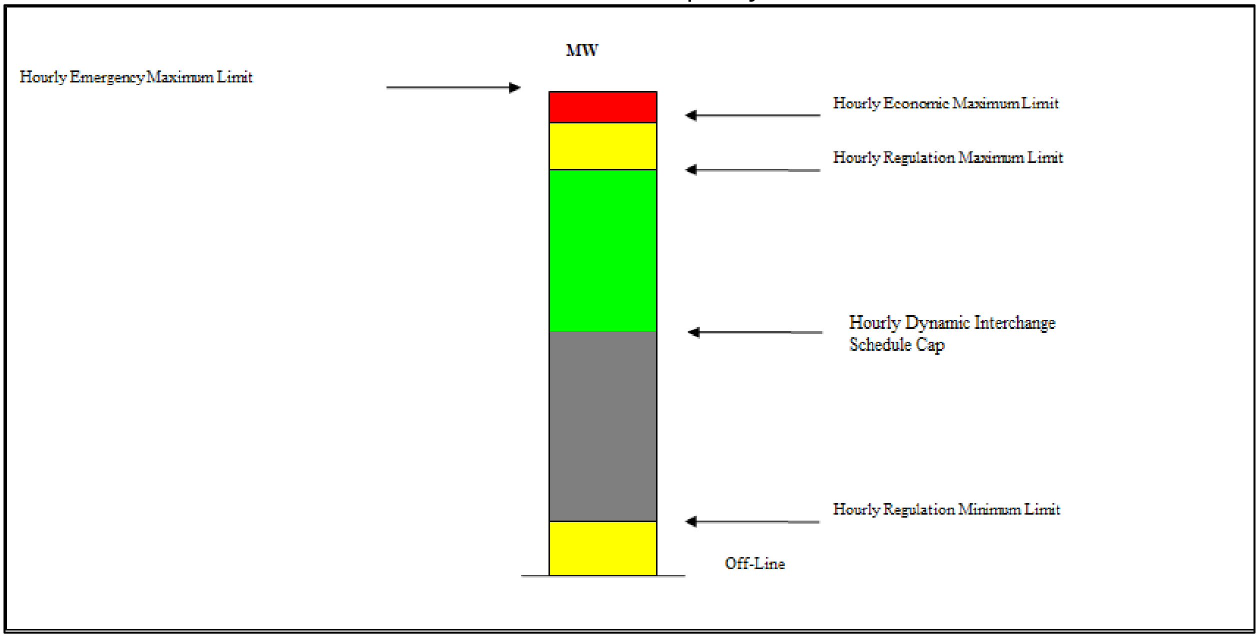
The following processes make use of the Day-Ahead Forecast:

- At the discretion of MISO, the Day-Ahead Forecast may be included in part or in whole into the Next-Day RAC, Multi-Day RAC and Intra-Day RAC study processes.
- For Intermittent Resources and DIRs that are designated as Capacity Resources for Module E purposes, the Day-Ahead Forecast is used to measure the Resource’s daily capacity availability. For more information on this process, see the BPM for *Resource Adequacy*.

4.2.3.4.4 Partial Generation Resources associated with Fixed Dynamic Interchange Schedules

Partial Generation Resources associated with a Fixed Dynamic schedule to an external Balancing Authority (“BA”) may maintain the remaining capacity associated with the Generation Resource within the MISO BA Area. Any portion of a Generation Resource dynamically scheduled to an external BA is not able to provide Ancillary Services to the external BA. Any capacity above the dynamically scheduled energy to an external BA Area is able to offer to provide Ancillary Services within the MISO BA Area.

Exhibit 1-13: Partial Generation Resources MISO Capacity



4.2.3.4.5 Temperature Sensitive Maximum Limits

Temperature sensitive maximum limits specify MW maximum limits for Combustion Turbines ("CTs") and Combined Cycle CTs as a function of temperature. Temperature sensitive limits are composed of both normal temperature sensitive maximum limits and Emergency temperature sensitive maximum limits. Both normal and Emergency temperature sensitive maximum limits are comprised of a day-time temperature forecast (hour ending 0700 EST through hour ending 2200 EST)

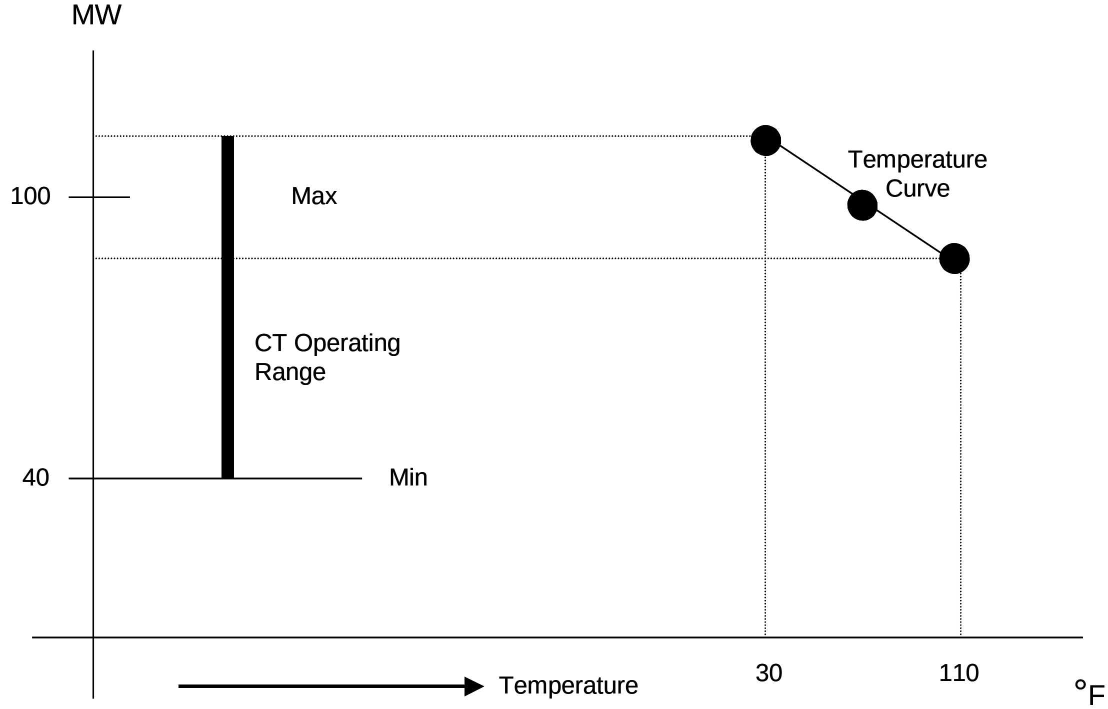
and night-time temperature forecast (hour ending 2300 EST through hour ending 0600 EST) for an MP specified Weather Point and up to three maximum limit points:

- Temperature Sensitive Maximum Limit Low Point
- Temperature Sensitive Maximum Limit Mid Point
- Temperature Sensitive Maximum Limit High Point

An MP may have one or more Weather Points modeled for one or more units, with each unit pointing to only one Weather Point. Only units modeled through the registration process as CTs and Combined Cycle CTs may submit temperature sensitive maximum limits.

Exhibit 1-14 presents an example of the use of temperature sensitive limits.

Exhibit 1-14: Weather Curve Example



4.2.3.4.6 Resource Offer Commitment Status

Both Day-Ahead Schedule Offers and Real-Time Schedule Offers for Generation Resources and DRRs-Type II have an associated Offer commitment status. The commitment status impacts the considerations made in unit commitment. The five commitment statuses for Generation Resources and DRRs-Type II are:

- ***Outage*** – Designates the Resource is not available for consideration in Energy and Operating Reserve Markets commitment because the Resource is on a Generator Planned Outage or Generator Forced Outage.
- ***Emergency*** – Designates the Resource is available for commitment in Emergency situations only.
- ***Economic*** – Designates the Resource is available for commitment by MISO.
- ***Must-Run (self-commit)*** – Designates the Resource as committed per MP request and is available for dispatch by MISO.

- ***Not Participating***[18] – Designates that the Resource will not participate in the Day-Ahead and/or Real-Time Energy and Operating Reserve Market but is otherwise available.

The single value commitment status is submitted via the Day-Ahead Schedule Offer and Real-Time Schedule Offer and will override the default commit status. The default value is set during asset registration.

The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market may commit a unit outside of the hours it has submitted as ”Must-Run” if the unit has an “Economic” status.

4.2.3.4.7 Resource Offer Dispatch Status

Dispatch Status can be selected on an hourly basis for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve on a Resource by Resource basis as part of the Day-Ahead and Real-Time Schedule Offer and such selections will override the default dispatch status values. The default dispatch status values are set during asset registration.

Exhibit 1-15 shows the valid Dispatch Status selections. Dispatchable Intermittent Resources are not eligible to provide Operating Reserves, and therefore, do not provide Dispatch Statuses for Operating Reserve products.

Exhibit 1-15: Valid Dispatch Status Selections

Status	Product				
	Energy	Regulating Reserve	Spinning Reserve	On-Line[19] Supplemental Reserve	Off-line Supplemental Reserve[20]
Economic	√	√	√	√	√

[18] Not available to Resources designated as Capacity Resources for Module E Purposes

[19] Only applies to Resources that are not Spin Qualified Resources, or to Spin Qualified Resources that have selected “Not Qualified” for an Hour, and that are Supplemental Qualified Resources. Based on current reliability standards which do not require Spinning Reserve to be frequency responsive, resources that are synchronized to the system will always be Spin Qualified Resources.

[20] Only applicable to uncommitted Quick-Start Resources.

Status	Product				
	Energy	Regulating Reserve	Spinning Reserve	On-Line[19] Supplemental Reserve	Off-line Supplemental Reserve[20]
Self-Schedule	√	√	√	√	√
Emergency	N/A	N/A	N/A	N/A	√
Not Qualified	N/A	√	√[21]	√	√
Not Participating	N/A	√	N/A	N/A	√[22]

The five valid Dispatch Status selections and rules associated with each are as follows. The default value is set during asset registration.

- **Economic –** Designates that Generation Resources or DRRs-Type II that have been committed are available for dispatch by MISO and Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve may be calculated for the Resource. For Generation Resources and DRRs-Type II that are Quick-Start Resources that have not been committed, only the selection for Off-Line Supplemental Reserve would apply.
- **Self-Schedule –** Indicates that the product is Self-Scheduled. The MW amounts of the Self-Schedules for Energy, Regulating Reserve, Spinning Reserve or Supplemental Reserve will be indicated as part of the Day-Ahead Schedule Offer or Real-Time Schedule Offer.
- **Not Qualified –** Indicates that Resource is not qualified to provide Regulating Reserve, Spinning Reserve, On-Line Supplemental Reserve and/or Off-Line Supplemental Reserve in an Hour. This status is only selected in the event of a physical Resource restriction that prevents the otherwise qualified Resource from providing the service in that Hour.

[21] Can only be selected if Regulating Reserve "Not Qualified" status is selected and Resource cannot meet reliability standards relating to provision of Spinning Reserve. Based on current reliability standards which do not require Spinning Reserve to be frequency responsive, resources that are synchronized to the system will always be Spin Qualified Resources.

[22] Not available to Resources designated as Capacity Resources for Module E purposes.

- **Not Participating –** Indicates that the Resource has elected not to provide either Regulating Reserve of Off-Line Supplemental Reserve in an Hour but is otherwise available to provide the service.
- **Emergency –** This option is only available to Generation Resources and DRRs-Type II that are Quick-Start Resources. Selection of this status option indicates that the Resource will be cleared for Off-Line Supplemental Reserve only in an Emergency.

4.2.3.4.8 Ramp Capability Dispatch Status

Ramp Capability Dispatch Status can be selected on an hourly basis on a Resource by Resource basis as part of the Day-Ahead and Real-Time Schedule Offer and such selections will override the default dispatch status values. The default dispatch status values are set during asset registration. The two valid Ramp Capability Dispatch Status selections and rules associated with each are as follows. The default value is set during asset registration.

- **Economic –** Designates that Generation Resources or DRRs-Type II that have been committed are available for ramp capability by MISO.
- **Not Participating –** Designates that Generation Resources or DRRs-Type II are not participating for ramp capability and won't be committed or dispatched to meet ramp needs.

4.2.3.4.9 Resource Self-Schedule

MPs may submit Self-Schedules, which consist of a fixed quantity (in MW) of Energy, Regulating Reserve and Spinning Reserve or On-Line Supplemental Reserve[23] per hour that may be dispatched from the Resource if it is on-line. In addition, an MP with a Quick-Start Resource may choose to Self-Schedule Off-Line Supplemental Reserve from that Resource.

- To submit a Self-Schedule for Energy, the MP submits a Resource Self-Schedule MW value for Energy and sets Energy Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the Resource's Hourly Economic Maximum Limit, the Resource may be dispatched above the Self-Schedule MW amount, based upon the Resource's Energy Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing and dispatch process.
- To submit a Self-Schedule for Regulating Reserve, the MP submits a Resource Self-Schedule MW value for Regulating Reserve and sets the Regulating Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the

[23] If not a Spin Qualified Resource.

Resource's Regulating Reserve capability, the Resource may clear Regulating Reserve above the Self-Schedule MW amount, based upon the Resource's Regulating Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process. The maximum amount of Regulating Reserve that can be self-scheduled on a Resource is equal to the lesser of i) the applicable bi-directional ramp rate multiplied by the Regulation Response Time or ii) the difference between the applicable regulation maximum limit and regulation minimum limit divided by 2. The Self-Schedule MW value shall be relaxed if necessary to enforce Resources limits or ramp rates and may be relaxed if necessary to manage transmission congestion, the Sub-Regional Power Balance constraint, supply Energy and/or meet Operating Reserve requirements.

- To submit a Self-Schedule for Spinning Reserve or On-Line Supplemental Reserve, the MP submits a Resource Self-Schedule MW value for Spinning Reserve or On-Line Supplemental Reserve and sets the Spinning Reserve Dispatch Status or On-Line Supplemental Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the Resource's Spinning Reserve or On-Line Supplemental Reserve capability, the Resource may clear Spinning Reserve or On-Line Supplemental Reserve above the Self-Schedule MW amount, based upon the Resource's Spinning Reserve Offer or On-Line Supplemental Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process. The maximum amount of Contingency Reserve that can be self-scheduled on an on-line Resource is equal to the lesser of i) the applicable ramp rate multiplied by the Contingency Reserve Deployment Period or ii) the difference between the applicable maximum limit and minimum limit. The Self-Schedule MW value shall be relaxed if necessary to enforce Resources limits or ramp rates and may be relaxed if necessary to manage transmission congestion, the Sub-Regional Power Balance constraint, supply Energy and/or meet Operating Reserve requirements.
- Self-Schedules for Off-Line Supplemental Reserve can only be submitted for an uncommitted Quick-Start Resource that is a Supplemental Qualified Resource. To submit a Self-Schedule for Off-Line Supplemental Reserve, the MP submits a Resource Self-Schedule MW value for Off-Line Supplemental Reserve and sets the Off-Line Supplemental Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the Resource's Maximum Off-Line Response Limit, the Resource may clear Off-Line Supplemental Reserve above the Self-Schedule MW amount, based upon the Resource's Off-Line Supplemental Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing

process. The maximum amount of Supplemental Reserve that can be self-scheduled on an off-line Resource is equal to the lesser of i) the Maximum Off-Line Response Limit or ii) the applicable economic maximum limit of the Resource. The Self-Schedule MW value shall be relaxed if it becomes necessary to commit the Resource.

In all cases, the minimum amount of Self-Schedule MW for Energy, Regulating Reserve, Spinning Reserve or Supplemental Reserve is equal to 1 MW, with the exception of Self-Scheduled Energy for DRR-Type II resources. A DRR-Type II may self-schedule Energy MW less than zero in its negative operating range.

Submitting a Self-Schedule value does not guarantee the unit is committed; the MP must designate the commitment status as “Must-Run” to achieve this result. A Self-Schedule is a price taker up to Self-Schedule MW level. Any amounts cleared above Self-Scheduled amounts are eligible to set price.

Submitted Self-Schedules will be reduced by MISO if such submitted schedules cannot be physically implemented based upon submitted Resource limits and ramp rates. Additionally, MISO may reduce accepted Self-Schedules as necessary to manage transmission constraints, the Sub-Regional Power Balance Constraint, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will the Transmission Provider violate the Resource limits or ramping capabilities.

4.2.4 Demand Response Resources-Type I (“DRR-Type I”) Offer Requirements

The following Subsection describes the economic and operational Offer data for DRRs-Type I and how these data are used in commitment and dispatch decisions.

4.2.4.1 Offer Information Summary

DRR-Type I Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

Exhibit 1-16 identifies the data that may be included in a DRR-Type I Offer and the markets in which they apply.

Exhibit 1-16: DRR-Type I Offer Data Summary

DRR-Type I Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Economic Offer Data				
Energy Offer	$/MWh	Hourly	Hourly	2
Hourly Curtailment Offer	$/hr	Hourly	Hourly	2
Shut-Down Offer	$	Daily	Daily	2
Spinning Reserve Offer	$/MW	Hourly	Hourly	1, 2
Supplemental Reserve Offer	$/MW	Hourly	Hourly	1, 2
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly	1
Self-Scheduled Supplemental Reserve	MW	Hourly	Hourly	1
Commitment and Dispatch Operating Parameter Offer Data				
Targeted Demand Reduction Level	MW	Hourly	Hourly	2, 3
Minimum Interruption Duration	hh:mm	Daily	Daily	3
Maximum Interruption Duration	hh:mm	Daily	Daily	3
Minimum Non-Interruption Interval	hh:mm	Daily	Daily	3
Shut-Down Time	hh:mm	Hourly	Hourly	3
Shut-Down Notification Time	hh:mm	Hourly	Hourly	3
Energy Commitment Status	Select	Hourly	Hourly	
Spinning Reserve Dispatch Status	Select	Hourly	Hourly	1
Supplemental Reserve Dispatch Status	Select	Hourly	Hourly	1
Maximum Daily Contingency Reserve Deployment	MWh	NA	Daily	1

Note 1: If qualified.
Note 2: The Targeted Demand Reduction is valid for the indicated hour. A DRR-Type I resource is capable of delivering this full reduction or no reduction, i.e., intermediate values are infeasible.
Note 3: Default Offers are used if no values are submitted for the day.

MISO maintains a Day-Ahead Energy and Operating Reserve Market Offer and a Real-Time Energy and Operating Reserve Market Resource Offer for each DRR-Type I. These Offers are standing offers and are maintained for each market independently of the other. Updates to DRR-Type I Offers may be designated as updating the Day-Ahead Energy and Operating Reserve Market Offer only, the Real-Time Energy and Operating Reserve Market Offer only, or both. If a submittal update is not received prior to the applicable Offer submittal timelines, the previous Offer data is in place and used unless otherwise removed or set to “Unavailable”.

4.2.4.2 Economic Offer Data

The economic Offer data parameters for a DRR-Type I as identified in

Exhibit 1-16 are described in more detail below.

4.2.4.2.1 Energy Offer

An Energy Offer in $/MWh is submitted as part of the Day-Ahead Schedule Offer, Real-Time Schedule Offer, or both. A single value may be submitted for each hour of the day for the Day-Ahead Energy and Operating Reserve Market and for the Real-Time Energy and Operating Reserve Market that represents an Energy Offer at the Targeted Demand Reduction Level. The $/MWh Offer values may range from -$500 to $1,000.

There is no connection between the Energy Offer for the Day-Ahead and Real-Time Energy and Operating Reserve Market (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market;. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. If Energy Offers are not submitted for any hour for either market, then the values are treated as the quantity zero (0).

4.2.4.2.2 Shut-Down Offers and Hourly Curtailment Offers

The Shut-Down Offer may be submitted as part of the default Offer and then overridden on a daily basis through submission of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The Hourly Curtailment Offer may be submitted on an hourly basis through submission of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The Real-Time Offer Shut-Down Offers and Hourly Curtailment Offers may be modified at any time prior to 1430 EPT (OD-1) for consideration in the pre Day-Ahead RAC. The Shut-Down Offers may be only one value for the day whereas the Hourly Curtailment Offers may vary for each hour of the day. If a DRR-Type I was shut down more than once per day during the commitment, each shut down would be considered separately.

4.2.4.2.3 Operating Reserve Offers

DRRs-Type I that are Spin Qualified Resources may submit Spinning Reserve Offers for use in the Energy and Operating Reserve Markets. DRRs-Type I that are Supplemental Qualified Resources may submit Supplemental Reserve Offers for use in the Energy and Operating Reserve Markets. Along with asset registration Spinning and Supplemental Reserve qualifications and Spinning and Supplemental Reserve Dispatch Statuses, the choice of DRR-Type I Contingency Reserve Status will determine whether the Resource will be eligible to clear Spinning Reserves or Supplemental Reserves in the Day-Ahead and Real-Time markets. The allowed range for Contingency Reserve Offers is currently -$100.00 to $100.00. If a DRR-Type I is committed for Energy, it cannot provide Spinning Reserve or Supplemental Reserve. If Operating Reserve Offer prices are not submitted for any hour for either market, then the values are treated as the quantity zero (0).

DRRs-Type I may submit up to three MW/Price pairs for each operating reserve product which includes Spinning Reserves and Supplemental Reserves. Similar to Energy Offer Curves, the MP may designate whether the Contingency Reserve Offer MW/Price pairs are considered as a slope or block Offer. The MW/Price pairs must be monotonically increasing for price and strictly increasing for MW.

4.2.4.3 Commitment and Dispatch Operating Parameter Offer Data

The Resource Offer parameters used in Day-Ahead Energy and Operating Reserve Market and RAC commitment and dispatch decisions are shown in Exhibit 1-17.

Exhibit 1-17: DRR -Type I Offer Parameters

Parameter	Validation	Use
Shut-Down Notification Time	The Shut-Down Notification Time parameter is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. These times are accepted in hh:mm format. The default value is 00:00. This value cannot exceed 23:59.	The Shut-Down Notification Time is used in evaluating the commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
Shut-Down Time	The Shut-Down Time parameter is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format.	The Shut-Down Time is used in evaluating commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Notification Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
Minimum Interruption Duration	The Minimum Interruption Duration is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format.	MISO schedule commitments in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market are for at least as many consecutive hours as specified by Minimum Interruption Duration. Commitment times may be for greater than the Minimum Interruption Duration if a DRR -Type I is economic for additional hours.

Parameter	Validation	Use
Minimum Non-Interruption Interval	The Minimum Non-Interruption Interval is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format. The default value is 00:00.	The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market commitments respect the Minimum Non-Interruption Interval in determining when a DRR -Type I is available for shut down.
Maximum Interruption Duration	The Maximum Interruption Duration is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format. The default value is 99:99.	The Maximum Interruption Duration restricts the number of consecutive hours a DRR -Type I can be committed during the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market.
Contingency Reserve Status	The Contingency Reserve Status is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. Valid entries for Contingency Reserve Status are “online” and “offline”.	The Contingency Reserve Status determines whether the DRR – Type I will be considered to clear and deploy Spinning Reserves, or whether it will be considered to clear and deploy Supplemental Reserves.. See Sections 0 and 8.2.9 for more information on the Contingency Reserve Status.
Maximum Daily Contingency Reserve Deployment	The Maximum Daily Contingency Reserve Deployment is submitted as part of the Real-Time Schedule Offer, in MWh.	The Maximum Daily Contingency Reserve is the maximum MWh a Resource is able to deploy as Contingency Reserve over a 24 hour Operating Day of the Real-Time Energy and Operating Reserve Market.

Further explanation of specific DRR -Type I parameters used for commitment purposes is provided below along with a graphical representation of how they tie together as depicted in

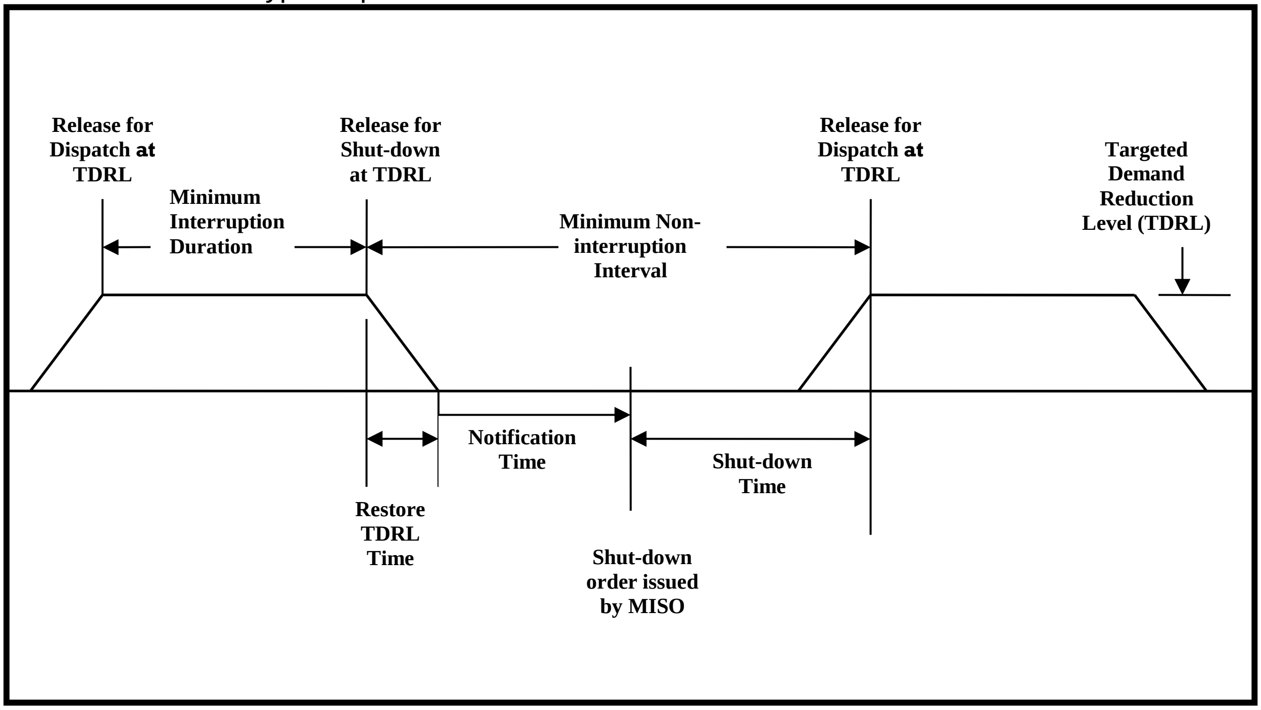
Exhibit 1-18:

- ***Shut-Down Notification Time*** **–** The minimum time required from the time an order is received from MISO to the time demand reduction procedures can be initiated. This value must be less than or equal to 23 hours, 59 minutes.
- ***Shut-Down Time*** – The total time required from the time demand reduction procedures begin to the time the DRR -Type I has reduced demand equal to the Targeted Demand Reduction Level.
- ***Minimum Interruption Duration*** – The minimum number of hours at the Targeted Demand Reduction Level that the DRR-Type I owner requires MISO to schedule when committing the Resource or when deploying Contingency Reserve on that Resource. The Minimum Interruption Duration applies from the point where the DRR-Type I has reduced consumption by the Targeted Demand Reduction Level to the point where MISO releases the DRR-Type I for de-commitment. MPs should exclude the Shut-Down Time and Restore TDRL Time (as defined in

- Exhibit 1-18) from the Minimum Interruption Duration to ensure the software recognizes the constraints described by all of the DRR-Type I parameters on cycling the Resource in the commitment process. DRR-Type I clearing in the Day-Ahead Energy and Operating Reserve Market or committed in the RAC will have schedules for consecutive hours that are equal to or greater than the Minimum Interruption Duration.
- ***Minimum Non-Interruption Interval*** – The minimum number of hours that the DRR-Type I owner requires between the time the DRR-Type I is released to restore the Targeted Demand Reduction Level by MISO and the time the DRR-Type I can again reduce consumption equal to the Targeted Demand Reduction Level. MPs should include the Restore TDRL Time (as illustrated in

- Exhibit 1-18) and the Shut-Down Time in the Minimum Non-interruption Interval to ensure the software recognizes the constraints described by all of the DRR-Type I parameters on cycling the Resource in the commitment process. DRRs-Type I clearing in the Day-Ahead Energy and Operating Reserve Market or committed in the RAC will have schedules that do not violate the Minimum Non-Interruption Interval.

Exhibit 1-18: DRR-Type I Operation Timeline



4.2.4.3.1 DRR-Type I Commitment Status

Both a Day-Ahead Schedule Offer and Real-Time Schedule Offer have an associated DRR-Type I commitment status. The commitment status impacts the considerations made in unit commitment. The three commitment statuses are:

- ***Not Participating*** – Designates the DRR-Type I is not available for Energy commitment in the Energy and Operating Reserve Markets for that Hour but could be available for Contingency Reserve clearing depending on the Spinning Reserve or Supplemental Reserve Dispatch Status. For a DRR – Type I that is designated as a Capacity Resource for Module E purposes, the Not Participating Commitment Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.
- ***Emergency*** – Designates the DRR-Type I is available for commitment for Energy in Emergency situations only.
- ***Economic*** – Designates the DRR-Type I is available for commitment for Energy by MISO.

The single value commitment status can vary by hour in the Day-Ahead Schedule Offer or Real-Time Schedule Offer and will override the default status. The default status is set during asset registration.

4.2.4.3.2 DRR-Type I Offer Dispatch Status

- Dispatch Status for a DRR-Type I can be selected on an hourly basis for Spinning Reserve, if the DRR-Type I is a Spin Qualified Resource and Supplemental Reserve if the DRR-Type I is a Supplemental Qualified Resource. Spinning Reserve or Supplemental Reserve Dispatch Status selections made in combination with Commitment Status selections allow a DRR-Type I to choose whether or not they are committed for Energy only or dispatched for Spinning Reserve or Supplemental Reserve only, as applicable, under both normal and Emergency conditions. Valid Dispatch Status selections for a DRR-Type I are: Economic, Self-Schedule, Emergency, Not Qualified or Not Participating. For a DRR – Type I that is designated as a Capacity Resource for Module E purposes, the Not Participating Spinning Reserve Dispatch Status or Supplemental Reserve Dispatch Status may only be selected if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

Exhibit 1-19 shows the valid Dispatch Status and Commit Status selection combinations to achieve the desired results. Dispatch status may be selected as part of the Day-Ahead and Real-Time Schedule Offer and will override the default status. The default status value is set during asset registration.

Exhibit 1-19: Valid DRR-Type I Commit and Dispatch Status Combinations

Commit Status	Spin or Supp Dispatch Status	Normal Operations				Emergency Operations[24]			
		Energy Only	Spin or Supp Reserve Only	Either	None	Energy Only	Spin or Supp Reserve Only	Either	None
Economic	Economic			√				√	
Economic	Not Participating	√				√			
Economic	Not Qualified	√				√			
Economic	Self-Schedule		√[25]				√[22]		
Economic	Emergency	√					√[22]		
Not Participating	Economic		√				√		
Not Participating	Not Participating				√				√
Not Participating	Not Qualified				√				√
Not Participating	Self-Schedule		√				√		
Not Participating	Emergency						√		
Emergency	Economic		√[26]			√			
Emergency	Not Participating					√			
Emergency	Not Qualified					√			
Emergency	Self-Schedule		√[22]			√			
Emergency	Emergency							√	

(Note 22 - Not available to Resources designated as Capacity Resources for Module E Purposes)

[24] Emergency Operations are initiated after all capacity that has not been designated as Emergency has been committed and prior to the declaration of an EEA 1.

[25] If not committed for Energy.

[26] If not committed for Energy during an Emergency.

4.2.4.3.3 DRR-Type I Contingency Reserve Status

The DRR – Type I Contingency Reserve Status is used to determine whether the Resource will be cleared and deployed in the same manner as on-line Spinning or Supplemental Reserves, or in the same manner as Off-Line Supplemental Reserves, when clearing and deploying Contingency Reserves.

If a Spin-Qualified DRR – Type I Resource selects “online” as its Contingency Reserve Status, its Spinning Reserve Offer will be considered against all other Resources offering Spinning Reserves, and any Reserves cleared on the Resource will be cleared as Spinning Reserves. If deployed, Resource commitment periods will not be considered SCUC-Instructed Hours of Operation, as defined in the Tariff.

If a DRR – Type I Resource that is Supplemental-Qualified, but not Spin-Qualified selects “online”, its Supplemental Reserve Offer will be considered against all other Resources offering Supplemental Reserves, and any Reserves cleared on the Resource will be cleared as Supplemental Reserves. If deployed, Resource commitment periods will not be considered SCUC-Instructed Hours of Operation, as defined in the Tariff.

If a DRR – Type I Resource selects “offline” as its Contingency Reserve Status, its Supplemental Reserve Offer will be considered against all other Resources offering Supplemental Reserves, and any Reserves cleared on the Resource will be cleared as Supplemental Reserves. If deployed, Resource commitment periods will not be considered SCUC-Instructed Hours of Operation, as defined in the Tariff.

Section 8.2.9 contains details on the Contingency Reserve Deployment methodology with respect to a DRR – Type I Resource’s choice of Contingency Reserve Status.

4.2.4.3.4 DRR-Type I Self-Schedule

DRRs-Type I can only submit Self-Schedules for Spinning Reserve or Supplemental Reserve in amounts less than or equal to the Targeted Demand Reduction Level. Submitting a Self-Schedule for Spinning Reserve or Supplemental Reserve will guarantee that the DRR-Type I clears for Contingency Reserve provided that the DRR-Type I has not been committed for Energy, and the Contingency Reserve Status matches the Self-Schedule. If the Self-Schedule MW value is less than the Targeted Demand Reduction Level, the Resource may clear Spinning Reserve or Supplemental Reserve above the Self-Schedule MW amount, based upon the DRR-Type I Spinning Reserve Offer or Supplemental Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process. A Self-Schedule is a price taker up to Self-Schedule MW level. Any amounts cleared above Self-Scheduled amounts are eligible to set price.

Submitted Self-Schedules will be reduced by MISO if such submitted schedules cannot be physically implemented based upon submitted Targeted Demand Reduction Level. Additionally, MISO may reduce accepted Self-Schedules as necessary to manage transmission constraints, the Sub-Regional Power Balance constraint, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will the Transmission Provider violate the DRR-Type I Targeted Demand Reduction Level.

4.2.5 External Asynchronous Resources (“EAR”) Offer Requirements

The following Subsection describes the economic and operational Offer data for EARs and how these data are used in commitment and dispatch decisions.

4.2.5.1 Offer Information Summary

EAR Offers consist of data submitted by MPs for consideration in dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

Exhibit 1-20 identifies the data that may be included in an EAR Offer and the markets in which they apply.

Exhibit 1-20: External Asynchronous Resource Offer Data Summary

EAR Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Economic Offer Data				
Energy Offer Curve	MW, $/MWh	Hourly	Hourly	9
Regulating Reserve Offer	$/MW	Hourly	Hourly	1
Spinning Reserve Offer	$/MW	Hourly	Hourly	1
Supplemental Reserve Offer	$/MW	Hourly	Hourly	1,6
Self-Scheduled Regulating Reserve	MW	Hourly	Hourly	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly	1
Self-Scheduled Supplemental Reserve	MW	Hourly	Hourly	1,6
Self-Scheduled Energy	MW	Hourly	Hourly	
Dispatch Operating Parameter Offer Data				
Hourly Economic Minimum Limit (Export)	MW	Hourly	Hourly	2,8
Hourly Economic Maximum Limit (Import)	MW	Hourly	Hourly	2,8
Hourly Regulation Minimum Limit	MW	Hourly	Hourly	2
Hourly Regulation Maximum Limit	MW	Hourly	Hourly	2, 8
Hourly Emergency Minimum Limit (Export)	MW	Hourly	Hourly	2
Hourly Emergency Maximum Limit (Import)	MW	Hourly	Hourly	2, 8
Availability Status	Select	Hourly	Hourly	2, 7
Energy Dispatch Status	Select	Hourly	Hourly	2
Regulating Reserve Dispatch Status	Select	Hourly	Hourly	2
Spinning Reserve Dispatch Status	Select	Hourly	Hourly	2
Supplemental Reserve Dispatch Status	Select	Hourly	Hourly	2,6
Hourly Single-Directional-Down Ramp Rate	MW/min	Hourly	Hourly	2,4
Hourly Single-Directional-Up Ramp Rate	MW/min	Hourly	Hourly	2,4
Hourly Bi-Directional Ramp Rate	MW/min	Hourly	Hourly	2,4
Hourly Ramp Rate	MW/min	Hourly	Hourly	2,3,4
Ramp Capability Dispatch Status	Select	Hourly	Hourly	

Note 1: If qualified.
Note 2: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets.
Note 3: Hourly Ramp Rate is used in Day-Ahead and RAC only.
Note 4: Ramp rates may be submitted by MPs at any time and remain fixed until changed by MPs.
Note 6: Only applies if EAR is a Supplemental Qualified Resource and not a Spin Qualified Resource.
Note 7: If the EAR is available, a Tag identifying the associated Fixed Dynamic Interchange Schedule must be entered in webTrans in order for the EAR to be considered for clearing by DART.
Note 8: Clearing limited to lesser of this value or “schedulemax” specified on Import/Export Tag.
Note 9: EAR Energy Offer Curve may include negative MW and/or negative price pairs

MISO maintains a Day-Ahead Energy and Operating Reserve Market Offer and a Real-Time Energy and Operating Reserve Market Resource Offer for each EAR. These Offers are standing Offers and maintained for each market independently of the other. Updates to EAR Offers may be designated as updating the Day-Ahead Energy and Operating Reserve Market Offer only, the Real-Time Energy and Operating Reserve Market Offer only, or both. If a submittal update is not received prior to the applicable Offer submittal timelines, the previous Offer data is in place and used unless otherwise removed or set to “Unavailable”.

Offers for EARS may be removed from either Energy and Operating Reserve Market by setting the Offer to “Unavailable”.

The following two Subsections describe the Economic Offer Data and the Dispatch Operating Data Offer Parameters specified in

Exhibit 1-20 in more detail.

4.2.5.2 Economic Offer Data

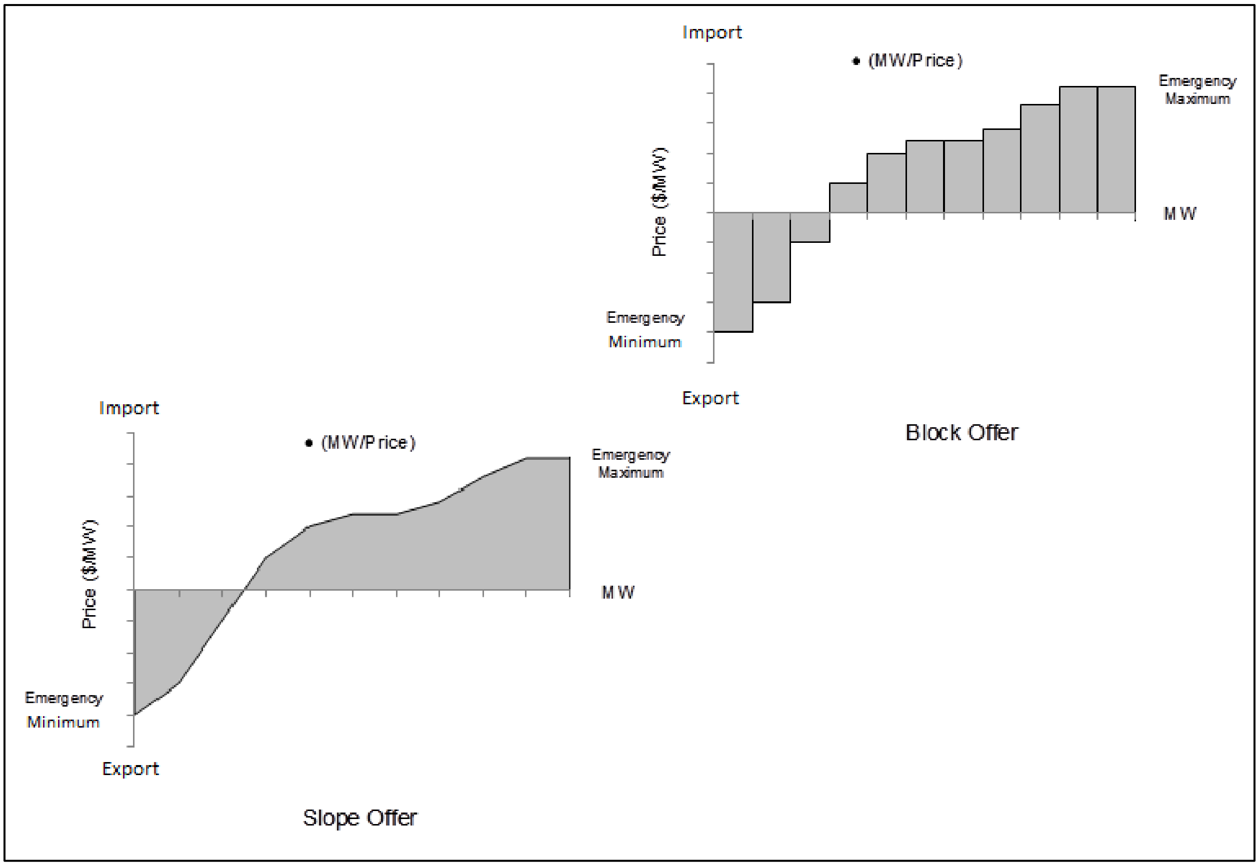
The economic Offer data parameters for EARs as identified in

Exhibit 1-20 are described in more detail below.

4.2.5.2.1 Energy Offer Curves (MW/Price Pairs)

Energy Offer MW/Price pairs are submitted as part of the Day-Ahead Schedule Offer, Real-Time Schedule Offer, or both. Up to ten MW/Price pairs may be submitted for each hour of the day for the Day-Ahead Energy and Operating Reserve Market and for the Real-Time Energy and Operating Reserve Market. Exhibit 1-21 illustrates the Energy Offer options.

Exhibit 1-21: Types of EAR Energy Offers



The MP may designate whether the MW/Price pairs are considered as a slope or block Offer. The MW values are accepted to the 10th of a MW and the Offer values from -$500 to $1,000. The MW/Price pairs must be monotonically increasing for price and strictly increasing for MW (e.g., 40 MW @ $2.00, 50 MW @ $2.00 is accepted; 40 MW @ $2.00 and 40 MW at $2.50 is not accepted due to the non-increasing MW values; and 40 MW @ $2.00, 50 MW @ $1.50 is not accepted due to the decreasing prices).

There is no connection between the MW/Price pairs for the Day-Ahead and Real-Time Energy and Operating Reserve Markets (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market;. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. Designating the Offer MW/Price pairs as “slope” designates to the dispatch and commitment tools to interpolate a curve from the first MW point to the last MW point submitted. MPs must submit Offer MW/Price pairs for the entire operating range of the EAR up to and including the Hourly Emergency Maximum Limit for importing into MISO, and down to and including Hourly Emergency Minimum Limit for exporting out of MISO. If Offer MW/Price pairs are not submitted for any hour for either market, then the values are treated as the quantity zero (0). EAR Offer MW/Price pairs are not cumulative, meaning if an MP submits an Offer MW/Price pair of 100 MW at $30 and 200 MW at $40 and the market clears at $40, the Resource clears 200 total MW. The Energy Offer Curve for EAR may include negative MW and/or negative price pairs.

4.2.5.2.2 Operating Reserve Offers

EARs that are Regulation Qualified Resources may submit Regulating Reserve Offers for use in the Energy and Operating Reserve Markets. The allowed range for Regulating Reserve Offers is currently -$500.00 to $500.00. EARs that are Spin Qualified Resources may submit Spinning Reserve Offers for use in the Energy and Operating Reserve Markets. The allowed range for Spinning Reserve Offers is currently -$100.00 to $100.00. EARs that are Supplemental Qualified Resources but are not Spin Qualified Resources may submit Supplemental Reserve Offers for use in the Energy and Operating Reserve Markets. The allowed range for Supplemental Reserve Offers is currently -$100.00 to $100.00. If Operating Reserve Offer prices are not submitted for any hour for either market, then the values are treated as the quantity zero (0).

4.2.5.3 Dispatch Operating Parameter Offer Data

The Resource Offer parameters associated with the External Asynchronous Resource dispatch used in Day-Ahead Energy and Operating Reserve Market and within the Operating Hour in the Real-Time Energy and Operating Reserve Market are described in the following Subsections.

4.2.5.3.1 Dispatch Limits and Ramp Rates

There are six operating limits that can be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer data: Hourly Economic Minimum and Maximum Limit, Hourly Regulation Minimum and Maximum Limits and Hourly Emergency Minimum and Maximum Limit. The Hourly Emergency Maximum Limit must be greater than or equal to the Hourly Economic Maximum Limit, which must be greater than or equal to the Hourly Regulation Maximum Limit, which must be greater than or equal to Hourly Economic Minimum Limit, which must be greater than or equal to Hourly Emergency Minimum Limit. Hourly Economic Minimum Limit and Hourly Emergency Minimum Limit must be equal to or less than zero. Maximum and Regulation Minimum Limits may be positive or negative. Ramp rate curves are not applicable to EARs. EARs are dispatched using the Hourly Ramp Rate in the Day-Ahead Energy and Operating Reserve Market and any RAC process. EARs are dispatched using the Hourly Bi-Directional Ramp Rate, Hourly Single-Directional Up Ramp Rate or Hourly Single-Directional Down Ramp Rate within the Operating Hour in the Real Time Energy and Operating Reserve Market.

Exhibit 1-22 portrays the relationship between the EAR dispatch limits.

Exhibit 1-22: EAR Dispatch Limits

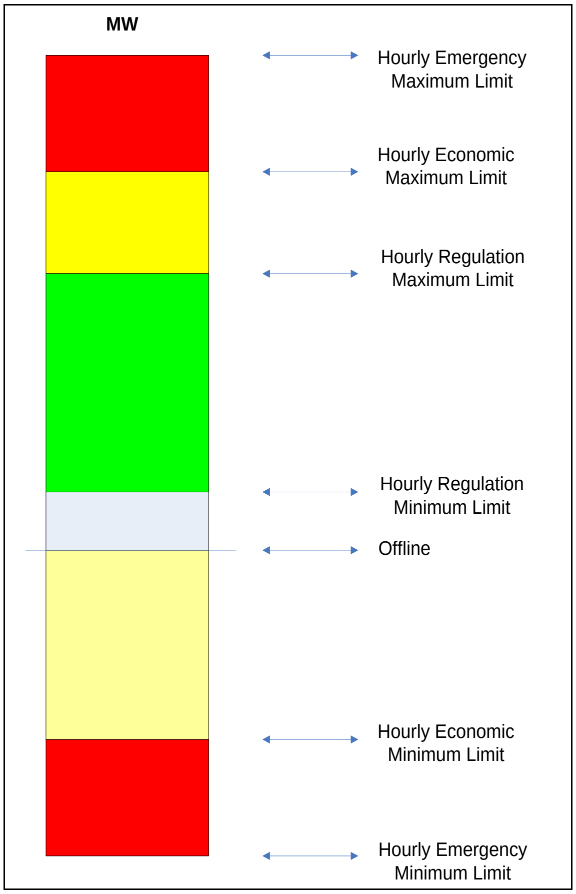


Exhibit 1-23 describes the use and validation of each of the limits and ramp rates.

Exhibit 1-23: EAR Overall Limit and Ramp Rate Use

Limit	Validation	Use
Hourly Bi-Directional Ramp Rate	The Hourly Bi-Directional Ramp Rate may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default offer.	The Hourly Bi-Directional Ramp Rate is only applicable for use in real-time and will apply to EARs scheduled to potentially provide Regulating Reserve to limit the change in Energy Dispatch Target and/or limit the total amount of Operating Reserve that can be cleared on the Resource.
Hourly Single-Directional-Up Ramp Rate	The Single-Directional-Up Ramp Rate may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer.	The Single-Directional-Up Ramp-Up Rate is only applicable for use in Real-Time and will apply only to EARs not scheduled to potentially provide Regulating Reserves to limit the change in Energy Dispatch Target in the current Dispatch Interval in the up direction, and/or limit the total amount of Operating Reserve that can be cleared on the Resource. Values submitted for The Hourly Single-Directional-Up Ramp Rate must be greater than or equal to the values submitted for the Hourly Bi-Directional Ramp Rate.
Hourly Single-Directional-Down Ramp Rate	The Single-Directional-Down Ramp Rate may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer.	The Single-Directional-Down Ramp Rate is only applicable for use in Real-Time and will apply only to EARs not scheduled to potentially provide Regulating Reserves to limit the change in Energy Dispatch Target in the current Dispatch Interval in the down direction. Values submitted for The Hourly Single-Directional-Down Ramp Rate must be greater than or equal to the values submitted for the Hourly Single-Directional-Up Ramp Rate.
Hourly Ramp Rate (single value)	The Hourly Ramp Rate may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer.	The Hourly Ramp Rate for EARs is used in the Day-Ahead Energy and Operating Reserve Market and all RAC processes.
Hourly Economic Minimum Limit	The Hourly Economic Minimum Limit may be submitted as part of the Day-Ahead Schedule Offer or Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Economic Minimum Limit designates the highest MW level available from the EAR under non-Emergency conditions while exporting out of MISO. This value may vary from hour to hour through submitting the Hourly Economic Minimum Limit in the Real-Time Schedule Offer. The Hourly Economic Minimum Limit may be limited by the Schedule Max[27] value associated with the required Fixed Dynamic Interchange Export Schedules if the absolute value of Schedule Max is less than the submitted Hourly Economic Minimum Limit. The export limit will be indicated by negative polarity in

[27] The Schedule Max value represents the schedule value from webTrans.

Limit	Validation	Use
		the EAR Schedule Offer.
Hourly Economic Maximum Limit	The Hourly Economic Maximum Limit may be submitted as part of the Day-Ahead Schedule Offer or Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Economic Maximum Limit designates the highest MW level available from the EAR under non-Emergency conditions while importing into MISO. This value may vary from hour to hour through submitting the Hourly Economic Maximum Limit in the Real-Time Schedule Offer. The Hourly Economic Maximum Limit may be limited by the Schedule Max[28] value associated with the required Fixed Dynamic Interchange Import Schedules if the Schedule Max is less than the submitted Hourly Economic Maximum Limit.
Hourly Regulation Minimum Limit	The Hourly Regulation Minimum Limit may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Minimum Limit designates the minimum operating level, in MW, at which the EAR can operate while scheduled to potentially provide Regulating Reserves while importing into MISO or exporting out of MISO. This value may vary from hour to hour through submission in the Real-Time Schedule Offer. The Hourly Regulation Minimum Limit may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Market. The Hourly Regulation Minimum Limit may be limited by the Schedule Max[29] value associated with the required Fixed Dynamic when exporting.
Hourly Regulation Maximum Limit	The Hourly Regulation Maximum Limit may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Maximum Limit designates the maximum operating level, in MW, at which the EAR can operate while scheduled to potentially provide Regulating Reserves while importing into MISO or exporting out of MISO. This value may vary from hour to hour through submission in the Real-Time Schedule Offer. The Hourly Regulation Minimum Limit may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The Hourly Regulation Maximum Limit may be limited by the Schedule Max[30] value associated with the required Fixed Dynamic
Hourly Emergency Maximum Limit	The Hourly Emergency Maximum Limit may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Emergency Maximum Limit designates the highest level of Energy, in MW, the EAR can produce and maintain a stable level of operation under Emergency conditions while importing into MISO or exporting out of MISO. This value may vary from hour to hour through submission in the Real-Time Schedule Offer. The Hourly Regulation Maximum Limit may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and

28 The Schedule Max value represents the schedule value from webTrans.

29 The Schedule Max value represents the schedule value from webTrans.

30 The Schedule Max value represents the schedule value from webTrans.

Limit	Validation	Use
		Operating Reserve Markets. The Hourly Emergency Maximum Limit may be limited by the Schedule Max value associated with the required Fixed Dynamic Interchange Import Schedules if the Schedule Max is less than the submitted Hourly Emergency Maximum Limit.
Hourly Emergency Minimum Limit	The Hourly Emergency Minimum Limit may be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer that will override the default Offer. The data value accepted may be to the tenth of a MW.	The Hourly Emergency Minimum Limit designates the highest level of Energy, in MW, the EAR can consume and maintain a stable level of operation under Emergency conditions while exporting out of MISO. The Hourly Emergency Minimum Limit may be limited by the Schedule Max value associated with the required Fixed Dynamic Interchange Export Schedules if the absolute value of Schedule Max is less than the submitted Hourly Emergency Minimum Limit. The export limit will be indicated by negative polarity in the EAR Schedule Offer.

4.2.5.3.2 EAR Offer Availability Status

The EAR Availability Status is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer and will override the default value. Valid Availability Status selections are: Available and Unavailable. If the Available Status is selected, the EAR is available to provide Energy and Operating Reserve. If the Unavailable Status is selected, the EAR is not available to provide Energy or Operating Reserve. The default value is set during asset registration.

4.2.5.3.3 EAR Offer Dispatch Status

Dispatch Status can be selected on an hourly basis for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve on a Resource by Resource basis as part of the Day-Ahead and Real-Time Schedule Offer that will override the default values. EAR Dispatch Status is only applicable if EAR Availability Status is set to “Available”.

Exhibit 1-24 shows the valid Dispatch Status selections.

Exhibit 1-24: Valid EAR Dispatch Status Selections

Status	Product			
	Energy	Regulating Reserve	Spinning Reserve	Supplemental Reserve
Economic	√	√	√	√[31]
Self-Schedule	√	√	√	√[22]
Not Qualified		√	√	√
Not Participating		√		

(Note 22 - Not available to Resources designated as Capacity Resources for Module E Purposes)

The four valid Dispatch Status selections and rules associated with each are as follows. The default values are set during asset registration.

- **Economic –** Designates that EAR is available for dispatch by MISO and Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve may be calculated for the EAR.
- **Self-Schedule –** Indicates that the product is Self-Scheduled. The MW amounts of the Self-Schedules for Energy, Regulating Reserve, Spinning Reserve or Supplemental Reserve will be indicated as part of the Day-Ahead Schedule Offer or Real-Time Schedule Offer.
- **Not Participating –** This option is only available for Regulating Reserve and indicates that the EAR is otherwise qualified and available to provide Regulating Reserve but has elected not to provide the service in that Hour.
- **Not Qualified –** Indicates that the EAR cannot physically provide Regulating Reserve, Spinning Reserve or Supplemental Reserve in that Hour.

4.2.5.3.4 EAR Offer Self-Schedule

MPs may submit Self-Schedules, which consist of a fixed quantity (in MW) of Energy, Regulating Reserve, Spinning Reserve and/or Supplemental Reserve[32] per hour that may be dispatched from the EAR.

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[31] Only if not a Spin Qualified Resource or "Not Qualified" Spinning Reserve Dispatch Status has been selected.

- To submit a Self-Schedule for Energy, the MP submits a Resource Self-Schedule MW value for Energy and sets Energy Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the EAR's Hourly Economic Maximum Limit, the EAR may be dispatched above the Self-Schedule MW amount, based upon the EAR's Energy Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing and dispatch process.
- To submit a Self-Schedule for Regulating Reserve, the MP submits a Resource Self-Schedule MW value for Regulating Reserve and sets the Regulating Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the EAR's Regulating Reserve capability, as determined by the submitted Hourly Bi-Directional Ramp Rate and Regulation Response Time, the EAR may clear Regulating Reserve above the Self-Schedule MW amount, based upon the EAR's Regulating Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process.
- To submit a Self-Schedule for Spinning Reserve, the MP submits a Resource Self-Schedule MW value for Spinning Reserve and sets the Spinning Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the EAR's Spinning Reserve capability, as determined by the applicable ramp rate and the Contingency Reserve Deployment Period, the EAR may clear Spinning Reserve above the Self-Schedule MW amount, based upon the EAR's Spinning Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process.
- Self-Schedules for Supplemental Reserve can only be submitted for an EAR that is not a Spin Qualified Resource or the "Not Qualified" Spinning Reserve Dispatch Status has been selected. To submit a Self-Schedule for Supplemental Reserve, the MP submits a Self-Schedule MW value for Supplemental Reserve and sets the Supplemental Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the EAR's Supplemental Reserve capability, as determined by the applicable ramp rate and the Contingency Reserve Deployment Period, the EAR may clear Supplemental Reserve above the Self-Schedule MW amount, based upon the EAR's Supplemental Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process.

[32] If not a Spin Qualified Resource or "Not Qualified" Spinning Reserve Dispatch Status has been selected.

In all cases, the minimum amount of Self-Schedule MW for Energy, Regulating Reserve, Spinning Reserve or Supplemental Reserve is equal to 1 MW. A Self-Schedule is a price taker up to Self-Schedule MW level. Any amounts cleared above Self-Scheduled amounts are eligible to set price.

Submitted Self-Schedules will be reduced by MISO if such schedules cannot be physically implemented based upon submitted Resource limit and ramp rates. Additionally, MISO may reduce accepted Self-Schedules as necessary to manage transmission constraints, the Sub-Regional Power Balance Constraint, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will the Transmission Provider violate the Resource limits or ramping capabilities.

4.2.5.3.5 EAR Ramp Capability Dispatch Status

Ramp Capability Dispatch Status can be selected on an hourly basis on a Resource by Resource basis as part of the Day-Ahead and Real-Time Schedule Offer and such selections will override the default dispatch status values. The default dispatch status values are set during asset registration. The two valid Ramp Capability Dispatch Status selections and rules associated with each are as follows. The default value is set during asset registration.

- **Economic –** Designates that EARs that have been committed are available for ramp capability by MISO.
- **Not Participating –** Designates that EARs are not participating for ramp capability and won't be committed or dispatched to meet ramp needs.

4.2.6 Stored Energy Resource Offer

The following Subsection describes the economic and operational Offer data for SERs and how these data are used in commitment and dispatch decisions.

4.2.6.1 Offer Information Summary

Stored Energy Resource Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Exhibit 1-25 and Exhibit 1-26 identify the data that may be included in a Stored Energy Resource Offer and the markets in which they apply.

Exhibit 1-25: Stored Energy Resource Economic Data Summary

Stored Energy Resource Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Economic Offer Data				
Regulating Reserve Offer	$/MW	Hourly	Hourly	
Self-Scheduled Regulation	MW	Hourly	N/A	1

Note 1: Real-Time Schedule Offer Regulation Self-Schedule is Not Available, as Stored Energy Resources are not eligible to submit Self-Schedule Regulation Offers to the Real-Time Market

Exhibit 1-26: Stored Energy Resource Operating Parameter Data Summary

Stored Energy Resource Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Commitment Operating Parameter Offer Data				
Commitment Status	Select	Hourly	Hourly	1
Dispatch Operating Parameter Offer Data				
Regulating Reserve Dispatch Status	Select	Hourly	Hourly	1
Hourly Regulation Minimum Limit	MW	Hourly	Hourly	1
Hourly Regulation Maximum Limit	MW	Hourly	Hourly	1
Hourly Maximum Energy Storage Level	MWh	Hourly	Hourly	1
Hourly Maximum Energy Charge Rate	MWh/min	Hourly	Hourly	1
Hourly Maximum Energy Discharge Rate	MWh/min	Hourly	Hourly	1
Hourly Bi-Directional Ramp Rate	MW/min	N/A	Hourly	1,3
Hourly Ramp Rate	MW/min	Hourly	Hourly	1,2,3
Hourly Energy Storage Loss Rate	MWh/min	Hourly	Hourly	1
Hourly Full Charge Energy Withdrawal Rate	MWh/min	Hourly	Hourly	1

Note 1: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets
Note 2: Hourly Ramp Rate is used in Day-Ahead and RAC
Note 3: Ramp Rates may be submitted by MPs at any time and remain fixed until changed by MPs

MISO maintains a Day-Ahead Schedule Offer[33] and a Real-Time Schedule Offer[34] for each Stored Energy Resource. These Offers are standing Offers and maintained for each market independently of the other. Updates to Stored Energy Resource Offers may be designated as updating the Day-Ahead Schedule Offer only, the Real-Time Schedule Offer only, or both.

The following subsections describe the Economic Offer Data and the Commitment and Dispatch Operating Data Offer Parameters specified in Exhibit 1-25 in more detail.

[33] An Offer submitted for use in the Day-Ahead Energy and Operating Reserve Market clearing.

[34] An Offer submitted for use in any RAC process and for use in the Real-Time Energy Operating Reserve Market clearing within the Operating Hour.

4.2.6.2 Economic Offer Data

The economic Offer data parameters for Stored Energy Resources as identified in Exhibit 1-26are described in more detail below.

4.2.6.2.1 Regulating Reserve Offers

All Stored Energy Resources are registered as Regulation Qualified Resources, and may submit Regulating Reserve Offers in $/MW for use in the Energy and Operating Reserve Markets. The allowed range for Regulating Reserve Offers is currently -$500.00 to $500.00/MW. There is no connection between the Regulating Reserve Offers for the Day-Ahead and Real-Time Energy and Operating Reserve Markets (i.e., Day-Ahead Schedule Offers only roll over to the next Day-Ahead Energy and Operating Reserve Market;. Day-Ahead Schedule Offers do not roll over into the Real-Time Energy and Operating Reserve Market and vice-versa.). A data submission to one hour of the Day-Ahead Energy and Operating Reserve Market does not affect the same hour for the Real-Time Energy and Operating Reserve Market and vice-versa. If Regulating Reserve Offer prices are not submitted for any hour for either market, the values are treated as the quantity zero (0).

4.2.6.3 Dispatch Operating Parameter Offer Data

The Stored Energy Resource Offer parameters shown in Exhibit 1-26associated with the Stored Energy Resource dispatch used in Day-Ahead Energy and Operating Reserve Market and within the Operating Hour in the Real-Time Energy and Operating Reserve Market are described in the following Subsections.

4.2.6.3.1 Dispatch Limits and Ramp Rates

One set of operating limits can be submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer data: Hourly Regulation Minimum and Maximum Limits. The Hourly Regulation Maximum Limit must be greater than or equal to the Hourly Regulation Minimum Limit. Stored Energy Resources utilize the Hourly Ramp Rate for use in the Day-Ahead Market, and the Bi-Directional Ramp Rate for use in the Real-Time Market.

Exhibit 1-27 describes the use and validation of each of the ramp rates and limits.

Exhibit 1-27: SER Overall Ramp Rate and Limit Use

Limit	Validation	Use
Hourly Bi-Directional Ramp Rate	An Hourly Bi-Directional Ramp Rate may be submitted as part of the Real-Time Schedule Offer to override the default value.	The Hourly Bi-Directional Ramp Rate is only applicable for use in real-time and will apply to all Stored Energy Resources to limit the change in Energy Dispatch Target and/or limit the total amount of Regulating Reserve that can be cleared on the Resource.
Hourly Ramp Rate	The Hourly Ramp Rate may be submitted as part of the Day-Ahead and Real-Time Schedule Offer to override the default value.	The Hourly Ramp Rate is used in the Day-Ahead Energy and Operating Reserve Market and all RAC processes but not within the Operating Hour.
Hourly Regulation Minimum Limit	The Hourly Regulation Minimum Limit may be submitted to override the default offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Minimum Limit designates the minimum operating level, in MW, at which the Resource can operate.. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Hourly Regulation Minimum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.
Hourly Regulation Maximum Limit	The Hourly Regulation Maximum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.	The Hourly Regulation Maximum Limit designates the maximum operating level, in MW, at which the Stored Energy Resource can operate. This value may vary from hour to hour through submission in the Day-ahead Offer and Real-Time Schedule Offer. The Hourly Regulation Maximum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Market.
Hourly Maximum Energy Charge Rate	The Hourly Maximum Energy Charge Rate may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MWh/min.	The Hourly Maximum Energy Charge Rate designates the maximum rate, in MWh/min (proportional to a MW quantity), at which the energy storage level of a Stored Energy Resource can increase. The Hourly Maximum Energy Charge Rate does not affect commitment but may affect Energy dispatch and/or Regulating Reserve dispatch in the Real-Time Energy and Operating Reserve Market, or the Regulating Reserve dispatch in the Day-Ahead Energy and Operating Reserve Market.
Hourly Maximum Energy Discharge Rate	The Hourly Maximum Energy Discharge Rate may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MWh/min.	The Hourly Maximum Energy Discharge Rate designates the maximum rate, in MWh/min (proportional to a MW quantity), at which the energy storage level of a Stored Energy Resource can decrease. The Hourly Maximum Energy Discharge Rate does not affect commitment but may affect Energy dispatch and/or Regulating Reserve dispatch in the Real-Time Energy and Operating Reserve Market, or the Regulating Reserve dispatch in the Day-

Limit	Validation	Use
		Ahead Energy and Operating Reserve Market.
Hourly Maximum Energy Storage Level	The Hourly Maximum Energy Storage Level may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MWh.	The Hourly Maximum Energy Storage Level, in MWh, designates the maximum level to which a Stored Energy Resource can be charged. The Hourly Maximum Energy Storage Level does not affect commitment but may affect Energy dispatch and/or Regulating Reserve dispatch in the Real-Time Energy and Operating Reserve Market.
Hourly Energy Storage Loss Rate	The Hourly Energy Storage Loss Rate may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MWh/min.	The Hourly Energy Storage Loss Rate, in MWh/min (proportional to a MW quantity), designates the rate at which energy must be consumed to maintain a Stored Energy Resource at its Maximum Energy Storage Level.
Hourly Full Charge Energy Withdrawal Rate	The Hourly Full Charge Energy Withdrawal Rate may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MWh/min.	The Hourly Full Charge Energy Withdrawal Rate, in MWh/min (proportional to a MW quantity), designates the rate at which a Stored Energy Resource can continue to absorb energy while the storage level is at the Resource's Maximum Energy Storage Level.

Further explanation of specific Stored Energy Resource parameters used for dispatching purposes is provided below:

- ***Maximum Energy Charge Rate*** – The maximum rate at which the energy storage level of a Stored Energy Resource can increase. Expressed in MWh/min, this rate is proportional to a power level expressed using the units 'MW'. The Maximum Energy Charge Rate is respected in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets; the more restrictive of the Maximum Energy Charge Rate and the Hourly Regulation Minimum Limit is used to establish a lower bound for the available power level (in MW) of the Resource.
- ***Maximum Energy Discharge Rate*** – The maximum rate at which the energy storage level of a Stored Energy Resource can decrease. Expressed in MWh/min, this rate is proportional to a power level expressed using the units 'MW'.. The Maximum Energy Discharge Rate is respected in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets; the more restrictive of the Maximum Energy Discharge Rate and the Hourly Regulation Maximum Limit is used to establish an upper bound for the available power level (in MW) of the Resource.
- ***Maximum Energy Storage Level*** – The maximum energy storage level of a Stored Energy Resource, expressed in MWh. When a Stored Energy Resource's storage level is at its Maximum Energy Storage Level, the Stored Energy Resource can no longer charge, and ignoring the Full Charge Energy Withdrawal Rate, can only have

an output greater than 0MW. Similarly, when a Stored Energy Resource's storage level is at 0MWh storage, the Stored Energy Resource can no longer discharge, and can only have an output less than 0MW.

- ***Energy Storage Loss Rate*** – The rate at which energy must be consumed to maintain a Stored Energy Resource at its Maximum Energy Storage Level. Expressed in MWh/min, this rate is proportional to a power level expressed using the units 'MW'. The Energy Storage Loss Rate models the losses inherent in energy storage.
- ***Full Charge Energy Withdrawal Rate*** – The rate at which energy can be consumed by a Stored Energy Resource when its storage level is equal to its Maximum Energy Storage Level. Expressed in MWh/min, this rate is proportional to a power level expressed using the units 'MW'. The Full Charge Energy Withdrawal Rate models additional facilities, such as resistor banks, integrated into a Stored Energy Resource, that allow the Resource to continue consuming energy while its storage level is equal to its Maximum Energy Storage Level.

4.2.6.3.2 Stored Energy Resource Offer Availability Status

The Stored Energy Resource Availability Status is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer and will override the default value. Valid Availability Status selections are: Available and Unavailable. If the Available Status is selected, the SER is available to provide Regulating Reserve. If the Unavailable Status is selected, the SER is not available to provide Regulating Reserve. The default value is set during asset registration.

4.2.6.3.3 Stored Energy Resource Self-Schedule

MPs may submit Self-Schedules to the Day-Ahead Market only, which consist of a fixed quantity (in MW) of Regulating Reserve per hour that may be dispatched from the Resource.

- To submit a Self-Schedule for Regulating Reserve, the MP submits a Resource Self-Schedule MW value for Regulating Reserve and sets the Regulating Reserve Dispatch Status to Self-Schedule. If the Self-Schedule MW value is less than the Resource's Regulating Reserve capability, the Resource may clear Regulating Reserve above the Self-Schedule MW amount, based upon the Resource's Regulating Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process. The maximum amount of Regulating Reserve that can be self-scheduled on a Resource is equal to the lesser of i) the applicable bi-directional ramp rate multiplied by the Regulation Response Time or ii) the lesser of the absolute value of the regulation maximum limit, the regulation minimum limit, the maximum energy charge rate expressed in MW, and the maximum energy discharge rate expressed in MW. The Self-Schedule MW value shall be relaxed if necessary to enforce Resources limits or ramp rates.

In all cases, the minimum amount of Self-Schedule MW for Regulating Reserve is equal to 1 MW.

Submitting a Self-Schedule value does not guarantee the Resource is committed; the MP must designate the commitment status as "Available" to achieve this result. A Self-Schedule is a price taker up to Self-Schedule MW level. Any amounts cleared above Self-Scheduled amounts are eligible to set price.

4.2.7 Emergency Demand Response

The Emergency Demand Response ("EDR") provisions are designed to encourage parties that have demand response capabilities, other than those registered as DRRs – Type I or DRRs – Type II, to offer such capabilities for use by MISO during specified Emergency conditions. Such demand response capabilities include Market Participants that are able to either reduce Load during Emergency conditions (e.g., through existing demand response programs) or to operate back-up generation resources (also referred to as "behind-the-meter" generation) to the same effect. For further information regarding the submission of EDR Offer data please refer to the EDR Participant XML Specification.

During an EEA2 event, EEA3 event, Transmission System Emergency and/or Local Transmission Emergency, MISO can issue an EDR Dispatch Instruction which will contain details regarding when the demand reduction will begin, the demand reduction amount, and necessary duration of the demand reduction. Further information regarding the commitment and EDR Dispatch Instruction communication will be provided in a Real Time Operating Procedure prior to the issuance of an EDR Dispatch Instruction. EDR Participants that reduce demand in response to an EDR Dispatch Instruction will be compensated the greater of Real-Time LMP or the EDR Offer Cost for the amount of verifiable demand reduction provided. EDR Participants that do not sufficiently reduce demand in response to an EDR Dispatch Instruction will receive a penalty.

For further information regarding the submission of EDR Demand Reduction data, Emergency Demand Reduction Make Whole Payment, and Emergency Demand penalty provisions please refer to the Emergency Demand Reduction section of Attachment C of the BPM for *Market*

Settlements. For further information regarding the Registration of Emergency Demand Response Resource please refer to the Emergency Demand Response section of the BPM for *Market Registration*.

Offer Data:

Once an EDR has been submitted and validated via the EDR registration process, EDR offers can be submitted. The EDR Offer data must contain the following Offer Data parameters:

- Commercial Pricing Node Name
- Emergency Demand Response Name
- Effective Date, representing the first day of the month for which the monthly offer is valid
- Minimum Reduction Megawatt value
- Maximum Reduction Megawatt value
- Minimum Reduction Time in Hours
- Maximum Reduction Time in Hours
- Reduction Notification Time in Hours
- Shut Down Cost in dollars, representative of the cost to reduce
- Reduction Offer in dollars per MWh

For further information regarding the validation and format of the EDR offer data, please refer to the EDR Participant XML Specification.

4.2.8 Resource Operating Parameter Limitations

The following limitations prevent changing Resource Operating Parameters to result in forced commitments and/or forced costs to the system.

- If the initial conditions for a Day-Ahead, RAC, or LAC study are such that a Resource is on-line, and the initial commitment period is a Must-Run commitment period, then the Minimum Run Time of the Resource is set to 0 for the study interval.
- If the initial conditions for a Day-Ahead, RAC, or LAC study are such that a Resource is on-line, and the initial commitment period is an Economic commitment period, then the Minimum Run Time of the Resource is set to the lesser of the offered Minimum Run Time at the time the commitment was made, and the Minimum Run Time as offered for the study interval.
- During Day-Ahead, RAC, and LAC studies, if the offers for Must-Run Commit Status violate the offered Minimum Run-Time (or Minimum Interruption Duration, for a

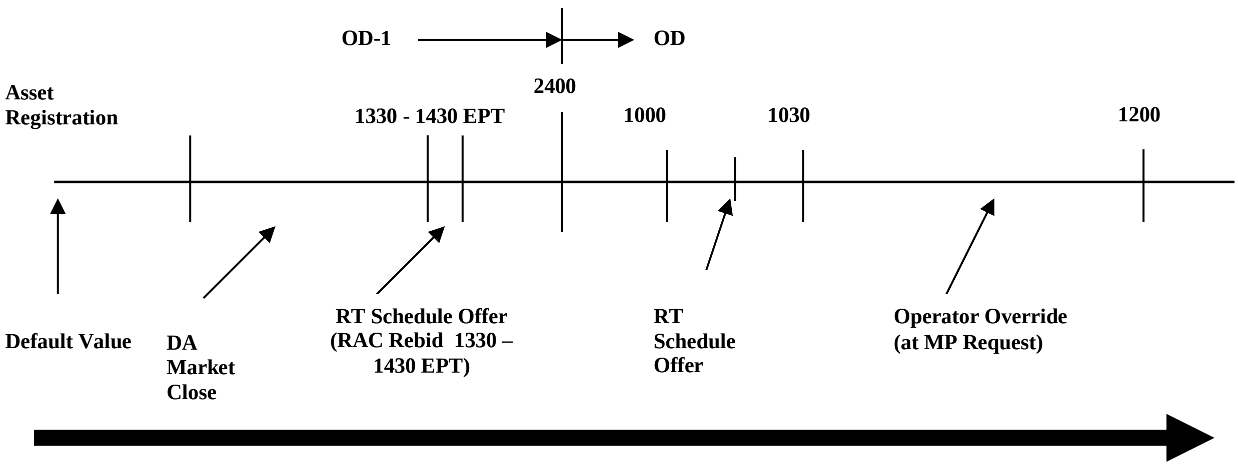
Demand Response Resource), then the Minimum Run-Time (or Minimum Interruption Duration) will be set to zero for the study interval. As an example, if the Minimum Run Time of a resource is three hours, and a segment of hourly commit status offers consist of: Economic, Must-Run, Must-Run, Economic; then the set of offers violates the offered Minimum Run Time.

- During Day-Ahead, RAC, and LAC studies, if the offers for Must-Run Commit Status violate the offered Minimum Down Time (or Minimum Non-Interruption Interval, for a Demand Response Resource), then the Minimum Down Time (or Minimum Non-Interruption Interval) will be set to zero for the study interval. As an example, if the Minimum Down Time of a resource is three hours, and a segment of hourly commit status offers consist of: Must-Run, Economic, Economic, Must-Run; then the set of offers violates the offered Minimum Down Time.
- During Day-Ahead, RAC, and LAC studies, if the offers for Must-Run Commit Status violate the offered Maximum Daily Starts (or Maximum Daily Interruptions, for a Demand Response Resource), then the Maximum Daily Starts (or Maximum Daily Interruptions) will be set to 99 for the study interval. As an example, if the Maximum Daily Starts of a resource is 1 per day, and a segment of hourly commit status offers consist of: Must-Run, Economic, Economic, Must-Run; then the set of offers violates the offered Maximum Daily Starts.

4.2.9 Resource Offer Hierarchy

Exhibit 1-28 presents the hierarchy of the data associated with Real-Time Resource Offers. Each data source starting at the right with Operator overrides supersedes the data source to the left, ending at the far left with default data. Submitted Day-Ahead Schedule Offer data will always override the Day-Ahead Schedule Offer default values.

Exhibit 1-28: Real-Time Resource Offer Hierarchy (all time in EST unless noted otherwise)



Submission times are governed by the following rules:

- Default values for Resource limits, ramp rates and other non-price related Offer parameters are submitted during the asset registration process for the both the Day-Ahead Schedule Offer and Real-Time Schedule Offer and may be changed at any time by the MP.
- Temperature sensitive maximum limits and daily Resource parameters may be submitted up to seven days prior to the Operating Day and until 1030 EPT on OD-1 when the Day-Ahead Energy and Operating Reserve Market closes.
- Hourly Resource parameters may be submitted up to seven days prior to and until 1030 EPT on OD-1 when the Day-Ahead Energy and Operating Reserve Market closes for use in the Day-Ahead Energy and Operating Reserve Market. Real Time Hourly offers for the next OD may not be submitted during DA Market Clearing (1030 to 1330 EPT). Hourly offers for the next OD may again be submitted during the re-bid period for use in the RAC processes from 1330 EPT to 1430 EPT on OD-1.
- Additionally after the RAC re-bid period, Real Time offers may be submitted up to 30 minutes prior to the Real-Time Energy and Operating Reserve Market Operating Hour for use in the Intra Day RAC, LAC and in Real Time dispatch processes in the Operating Hour.
- Limit and/or hourly Resource parameter updates between 30 minutes prior to the Real-Time Energy and Operating Reserve Market Operating Hour and during the Operating Hour cannot be updated via the Market Portal nor programmatically and require a phone call to MISO’s Real-Time Operator.

- Limit and/or hourly Resource parameter updates for subsequent hours are accepted through the Market Portal without requiring a phone call.
- Physical limitations occurring after the Real Time Offer window closes at 30 minutes prior to the Operating Hour should be reflected by entering a Real Time Offer Override request via an XML submission through the Market Portal.

4.2.9.1 Ramp Rate Priority

Within the Operating Hour, the following priorities apply to use of ramp rates:

- Operator overrides have the highest priority;
- MP overrides submitted through Real-Time Offer Override Enhancement (RTOE) request
- If ramp rate curves are not activated, Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional-Down Ramp Rate submitted no later than 30 minutes prior to the Operating Hour have priority;
- If ramp rate curves are not activated and no Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional-Down Ramp Rate have been submitted as part of the Real-Time Schedule Offer, then the default values for Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional-Down Ramp Rate are used.

4.2.10 Resource Modeling

The following Subsections describe the special modeling requirements associated with DRRs-Type I, DRRs-Type II, External Asynchronous Resources, Jointly-Owned Generation Resources, Combined Cycle Resources, Cross Compound Resources, Energy Limited Resources, System Support Resources, Intermittent Resources, Resources under 5 MW, and Dispatchable Intermittent Resources. As Stored Energy Resources are modeled in an equivalent manner to Generation Resources, no resource modeling detail is needed. For Schedule Offer information specific to Stored Energy Resources, see Section 4.2.5.3.5.

4.2.10.1 Demand Response Resources-Type I

A Demand Response Resource-Type I (“DRR”-Type I) is defined as any Resource hosted by an Energy Consumer, an Aggregator of Retail Customers or a Load Serving Entity that is capable of supplying a specific amount of Energy or Contingency Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through physical Load interruption or behind-the-meter generation. This specific amount of Energy or Contingency Reserve is determined through the Targeted Demand Reduction Level Offer parameter.

No special modeling of a DRR-Type I is required in the Network Model. For Commercial Modeling purposes, a DRR-Type I Resource is modeled as an Aggregate CPNode, and is linked directly to the underlying EPNode or EPNodes that constitute the physical locations of the Load interruption or behind-the-meter generation. A single DRR-Type I is limited to Load interruption or behind-the-meter generation located within a single Local Balancing Authority Area.

If the DRR-Type I is committed for Energy, a Dispatch Target for Energy is created for the DRR-Type I that is equal to the Targeted Demand Reduction Level. If the DRR-Type I is cleared for Contingency Reserve, amounts cleared can range from 1 MW up to the Targeted Demand Reduction Level, however, any Contingency Reserve Deployment Instructions issued to the DRR-Type I in Real-Time will be equal to the Targeted Demand Reduction Level.

More information regarding metering and baseline methodology requirements, as well as Settlements regarding DRRs-Type I can be found in the BPM for *Demand Response* and BPM for *Settlements*, respectively.

4.2.10.2 Demand Response Resources-Type II

A Demand Response Resource-Type II ("DRR – Type II") is defined as any Resource hosted by an energy consumer, an Aggregator of Retail Customers, or a Load Serving Entity that is capable of supplying a range of Energy and/or Operating Reserve, at the choice of the MP, to the Energy and Operating Reserve Markets through behind-the-meter generation and/or controllable Load. Because a DRR-Type II may consist of both behind-the-meter generators and controllable Load and MISO is modeling the DRR-Type II as a supply Resource and revenue metering and telemetering are provided on a net basis at the Bus, the DRR-Type II is modeled as a negative generator. The minimum dispatch limit of the resource represents the consumption baseline, and demand response is calculated as the difference between the net telemetered output and the minimum limit.

The following illustration shows a DRR-Type II providing 10 MW of demand response:

More information regarding metering and baseline methodology requirements, as well as Settlements regarding DRRs-Type II can be found in the BPM for *Demand Response, BPM-026* and BPM for *Market Settlements, BPM-005*, respectively.

Each MP representing a DRR-Type II that is qualified to provide Regulating Reserves must submit to MISO telemetered output via ICCP for each DRR-Type II.

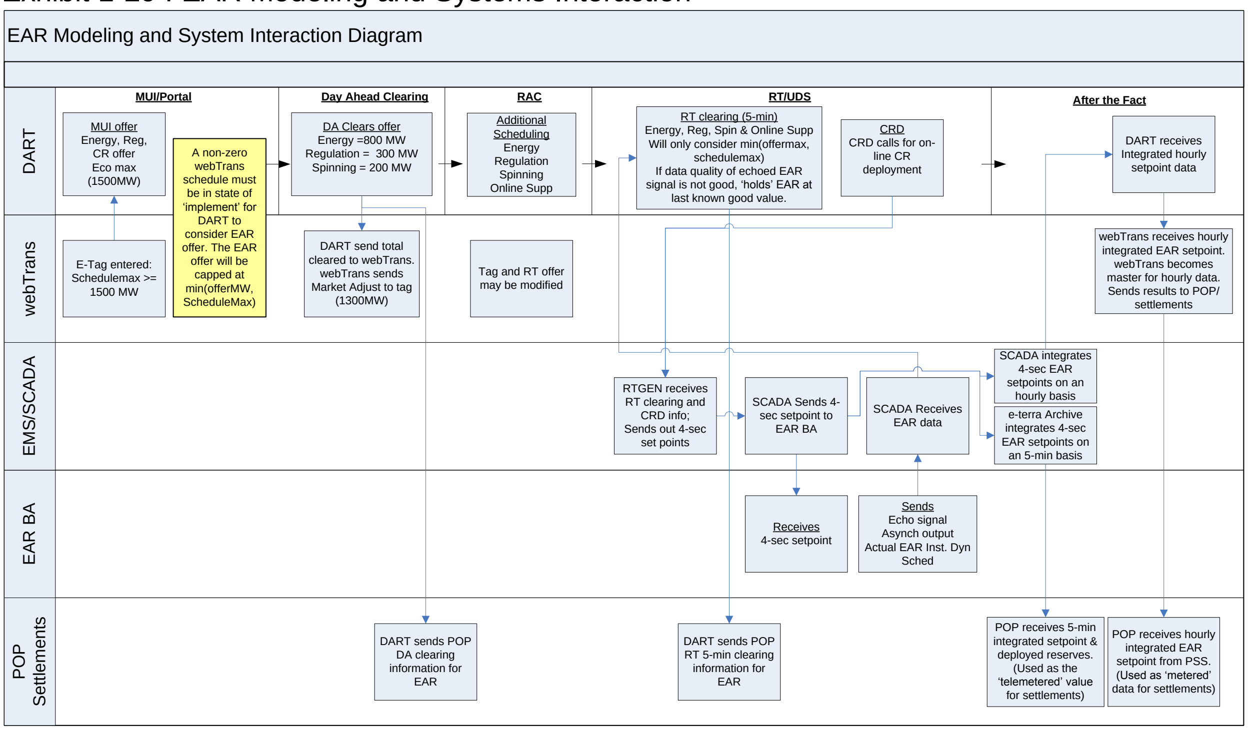
4.2.10.3 External Asynchronous Resources

An External Asynchronous Resource is defined as a DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is represented within the MISO Region through a Fixed Dynamic Interchange Schedule Import Schedule and/or Fixed Dynamic Interchange Schedule Export Schedule. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid. An EPNode and CPNode are created for the EAR at the time of asset registration. Even though an EAR is modeled as a Resource internal to the MISO BA Area similar to a Pseudo-Tied External Resource, an EAR must have an associated Fixed Dynamic Interchange Schedule Import Schedule and/or Fixed Dynamic Interchange Schedule Export Schedule to participate in either the Day-Ahead and Real-Time Energy and Operating Reserve Markets or just the Real-Time Energy and Operating Reserve Market that is linked to the EAR CPNode. This Fixed Dynamic Interchange Schedule Import Schedule and/or Fixed Dynamic Interchange Schedule Export Schedule is used to ensure that the proper transmission reservation and corresponding estimated schedule has been made prior to accepting the EAR Offers for use in market clearing. The estimated schedule amounts are then updated Day-Ahead via a Market Adjust to reflect the actual EAR clearing results (which are equal to the sum of Energy, Regulating Reserve and Contingency Reserve clearing) which, in turn, flow into Real-Time as the Real-Time Fixed

Dynamic Interchange Schedule estimate. This Real-Time schedule estimate is then updated after-the-fact to reflect the actual Real-Time EAR Energy deployment which includes 5-minute Dispatch Targets for Energy adjusted for Regulating Reserve deployment and Contingency Reserve deployment.

summarizes this process and identifies the systems involved.

Exhibit 1-29 : EAR Modeling and Systems Interaction



4.2.10.4 Jointly-Owned Unit Resources

Each MP representing an owner of a JOU has two options for submitting Offer data for unit output:

1) ***Pseudo-Tie JOU*** – The unit is modeled as separate physical units in different LBA Areas. Each MP submits offers for its share of the JOU and receives Setpoint Instructions and price from MISO for its share.
2) ***Combined Offer JOU*** – One owner can aggregate on behalf of the other owners. JOUs where the owners have decided to have a single entity Offer and dispatch the unit on behalf of all owners are modeled as a single unit in MISO's Energy Management System ("EMS"). MISO settles only with the single entity. Each of the other owners settles with the dispatching entity outside of the MISO Energy Markets. The unit does not appear as a JOU to MISO.

The desired option must be specified during the registration process, however, and it cannot be changed on a day-to-day basis.

JOUs modeled as multiple units in MISO's EMS (i.e., "pseudo-tie" JOUs) are modeled as independent Resources in the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Offers for these JOUs are treated independently. Each owner has an asset and MISO settles independently with each owner.

4.2.10.5 Combined Cycle Resources

A Combined Cycle CT Generation Resource typically incorporates one or more gas-fired CTs, followed by heat recovery steam Generator(s) that use the exhaust heat from the CTs to generate steam, powering one or more steam turbine Generators. A Combined Cycle CT is normally offered as a single (aggregate) unit; however, the component CTs and/or steam turbine ("ST") with an alternate steam or thermal source may be offered as separate units (for example, when the steam turbine unit or CTs are not in service).

When the Combined Cycle CT is offered as a single aggregate unit, it will be associated with a single aggregated CPNode. The Ex Ante and Ex Post LMP for this aggregated CPNode is calculated as the weighted average of the Ex Ante and Ex Post LMPs of the individual unit EPNodes.

In the Day-Ahead Energy and Operating Reserve Market, a Combined Cycle CT's aggregate Resource Offer consists of the same information required for any Generation Resource. Similar to CTs, Combined Cycle CTs are allowed to submit weather curve data that specify MW limits as a function of temperature. For any changes anticipated in the configuration of the component units of a Combined Cycle CT during the future day, the MP must submit the Combined Cycle CT's aggregate Day-Ahead Energy and Operating Reserve Market Offer that matches the aggregate characteristics of the various operating modes.

If an aggregate Offer exists for a Combined Cycle CT, then it is used and any individual Offers for CTs that are components of the Combined Cycle CT are ignored. If an aggregate Offer for a Combined Cycle CT does not exist, individual CT or ST Offers are used.

In the Day-Ahead Energy and Operating Reserve Market, transitions between a Combined Cycle CT's aggregate Offer and its individual CT Offers are not permitted within the same day. If the aggregate Offer is used for any hour in a day, the aggregate Offer's hourly values will be used for the entire day.

In the Real-Time Energy and Operating Reserve Market for the purposes of Forward RAC and Intra-Day RAC, if the Combined Cycle Resource was not committed in the Day-Ahead Energy and Operating Reserve Market or any RAC process (for both aggregate and single unit modeling), the MP may elect to change its Offer from aggregate to single unit or vice versa. However, once the Resource is committed, no further changes in modeling are allowed for that Operating Day.

For the purposes of compliance with Contingency Reserve Deployment Instructions, an MP must elect Common Bus treatment for each individual component (steam turbine and each CT) EPNode associated with a Combined Cycle Generation Resource during the asset registration process in order for the output of any individual components in an Aggregate Combined Cycle Offer to be included in the determination of compliance.

4.2.10.6 Cross Compound Resources

A Cross Compound Resource consists of a high-pressure turbine/Generator and a low-pressure turbine/Generator connected to separate electrical Nodes in the Network Model.

The Cross Compound Resource will have an EPNode and corresponding CPNode for each Generator and if desired, a third CPNode will be defined representing the aggregate of the two. Since the two Generators usually must operate in a coordinated fashion, a single Resource Offer must be submitted to represent the combined output of the two Generators.

4.2.10.7 Energy Limited Resources

MISO has the ability to optimize the output of an energy limited Resource within its Offer parameters in the Day-Ahead Energy and Operating Reserve Market and will do this in a manner that minimizes total system production cost within this market. This functionality exists on a one day-at-a-time basis only. The Resource must specify the maximum MWhs that can be supplied from the Resource via the Maximum Daily Energy offer parameter.

4.2.10.8 System Support Resources

SSRs are Generation Resources (DRRs are not eligible) and Synchronous Condenser Units that are operated to maintain power system reliability at the direction of MISO. These are Resources that were/are planned for decommissioning but are kept in service by SSR Agreements between the MPs and MISO. The following rules apply to SSRs:

- MISO shall notify Market Participants with SSR Units, with respect to those resources' startup/notification offer, as to the time period of Energy, Operating Reserve and/or Other Ancillary Services required from each SSR Unit. Notifications will correspond with the posting of the results of the Day-Ahead Energy and Operating Reserve Markets, Reliability Assessment Commitment processes, or the Look Ahead Commitment processes.
- MPs may offer capacity from SSRs in the Day-Ahead Energy and Operating Reserve Market, RAC, or the Real-Time Energy and Operating Reserve Market during times when MISO has requested the MP to run the SSR at less than full capacity, unless this would impair the ability of the SSR to provide Reactive Supply and Voltage Control requested by MISO.
- A Generation Resource which is identified as an SSR:
- May offer Energy not requested by MISO into the Day-Ahead and Real-Time Energy and Operating Reserve Markets.
- MPs that own or operate SSRs are not permitted to use the SSRs to:
- Participate in Bilateral Transactions (see Exhibit 0-1).
- Supply energy as a Self-Scheduled Resource, except if it was committed or for plant auxiliary Load obligations under the SSR Agreements.
- Self-Schedule Operating Reserve.
- MISO determines the appropriate Settlement and compensation for the MPs that own SSRs, according to negotiation and contractual agreement between the MPs and MISO.
- MISO performs an annual review of SSR status to determine if the SSR is still qualified to remain as an SSR.

4.2.10.9 Resources Under 5 MWs

MISO has chosen a threshold of 5 MW for its cut-off point for Network Modeling purposes. All Generation Resources, External Asynchronous Resources and DRRs-Type II greater than or equal to 5 MW will be modeled explicitly in the Network Model[35]. Generation Resources smaller than 5 MW will not be modeled explicitly in the Network Model. Exceptions to this rule will be handled on a case-by-case basis.

However, the following rules will apply in order for Generation Resources, External Asynchronous Resources and DRRs-Type II smaller than 5 MW to be modeled:

- The Resource must have Real-Time telemetry.
- If this Resource is on a lower voltage than is included in the Network Model, it will need to be reflected up to the appropriate Node in the Network Model.
- If this Resource provides reactive support for Network Model solution that cannot be effectively represented by a negative Load.

If a Resource smaller than 5 MW wants or needs to be settled by the Energy and Operating Reserve Markets, MISO will provide a CPNode for this Resource that will allow the Resource to be represented by an MP, designate an MDMA, and submit Metered values After-the-Fact (“ATF”) that will be used for Settlement purposes.

However, the Resource will not be able to offer into the Energy and Operating Reserve Markets and will be a price taker at the appropriate Ex Ante and Ex Post LMP price for its output unless Real-Time telemetry is available to MISO through ICCP.

4.2.10.10 Intermittent Resources

MISO supports Intermittent Resources. Intermittent Resources are Resources that are not dispatchable and can be designated as such in the Customer Care System, subject to Intermittent registration provisions as set forth in the Tariff. See the BPM for *Network and Commercial Models* for more information regarding Intermittent Resource qualification requirements.

Intermittent Resources are not charged Excessive/Deficient Energy Deployment Charges, and as such, they are not eligible to submit Energy or Operating Reserve Offers, and for each

[35] Except in the case of Behind-the-Meter generation that has not been registered as a DRR-Type I or DRR-Type II.

Dispatch Interval, will receive a Dispatch Target for Energy equal to their Energy output in the previous State Estimator solution. These Resources may also register in whole as Generation Resources to the extent they are partially dispatchable. The Market Participant must then select the Off-Control Flag during periods when the Resources cannot follow dispatch. If the Off-Control Flag is set, the Resource is not eligible to clear Operating Reserve and would clear Energy as described above.

4.2.10.11 Dispatchable Intermittent Resources

Dispatchable Intermittent Resources ("DIRs") are Generation Resources whose maximum limit is dependent on a forecast of their variable fuel source. Resources that are fueled by wind, solar, or other types of variable energy can be DIRs. Because DIRs have a maximum limit that can vary, even over short time durations, DIRs do not submit maximum limits to the Real-Time Energy and Operating Reserve Markets. Instead, they provide a Forecast Maximum Limit in Real-Time, submitted through the MUI. More information regarding the Forecast Maximum Limit can be found in Section 4.2.3.4.20.

In the Day-Ahead Energy and Operating Reserve Markets, DIRs are treated in the same manner as other Generation Resource types, including the submittal of Economic and Emergency Maximum Limits. In both Day-Ahead and Real-Time Markets, DIRs are eligible for commitment in the same manner as other Generation Resource types, including being considered for Economic commitment. A DIR with an 'Economic' Commit Status may or may not be committed; commitment of all 'Economic' Resources is dependent on the economic value of each commitment decision, weighed against other commitment decisions.

DIRs are not eligible to provide Operating Reserves to the Day-Ahead or Real-Time Energy and Operating Reserves Markets. For this reason, DIRs do not submit Dispatch Statuses for Regulating, Spinning, On-Line Supplemental, or Off-line Supplemental Reserves.

4.2.10.12 Non-Telemetered Resources

All Generation Resources, External Asynchronous Resources and Regulating Reserve-Qualified DRRs-Type II greater than 5 MW must have Real-Time telemetry. Such Resources without Real-Time telemetry (smaller than 5 MW) are price takers in the Real-Time Energy and Operating Reserve Market. These Resources can have a CPNode established that allows them to submit meter values for energy settlements, but will not be dispatched in the Real-Time Energy and Operating Reserve Market.

4.3 Demand Bids

Demand Bids apply to the Day-Ahead Energy and Operating Reserve Market only and represent a financially binding Bid to purchase Energy at Day-Ahead prices for Real-Time consumption in the next Operating Day. Only MPs that are Load Serving Entities (“LSEs”) or are purchasing Energy on behalf of an LSE as an SA may submit Demand Bids.

MISO maintains a list of Load Zones represented by CPNodes. Each Load Zone is a representation of the relative size and location of the Load represented by the Load Zone. The Demand Bids submitted to the Load Zone CPNodes are distributed to its individual Loads according to the Load Zone Load Distribution Factors (“LDFs”). The Load Zone LDFs describe the daily allocation of MW activity at the Load Zone to its member Loads, based on the average of the State Estimator over the twenty-four (24) hours of seven (7) Days prior to the Operating Day. Demand Bids are allowed to be submitted only to Load Zone CPNodes.

At 1330 EPT MISO posts the Day-Ahead Energy and Operating Reserve Market Awards results and Ex-Ante LMP and MCP prices. The results include the cleared Day-Ahead Demand Bids at the same Load Zone CPNode that MPs specified when they submitted their Demand Bids. Between 1330 EPT and 1630 EPT Ex-Post LMP and MCP prices will be posted. Cleared Day-Ahead Demand Bids are settled using the Day Ahead Ex Post LMPs for that Load Zone CPNode. MPs must submit Settlement quality meter data for Loads to MISO using the same aggregations that are used when submitting the Demand Bids. Deviations between cleared Day-Ahead Demand Bids and the settlement quality meter data are settled at the Real-Time Ex Post LMPs.

There are two types of Demand Bids.

- Fixed Demand Bids
- Price-Sensitive Demand Bids as illustrated in Exhibit 1-30

4.3.1 Fixed Demand Bids

Fixed Demand Bids are “price takers” and are charged the Ex Post LMP determined in the Day-Ahead Energy and Operating Reserve Market for that CPNode location. MPs may submit only one Fixed Demand Bid at a CPNode location. The following information is submitted for a Fixed Demand Bid:

- MW quantity, with a default of zero MW
- Location (Load Zone CPNode) at which the purchase occurs

- Hours over which the Fixed Demand Bid applies

MPs may only indicate their desire to purchase a particular Fixed Demand Bid MW of Energy if the MPs have demonstrated to MISO in advance that they are financially capable of paying the highest possible price for the designated MW of Energy in accordance with MISO's credit policy.

4.3.2 Price-Sensitive Demand Bids

MPs are able to express a willingness to buy Energy at specified prices by submitting Price-Sensitive Demand Bids. This type of Demand Bid is modeled in blocks as shown in Exhibit 1-30. Price-Sensitive Demand Bids are accepted in separate bid blocks only. Up to nine Bid blocks can be submitted per CPNode location. This is in addition to the one Fixed Demand Bid at that CPNode location. The following information is submitted for a Price-Sensitive Demand Bid:

- MW quantity/price representing the maximum price (positive or negative without price caps) the MP is willing to pay to purchase the desired MW of Energy. The (MW/Price) blocks can be entered in an arbitrary sequence with respect to MW block size and price as illustrated in Exhibit 1-30. The application software will process the blocks in the proper sequence, as required.
- Location (Load Zone CPNode) at which the purchase occurs.
- Hours over which the Price-Sensitive Demand Bid applies.
- The $/MWh Offer values may range from -$500 to $1,000.

An MP may only indicate their desire to purchase a particular Price-Sensitive Demand Bid MW of Energy if the MP has demonstrated to MISO in advance that they are financially capable of paying the highest submitted price for the designated MW of Energy in accordance with MISO's credit policy.

MPs external to the Market Footprint may purchase Energy from the Day-Ahead Energy and Operating Reserve Market through Export Schedules as previously described in this Section 4.

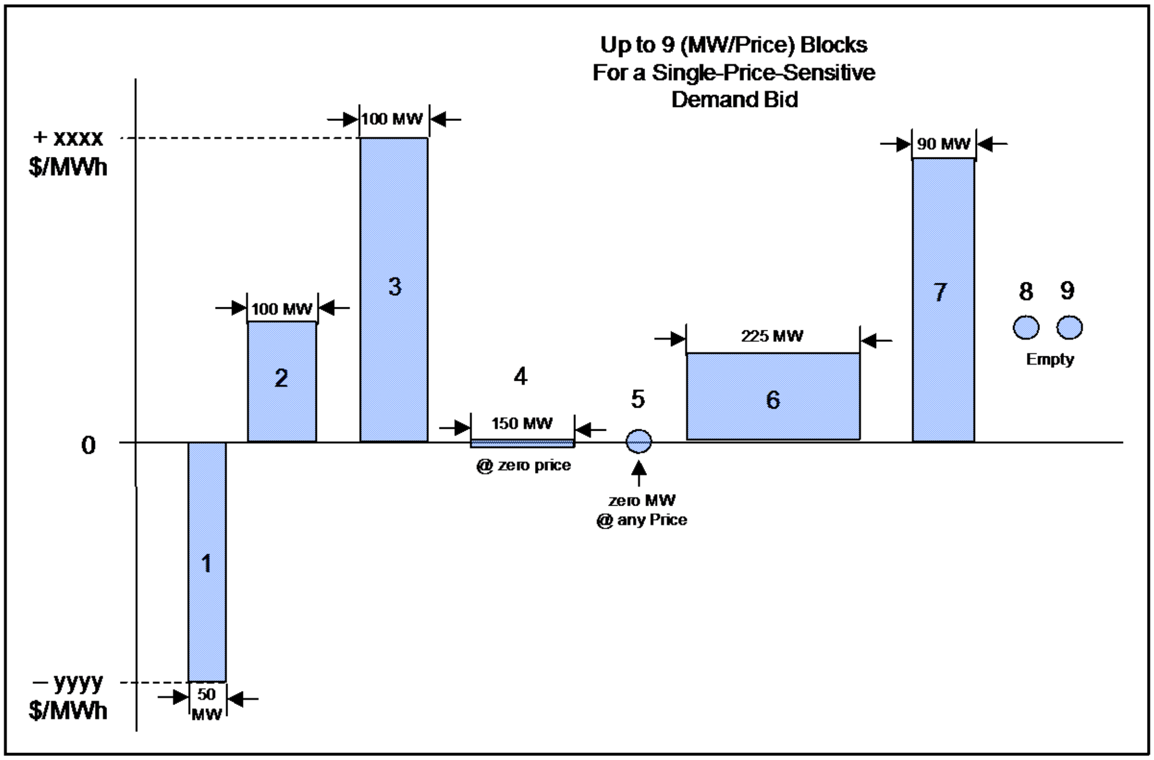


Exhibit 1-30: Price-Sensitive Demand Bid Submittal Example

MPs may submit the Bid blocks in any order as illustrated in Exhibit 1-30; however, when queried after submittal, the Price-Sensitive Demand Bid blocks will appear sorted in descending price order, starting with the highest priced block (#3 in the example).

4.4 Virtual Transactions

Virtual Transactions are generally used by MPs to hedge against changes in Ex Ante and Ex Post LMP between the Day-Ahead Energy Operating Reserve Market and Real-Time Energy and Operating Reserve Market. Virtual Transactions are supported in the Day-Ahead Energy and Operating Reserve Market only and are available to all MPs.

There are two types of Virtual Transactions:

- Virtual Supply Offers
- Virtual Demand Bids

Virtual Transactions have a price at which MPs are willing to inject Energy (Virtual Supply Offer) or withdraw Energy (Virtual Demand Bid) in response to the dispatch in the Day-Ahead Energy and Operating Reserve Market. Virtual Transactions are financial in that they are not required to be backed by physical generation or Load. There are several uses for Virtual Transactions, including:

- Covering one side of an Interchange Schedule (use a Virtual Supply Offer or Virtual Demand Bid)
- Protecting a Day-Ahead Generation Offer (use a Virtual Demand Bid)
- Covering congestion (use a Virtual Supply Offer and a Virtual Demand Bid)

4.4.1 Virtual Supply Offers

Virtual Supply Offers are Offers to supply Energy in the Day-Ahead Energy and Operating Reserve Market. They are not necessarily supported by a Generation Resource in the Real-Time Energy and Operating Reserve Market and, as such, Virtual Supply Offers cannot be used to supply Operating Reserve.

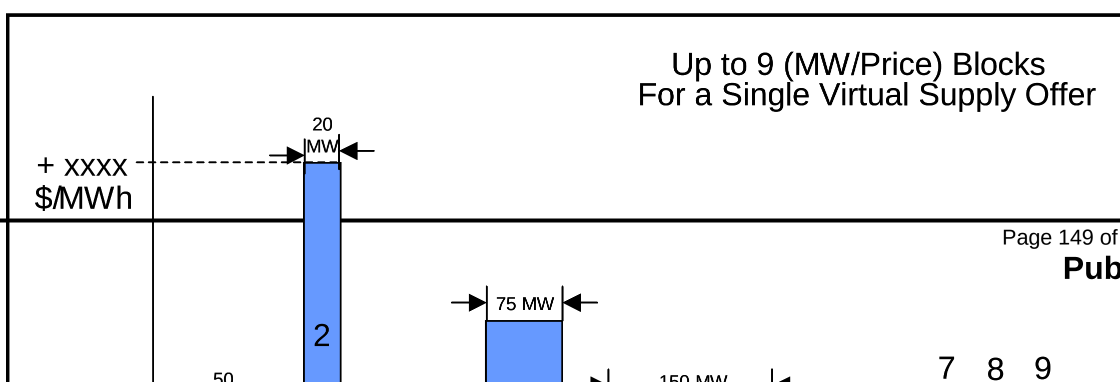
MPs submit the following information for Virtual Supply Offers:

- MW, at least 0.1 MW, subject to credit limits and Independent Market Monitor ("IMM") volume limits.
- Location (any CPNode).
- Hours over which the Offer applies.
- Offer price (the minimum price the market seller is willing to accept for Energy sold into the Day-Ahead Energy Market, where the $/MWh Offer values may range from -$500 to $1,000.
- Up to 9 (MW/Price) blocks per Virtual Supply Offer.

The (MW/Price) blocks in a Virtual Supply Offer can be entered in an arbitrary sequence with respect to MW block size and price as illustrated in

Exhibit 1-31.

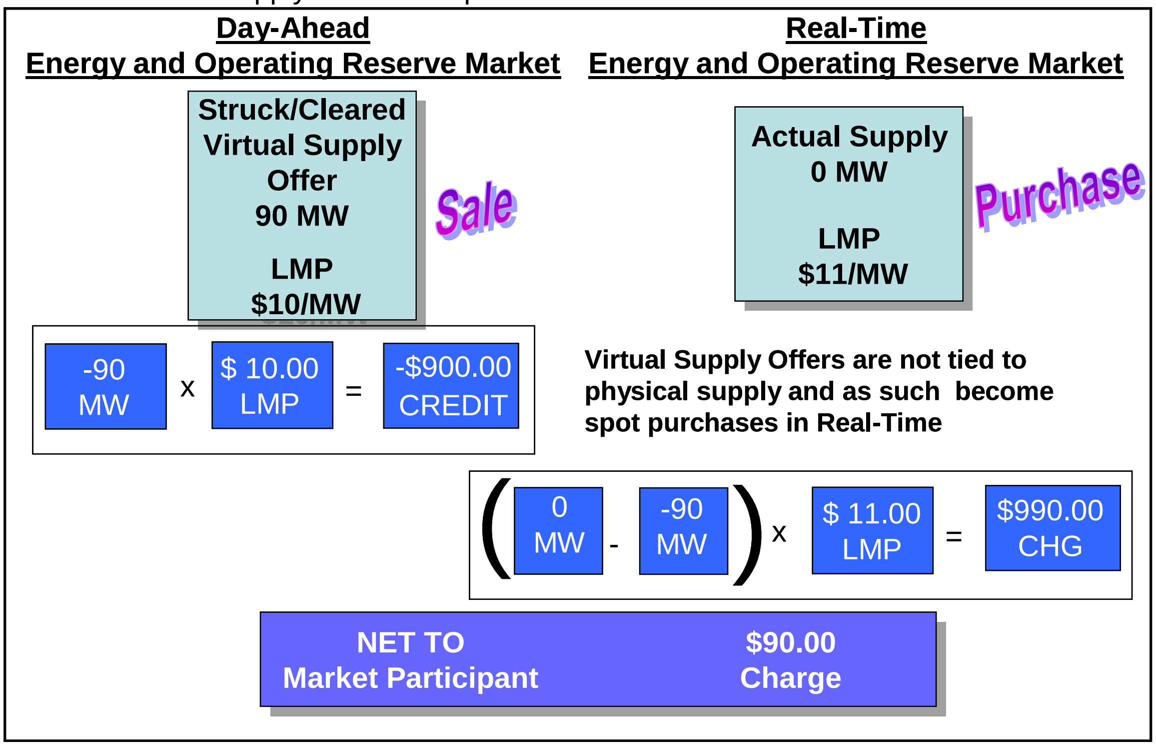
Exhibit 1-31: Virtual Supply Offer Submittal Example



MPs may submit the Offer blocks in any order as illustrated in
Exhibit 1-31; however, when queried after submittal, the Virtual Supply Offer blocks will appear sorted in ascending price order, starting with the lowest priced block (#3 in the example).

Exhibit 1-32 is an example of a Virtual Supply Offer with a single (MW/Price) block.

Exhibit 1-32: Virtual Supply Offer Example



For simplicity, this Virtual Supply Offer example consists of one (MW/Price) block. The Virtual Supply Offer clears in the Day-Ahead Energy and Operating Reserve Market for $10/MWh or -$900, meaning this MP is paid $900 in the Day-Ahead Settlement. In the Real-Time Energy and Operating Reserve Market, the MP supplies no Energy, creating a short position in the Real-Time Energy and Operating Reserve Market with a clearing price of $11/MWh or $990. The net to the MP that submits the Virtual Supply Offer is a $90 charge.

4.4.2 Virtual Demand Bids

A Virtual Demand Bid is a Bid to purchase Energy in the Day-Ahead Energy and Operating Reserve Market. There is not necessarily the intent to consume the Energy in the Real-Time Energy and Operating Reserve Market.

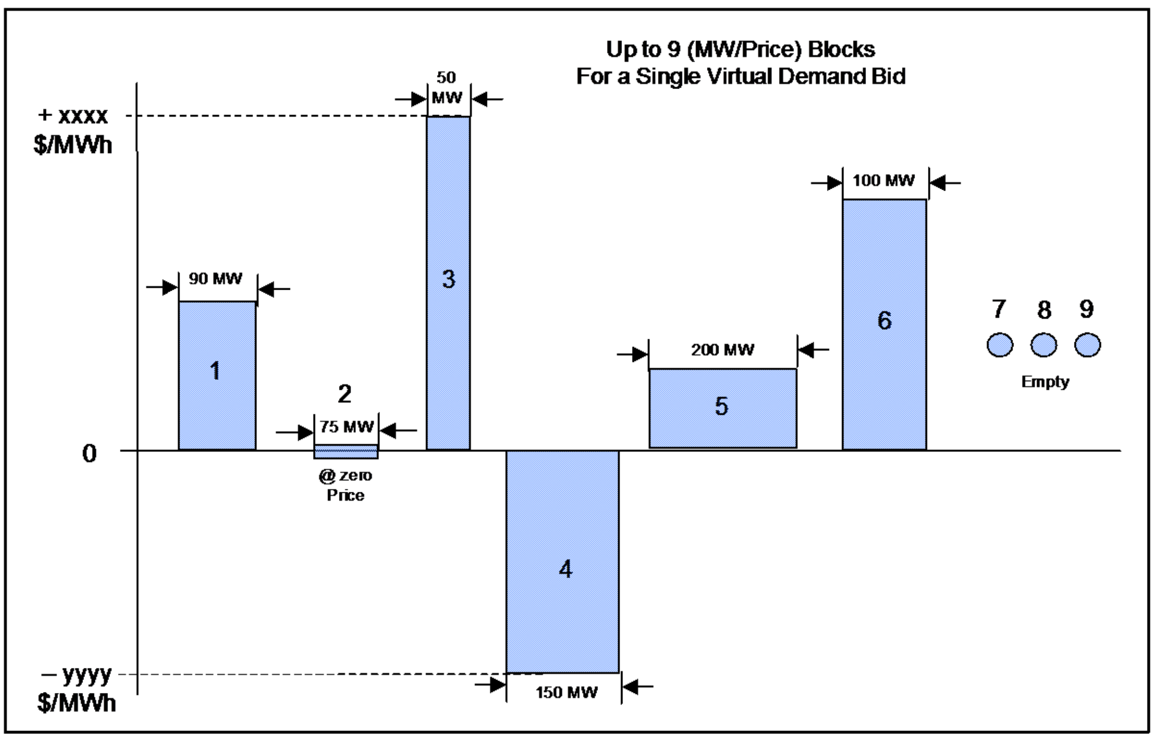
MPs submit the following information for Virtual Demand Bids:

- MW, at least 0.1 MW, subject to credit limits and IMM volume limits.
- Location (any CPNode).

- Hours over which the Bid applies.
- Bid price (the maximum price the market buyer is willing to pay for Energy purchased in the Day-Ahead Energy and Operating Reserve Market, where the $/MWh Offer values may range from -$500 to $1,000.
- Up to 9 (MW/Price) blocks per Virtual Demand Bid.

The (MW/Price) blocks in a Virtual Demand Bid can be entered in an arbitrary sequence with respect to MW block size and price as illustrated in Exhibit 1-33.

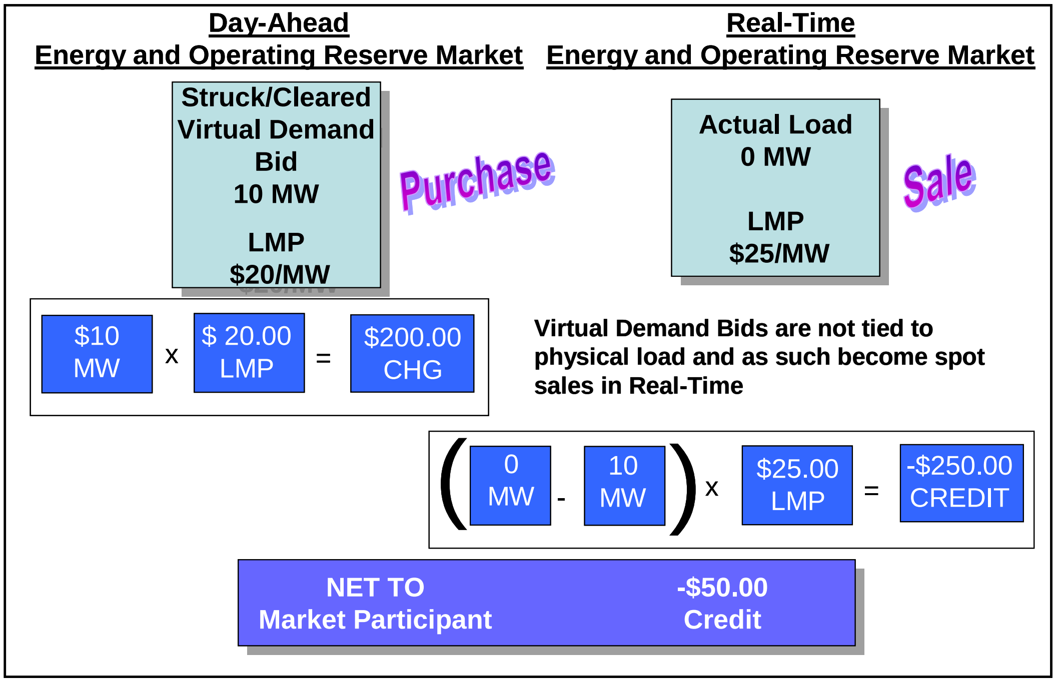
Exhibit 1-33: Virtual Demand Bid Submittal Example



MPs may submit the Bid blocks in any order as illustrated in Exhibit 1-33; however, when queried after submittal, the Virtual Demand Bid blocks will appear sorted in descending price order, starting with the highest priced block (#3 in the example).

Exhibit 1-34 is an example of a Virtual Demand Bid with a single (MW/Price) block.

Exhibit 1-34: Virtual Demand Bid Example



For simplicity, this Virtual Demand Bid example consists of one (MW/Price) block. The Virtual Demand Bid clears in the Day-Ahead Energy and Operating Reserve Market for $20/MWh or $200, meaning this MP owes $200 in the Day-Ahead Settlement. In the Real-Time Energy and Operating Reserve Market, the MP consumes no Energy, creating a long position in the Real-Time Energy and Operating Reserve Market with a clearing price of $25/MWh or $250. The net to the MP that submits the Virtual Demand Bid is a $50 credit.

4.5 Market User Interface Bid/Offer Validations

The Market User Interface places limitations on the values that can be submitted for certain parameters for several reasons, including reasonability and Tariff compliance. The following list of validations can be used to determine whether a submittal to the MUI will be accepted.

Validations on Resource Limits and Ramp Rates

- EmerMax >= EcoMax >= RegMax >= RegMin >= EcoMin >= EmerMin
- EmerMin > =0 (except for EARs)
- If a “NULL” value is submitted for one Resource Limit parameter, then “NULL” values must be submitted for ALL Resource Limit parameters
- EmerMax >= OfflineResponseMax

- Down Ramp Rate >= Up Ramp Rate >= BiDirectional Ramp Rate > 0
- Day-Ahead Ramp Rate > 0
- Real-Time Studies Ramp Rate > 0

Other Resource Operating Parameter Validations

- Cold StartUp Time >= Intermediate StartUp Time >= Hot StartUp Time
  - Also true for shutdown times on Demand Response Resources
- Resources qualified as Quick-Start Resources must provide Minimum Run Time <= 3)
  - Also true for Minimum Interruption Duration for Demand Response Resources
- Self-Scheduled MW (for Energy, Reg, Spin, Supp) >= 1
- Minimum Run Time <= 24 (also true for Minimum Interruption Duration)
- Maximum Run Time >= Minimum Run Time
- Hot-to-cold Time >= Hot-to-Intermediate Time

Validations on Resource Offers

- Cold Startup Cost >= Intermediate Startup Cost >= Hot Startup Costs>=0
- Cold Startup Notification Time >= Intermediate Startup Notification Time >= Hot Startup Notification Time

Validations on Temperature Sensitive Limits

- Temperature sensitive limits only apply for Resources registered as Combustion Turbine or Combined Cycle Combustion Turbine Resources.
- Temperature Limits: If one value is provided during a submittal then all values must be provided.
- Upper Temp >= Mid Temp >= Lower Temp

Validations on Operating Reserve Offer Parameters

- If a resource is offered in Regulation Market (Dispatch Status is Economic or Self-Schedule) then the Resource must have Spin Dispatch Status of Economic or Self-Schedule and Online Supplemental Dispatch Status of Economic or Self-Schedule
- If a Resource is offered in Spin Market (Dispatch Status is Economic or Self-Schedule), then the Resource must have Online Supplemental Dispatch Status of Economic or Self-Schedule

Validations on Bid/Offer Prices

- -$500 >= Energy Bids and Offers <= $1,000
- -$500 >= Regulating Reserve Offers <= $500
- -$100 >= Spinning Reserve Offers <= $100
- -$100 >= Supplemental Reserve Offers <= $100

5. Locational Marginal Prices and Market Clearing Prices

MISO calculates both Ex Ante and Ex Post Locational Marginal Prices (“LMPs”) for Energy at Load Zone, Hub, Interface, and Resource Commercial Pricing Nodes and Ex Ante and Ex Post Market Clearing Prices (“MCPs”) for Regulating Reserve, Spinning Reserve and Supplemental Reserve at Resource CPNodes on a simultaneously co-optimized basis using a SCED and SCED-Pricing algorithm, respectively, for both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The SCED-Pricing algorithm is based on the SCED algorithm but is enhanced with the Extended Locational Marginal Pricing (“ELMP”) mechanism that allows the cost of committing Fast Start Resources, the Energy cost of Fast Start Resources dispatched at limits and Emergency Demand Response Resources to set price. Also, under Maximum Generation Emergency conditions, where available economic supply is insufficient to meet fixed demand, emergency pricing is utilized to price the Emergency Energy and Demand Response Resources to provide proper pricing signals reflective of the emergency conditions and thus prevent inefficient price depression associated with injection of the emergency supply. For the Day-Ahead Energy and Operating Reserve Market, Ex Ante LMPs, Ex Post LMPs, Ex Ante MCPs and Ex Post MCPs are calculated on an hourly basis. For the Real-Time Energy and Operating Reserve Markets, LMPs and MCPs are calculated for each five-minute Dispatch Interval on both an ex-ante and ex-post basis. Inputs to SCED and SCED-Pricing for Day-Ahead and Real-Time calculations will differ based on forecasted versus actual system conditions. These inputs are described under Sections 7 and Section 8 of this BPM.

The following Sections further describe how LMPs and MCPs are calculated.

5.1 LMP Calculations

The LMP represents the cost incurred, expressed in $/MWh, to supply the last incremental amount of Energy at a specific Elemental Pricing Node on the transmission grid. The Ex Ante LMP does this in a manner that respects the physical and operational limitations of generation and transmission facilities while the Ex Post LMP does not necessarily respect the physical limit of Fast Start Resources. Ex Post LMPs are calculated through Extended LMP (“ELMP”), an enhanced pricing mechanism expanding upon LMP and MCP in which Fast Start Resources (“FSR”) that are scheduled to operate at limits, certain off-line FSR, and the start-up or shut-down and no-load or curtailment costs of these FSR resources, may be included in the calculation of prices at the CPNodes located throughout the Transmission Provider Region. ELMP also provides the mechanism to introduce emergency pricing, in ex post manner, to prevent inefficient price depression during system or local area shortage conditions when MISO utilizes Emergency Resources, including Emergency range of available resources, Emergency Demand Response Resources, Load Modifying Resources, External Resources that are qualified as Planning Resources or Emergency Energy purchases.

Regardless of Ex Ante or Ex Post, the LMP can be impacted by Energy Offers and Bids, Operating Reserve Offers and Demand Curves. Stated another way, the LMP is the marginal cost of Energy at a specific EPNode, where marginal costs include marginal Energy costs, marginal Operating Reserve costs and marginal Reserve Scarcity costs. Marginal Energy costs are the marginal costs incurred to produce the last incremental amount of Energy, including any associated transmission loss impacts, at a specific EPNode. Marginal Operating Reserve costs are the Operating Reserve costs associated with the incremental shifting of Operating Reserve from one Resource to another to accommodate the least cost production of the last incremental amount of Energy, including any associated transmission loss impacts, at a specific EPNode. Marginal Reserve Scarcity costs are the costs associated with any increase in Reserve Scarcity that is necessary to accommodate the production of the last incremental amount of Energy, including any associated transmission loss impact, at a specific EPNode. MISO establishes LMPs for both EPNodes and APNodes. APNodes represent the weighted average of two or more EPNodes and may include Hubs, External Interfaces, Load Zones and Resources with multiple injection points. The LMPs include separate components for the marginal costs of Energy at the Reference Bus, the marginal cost of losses with respect to the Reference Bus, and the marginal cost of congestion with respect to the Reference Bus.

5.1.1 LMP Components

The following is true for both Ex Ante and Ex Post LMPs. There is a specific LMP calculated for each EPNode in the network. The LMP at a specific EPNode is very closely approximated by the cost incurred to supply the last MWh of Energy demanded at the EPNode. Therefore, for the purpose of understanding how LMPs and their associated components are determined, it is convenient to assume that a MWh of Energy is incremental, and that the LMP is equal to the cost incurred to supply the last MWh of Energy demanded at the corresponding EPNode. In a lossless transmission system with infinite transmission branch flow limits, all LMPs would be the same, and would represent the cost to supply the last MWh of system Energy from the least cost Resource. The least cost Resource is the marginal Energy Resource in this scenario, and could represent an aggregation of two or more Resources based on the Energy Offer curves. The cost to supply the last MWh from the marginal Energy Resource is referred to as the system λ.

In the real world, the existence of transmission losses, transmission branch flow limits and the need to manage intra-regional flows in accordance with applicable seams agreements results in an increase in the cost to supply the last MWh of Energy demanded at all EPNodes other than the least cost Resource Bus (i.e., there are no transmission flow impacts of serving demand at the least cost Resource Bus, thus there are no associated marginal loss and congestion impacts). That is, for an incremental increase in Energy demand at any EPNode other than the least cost Resource Bus, the marginal Energy Resource is no longer represented by the least cost Resource, but instead is represented by the Resource (or Resources) that results in the lowest total cost of Energy taking into consideration both the impact on losses, physical transmission constraints and the Sub-Regional Power Balance Constraint. The additional cost incurred to supply the last MWh of Energy at EPNodes other than the least cost Resource Bus can be thought of as the marginal cost of losses and congestion at that EPNode. Since the marginal costs of losses and congestion is zero at the least cost Resource Bus, the marginal costs of losses and congestion at all other EPNodes are stated with respect to the least cost Resource Bus. Therefore, the least cost Resource Bus can be thought of as a Reference Bus, and the marginal loss and congestion impacts of Energy injections and withdrawals at other EPNodes can be modeled based on the linearized sensitivity of the Energy flow changes on specific branches resulting from an injection at the EPNode in question coupled with a withdrawal at the Reference Bus to maintain power balance.

Unfortunately, the least cost Resource Bus is not known in advance. To solve this problem, an arbitrary Bus can be chosen as the Reference Bus, and the LMP at this Reference Bus, which is referred to as the Marginal Energy Component at the reference Bus or MEC*r*, can be used in place of the system λ. By definition, the marginal cost of losses and congestion at this arbitrary Reference Bus is equal to zero, thus depending on which Bus is selected to be the Reference Bus, other EPNodes may have either a positive or negative marginal cost of losses and congestion. In practice, the marginal cost of losses and congestion is further subdivided into the marginal cost of losses and the marginal cost of congestion. Therefore, for each EPNode, MISO determines separate components of the LMP for the marginal costs of Energy at the Reference Bus, marginal cost of losses with respect to the Reference Bus, and the marginal cost of congestion with respect to the Reference Bus, consistent with the following equation:

(5-1) $LMP_i = MEC_r + MLC_i + MCC_i$

(5-2) $LMP_r = MEC_r$

(5-3) $MLC_r = 0$

(5-4) $MCC_r = 0$

Where:

- MEC_r is the component of LMP_i representing the marginal cost of Energy, or LMP, at the Reference Bus, *r*.
- MLC_i is the component of LMP_i representing the marginal cost of losses at EPNode *i* relative to the Reference Bus, *r*.
- MCC_i is the component of LMP_i representing the marginal cost of congestion at EPNode *i* relative to the Reference Bus, *r*.

The Reference Bus used by MISO is the fixed market Load distributed Reference Bus. That is, this Bus is an aggregation of fixed market Load Buses where the weighting factors are based on the fixed market Load at those Buses. For this reason, the exact definition of the Reference Bus will change from one hour or Dispatch Interval to the next. In the Day-Ahead Energy and Operating Reserve Market, the fixed market Load is driven by fixed Demand Bids. In the Real-Time Energy and Operating Reserve Market, the fixed market Load is driven by the short-term Load Forecasts.

A note on "Reserve Procurement" constraints: MISO has developed an approach to allow the SCUC, SCED and SCED-Pricing algorithms to ensure that operating reserves are procured on resources that can deliver the reserves across system transmission constraints. These resulting modifications to the SCUC, SCED and SCED-Pricing are called reserve procurement constraints. Reserve procurement constraints are enabled for a specific, pre-determined subset of active transmission constraints, including Interconnection Reliability Operating Limits ("IROL") constraints. The addition of this new set of constraints modifies the calculation of LMPs, as well as operating reserve marginal clearing prices. More details regarding reserve procurement constraints and pricing modifications can be found in the Attachments to this BPM, and in Sections 5.1.1.2 and 5.2.2 below.

5.1.1.1 Marginal Losses Component ("MLC_i") Calculation

MISO calculates the MLC_i at each EPNode *i*. The MLC_i of the LMP at any EPNode *i* can be calculated using the following equation:

(5-5) $MLC_i = - MLSF_i * MEC_r$

Where:

- $MLSF_i$ is the Marginal Loss Sensitivity Factor for EPNode *i* with respect to the system Reference Bus. That is, $MLSF_i$ is a linearized estimate of the change in MISO transmission losses that will result from a 1 MW injection at EPNode *i* coupled with a corresponding withdrawal at the Reference Bus to maintain global power balance (the withdrawal at the Reference Bus will generally be higher or lower than 1 MW since there will be a change in island losses). Marginal loss sensitivity factors are dependent on topology, Bus injections and Bus withdrawals, and are only considered constant within a small deviation from a fixed operating point. The marginal loss sensitivity factors are expressed mathematically at a specific operating point as:

(5-6) $MLSF_i = \partial MISOLoss / \partial P_i$

where MISOLoss = Average MISO losses

P_i = Net energy injection into EPNode *i*

- MEC_r is the LMP component representing the marginal cost of Energy at the Reference Bus, *r*.

5.1.1.2 Marginal Congestion Component ("MCC_i") Calculation

MISO calculates the MCC_i at each EPNode *i*. The MCC_i of the LMP at any EPNode *i* can be calculated using the following equation:

$$
\begin{aligned}
\mathrm{MCC}_i = & -\left(\sum_{k=1}^{K} \mathrm{Sens}_{ik} * \mu_k\right) \\
& + \left(\sum_{k=1}^{k'} \mathrm{Sens}_{ik} * \gamma_{\mathrm{RPRU}}(\mathbf{k})\right) \\
& + \left(\sum_{k=1}^{k'} \mathrm{Sens}_{ik} * \gamma_{\mathrm{RPRD}}(\mathbf{k})\right) \\
& + \left(\sum_{k=1}^{k'} \sum_{z}^{Z} \mathrm{Sens}_{ik} * \gamma_{\mathrm{RPRCR}}(\mathbf{k,z})\right) \\
& -\left(\sum_{s=1}^{NS} InyC_{is} * \bar{\mu}_s\right)
\end{aligned}
\quad (5\text{-}7)
$$

Where:

- *K* is the number of transmission flow constraints and generic constraints.
- *NS* is the number of Sub-Regional Power Constraints
- *Z* is the number of Reserve Zones.

- k' is the number of transmission constraints that are modeled as Reserve Procurement constraints.
- μ_k is the shadow price of constraint *k* and is equivalent to the incremental reduction in Energy, Operating Reserve and Reserve Scarcity costs, expressed in $/MWh, that results from an incremental increase in the constraint *k* limit (i.e., "right hand side", or RHS).
- μ_s is the shadow price of the Sub-Regional Power Constraint *s* and is equivalent to the incremental reduction in Energy, Operating Reserve and Reserve Scarcity costs, expressed in $/MWh, that results from an incremental increase in the Sub-Regional Power Constraint *s* limit (i.e., "right hand side", or RHS).
- $\gamma_{RPRU}(k)$ is the shadow price of the reserve procurement regulation-up deployment constraint for constraint k.
- $\gamma_{RPRD}(k)$ is the shadow price of the reserve procurement regulation-down deployment constraint for constraint k.
- $\gamma_{RPRCR}(k,z)$ is the shadow price of the reserve procurement contingency reserve deployment constraint for constraint k in zone z.
- $InyC_{is}$ is the Injection coeficient for Elemental Pricing Node *i* over Sub-Regional Power Balance Constraint *s*.
- $Sens_{ik}$ is the linearized estimate of the change in the constraint k flow resulting from an incremental energy injection at Elemental Pricing Node *i* coupled with an incremental energy withdrawal at the Reference Bus, expressed mathematically as:

(5-8) $Sens_{ik} = \partial Flow_k / \partial P_i$

where $Flow_k$ = Calculated flow for constraint *k* (i.e., LHS of *k*)

Note: *The industry convention is to ignore the effect of losses in the determination of* $Sens_{ik}$.

5.1.1.3 Marginal Energy Component ("MEC$_r$") Calculation

MISO calculates the MEC_r. The MEC_r, which is the LMP at the fixed market Load distributed Reference Bus, can be calculated using the following equation:

(5-9) $$MEC_r = [\sum_{i=1}^{I}\{Demand_i * LMP_i\}]/[\sum_{i=1}^{I}\{Demand_i\}]$$

where $Demand_i$ = Fixed Market Demand at EPNode *i*

5.1.1.4 Locational Marginal Price Calculation

MISO calculates the LMP_i at each EPNode *i*. The LMP at a specific EPNode is equal to the shadow price of the global power balance constraint for that EPNode. As stated earlier, this Shadow Price represents the Energy, Operating Reserve and Reserve Scarcity cost savings that would occur if the global power balance constraint were relaxed by 1 MWh, which means the last MWh of Energy at the Bus would not need to be served. This value corresponds to the marginal energy cost at the Elemental Pricing Nodes. As stated earlier, actual calculations are based on incremental relaxations.

5.1.1.5 Actual Calculation of LMPs and Associated LMP Components

In practice, only three of the four values associated with an LMP and its three components are calculated. The fourth value is determined based on the other three.

For example, in the Day-Ahead SCED algorithm, the LMP is determined as the Shadow Price of the global power balance constraint per Section 5.1.1.4, the MEC_r is determined per Section 5.1.1.3 and the MLC_i is determined per Section 5.1.1.1. The MCC_i is then determined as follows:

(5-10) $MCC_i = LMP_i - MEC_r - MLC_i$

On the other hand, in the Real-Time SCED algorithm, the MEC_r is determined as the Shadow Price of the global power balance constraint (i.e., the Real-Time SCED algorithm uses a global power balance constraint in lieu of global power balance constraints since only constraints activated by a Reliability Coordinator are processed), the MLC_i is determined per Section 5.1.1.1 and the MCC_i is determined per Section 5.1.1.2. The LMP is then determined as follows:

(5-11) $LMP_i = MEC_r + MLC_i + MCC_i$

5.1.2 Hub LMP Calculation

MISO calculates an LMP for each Hub based on the LMPs for the set of EPNodes that comprise the Hub. These hub LMPs are the weighted average of the LMPs at the EPNodes that comprise the hub. For most Hubs, the weights are pre-determined and remain fixed.

The price for Hub *j* is:

$$\text{(5-12)} \quad \text{Hub Price}_j = \sum_{i=1}^{I} \left(W_i * LMP_i \right)$$

Where:

- I is the number of EPNodes in Hub *j*.
- W_i is the weighting factor for EPNodes *i* in Hub *j*. The sum of the weighting factors must add up to 1.

For Hubs that are ARR CPNodes, the weighting factor is calculated in the same manner as weighting factors for Load Zones.

5.1.3 Load Zone Price Calculation

MISO calculates a Load Zone price based on the LMPs for the set of EPNodes that comprise the Load Zone. These Load Zone prices are the weighted average of the LMPs at the individual EPNodes that comprise the Load Zone. The Load Zone EPNode weight is equal to the ratio of the Load Zone Demand at that EPNode to the total Demand of the Load Zone.

The price for Load Zone *j* is:

$$\text{(5-13)} \quad \text{Load Zone Price}_j = \sum_{i=1}^{I} \left(W_i * LMP_i \right)$$

Where:

- I is the number of EPNodes in Load Zone *j*.

  W_i is the weighting factor for EPNode *i* in Load Zone *j*. The sum of the weighting factors must add up to 1. For the Day-Ahead and Real-Time Energy and Operating Reserve Markets, a common set of weighting factors is used for all 24 hours of the operating day and is based on the average of the 24 hourly State Estimator, seven days prior to the Operating Day.

When the Load Zone Price is used for Settlements, it is subject to the following rules:

- Each Load Zone includes only the EPNodes of Asset Owners who are in the Load Zone and who have Load that is represented by that Load Zone's definition. Asset Owners that have metered Load must either be settled at a Load Zone defined by their Load points (zonal settlement) or must have a separate Load Zone created for each Load point (nodal settlement). Asset Owners in retail choice areas where profiling is used in lieu of metering, settlement can be made at an aggregate of all Load Buses in the LBAA.
- MPs who want to be billed at a zonal price must include in their Load Zone all of the Buses where energy deliveries are billed at the zonal price.

5.1.4 Multi-Element Flowgate Shadow Price Calculation

In addition to the calculation of the LMPs, MISO calculates Flowgate Shadow Prices for sets of transmission constraints that have been defined by a Flowgate. MISO calculates the Flowgate Shadow Price on the set of transmission constraints designated as a Flowgate, based on a weighted average of the transmission Flowgate Shadow Prices that comprise the Flowgate:

$$\text{(5-15)}\quad \text{Flowgate Shadow Price } f = \sum_{k=1}^{K} \left(W_k * \mu_k \right)$$

Where:

- *f* is the index of Flowgates.
- *k* is a transmission constraint in the Flowgate *f*.
- *K* is the set of the transmission constraints that comprise Flowgate *f*.
- W_k is the weight attached to each of the *K* transmission elements that comprise Flowgate *f*. The sum of the weighting factors adds up to 1. For Flowgates comprised of one transmission element, the W_k for that element is equal to 1. MISO determines the W_k for transmission elements defined as Flowgates.
- μ_k is the Shadow Price of transmission constraint *k* and is equivalent to the reduction in energy, Operating Reserve and Reserve Scarcity costs, expressed in $/MWh, that results from an incremental increase in the transmission constraint *k* limit.

5.1.5 External Interface Price Calculation

MISO calculates an External Interface price for all external BAs. These prices are generally based on the LMPs for a set of Generator EPNodes that exist in the external BAs, but could be based on other definitions as individual situations warrant. Generally speaking, the set of EPNodes used for an External Interface price is the set of Generators (excluding Nuclear Generation Resources) in the external BA for which the calculation is being done. If the external BA is not in the MISO Network Model, then an electrically approximate BA will be assigned for the BA and the Interface price for that non-modeled BA will use the same Interface price as is used for the electrical approximate BA (e.g., the Southern Company BA Interface bus price is used to settle any transactions that sourced or sink in Florida since facilities in Florida are not currently included in the Network Model, etc.). MISO may need to change which EPNodes are used in the External Interface price calculations as operational experience dictates.

The price for an External Interface** *j* is:

$$\text{(5-16)}\quad \text{External Interface Price} = \left(\sum_{i=1}^{I} LMP_i \right) / I$$

Where:

- *l* is the number of EPNodes included in the External Interface *j*.

** Exception to this is rule is for MHEB interface due to EAR. MHEB interface price is weighted by the capacity of each Generation Resource and EAR Non Injection Non Withdrawal (NINW) Elemental Pricing Node.

5.2 Market Clearing Price Calculation

The Ex Ante Day-Ahead and Ex Ante Real-Time Market Clearing Prices for Regulating Reserve, Spinning Reserve and Supplemental Reserve at a Resource CPNode for Resources with cleared Regulating Reserve, Spinning Reserve and/or Supplemental Reserve at that CPNode are equal to the summation of the applicable Shadow Prices. The Ex Post Day-Ahead and Ex Post Real-Time Market Clearing Prices are calculated through Extended LMP (“ELMP”), an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources, may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region.

During times of Operating Reserve scarcity, Ex Ante LMPs, Ex Post LMPs, Ex Ante MCPs and Ex Post MCPs will be impacted by Scarcity Prices determined by Reserve Demand Curves and will be capped at the Value of Lost Load (“VOLL”). In the unlikely event of an Energy deficiency, all LMPs and MCPs will be set equal to the VOLL. During declared Maximum Generation Emergency events in real time or shortage conditions in Day Ahead Market clearing, Ex Post LMPs and MCPs will also be impacted by Proxy Offers assigned to Emergency Resources, including Emergency ranges of available Resources, External Resources that are qualified as Planning Resources, (for Day Ahead and Real Time), Emergency Energy purchases, Load Modifying Resources and Emergency Demand Response (for real time only). Under emergency pricing, emergency resources as described above are cleared based on their Proxy Offer that is established as the maximum of the Emergency Offer Floor and the resource’s offer if applicable. Two Emergency Offer Floors are established. The Emergency Tier I Offer Floor is established at the initiation of the emergency operating procedure as the highest available economic offer in the Energy Emergency Area considering the costs of committing and dispatching Fast Start Resources. The Emergency Tier II Offer Floor is established at the declaration of a Maximum Generation Emergency event, Step 2 as the highest available economic or emergency offer in the Energy Emergency Area.

The following is true for both Ex Ante and Ex Post MCPs. The MCP formulations allow for the substitution of higher quality reserve products for lower quality reserve products to meet the Operating Reserve requirements to the extent that there is excess higher quality Operating Reserve available and these excess amounts provide a more economical solution[36]. Allowing for this substitution is an effort to ensure that the Energy and Operating Reserve Market clearing for Operating Reserve produces Regulating Reserve MCPs that are greater than or equal to Spinning Reserve MCPs and Spinning Reserve MCPs that are greater than or equal to Supplemental Reserve MCPs. This pricing hierarchy applies zonally, and among resources of like product capabilities. The hierarchy does not necessarily apply, for example, across zones, between a Generation Resource clearing Supplemental Reserves and a DRR Type I clearing Spinning Reserves, or between a SER clearing Regulating Reserves and a Generation Resource clearing Spinning Reserves. However, allowing for substitution of higher quality reserve products for lower quality reserve products necessitates a distinction between the amount of Operating Reserve cleared on a Resource and the amount of physical Operating Reserve dispatched to a Resource via Dispatch Targets for Operating Reserve. Cleared amounts of Operating Reserve products on a Resource will generally be the same as the Dispatch Targets for these Operating Reserve products but will be different if substitution of higher quality reserve products to meet lower quality reserve product requirements has taken place. Settlements will always be based on cleared amounts whereas Operating Reserve *deployment* will always be based on the dispatched amount (i.e., Dispatch Targets), and subject to the deployment needs of a dispatch interval. The example under Section 5.2.4.1 illustrates this difference through substitution of Regulating Reserve to meet Spinning Reserve requirements. It is important to note that due to the physical characteristics of Stored Energy Resources, the Regulating Reserve cleared on Stored Energy Resources is ineligible to substitute for Spinning Reserve and Supplemental Reserve; therefore, SER-based Regulating Reserve MCPs can be less than Spinning Reserve and/or Supplemental Reserve MCPs.

MISO limits the maximum amount of Regulating Reserve that can be cleared on a Regulation Qualified Resource by a configurable percentage of the Market-Wide Regulating Reserve Requirement and limits the amount of Contingency Reserve that can be cleared on Spin Qualified Resource or Supplemental Qualified Resource to a configurable percentage of the

[36] Regulating Reserve is highest quality, Spinning Reserve is next highest quality and Supplemental Reserve is lowest quality.

Market-Wide Contingency Reserve Requirement. The reason for these limits is to prevent a situation where more than that configurable percentage of the cleared Regulating Reserve and/or Contingency Reserve is lost as the result of a single contingency event. MISO may change this limit from time to time as system conditions warrant. Additionally, MISO may limit the amount of Operating Reserve cleared on DRRs-Type I based on Applicable Reliability Standards relating to demand response resource capability to provide Operating Reserve.[37]

Finally, the MCPs for the various Operating Reserve products as determined by the market clearing process will be sufficient to cover the Offer costs of each Resource as well as the Opportunity Costs incurred to allocate a portion of the Resource capacity to the supply of the corresponding Operating Reserve product in lieu of another product. The recovery of both Offered cost and Opportunity Costs via Market Clearing Prices is inherent in the simultaneously co-optimized SCED and SCED-Pricing formulations; thus, the separate calculation of Opportunity Costs is unnecessary.

5.2.1 Demand Curves

MISO utilizes Demand Curves to ensure the appropriate amount of Operating Reserve is cleared under abundant conditions and to ensure the appropriate pricing signals are used under scarce conditions. The Demand Curves are designed such that i) under abundant conditions, the supply curve sets the price and the Demand Curve determines the amount supplied and ii) under scarce conditions, the Demand Curve sets the price and the supply curve determines the amount supplied. Demand Curves are used both for Operating Reserve and the sum of Regulating and Spinning Reserve, and Regulating Reserve, and are applied to both the entire market (Market-Wide Operating Reserve, etc.) and to each Reserve Zone (Zonal Operating Reserve, etc.).

The Market-Wide and Zonal Operating Reserve Demand Curves are designed to communicate the value of capacity to the MISO markets on a market-wide or Reserve Zone basis. Capacity is required by all products (Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve). Therefore, a shortage of Operating Reserve will invoke Scarcity Pricing for all products, indicating that there is a deficiency in overall capacity in the entire market and/or one or more Reserve Zones.

[37] Current settings for the single-Resource limit parameters for providing Regulation Reserve and for providing Contingency Reserve can be found in Attachment B of this BPM.

The Market-Wide and Zonal Regulating and Spinning Reserve Demand Curves are designed to communicate the value of Regulating and Spinning Reserve capacity to the MISO markets on a market-wide or Reserve Zone basis. A shortage of Regulating and Spinning Reserve Demand Curve will invoke Scarcity Pricing for Spinning Reserve Market Clearing Prices, indicating that there is a deficiency in the Regulating and Spinning Reserve capacity in the entire market and/or one or more Reserve Zones. Similarly, Regulating Reserve Market Clearing Prices will reflect the deficiency observed in the Regulating and Spinning Reserve capacity.

The Market-Wide and Zonal Regulating Reserve Demand Curves are designed to communicate the value of Regulation Capability to the MISO market, where Regulation Capability is the ability of Resources to adjust their outputs in both the upward and downward directions by a certain MW amount within a certain period of time in response to an AGC signal. There are three types of Regulation Capability shortages, each of which is described below:

- An overall shortage of capacity (i.e., Operating Reserve) may result in a shortage of Regulation Capability since Regulation Capability requires capacity. This type of shortage is a shortage of Regulating Reserve in the upward direction and Regulating Reserve Scarcity Pricing will impact Ex Ante and Ex Post Energy LMPs and Regulating Reserve Ex Ante and Ex Post MCPs. Spinning Reserve Ex Ante and Ex Post MCPs and Supplemental Reserve Ex Ante and Ex Post MCPs are not impacted by Regulating Reserve scarcity since Regulating Reserve is a higher priority product than Spinning Reserve or Supplemental Reserve. However, under this scenario, there will also be a shortage of Operating Reserve, and Operating Reserve scarcity pricing will impact all products.
- A surplus of on-line or committed capacity could also result in a shortage of Regulation Capability since Regulation Capability requires negative capacity (i.e., loaded capacity than can be unloaded without decommitting the Resource) as well. This type of shortage is a shortage of Regulating Reserve in the downward direction and Regulating Reserve Scarcity Pricing will negatively impact Ex Ante and Ex Post Energy LMPs and positively impact Regulating Reserve Ex Ante and Ex Post MCPs. Again, Spinning Reserve Ex Ante and Ex Post MCPs and Supplemental Reserve Ex Ante and Ex Post MCPs are not impacted by Regulating Reserve scarcity since Regulating Reserve is a higher priority product than Spinning Reserve or Supplemental Reserve.
- A shortage of Resources with Regulation Capability could also result in a shortage of Regulation Capability. This type of shortage of Regulation Capability is in both the

upward and downward directions and will impact Regulating Reserve Ex Ante and Ex Post MCPs. This type of shortage will not impact Ex Ante and Ex Post Energy LMPs, Spinning Reserve Ex Ante and Ex Post MCPs or Supplemental Reserve Ex Ante and Ex Post MCPs since capacity is not a factor.

5.2.1.1 Market-Wide Operating Reserve Demand Curve Development

The MISO Market-Wide Operating Reserve Demand Curves are developed utilizing the following criteria:

- For cleared Market-Wide Operating Reserve levels greater than or equal to the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price is set equal to zero.
- For cleared Market-Wide Operating Reserve levels greater than or equal to 96% but less than 100% of the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price is set equal to $200 per MW.
- For cleared Market-Wide Operating Reserve levels less than 96% but greater than or equal to 4% of the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price for a specific Market-Wide Operating Reserve level is set equal to the product of the VOLL and the estimated conditional probability that a loss of Load will occur given a single Resource contingency will occur. The following assumptions are made in estimating this conditional probability:
    - It will be assumed that a Generation Resource, External Asynchronous Resource or DRR - Type II is operating at its Economic Maximum Limit, or that a DRR - Type I is interrupting demand at its Targeted Demand Reduction Level, at the time of the corresponding Resource contingency.
    - Equal probabilities are assumed for all Resource contingencies.
    - Only Resource contingencies of 100 MW or greater will be considered for the purpose of calculating the estimated conditional probability that a loss of Load will occur given a single Resource contingency will occur.
- The Market-Wide Operating Reserve Demand Curve, which corresponds to the minimum Market-Wide Operating Reserve Demand Curve price for the portion of the curve less than 96% but more than about 11% of the Market-Wide Operating Reserve Requirement, is set equal to $1,100.00 per MW, which is equal to the sum of the Energy Offer Price Cap ($1,000.00 per MWh) and the Contingency Reserve Offer Price Cap ($100.00 per MW).
    - The maximum Scarcity Price of the Market-Wide Operating Reserve Demand Curve, which corresponds to the maximum Market-Wide Operating Reserve

Demand Curve price, is set equal to the VOLL less the Market-Wide Regulating Reserve Demand Curve Price.

- For cleared Market-Wide Operating Reserve levels less than 4% of the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve Price is set equal to VOLL less the Market-Wide Regulating Reserve Demand Curve Price..

- The Market-Wide Operating Reserve Demand Curve will be converted to an approximated stepped curve. The maximum number of steps in the Market-Wide Operating Reserve Demand Curve will be 50 steps.
- The formula to be used to calculate the Market-Wide Operating Reserve Demand Curve price at a specific market-wide Operating Reserve level is given as follows:

  If {Market-Wide Operating Reserve Level < 0},
  Market-Wide Operating Reserve Demand Curve not defined
  else if {Market-Wide Operating Reserve Level ≥ Market-Wide Operating Reserve Requirement},
  Market-Wide Operating Reserve Demand Curve Price = $0 per MW
  else if {96% Market-Wide Operating Reserve Requirement ≤ Market-Wide Operating Reserve Level < 100% Market-Wide Operating Reserve Requirement},
  Market-Wide Operating Reserve Demand Curve Price = $200 per MW
  else if {0 ≤ Market-Wide Operating Reserve Level ≤ 4% Market-Wide Operating Reserve Requirement},
  Market-Wide Operating Reserve Demand Curve Price = VOLL - MWRRDCP

else if {4% Market-Wide Operating Reserve Requirement ≤ Market-Wide Operating Reserve Level ≤ 96% Market-Wide Operating Reserve Requirement},

  Market-Wide Operating Reserve Demand Curve Price(ORL(1))
  = Minimum {Maximum{VOLL * A(ORL(1)) / B, ORMSP}, VOLL -MWRRDCP}
  and,
  Market-Wide Operating Reserve Demand Curve Price(ORL(2))
  = Minimum {Maximum{VOLL * A(ORL(2)) / B, ORMSP}, VOLL - MWRRDCP }
  Where,

    ORL = Operating Reserve Level
    VOLL = Value of Lost Load

A(ORL(1)) = Number of Resources with Maximum Economic Limits or Targeted Demand Reduction Levels greater than or equal to the Operating Reserve Level corresponding to ORL

A(ORL(2)) = Number of Resources with Maximum Economic Limits or Targeted Demand Reduction Levels greater than the Operating Reserve Level corresponding to ORL

B = Number of Resources with Economic Maximum Limits or Targeted Demand Reduction Levels greater than or equal to 100 MW

ORMSP = Operating Reserve Minimum Scarcity Price

MWRRDCP = Market-Wide Regulating Reserve Demand Curve Price

Note: For Market-Wide Operating Reserve levels that have two price levels (e.g., 100 MW, Market-Wide Operating Reserve Requirement, etc.), the Demand Curve is represented by a multi-valued vertical segment connecting the two price levels to represent a stepped curve.

For example, assume that the Market-Wide Operating Reserve requirement is 2,000 MW, the Market-Wide Regulating Reserve Demand Curve Price is calculated to be $1,000 per MW and that there are 20 market Resources with economic maximum limits that are greater than or equal to 100 MW as follows:

Economic Maximum Limit = 1,200 MW	(1 Resource)
Economic Maximum Limit = 800 MW	(4 Resources)
Economic Maximum Limit = 600 MW	(6 Resources)
Economic Maximum Limit = 300 MW	(5 Resources)
Economic Maximum Limit = 100 MW	(4 Resources)

The Demand Curve points are determined as shown in Exhibit 5-1 based on the formula above assuming a stepped curve construction. The highlighted values in Exhibit 5-1 represent Operating Reserve levels that have two price points that are connected by a vertical segment.

Exhibit 5-2 : Market-Wide Operating Reserve Demand Curve Example

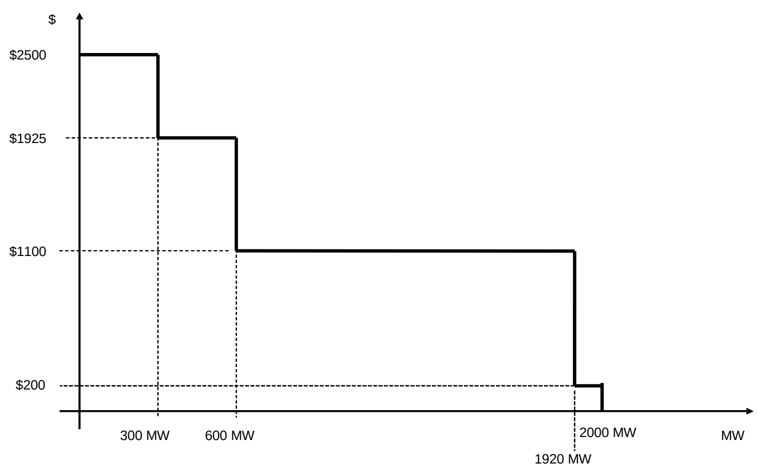


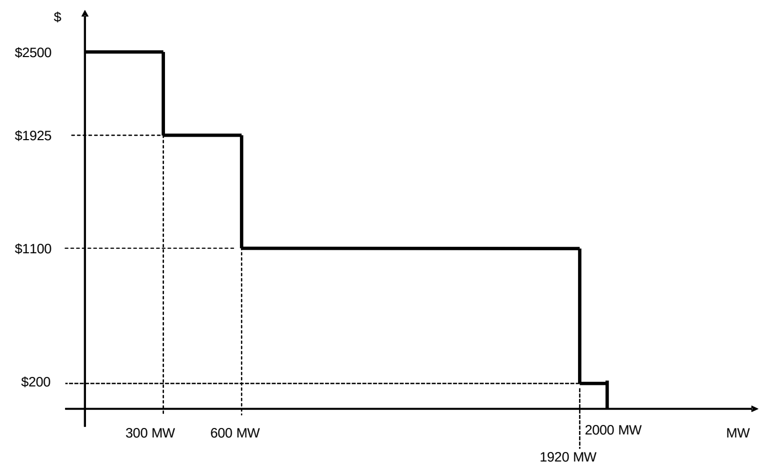
Exhibit 5-2 shows a graphical representation of the Market-Wide Operating Reserve Demand Curve calculated in Exhibit 5-1.

Exhibit 5-1: Market-Wide Operating Reserve Demand Curve Calculation

OR Level MW	Resources GE OR Level (1)	Resource Prob. GE OR Level (2)=(1)/20	Resources GT OR Level (3)	Resource Prob. GE OR Level (4)=(2)/20	VOLL*(2)	VOLL * (4)	ORMSP	VOLL - RRSP	OR Demand Curve Points	OR Demand Curve Points
0	20	1.00	20	1.00	3500	3500	1100	2500	2500	2500
100	20	1.00	16	0.80	3500	2800	1100	2500	2500	2500
200	16	0.80	16	0.80	2800	2800	1100	2500	2500	2500
300	16	0.80	11	0.55	2800	1925	1100	2500	2500	1925
400	11	0.55	11	0.55	1925	1925	1100	2500	1925	1925
500	11	0.55	11	0.55	1925	1925	1100	2500	1925	1925
600	11	0.55	5	0.25	1925	875	1100	2500	1925	1100
700	5	0.25	5	0.25	875	875	1100	2500	1100	1100
800	5	0.25	1	0.05	875	175	1100	2500	1100	1100
900	1	0.05	1	0.05	175	175	1100	2500	1100	1100
1000	1	0.05	1	0.05	175	175	1100	2500	1100	1100
1100	1	0.05	1	0.05	175	175	1100	2500	1100	1100
1200	1	0.05	0	0	175	0	1100	2500	1100	1100
1300	0	0	0	0	0	0	1100	2500	1100	1100
1400	0	0	0	0	0	0	1100	2500	1100	1100
1500	0	0	0	0	0	0	1100	2500	1100	1100

1600	0	0	0	0	0	0	1100	2500	1100	1100
1700	0	0	0	0	0	0	1100	2500	1100	1100
1800	0	0	0	0	0	0	1100	2500	1100	1100
1920	0	0	0	0	0	0	1100	2500	1100	200
2000	0	0	0	0	0	0	1100	2500	200	0

Exhibit 5-2 : Market-Wide Operating Reserve Demand Curve Example



5.2.1.2 Zonal Operating Reserve Demand Curve Development

The Zonal Operating Reserve Demand Curves for specific Reserve Zones are developed utilizing the following criteria:

- For cleared Operating Reserve levels within the Reserve Zone that are greater than or equal to the Operating Reserve requirement of the Reserve Zone, the Zonal Operating Reserve Demand Curve price for the Reserve Zone is set equal to zero;
- For cleared Operating Reserve levels within the Reserve Zone that are less than the Operating Reserve requirement of the Reserve Zone, but greater than or equal to 80% of the Operating Reserve requirement of the Reserve Zone, the Zonal Operating Reserve Demand Curve price for a specific zonal Operating Reserve level is set equal to $200 per MWh.
- For cleared Operating Reserve levels within the Reserve Zone that are less than 80% of the Operating Reserve requirement of the Reserve Zone, but greater than or equal to 10% of the Operating Reserve requirement of the Reserve Zone, the Zonal Operating Reserve Demand Curve price for a specific zonal Operating Reserve level is set equal to $1,100.00 per MW, which is equal to the sum of the Energy Offer

Price Cap ($1,000.00 per MWh) and the Contingency Reserve Offer Price Cap ($100.00 per MW).

- For cleared Operating Reserves levels within the Reserve Zone that are less than 10% of the Operating Reserve requirement of the Reserve Zone, but greater than or equal to zero, the Zonal Operating Reserve Demand Curve price for a specific zonal Operating level is set equal to the VOLL less the Zonal Regulating Reserve Demand Curve Price.
- The formula to be used to calculate the Zonal Operating Reserve Demand Curve price at a specific zonal Operating Reserve Level is given as follows:

If {Zonal Operating Reserve Level < 0},

Zonal Operating Reserve Demand Curve not defined

else if {Zonal Operating Reserve Level ≥ Zonal Operating Reserve Requirement},

Zonal Operating Reserve Demand Curve Price = $0 per MW

else if {0 ≤ Zonal Operating Reserve Level ≤ Zonal Operating Reserve Requirement * 10%},

Zonal Operating Reserve Demand Curve Price

= VOLL - Zonal Regulating Reserve Demand Curve Price

else {if Zonal Operating Reserve Requirement * 10% ≤ Zonal OR Level ≤ Zonal OR Requirement * 80%},

Zonal Operating Reserve Demand Curve Price = $1,100.00 per MW

else {if Zonal Operating Reserve Requirement * 80% ≤ Zonal OR Level ≤ Zonal OR Requirement},

Zonal Operating Reserve Demand Curve Price = $200.00 per MW

Note: For zonal Operating Reserve levels that have two price levels (i.e., 10% of Zonal Operating Reserve requirement or 100% of the Zonal Operating Reserve requirement), the Demand Curve is represented by a multi-valued vertical segment connecting the two price levels.

Exhibit 5-3 : Zonal Operating Reserve Demand Curve Development

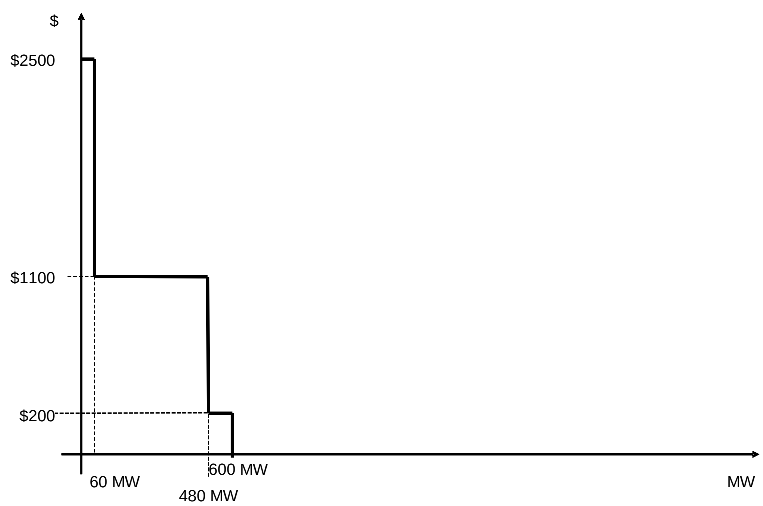


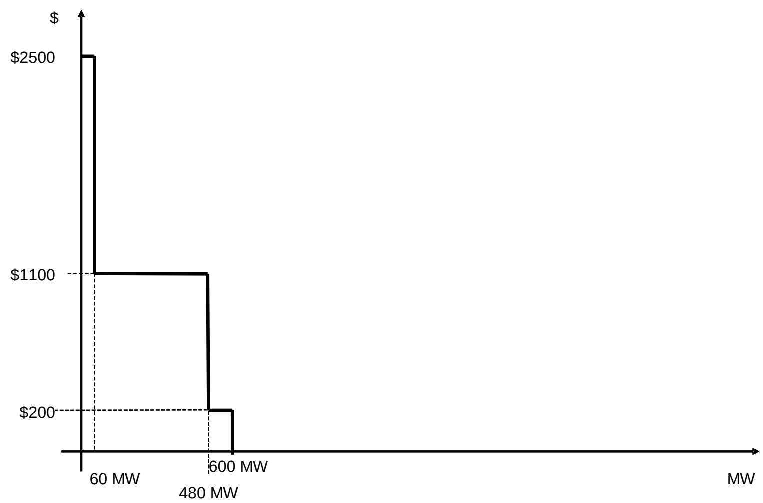
Exhibit 5-3 is illustrative of how the Zonal Operating Reserve Demand Curve is constructed.

In Exhibit 5-3, it is assumed that the Zonal Operating Reserve requirement is 600 MW, and the Zonal Regulating Reserve Demand Curve Price is calculated to be $1,000 per MW.

The Demand Curve points are determined as follows based on the formula above:

$2,500 @ 0 MW
$2,500 @ 60 MW
$1,100 @ 60 MW
$1,100 @ 600 MW
$0 @ 600 MW

Exhibit 5-3 : Zonal Operating Reserve Demand Curve Development



5.2.1.3 Market-Wide Regulating Reserve Demand Curve Development

MISO develops Market-Wide Regulating Reserve Demand Curves based upon the following criteria:

- For cleared Market-Wide Regulating Reserve levels greater than or equal to the Market-Wide Regulating Reserve Requirement, the Market-Wide Regulating Reserve Demand Curve price is set equal to zero;
- For cleared Market-Wide Regulating Reserve levels less than the Market-Wide Regulating Reserve Requirement, the Market-Wide Regulating Reserve Demand Curve price is set equal to the greater of the Contingency Reserve Offer Cap ($100 per MWh) or the average cost per MW of committing and running a peaking unit for an hour as established in Schedule 28 - Section IV of the Tariff. This price will be updated on a monthly basis as outlined in Schedule 28 - Section IV of the Tariff. This price is designated as the "Monthly Average Peaker Proxy Price" in this BPM Section.
- The formula to be used to calculate the Market-Wide Regulating Reserve Demand Curve price at a specific Market-Wide Regulating Reserve level is given as follows:
  If {Market-Wide Regulating Reserve Level < 0},

  Market-Wide Regulating Reserve Demand Curve not defined

else if {Market-Wide Regulating Reserve Level ≥ Market-Wide Regulating Reserve Requirement},

Market-Wide Regulating Reserve Demand Curve Price = $0 per MW

else if {0 ≤ Market-Wide Regulating Reserve Level ≤ Market-Wide Regulating Reserve Requirement},

Market-Wide Regulating Reserve Demand Curve Price

= Maximum {Contingency Reserve Offer Cap, Monthly Average Peaker Proxy Price}

Exhibit 5-4 is illustrative of how the Regulating Reserve Demand Curve is constructed. In Exhibit 5-4, it is assumed that the Market-Wide Regulating Reserve Requirement is 1,000 MW, and the Monthly Average Peaker Proxy Price is calculated as $175.00.

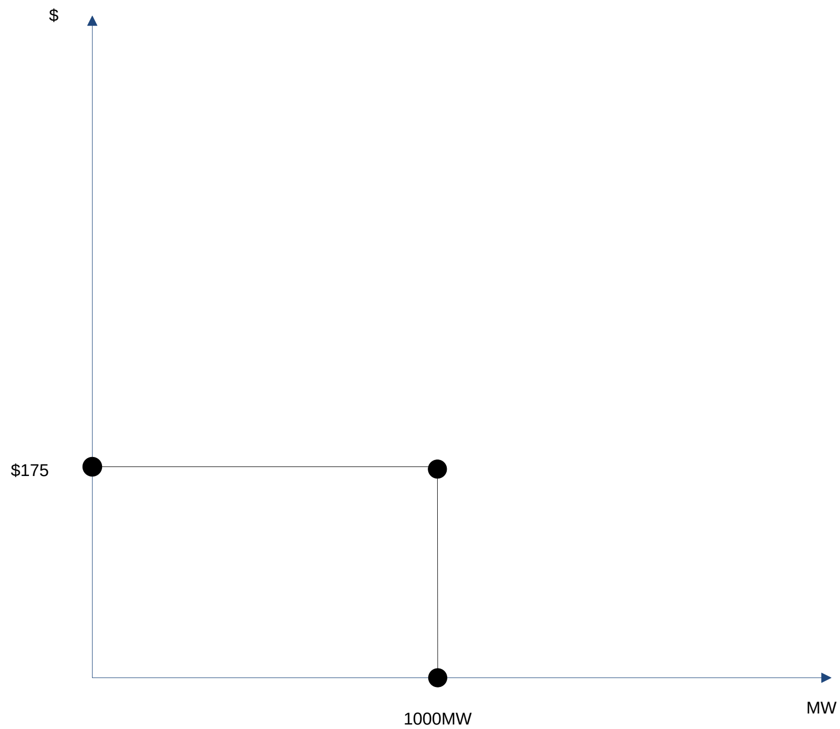
The Demand Curve points are determined as follows based on the formula above:

$175 @ 0 MW

$175 @ 1,000 MW

$0 @ 1,000 MW

Exhibit 5-4 : Market-Wide Regulating Reserve Demand Curve Development



5.2.1.4 Zonal Regulating Reserve Demand Curve Development

MISO develops Zonal Regulating Reserve Demand Curves based upon the following criteria:

- For cleared Regulating Reserve levels within the Reserve Zone that are greater than or equal to the Regulating Reserve requirement within the Reserve Zone, the Zonal Regulating Reserve Demand Curve price is set equal to zero;
- For cleared Regulating Reserve levels within the Reserve zone that are less than the Regulating Reserve requirement within the Reserve Zone, the Zonal Regulating Reserve Demand Curve price is set equal to Market-Wide Regulating Reserve Demand Curve price as described above.
- The formula to be used to calculate the Zonal Regulating Reserve Demand Curve price at a specific Zonal Regulating Reserve level is given as follows:

  If {Zonal Regulating Reserve Level < 0},

  Zonal Regulating Reserve Demand Curve not defined

  else if {Zonal Regulating Reserve Level ≥ Zonal Regulating Reserve Requirement},

  Zonal Regulating Reserve Demand Curve Price = $0 per MW else if {0 ≤ Zonal Regulating Reserve Level ≤ Zonal Regulating Reserve Requirement},

Zonal Regulating Reserve Demand Curve Price

= Market-Wide Regulating Reserve Demand Curve Price

Exhibit 5-5 Exhibit 5-5 is illustrative of how the Zonal Regulating Reserve Demand Curve is constructed. In Exhibit 5-5, it is assumed that the Zonal Regulating Reserve requirement is 25 MW, and the Market-Wide Regulating Reserve Demand Curve Price is set at $175.00.

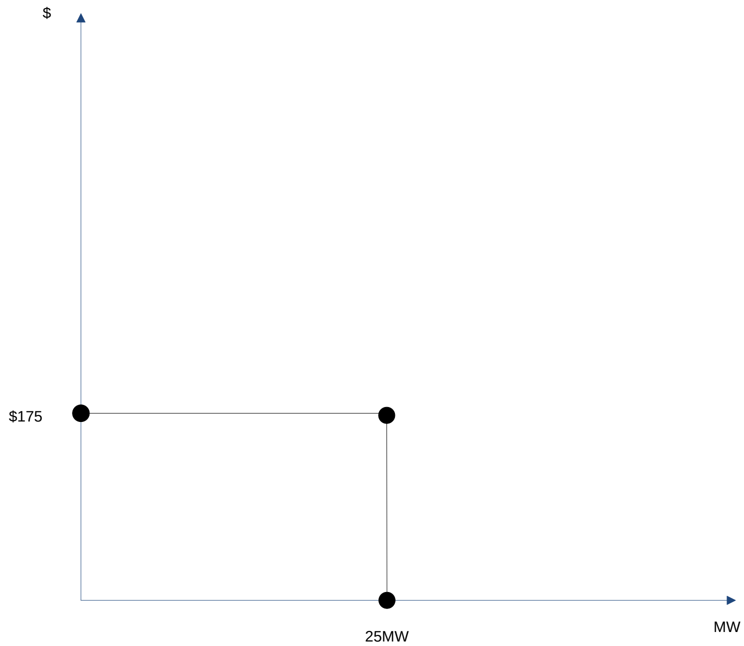
The demand curve points are determined as follows based on the formula above:

$175 @ 0 MW

$175 @ 25 MW

$0 @ 25 MW

Exhibit 5-5: Zonal Regulating Reserve Demand Curve Development



5.2.1.5 Market -Wide Regulating and Spinning Reserve Demand Curve Development

MISO develops Market-Wide Regulating and Spinning Reserve Demand Curves based on the following criteria:

- For cleared Market-Wide Regulating and Spinning Reserve levels greater than or equal to the Market-Wide Regulating and Spinning Reserve Requirement, the Market-Wide Regulating and Spinning Reserve Demand Curve price is set equal to zero;
- For cleared Market-Wide Regulating and Spinning Reserve levels less than the Market-Wide Regulating and Spinning Reserve Requirement, the following Market-Wide Regulating and Spinning Reserve Demand Curve prices are used:
  - For cleared Market-Wide Regulating and Spinning Reserve levels greater than ninety percent (90%) but less than one hundred percent (100%) of the Market-Wide Regulating and Spinning Reserve, the Market-Wide Regulating and Spinning Reserve Demand Curve price is $65 per MWh.
  - For cleared Market-Wide Regulating and Spinning Reserve levels less than ninety percent (90%), of the Market-Wide regulating and Spinning Reserve, the

Market Wide Regulating and Spinning Reserve Demand Curve price is $98 per MWh.

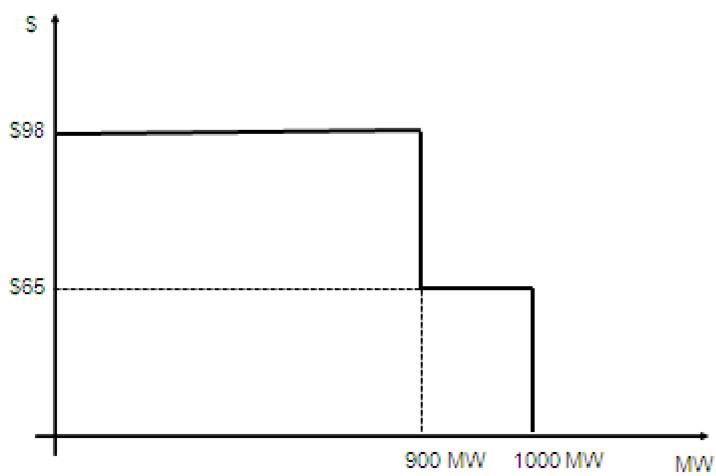
Exhibit 5-6 is illustrative of how the Market-Wide Regulating and Spinning Reserve Demand Curve is constructed. In

Exhibit 5-6, it is assumed that the Market-Wide Regulating and Spinning Reserve Requirement is 1,000 MW.

The Demand Curve points are determined as follows based on the formula above:

$98 @ 0 MW
$65 @ 900 MW to 1,000 MW
$0 @ 1,000 MW

Exhibit 5-6: Market-Wide Regulating and Spinning Reserve Demand Curve Development



5.2.1.6 Zonal Regulating and Spinning Reserve Demand Curve Development

MISO develops Zonal Regulating and Spinning Reserve Demand Curves based on the following criteria:

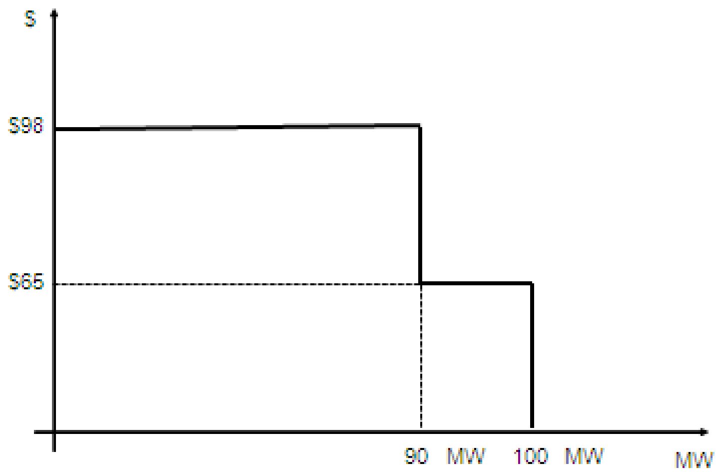
- For cleared Zonal Regulating and Spinning Reserve levels greater than or equal to the Zonal Regulating and Spinning Reserve Requirement, the Zonal Regulating and Spinning Reserve Demand Curve price is set equal to zero;
- For cleared Zonal Regulating and Spinning Reserve levels less than the Zonal Regulating and Spinning Reserve Requirement, the following Zonal Regulating and Spinning Reserve Demand Curve prices are used:
    - For cleared Regulating and Spinning Reserve levels within a Reserve Zone greater than ninety percent (90%) but less than one hundred percent (100%) of the Reserve Zone's Regulating and Spinning Reserve, the Zonal Regulating and Spinning Reserve Demand Curve price is $65 per MWh.
    - For cleared Regulating and Spinning Reserve levels within a Reserve Zone less than ninety percent (90%), of the Reserve Zone's Regulating and Spinning Reserve, the Zonal Regulating and Spinning Reserve Demand Curve price is $98 per MWh.

Exhibit 5-7 is illustrative of how the Zonal Regulating and Spinning Reserve Demand Curve is constructed. In Exhibit 5-7, it is assumed that the Zonal Regulating and Spinning Reserve Requirement is 100 MW.

The Demand Curve points are determined as follows based on the formula above:

$98 @ 0 MW
$65 @ 90 MW to 100 MW
$0 @ 100 MW

Exhibit 5-7: Zonal Regulating and Spinning Reserve Demand Curve Development



5.2.1.7 Market Wide Up Ramp Capability and Down Ramp Capability Demand Curve Development

The Market-Wide Up and Down Ramp Capability Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. MISO develops Market Wide Up Ramp Capability and Down Ramp Capability based on the following criteria:

- For cleared Market Wide Ramp Capability levels greater than or equal to the corresponding Requirement, the Ramp Capability Curve price is set equal to zero;
- For cleared Market Wide Ramp Capability levels less than the corresponding Requirement, the Demand Curve of $5 per MWh is applied

5.2.1.8 Ramp Procurement Minimum Reserve Zone Up Ramp Capability and Down Ramp Capability Demand Curve Development

Ramp Procurement Minimum Reserve Zone Up Ramp Capability and Down Ramp Capability Down requirement constraints are used to ensure that for a specific subset of transmission constraints, the flow across the transmission constraint will be within limits under circumstances when all cleared Up Ramp Capability or Down Ramp Capability are deployed in the corresponding direction. For cleared values that would violate this requirement, the Demand Curve of $20 per MWh is applied.

5.2.2 Market Clearing Price Calculation Details

The MCP calculations, including Shadow Price descriptions, are described below.

$$\mathbf{MCP_{REG} = \gamma_{OR}(z) + \gamma_{RS}(z) + \gamma_{RR}(z) + \gamma_{RPOR}(z) + \gamma_{RPRS}(z) + \gamma_{RPRR}(z) + \gamma_{GOR} + \gamma_{GRS}}$$

$$\mathbf{MCP_{REGSER} = \gamma_{OR} + \gamma_{MSERR} + \gamma_{RS} + \gamma_{RR} + \gamma_{GOR}}$$

$\mathbf{MCP_{RegMile}}$ - see description below

$$\mathbf{MCP_{SPING} = \gamma_{OR}(z) + \gamma_{RS}(z) + \gamma_{RPOR}(z) + \gamma_{RPRS}(z) + \gamma_{GOR} + \gamma_{GRS}}$$

$$\mathbf{MCP_{SPIND} = \gamma_{OR}(z) + \gamma_{RS}(z) + \gamma_{RPOR}(z) + \gamma_{RPRS}(z)}$$

$$\mathbf{MCP_{SUPPG} = \gamma_{OR}(z) + \gamma_{RPOR}(z) + \gamma_{GOR}}$$

$$\mathbf{MCP_{SUPPD} = \gamma_{OR}(z) + \gamma_{RPOR}(z)}$$

$$\mathbf{MCP_{URCP} = \gamma_{RPURCP}(z)}$$

$$\mathbf{MCP_{DRCP} = \gamma_{RPDRCP}(z)}$$

Where:

- **$\mathbf{MCP_{REG}}$** = market clearing price for non-SER Regulating Reserve. Non-SER Regulating Reserve includes Regulating Reserve cleared on Generation Resources, DRRs – Type II and External Asynchronous Resources;

- **MCP_{REGSER}** = market clearing price for SER-based Regulating Reserve. SER-based Regulating Reserve includes Regulating Reserve cleared on Stored Energy Resources; **MCP_{REGSER}** is less than or equal to **MCP_{REG}**.
- **$MCP_{RegMile}$** = market clearing price for Regulation Mileage. A Regulation Mileage MCP is calculated ONLY for the Real-Time market. The Real-Time Regulation Mileage MCP is the greatest Regulation Mileage Offer among the following set of resources: (1) all Resources that have a Day-Ahead schedule for Regulating Reserve AND that had a Regulating Reserve Dispatch Status of "Economic" for the Day-Ahead market AND that clear for Regulating Reserve in the Real-Time Dispatch Interval; (2) all Resources that do not have a Day-Ahead schedule for Regulating Reserve AND that have a Regulating Reserve Dispatch Status set to "Economic" in the Real-Time Market, AND that clear for Regulating Reserve in the Real-Time Dispatch Interval.[38]
- **MCP_{SPING}** = market clearing price for generation-based Spinning Reserve. Generation-based Spinning Reserve includes Spinning Reserve cleared on Generation Resources, DRRs – Type II and External Asynchronous Resources;
- **MCP_{SPIND}** = market clearing price for demand-based Spinning Reserve. Based on current reliability standards, DRRs-Type II are considered generation-based, not demand-based and DRRs-Type I do not qualify to provide Spinning Reserve;
- **MCP_{SUPPG}** = market clearing price for generation-based Supplemental Reserve. Generation-based Supplemental Reserve includes Supplemental Reserve cleared on Generation Resources, DRRs – Type II and External Asynchronous Resources;
- **MCP_{SUPPD}** = market clearing price for demand-based Supplemental Reserve. Based on current reliability standards, DRRs-Type II are considered generation-based, not demand-based and DRRs-Type I may qualify to provide Supplemental Reserve;
- **γ_{OR}** = the Shadow Price of the MISO market-wide Operating Reserve balance constraint. Under abundant capacity conditions, this Shadow Price represents the marginal cost of supplying Operating Reserve. Under scarce capacity conditions, this Shadow Price represents the Operating Reserve Demand Curve price at the cleared market-wide Operating Reserve level. This Shadow Price will be equal to zero if the

[38] There are two portions of cleared Regulating Reserve. For portion 1, the entire regulating reserve offer is considered during the clearing process; for portion 2, just the capacity offer is considered. Here, by "Resources that clear for Regulating Reserve", portion 1 is meant. For details regarding these formulations, see Attachment D to this BPM; specifically, "ClearedRegRes1" and ClearedRegRes2".

cleared MISO market-wide Operating Reserve exceeds the MISO market-wide Operating Reserve requirement due to: (i) the need to meet the Operating Reserve requirements of one or more Reserve Zones; or (ii) an excessive amount of self-scheduled Operating Reserve within the market;

- γ_{RS} = the Shadow Price of the MISO market-wide Regulating Reserve plus Spinning Reserve constraint. This Shadow Price represents the marginal cost of satisfying the Regulating Reserve plus Spinning Reserve requirement. This Shadow Price will be equal to zero if the cleared MISO market-wide Regulating Reserve plus Spinning Reserve exceeds the MISO market-wide Regulating Reserve plus Spinning Reserve requirement due to: (i) the need to meet the Regulating Reserve plus Spinning Reserve requirements of one or more Reserve Zones; (ii) an excessive amount of self-scheduled Regulating Reserve and/or Spinning Reserve within the market; or (iii) substitution of Regulating Reserve and/or Spinning Reserve for Supplemental Reserve;
- γ_{RR} = The Shadow Price of the MISO market-wide Regulating Reserve constraint. Under abundant regulation capability conditions, this Shadow Price represents the marginal cost of supplying Regulating Reserve. Under scarce regulation capability conditions, this Shadow Price represents the Regulating Reserve Demand Curve price at the cleared market-wide Regulating Reserve level. This Shadow Price will be equal to zero if the cleared MISO market-wide Regulating Reserve exceeds the MISO market-wide Regulating Reserve requirement due to: (i) the need to meet the Regulating Reserve requirements of one or more Reserve Zones; (ii) an excessive amount of self-scheduled Regulating Reserve within the market; and/or (iii) substitution of Contingency Reserve with Regulating Reserve;
- γ_{MSERR} = The Shadow Price of the MISO Maximum Stored Energy Resource Regulation constraint. This shadow price represents the marginal cost of satisfying the maximum SER-based regulation requirement. This Shadow Price will be equal to zero if the quantity of Regulating Reserve cleared on Stored Energy Resources is less than the Market-Wide Regulating Reserve Demand Requirement. If the entire Market-Wide Regulating Reserve Demand Requirement is satisfied by Regulating Reserve cleared on Stored Energy Resource, this shadow price may be non-zero; more specifically, the shadow price will be negative, reflecting the inability of Regulating Reserve cleared on Stored Energy Resources to substitute and satisfy Spinning and/or Supplemental Reserve Requirements.

- $\gamma_{OR}(z)$ = The Shadow Price of the Reserve Zone z Off-line Studies Operating Reserve constraint. Under abundant capacity conditions within Reserve Zone z, this Shadow Price represents the marginal cost of supplying Operating Reserve within Reserve Zone z. Under scarce capacity conditions within Reserve Zone z, this Shadow Price represents the Reserve Zone z Operating Reserve Demand Curve price at the cleared market-wide Operating Reserve level within Reserve Zone z. This Shadow Price will be equal to zero if the cleared Operating Reserve within Reserve Zone z exceeds the Operating Reserve requirement of Reserve Zone z due to: (i) the need to meet the MISO market-wide Operating Reserve requirement; or (ii) an excessive amount of self-scheduled Operating Reserve within Reserve Zone z;
- $\gamma_{RS}(z)$ = The Shadow Price of the Reserve Zone z Off-line Studies Regulating Reserve plus Spinning Reserve constraint. This Shadow Price represents the marginal cost of satisfying the Regulating Reserve plus Spinning Reserve requirement within Reserve Zone z. This Shadow Price will be equal to zero if the cleared Regulating Reserve plus Spinning Reserve within Reserve Zone z exceeds the Regulating Reserve plus Spinning Reserve requirement of Reserve Zone z due to: (i) the need to meet the MISO market-wide Regulating Reserve plus Spinning Reserve requirement; (ii) an excessive amount of self-scheduled Regulating Reserve and/or Spinning Reserve within Reserve Zone z; or (iii) substitution of Regulating Reserve and/or Spinning Reserve for Supplemental Reserve within Reserve Zone z;
- $\gamma_{RR}(z)$ = The Shadow Price of the Reserve Zone z Off-line Studies Regulating Reserve constraint. Under abundant regulation capability conditions within Reserve Zone z, this Shadow Price represents the marginal cost of supplying Regulating Reserve in Reserve Zone z. Under scarce regulation capability conditions within Reserve Zone z, this Shadow Price represents the Reserve Zone z Regulating Reserve Demand Curve price at the cleared Regulating Reserve level within Reserve Zone z. This Shadow Price will be equal to zero if the cleared Regulating Reserve within Reserve Zone z exceeds the Regulating Reserve requirement of Reserve Zone z due to: (i) the need to meet the MISO market-wide Regulating Reserve requirement; (ii) an excessive amount of self-scheduled Regulating Reserve within Reserve Zone z; or (iii) substitution of Contingency Reserve with Regulating Reserve within Reserve Zone z;
- $\gamma_{RPOR}(z)$ = The Shadow Price of the Reserve Procurement Minimum Reserve Zone Operating Reserve constraint. This Shadow Price represents the marginal cost of

ensuring that the sum of the minimum Reserve Zone regulation, spinning, and supplemental reserve requirements is greater than the market-wide Operating Reserve requirement;

- $\gamma_{RPRS}(z)$ = The Shadow Price of the Reserve Procurement Minimum Reserve Zone Regulating plus Spinning Reserve constraint. This Shadow Price represents the marginal cost of ensuring that the sum of the minimum Reserve Zone regulation and spinning reserve requirements is greater than the market-wide regulating plus spinning reserve requirement;
- $\gamma_{RPRR}(z)$ = The Shadow Price of the Reserve Procurement Minimum Reserve Zone Regulating Reserve constraint. This Shadow Price represents the marginal cost of ensuring that the sum of the minimum Reserve Zone Regulating Reserve requirement is greater than the market-wide Regulating plus Spinning Reserve requirement;
- γ_{GOR} = The Shadow Price of the MISO Non-DRR1 Operating Reserve constraint. This Shadow Price represents the marginal cost of satisfying the generation-based Operating Reserve requirement;
- γ_{GRS} = The Shadow Price of the MISO Non-DRR1 Regulating plus Spinning Reserve constraint. This Shadow Price represents the marginal cost of satisfying the generation-based Regulating plus Spinning Reserve requirement.
- $\gamma_{RPURCP}(z)$ = The Shadow Price of the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint that ensures the cleared Up Ramp Capability in a zone can be converted to Energy when needed while respecting transmission constraints. This Shadow Price represents the marginal cost of supplying Up Ramp Capability Product in satisfying the minimum Reserve Zone Up Ramp Capability requirement;
- $\gamma_{RPDRCP}(z)$ = The Shadow Price of the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint that ensures the cleared Down Ramp Capability in a zone can be converted to Energy when needed while respecting transmission constraints. This Shadow Price represents the marginal cost of Down Ramp Capability Product in satisfying the minimum Reserve Zone Down Ramp Capability requirement.

5.2.3 Market Clearing under Emergency Shortage Conditions

System Emergency Shortage Conditions may occur, infrequently but the price signals during these periods are important to incent desired behavior that will support system reliability and provide more accurate signals reflective of these conditions. Market-clearing prices can be inefficiently depressed if Emergency Resources, including Emergency ranges of available resources, External Resources that are qualified as Planning Resources (for day-ahead and real-time), and Load Modifying Resources, Emergency Demand Response, and Emergency Energy Purchases (for real-time) are deployed but are not appropriately valued or unable to participate in pricing. Emergency pricing in the Ex Post Pricing calculations will meet the following objectives:

- Ensure economic prices during an emergency event, resulting in evaluating the emergency resources available and acknowledging MISO's emergency operating procedures
- Incent efficient Market Participant behavior, including the development of adequate supply resources and demand-response capability
- Promote Market Participants' competitive offers and optimization-based and cost-efficient operation of MISO's markets.

The emergency pricing logic is limited to Maximum Generation Emergencies (shortage conditions). It does not apply to minimum generation emergencies (surplus conditions). Note also that generation emergencies may be declared on the LBA-level, Regional level, or MISO-wide.

During Emergency events a Proxy Offer is established for emergency resources that are scheduled during Emergency Operating Procedures (EOP-002) in Real Time or under System Shortages in Day Ahead. In Real-Time the steps taken by MISO during a Maximum Generation Emergency procedure generate two tiers of emergency pricing. The first tier reflects escalating above 'System Alert' but below 'Step 2'. The second tier reflects initiation of Load Management at or above Step 2 of an EOP. The Emergency Tier I Offer Floor will be established, equal to the highest available economic offer in the affected area. This Offer Floor will be determined based on the ELMP logic including start-up and no-load costs of Fast Start Resources and also the cost of feasible offline Fast Start Resources. As the system progresses deeper into the emergency, Emergency Tier II Offer Floor will be used to further prevent the price from dropping. This Offer Floor is established at the initiation of Step II of the Emergency Event in the affected area using the same ELMP logic as the highest available economic or emergency energy offer.

Emergency resources' Proxy Offer will be established as the higher of the resource offer if available and the applicable Emergency Offer Floor. ELMP logic is then applied to allow these emergency resources to be able to participate in price setting. Inside the ELMP logic, a non-fast start emergency unit is also allowed to participate in partial clearing.

5.2.4 Market Clearing Price Calculation Examples

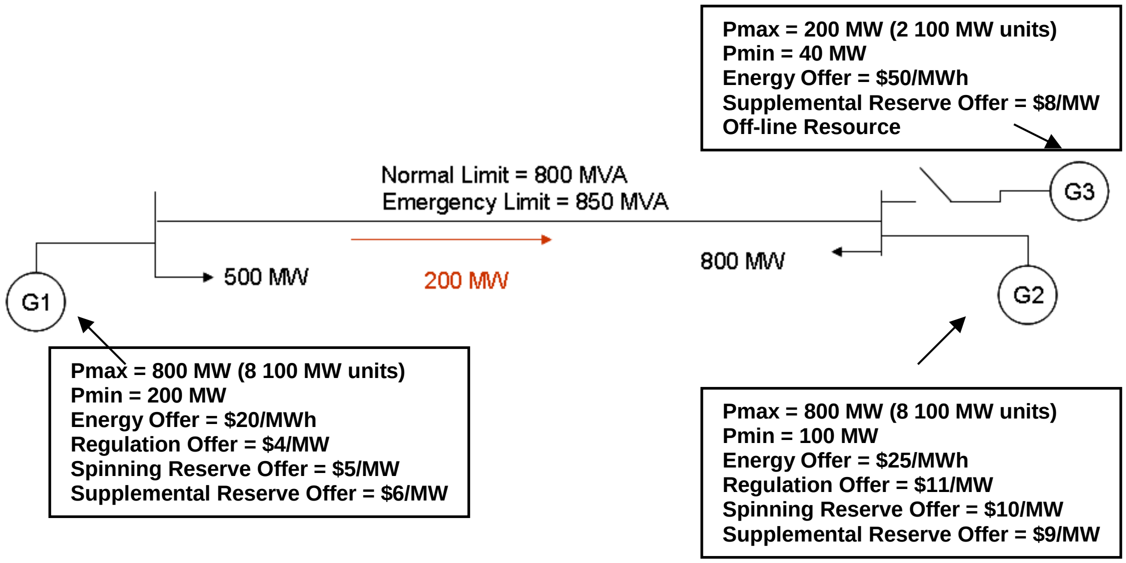
The following examples illustrate how MCPs for Regulation and Contingency Reserve are calculated based upon the methodology described above under varying input assumptions. For simplicity, all examples assume a two generating unit system.

5.2.4.1 Co-optimized Clearing Example – No Scarcity Pricing

Consider the two Bus system as depicted in Exhibit 5-8 For this example, two 800 MW[39] on-line generating units and one off-line generating unit with a capacity of 200 MW are available to meet a 1300 MW Load requirement, a 50 MW Regulating Reserve requirement and a 100 MW Contingency Reserve requirement of which 50 MW must be Spinning Reserve. None of the three generating units are designated as a Fast Start Resource. For simplicity, Energy Offers for each generating unit represent the price for the entire Energy output. Also, in this example, generating unit 1 has a Regulating Reserve Offer that is less than its Spinning Reserve Offer thus allowing for economic substitution of Regulating Reserve to meet the Spinning Reserve requirement.

[39] Each Resource consists of eight 100 MW units.

Exhibit 5-8: Co-optimized Clearing, No Scarcity – Assumptions



Note that none of the resources in the example are designated as Fast Start Resources so the Ex Ante LMP is equal to the Ex Post LMP and is denoted as simply LMP. For the same reason, each individual Ex Ante MCP is equal to the appropriate Ex Post MCP. For simplicity we are assuming that sufficient ramp capability is clearing off of available ramp at no additional costs.

Exhibit 5-9 summarizes the results of the co-optimized solution to meet the Energy, Regulating Reserve and Contingency Reserve requirements:

Exhibit 5-9: Co-optimized Clearing, No Scarcity – Results

Results Summary	Generator 1	Generator 2	Generator 3
Cleared Energy - MWh	700	600	0
LMP - $/MWh	25	25	25
Cleared Regulating Reserve - MW	100	0	0
Dispatch Target Regulating Reserve - MW	50	0	0
Regulation MCP - $/MW	9	9	9
Cleared Spinning Reserve - MW	0	0	0
Dispatch Target Spinning Reserve - MW	50	0	0
Spinning Reserve MCP - $/MW	9	9	9
Cleared Supplemental Reserve - MW	0	0	50
Dispatch Target Supplemental Reserve - MW	0	0	50
Supplemental Reserve MCP	8	8	8

The sections below describe how the MCPs shown in Exhibit 5-9 were calculated, beginning with the calculation of the Shadow Prices for the Operating Reserve, Regulating plus Spinning Reserve and Regulating Reserve constraints. The example assumes that there are no binding zonal constraints or minimum generation-based constraints.

Operating Reserve Shadow Price (γ_{OR})

In this case, where the Operating Reserve constraint is the sum of the Regulation requirement and the Contingency Reserve requirement, or 150 MW, the shadow price of the Operating Reserve constraint is calculated as the change in cost that would be realized by reducing the Operating Reserve requirement to 149 MW. Since reducing this requirement has no impact on meeting the Regulation or Spinning Reserve requirements and there is no generating unit re-dispatch required (i.e., there is no Opportunity Cost component), the Shadow Price is equal to the Supplemental Reserve availability cost reduction of $8/MW ($8 cost reduction / 1 MW).

Regulation plus Spinning Reserve Shadow Price (γ_{RS})

In this case, where the Regulating plus Spinning Reserve requirement is equal to 100 MW[40], the Shadow Price of the Regulating plus Spinning Reserve constraint is calculated as the change in cost that would be realized by reducing the Regulating plus Spinning Reserve requirement to 99 MW while holding the Operating Reserve requirement at 150 MW. Reducing the Regulating plus Spinning Reserve requirement would create an incremental Energy cost savings = $5 since Generator 1's output would increase by 1 MW (at $20/MW) and Generator 2 would reduce output by 1 MW (at $25/MW). This $5 incremental Energy cost savings also represents Generator 1's Opportunity Cost since this is the margin that Generator 1 would make from an additional 1 MW sale of Energy. Additionally, a reduced cost of $4 will be realized that is equal to the Regulating Reserve availability Offer price for Generator 1 multiplied by 1 MW. Finally, since the Operating Reserve requirement must be kept at 150 MW, the Supplemental Reserve requirement must be increased to 51 MW resulting in an increase in Supplemental Reserve cost of $8. The Regulating plus Spinning Reserve Shadow Price is then equal to: ($5 Opportunity Cost + $4 Regulating Reserve availability cost savings - $8 Supplemental Reserve cost increase) / 1 MW = $1/MW.

Regulating Reserve Shadow Price (γ_{RR})

In this case, where the Regulation constraint is a Regulating Reserve requirement of 50 MW, the Shadow Price of the Regulating Reserve constraint is calculated as the change in cost that would be realized by reducing the Regulating Reserve requirement to 49 MW while holding the Regulating plus Spinning Reserve requirement at 100 MW. Because reducing the Regulating Reserve requirement by 1 MW is offset by the need to increase the amount of Spinning Reserve requirement by 1 MW in order to maintain the 100 MW requirement, no re-dispatch is required and, therefore, there is no Opportunity Cost component. In addition, since the Spinning Reserve availability cost is greater than the Regulating Reserve availability cost for Generator 1 and Regulating Reserve can be used to meet Spinning Reserve requirements, Regulating Reserve would be procured to meet the 1 MW increase in Spinning Reserve requirement, resulting in a change in Regulating plus Spinning Reserve availability costs of $0. The Regulating Reserve Shadow Price is then equal to $0/MW.

[40] The Regulating plus Spinning Reserve requirement is equal to the sum of the Regulating Reserve requirement and the Spinning Reserve requirement.

Supplemental Reserve MCP

By definition, the generation based Supplemental Reserve $MCP_{SUPPG} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{GOR}$ and the demand-based Supplemental Reserve $MCP_{SUPPD} = \gamma_{OR} + \gamma_{OR(z)}$. In this example, there is no binding zonal Operating Reserve requirement or minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{GOR} = \gamma_{OR(z)} = 0$ and $MCP_{SUPPG} = MCP_{SUPPD}$. The Supplemental Reserve MCP_{SUPPG} and MCP_{SUPPD} are then equal to the Shadow Price of the Operating Reserve constraint, or $8/MW.

Spinning Reserve MCP

By definition, the generation-based Spinning Reserve $MCP_{SPING} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z)} + \gamma_{GOR}$ and the demand-based Spinning Reserve $MCP_{SPIND} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z).}$ In this example, there is no binding zonal Operating Reserve requirement, no binding zonal Regulating plus Spinning Reserve requirement and no binding minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{OR(z)} = \gamma_{RS(z)} = \gamma_{GOR} = 0$ and $MCP_{SPING} = MCP_{SPIND}$. The Spinning Reserve MCP_{SPING} and MCP_{SPIND} are then equal to the Shadow Price of the Operating Reserve constraint plus the Shadow Price of the Regulating plus Spinning Reserve constraint, or $8/MW + $1/MW = $9/MW. It is important to note that the amount of cleared Spinning Reserve MWs is equal to zero in this case as Regulating Reserve is being procured to meet the Spinning Reserve requirement.

Regulating Reserve MCP

By definition, the generation-based Regulating Reserve $MCP_{REGG} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z)} + \gamma_{RR} + \gamma_{RR(z)} + \gamma_{GOR.}$ In this example, there is no binding zonal requirements or binding minimum Non-DRR1 Operating Reserve requirements and therefore, $\gamma_{RR(z)} = \gamma_{RS(z)} = \gamma_{OR(z)} = \gamma_{GOR} = 0$. The Regulating Reserve MCP_{REG} is then equal to the Shadow Price of the Operating Reserve constraint plus the Shadow Price of the Regulating plus Spinning Reserve constraint plus the Shadow Price of the Regulating Reserve constraint, or $8/MW + $1/MW + $0/MW = $9/MW. It is important to note that the amount of cleared Regulating Reserve MWs is greater than the Regulating Reserve requirement in this case as additional Regulating Reserve is being procured to meet the Spinning Reserve requirement.

5.2.4.2 Co-optimized Clearing Example – Contingency Reserve Scarcity

Consider the two Bus system as depicted in Exhibit 5-10. For this example, two on-line 800 MW[41] Resources are available to meet a 1475 MW Load requirement, a 50 MW Regulation requirement and a 100 MW Contingency Reserve requirement of which 50 MW must be Spinning Reserve. None of the three generating units are designated as a Fast Start Resource. For simplicity, Energy Offers for each generating unit represent the price for the entire Energy output. Additionally, the example also assumes that there are no binding zonal constraints or minimum generation-based constraints. For this example, the applicable Operating Reserve Demand Curve Scarcity Price is $1100/MW.

Exhibit 5-10: Co-optimized Clearing, Contingency Reserve Scarcity – Assumptions

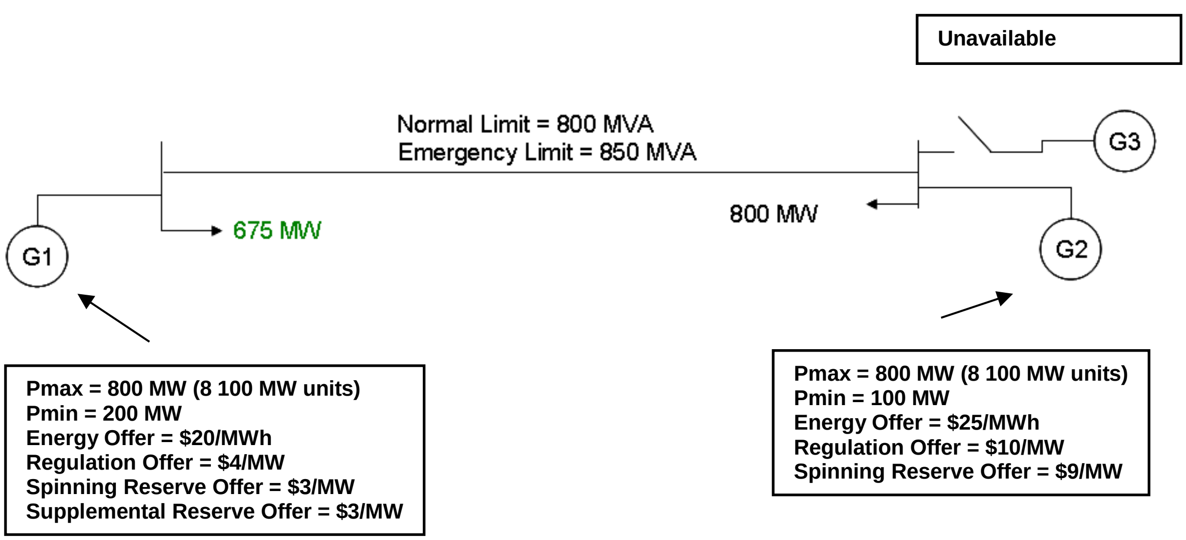


Exhibit 5-11summarizes the results of the co-optimized solution to meet the Energy, Regulation and Contingency Reserve requirements. In this example, the Supplemental Reserve requirement of 50 MW cannot be met, causing an Operating Reserve shortage, thus invoking scarcity pricing. Additionally, as shown in

[41] Each Resource consists of eight 100 MW units.

Note that none of the resources in the example are designated as Fast Start Resources, so the Ex Ante LMP is equal to the Ex Post LMP and is denoted as simply LMP. For the same reason, each individual Ex Ante MCP is equal to the appropriate Ex Post MCP.

Exhibit 5-11Exhibit 5-11, in this example the LMP is impacted by the Operating Reserve Scarcity Price[42] and the change in incremental cost realized by reducing demand by 1 MW. The LMP of $1117/MWh consists of:

- a reduction in Operating Reserve scarcity cost of $1100/MW;
- a reduction in Energy cost of $20 associated with reducing the demand by 1 MW; and
- an increase in cost of $3 associated with the purchase of 1 MW of Supplemental Reserve from Generator 1.

Note that none of the resources in the example are designated as Fast Start Resources, so the Ex Ante LMP is equal to the Ex Post LMP and is denoted as simply LMP. For the same reason, each individual Ex Ante MCP is equal to the appropriate Ex Post MCP.

[42] A 1 MW decrease in demand would reduce the Operating Reserve shortage by 1 MW, resulting in the purchase of an additional MW of Supplemental Reserve from Generator 1.

Exhibit 5-11: Co-optimized Clearing, Contingency Reserve Scarcity – Results

Results Summary	Generator 1	Generator 2	Generator 3
Cleared Energy - MWh	675	800	0
LMP - $/MWh	1117	1117	1117
Cleared Regulating Reserve - MW	50	0	0
Dispatch Target Regulating Reserve - MW	50	0	0
Regulation MCP - $/MW	1101	1101	1101
Cleared Spinning Reserve - MW	50	0	0
Dispatch Target Spinning Reserve - MW	50	0	0
Spinning Reserve MCP - $/MW	1100	1100	1100
Cleared Supplemental Reserve - MW	25	0	0
Dispatch Target Supplemental Reserve - MW	25	0	0
Supplemental Reserve MCP	1100	1100	1100

Exhibit 5-11 were calculated, beginning with the calculation of the Shadow Prices for the Operating Reserve, Spinning Reserve and Regulation constraints.

Operating Reserve Shadow Price (γ_{OR})

In this case, where the Operating Reserve constraint is the sum of the Regulating Reserve requirement and the Contingency Reserve requirement, or 150 MW, the Shadow Price of the Operating Reserve constraint is calculated as the change in cost that would be realized by reducing the Operating Reserve requirement to 149 MW. In this case, there is a shortage of Operating Reserve in the form of a Supplemental Reserve shortage which sets the Shadow Price equal to the Operating Reserve Scarcity Price of $1100/MW.

Regulating plus Spinning Reserve Shadow Price (γ_{RS})

In this case, where the Regulating plus Spinning Reserve constraint is equal to 100 MW[43], the Shadow Price of the Regulating plus Spinning Reserve constraint is calculated as the change in cost that would be realized by reducing the Regulating plus Spinning Reserve requirement to 99 MW while holding the Operating Reserve requirement at 150 MW. In this case, all of the Contingency Reserve is being supplied by Generator 1 and the amount of Contingency Reserve

[43] The Regulating plus Spinning Reserve requirement is equal to the sum of the Regulating Reserve requirement and Spinning Reserve requirement.

procured remains the same[44]. Therefore, a reduction in cost of $3 will be realized which is equal to the Spinning Reserve availability Offer price for Generator 1 multiplied by 1 MW and an increase in cost of $3 will be incurred which is equal to the Supplemental Reserve availability Offer price for Generator 1 multiplied by 1 MW. The Regulating plus Spinning Reserve Shadow Price is then equal to: ($3 Spinning Reserve availability cost reduction - $3 Supplemental Reserve cost increase) / 1 MW = $0/MW.

Regulating Reserve Shadow Price (γ_{RR})

In this case, where the Regulating Reserve constraint is a Regulating Reserve requirement of 50 MW, the Shadow Price of the Regulating Reserve constraint is calculated as the change in cost that would be incurred by reducing the Regulating Reserve requirement to 49 MW while holding the Regulating plus Spinning Reserve requirement at 100 MW. In this case, all of the Regulating plus Spinning Reserve is being supplied by Generator 1 and the amount of Regulating plus Spinning Reserve procured remains the same[45]. Therefore, a reduction in cost of $4 will be realized which is equal to the Regulating Reserve availability Offer price for Generator 1 multiplied by 1 MW and an increase in cost of $3 will be incurred which is equal to the Spinning Reserve availability Offer price for Generator 1 multiplied by 1 MW. The Regulating Reserve Shadow Price is then equal to: ($4 Regulating Reserve availability cost reduction - $3 Spinning Reserve cost increase) / 1 MW = $1/MW.

Supplemental Reserve MCP

By definition, the generation based Supplemental Reserve $MCP_{SUPPG} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{GOR}$ and the demand-based Supplemental Reserve $MCP_{SUPPD} = \gamma_{OR} + \gamma_{OR(z)}$. In this example, there is no binding zonal Operating Reserve requirement or minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{GOR} = \gamma_{OR(z)} = 0$ and $MCP_{SUPPG} = MCP_{SUPPD}$. The Supplemental Reserve MCP_{SUPPG} and MCP_{SUPPD} is then equal to the Shadow Price of the Operating Reserve constraint, or $1100/MW.

[44] A reduction in Spinning Reserve requirement by 1 MW will force an additional MW of Supplemental Reserve to be procured to prevent any additional shortage of Operating Reserve.

[45] A reduction in Regulation requirement by 1 MW will force an additional MW of Spinning Reserve to be procured to prevent a shortage of Regulating plus Spinning Reserve.

Spinning Reserve MCP

By definition, the generation-based Spinning Reserve $MCP_{SPING} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z)} + \gamma_{GOR} + \gamma_{GRS}$ and the demand-based Spinning Reserve $MCP_{SPIND} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z)}$. In this example, there is no binding zonal Operating Reserve requirement, no binding zonal Regulating plus Spinning Reserve requirement, no binding minimum generation-based Operating Reserve requirement and no binding minimum generation-based Regulating plus Spinning Reserve requirement and therefore, $\gamma_{OR(z)} = \gamma_{RS(z)} = \gamma_{GOR} = \gamma_{GRS} = 0$ and $MCP_{SPING} = MCP_{SPIND}$. The Spinning Reserve MCP_{SPING} and MCP_{SPIND} is then equal to the Shadow Price of the Operating Reserve constraint plus the Shadow Price of the Regulating plus Spinning Reserve constraint, or $1100/MW + $0/MW = $1100/MW.

Regulating Reserve MCP

By definition, the generation-based Regulation $MCP_{REGG} = \gamma_{OR} + \gamma_{OR(z)} + \gamma_{RS} + \gamma_{RS(z)} + \gamma_{RR} + \gamma_{RR(z)} + \gamma_{GOR}$. In this example, there is no binding zonal requirements or binding minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{RR(z)} = \gamma_{RS(z)} = \gamma_{OR(z)} = \gamma_{GOR} = 0$. The Regulating Reserve MCP_{REG} is then equal to the Shadow Price of the Operating Reserve constraint plus the Shadow Price of the Regulating plus Spinning Reserve constraint plus the Shadow Price of the Regulating Reserve constraint, or $1100/MW + $0/MW + $1/MW = $1101/MW.

6. Reliability Assessment Commitment and Look-Ahead Commitment Activities

The RAC and LAC processes provide input into the operation of the Real-Time Energy and Operating Reserve Market to ensure that sufficient Resources are available and on-line to meet the demand and Operating Reserve requirements within the Market Footprint, as projected by MISO for each hour, or sub-hour, or sub-hour, period of the Operating Day. These processes enable MISO to reliably operate the Transmission System throughout the Operating Day by committing additional Resources:

- Before the clearing of the Day-Ahead Energy and Operating Reserve Market, if required
- After the posting of the Day-Ahead Energy and Operating Reserve Market results but before the start of the Operating day, if required or
- Anytime during the Operating Day, if required.

The RAC process employs a SCUC algorithm to minimize the cost of committing the required capacity to meet forecasted demand, confirmed Interchange Schedule Exports and Operating Reserve requirements, including Start-Up Offer, No-Load Offer, cost to operate at the Hourly Economic Minimum Limit, Regulating Reserve Offers, Spinning Reserve Offers and Supplemental Reserve Offers for Generation Resources and DRRs-Type II and including Energy Offers, Shut-Down Offers, Hourly Curtailment Offers, Spinning Reserve Offers and Supplemental Reserve Offers for each DRR-Type I. The RAC analysis minimizes the cost of committing sufficient Resources to meet the forecasted capacity requirements, not the cost to serve the forecasted Energy. The RAC SCUC analysis focuses on hourly time intervals.

The LAC process employs a similar SCUC algorithm, with the exception that the SCUC algorithm used by LAC minimizes the total cost of production of the required capacity to meet forecast demand and other requirements. In other words, it minimizes the cost of committing sufficient Resources to meet the cost to serve the forecasted Energy, in addition to forecasted capacity requirements. When the forecast time gets closer to the current time, uncertainty decreases. For intervals further in the future, it is better to minimize commitment cost because of the higher uncertainty of need. Whereas, in near term, much of that uncertainty is resolved and it is better to minimize total production cost. The LAC SCUC analysis focuses on fifteen to thirty minute time intervals.

Resources are guaranteed to receive their Offers if committed. Offer rules that apply to the RAC/LAC are described in Section 4 of this BPM. The RAC/LAC timeline is presented in Exhibit 6-1, covering the four RAC/LAC processes:

- RAC Pre Day-Ahead
- RAC Post Day-Ahead
- RAC Intraday
- LAC

Exhibit 6-1: RAC/LAC Timeline

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Data Required for RAC Pre Day-Ahead Process		
OD-7 @ 0000	As available during RAC run	Transmission Owners/Operators submit requests for transmission facility outages
OD-7 @ 0000	As available during RAC run	Generation Owners/Operators submit planned generation facility outage Schedules
OD-7 @ 0000	As available during RAC run	LBAs submit Load Forecasts that are utilized as input to the MISO Load Forecast
RAC Pre Day-Ahead Process		
OD-7 @ 0000	OD-1 @ 1430 EPT	Perform Multi-day RAC as necessary to evaluate need for Long Lead Start Units
RAC Post Day-Ahead Process		
OD-1 @ 1330 EPT	OD-1 @ 1430 EPT	Resource Offer re-bidding
OD-1 @ 1430EPT	OD-1 @ 1800EPT	Perform RAC Next-Day Analysis
OD-1 @ 1800EPT	OD @ 0000	Notify Resources of scheduled commitment: ▪ Start time and Dispatch Minimum ▪ Stop time
RAC Intraday Process		
OD-1 @ 1800 EPT	OD @ 2400	Perform RAC Intraday Analysis as needed
LAC Process		
OH-4	DI-15	Perform LAC Analysis as needed
OD = Operating Day OH = Operating Hour (00 to 23) DI = Dispatch Interval RAC = Reliability Assessment Commitment LBA = Balancing Authority		Note: All times are in EST unless noted otherwise.

6.1 RAC/LAC Process Input Assumptions

The following assumptions are taken into account as part the RAC processes:

- Forecasted Load
- Operating Reserve Requirements
- Interchange Schedules greater than one day out
- Commitment of Resources where the sum of the Start-up Time and Start-up Notification Time exceeds 24 hours
- Scheduled outages
- Maintaining facility ratings

6.1.1 Forecasting Load

MISO produces and publishes an initial hourly forecast of Load for the Operating Day beginning seven days prior to that day and updated daily as the Operating Day approaches.

MISO requires LBAs to submit hourly Load Forecasts for a rolling seven days in the future. For each day, a 24-hour Load shape is developed. The first step in developing a Load Forecast is to obtain weather information for the time period. Weather information is provided at regular intervals by a contracted-for weather service. The forecast period is reviewed to determine any conditions that could affect MISO's Load, including but not limited to: day of week, holidays, special events, Daylight Savings Time ("DST") changes, and LBA Load Forecasts.

Load Forecast and Operating Reserve requirements are required by the Real-Time Energy and Operating Reserve Market RAC to ensure that sufficient Resources are committed. The RAC process ensures that sufficient generation capacity is scheduled on-line (or that available Quick-Start Resources will contribute to meeting Contingency Reserve requirements) to meet the Load in MISO's Market Footprint, including capacity needed for reserves. The RAC process is performed several times throughout the timeline. This Load Forecast is used in the Real-Time Energy and Operating Reserve Market RAC only; it is not used to clear the Day-Ahead Energy and Operating Reserve Market.

The LBAs provide to MISO, by the Day-Ahead Energy and Operating Reserve Market Offer deadline at 1030 EPT, a Load Forecast at an hourly granularity for the next seven days. MISO requires the MPs serving Load in a LBA to supply a forecast of these values to its LBA for the Load served by the MPs if the LBA needs the data to develop the LBA Forecast. MISO also produces a seven-day hourly forecast for each LBA, considering the Load Forecasts provided by the LBAs, and utilizes its Load Forecast produced for use in the RAC process.

The coincident peak of the MISO STLF (as described in Section 3.5.3.2) is used as the forecast for the LAC process.

6.1.2 Operating Reserve Requirements

The Market-wide and Zonal Regulating Reserve and Contingency Reserve Requirements for the Post Day-Ahead, Intra-Day RAC, and LAC processes are generally the same as those requirements developed for use in the Day-Ahead Energy and Operating Reserve Market. MISO may increase these requirements if necessary to address system condition changes following the clearing of the Day-Ahead Energy and Operating Reserve Market and/or Emergency conditions in Real-Time.

6.1.3 Pre-Scheduling Interchange Schedules Greater than One Day Out

Pre-scheduled Interchange Schedules are transactions that are scheduled one or more days prior to their Operating Day for the Day-Ahead or Real-Time Energy and Operating Reserve Markets. Each MP making an Import Schedule or Export Schedule covering a period greater than the Operating Day must furnish all required information to MISO via a NERC E-Tag that transfers into webTrans.

MISO confirms the Interchange Schedule E-Tag with the affected adjacent external BA, as necessary, and may condition acceptance for scheduling on such confirmation. MISO provides the requesting MP with notice, as soon as is practicable, as to whether the pre-scheduled Interchange Schedule E-Tag request is accepted for scheduling and, if it is not accepted, the reason why. MISO responds to E-Tags in accordance with NERC established guidelines. MPs with pre-scheduled Interchange Schedules are subject to Ex Ante and Ex Post LMPs established for the Interface CPNode(s) that the schedule utilizes.

See Section 4.1.14.1.1 of this BPM for additional information on Interchange Schedules.

6.1.4 Submitting Resource Offers for Reliability Assessment Commitment

The following rules apply to all Resources:

- ***Resources designated as Capacity Resources for Module E Purposes*** – Not on a forced or maintenance outage must offer into the RAC any designated capacity, including Energy, and Contingency Reserve if qualified, not scheduled in the Day-

Ahead Energy and Operating Reserve Market or during any RAC process conducted prior to the Operating Day except to the extent that the Resource is unable to provide Energy or Contingency Reserve due to a forced or planned outage or other physical operating restrictions. These Resources can, but are not obligated to, offer any available capacity that has not been scheduled in the Day-Ahead Energy and Operating Reserve Market or any RAC processes performed prior to the Operating Day for use during the Operating Day.

- ***Other Resources*** – Can, but are not obligated to offer any available capacity that has not been scheduled in the Day-Ahead Energy and Operating Reserve Market.

Resources selected and committed by MISO in any RAC or LAC process(es) must adhere to MISO instructions, including start times. These Resources (except for Stored Energy Resources) must also submit an Energy Offer for their full range of Operable Capacity (or for Targeted Demand Reduction Level for DRRs-Type I), from Hourly Emergency Minimum Limit to Hourly Emergency Maximum Limit (or, to expected maximum limit, for DIRs), regardless of Module E capacity designation status, for use in the Real-Time Energy and Operating Reserve Market.

Generation Resources and DRRs-Type II committed by MISO are guaranteed recovery of Start-Up Offers, No-Load Offers, Energy Offers (at Non-Excessive Energy actual output), Regulating Reserve Offers, Spinning Reserve Offers and On-Line Supplemental Reserve Offers (if applicable) net the value of Real-Time Energy and Operating Reserve Market revenues for Energy and Operating Reserve earned during the commitment period. DRRs-Type I committed by MISO are guaranteed recovery of Energy Offers, Shut-Down Offers and Hourly Curtailment Offers net of the value of Real-Time Energy and Operating Reserve Market revenues for Energy earned during the commitment period (as calculated based upon DRR-Type I Actual Energy Injection). Further detailed Settlement information regarding Revenue Sufficiency Guarantees can be found in the BPM for *Market Settlements*.

6.1.5 Committing Long Start-Up Resources

MISO supports unit commitment service for Generation Resources or DRRs-Type II with Start-up Notification Time + Start-Up Times (or Shut-Down Notification Time + Shut-Down Times for DRRs-Type I) longer than those that can be accommodated in the post Day-Ahead RAC processes. These Resources can also Self-Schedule (except for DRRs-Type I) or engage in Financial Schedules and Interchange Schedules to utilize the Resource.

Uncommitted Generation Resources or DRRs-Type II with Start-Up Notification Times + Start-Up Times (or Shut-Down Notification Times + Shut-Down Times for DRRs-Type I) longer than those that can be committed as part of the post Day-Ahead RAC process can submit Offers for consideration by MISO as part of the Pre Day-Ahead RAC process. The following time frames reflect the process employed:

- ***Seven to Four Days prior to Operating Day:***
  - Generation Resources and DRRs-Type II with Start-Up Time plus Start-Up Notification Times greater than 24 hours must submit binding Hourly Economic Minimum and Maximum Limits and binding Start-Up Offers, No-Load Offers, and Energy Offers at Hourly Economic Minimum Limit along with the submittal of Start-Up Time and Start-Up Notification Time.
  - DRRs-Type I with Shut-Down Time plus Shut-Down Notification Times greater than 24 hours must submit binding Targeted Demand Reduction Levels and binding Energy Offers, Shut-Down Offers and Hourly Curtailment Offers along with the submittal of Shut-Down Time and Shut-Down Notification Time.
  - If adequacy violations are detected, they are logged and evaluated but no specific commitment action is taken until three days prior to the market day, unless three days prior would not allow sufficient time to resolve the potential violations.
- ***Three to Two Days prior to Operating Day:***
  - Generation Resources and DRRs-Type II that have not been committed by MISO may submit revised Start-Up Times and Start-Up Notification Times and binding Hourly Economic Minimum and Maximum Limits and binding Start-Up Offers, No-Load Offers, and Energy Offers at Hourly Economic Minimum Limit.
  - DRRs-Type I with Shut-Down Time plus Shut-Down Notification Times greater than 24 hours must submit binding Targeted Demand Reduction Levels and binding Energy Offers, Shut-Down Offers and Hourly Curtailment Offers along with the submittal of Shut-Down Time and Shut-Down Notification Time.
  - If violations of reliability criteria are detected, MISO coordinates with the local Operators to verify the violation. After the violation has been verified, MISO will direct certain Resource operations if the only alternative to resolve the Resource-adequacy or constraint violation is to commit a Generation Resource or DRR-Type II with a Start-Up Time plus Start-Up Notification

Time requirement or commit a DRR-Type I with a Shut-Down Time plus Shut-Down Notification Time requirement that is longer than can be accommodated in (OD-2) or (OD-1) RAC processes.

6.1.6 Scheduling Outages

MISO is responsible for approving the scheduling of maintenance on all transmission facilities making up the MISO Transmission System and coordinating with Generation Owners, as appropriate, the scheduling of maintenance on generation facilities. This information is required for determining Resource availability and the topology and capability of the transmission network. See the BPM for *Outage Operations* for a description of transmission and generation outage coordination process, which includes outage scheduling, outage analysis, and outage reporting.

6.1.7 Maintaining Facility Ratings

MPs, Transmission Owners, and MISO are required to fulfill requirements for facility ratings. All Transmission Owners must regularly update and verify facility ratings to the MISO Operations Planning Department (or successor department). These procedures are updated as needed and are further described in the Transmission Owner Agreement.

See MISO's facility rating Coordination Policy Manual for a description of the facility rating coordination process, including the responsibilities of MPs, Transmission Owners, and MISO.

6.1.8 Managing Hourly Regulation Schedules

The RAC process (specifically the intra-day RAC process) continuously evaluates which Resources should be scheduled to potentially provide Regulating Reserves for a given Operating Hour to ensure 1) a sufficient number of Resources are scheduled to meet the Market-Wide Regulating Reserve Requirement and the Reserve Zone Regulating Reserve Requirements and 2) the scheduling of Resources does not consume excessive amounts of capacity and ramp capability. In addition, the RAC process is used to manage the transition of Resources from a non-regulating state to a regulating state or vice versa to avoid situations where an excessive number of Resources scheduled to potentially provide Regulation Capability may not be available for Regulation Deployment Instructions at the beginning of the Operating Hour due to initial operation outside the regulation limits. To address these issues, MISO may limit the number of Resources that can transition from a regulating state to a non-regulating state at the beginning of an Operating Hour and/or utilize Manual Redispatch provisions to move a Resource into the regulation operating range just prior to the beginning of the Operating Hour.

The SCUC algorithm incorporated into the Day Ahead and RAC processes determines the initial Regulation Schedule for a specific Operating Hour based on offers, constraints and the most up-to-date medium term load forecast (see Attachment C of this BPM for more details). However, given the dynamic nature of generation offers and control statuses, it is necessary for MISO to make incremental changes to the latest Regulation Schedule provided by prior regulation scheduling processes.

A regulation management tool provides MISO Real-Time Operations personnel with the information needed to make appropriate decisions regarding the adjustment of the Regulation Schedule provided by prior regulation scheduling processes. The regulation management tool provides an assessment of the current Regulation Capability of Resources in the Regulation Schedule and ranks Resources with regard to physical and economic attributes.

MISO system operators utilize the regulation management tool to determine if the number of resources scheduled to potentially provide Regulating Reserves during an Operating Hour is too high or too low based on up-to-date information including, but not limited to:

- Updated offer data
- Updated load forecast
- Updated net scheduled interchange
- Updated status of resources (including dispatch levels)
- Updated status of the transmission system.

Should it be necessary to adjust the Regulation Schedule produced by the prior regulation scheduling processes, MISO considers the following factors in making decisions to adjust the number of Resources scheduled to potentially provide Regulating Reserves:

- Regulating reserve offer price vs. energy offer price.
- Regulation capability based on applicable bi-directional ramp rate and regulation limits.
- Applicable economic maximum limit vs. regulation maximum limit.
- Applicable economic minimum limit vs. regulation minimum limit.
- Applicable bi-directional ramp rates vs. single-directional ramp rates.
- Number of resources transitioning from a non-regulating to a regulating state.

6.2 RAC Processes Under Shortage Conditions

If, during the Post Day-Ahead RAC or any of the Intra-Day RAC processes, MISO projects a shortage of available Capacity either on a system-wide basis or Sub-Area basis, based upon the sum of all non-Emergency Capacity (including Capacity from available Import Schedules, Generation Resources, DRRs-Type I, DRRs-Type II and External Asynchronous Resources) and Emergency Capacity (including both Resource Hourly Emergency Maximum Limits and Generation Resources, DRRs-Type I and DRRs-Type II designated for use only during Emergency conditions) to meet projected Energy (assuming Export Schedules are curtailed) and Operating Reserve requirements in any Hour of the Operating Day, MISO will implement the following procedures:

- ***Step One:*** MISO issues an alert, warning or event , in accordance with Emergency Operating Procedure – 002 (EOP-002) and posts on its website: (1) the hours in the Operating Day during which an EEA Level 1 is anticipated; (2) the hours during the Operating Day in which Export Schedules are expected to be curtailed; (3) the hours during the Operating Day in which Resource Hourly Emergency Maximum Limits[46] are expected to be utilized; and (4) the hours during the Operating Day in which Emergency only Resources[47] are expected to be committed.
- ***Step Two:*** If MISO projects that it cannot meet its Regulating Reserve requirement and all Contingency Reserve has been depleted, MISO issues an alert or warning in accordance with Emergency Operating Procedure – 002 (EOP-002) and posts on its website the anticipated hour in which an EEA Level 2 Emergency is expected to occur. If MISO declares an EEA-2 event, the following actions may be initiated in accordance with EOP-002: (1) instruct the Local Balancing Authorities to issue public appeals, (2) begin Emergency Energy purchase procedures described under Section 6.2.1 of this BPM; (3) issue EDR Dispatch Instructions to EDR Participants based on EDR Offers submitted; (4) direct LBAs to initiate voltage reduction procedures; and/or (5) direct LSEs to curtail appropriate amounts of Load Modifying Resources. At this point, MISO has exhausted all measures at its disposal to alleviate the shortage condition prior to entering into the real-time Operating Hour.

[46] Individual Resources are notified directly by MISO.

[47] Individual Resources are notified directly by MISO.

6.2.1 Emergency Energy Purchases

Following the declaration of an EEA Level 2, MISO may contact external Balancing Authorities through the applicable MISO to external Balancing Authority Agreements (BA-to-BA Agreements) and indicate that Emergency Energy may be needed. Payment for such purchases, if scheduled, will be in accordance with the payment terms specified in the applicable BA-to BA Agreement. Emergency Energy purchases shall be implemented in the form of a schedule in webTrans between MISO and the selected adjacent external Balancing Authority. Note that Transmission Service on external non-MISO transmission facilities provided may be needed to effectuate the schedule. MISO will implement and curtail these schedules with as much notice as practical to allow for a reasonable transition into and out of the shortage condition.

6.3 RAC Processes Under Surplus Conditions

If during the Post Day-Ahead RAC or any of the Intra-Day RAC processes, MISO projects a surplus of non-Emergency minimum Capacity (including minimum Capacity from firm Import Schedules, on-line Generation Resources, DRRs-Type I and DRRs-Type II) to meet projected Energy requirements less the Regulating Reserve requirement in any Hour of the Operating Day, MISO will implement the following procedures:

- ***Step One:*** MISO issues an appropriate Emergency alert, in accordance with Emergency Operating Procedure – 003 (EOP-003), and includes Resource Hourly Emergency Minimum Limits for both Generation Resources and DRRs-Type II as part of the RAC process.
- ***Step Two:*** If use of Hourly Emergency Minimum Limits is not sufficient to relieve the anticipated surplus condition, MISO may de-commit non-Must Run Resources on an economic basis that were committed as part of the Day-Ahead Energy and Operating Reserve Market clearing to relieve the anticipated surplus condition.

6.4 LAC Processes Under Shortage/Surplus Conditions

The actions described in Sections 6.3 and 6.4 above also apply during the LAC process. In addition, if shortage or surplus conditions have been identified, Resource emergency limits, as described in Sections 0 and 8.2.3.2, are also considered for use in the LAC process.

6.5 RAC/LAC Processes Results

The following output results are produced by all RAC/LAC Processes:

- For each affected Resource, a commitment schedule is produced for the Operating Day indicating which hours the Resource is scheduled to operate and which hours uncommitted Quick-Start Resources have been scheduled to provide off-line Supplemental Reserve. This schedule does not become physically binding until it is communicated to the MP by MISO.

- For each affected Resource under the shortage conditions described under Section 6.2 above, a commitment schedule is produced for Resources with a Commitment Status of "Emergency" and an off-line Supplemental Reserve schedule is produced for uncommitted Resources with an Off-Line Supplemental Reserve Dispatch Status of Emergency. In addition, MISO will notify Market Participants electronically that the Hourly Emergency Maximum Limit will be used for a specific Resource for an Operating Hour. The notification that the Hourly Emergency Maximum Limit will be used will occur at least 10 minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour. Emergency commitment schedules, Emergency off-line Supplemental Reserve schedules and the use of Hourly Emergency Maximum Limits will become physically binding once communicated to affected MPs by MISO after MISO has verified and accepted the RAC/LAC results.
- For each affected Resource under the surplus conditions described under Section 6.3 above, a de-commitment schedule is produced and MISO will notify MPs electronically that the Hourly Emergency Minimum Limit will be used for a specific Resource for an Operating Hour. The notification that the Hourly Emergency Minimum Limit will be used will occur at least 10 minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour. Emergency de-commitment schedules and the use of Hourly Emergency Minimum Limits become physically binding once communicated to affected MPs by MISO after MISO has verified and accepted the RAC/LAC results.

6.6 MISO-PJM Coordinated Transaction Scheduling (CTS)

MISO-PJM Coordinated Transaction Scheduling (CTS) is an optional product available for scheduling real-time energy market transactions between MISO and PJM. CTS facilitates the efficient scheduling of interchange between the two regional transmission organizations (RTO) by utilizing forecasted LMPs, and participant-provided interface bids to clear only those transactions deemed economically consistent with projected interface price spreads.

Market Participants submit MISO-PJM CTS bids in PJM's ExSchedule system. Validated bids are then passed to both PJM and MISO's look-ahead commitment engines. In Real-Time, PJM sends MISO the forecasted LMPs calculated for PJM's MISO interface, while MISO sends PJM the forecasted LMPs calculated for MISO's PJM interface to use as inputs to the CTS clearing process. Every 15 minutes in real-time (i.e., HH:00the top, HH:15, HH:30 and HH:45 of each hour of the Real-Time Energy and Operating Reserves Market), each RTO uses its Look Ahead Commitment engine to clear only those CTS bids that have an interface bid price that is less than or equal to the projected interface price spread. PJM and MISO then exchange the CTS clearing results. A common clearing process reconciles the CTS bids independently cleared by MISO and PJM. For each CTS bid, only those transaction MW cleared by both PJM and MISO will be scheduled to flow.

6.6.1 MISO-PJM Coordinated Transaction Scheduling Business Rules

A Coordinated Transaction Schedule (CTS) bid can have up to ten monotonically increasing price and MW quantity pairs with minimum price at $0.01 for each 15-minute scheduling interval. Coordinated Transaction Schedules must be submitted 75 minutes before the start of the scheduling interval.

Please refer to the BPM #007 Physical Scheduling document for rules governing the submission of MISO-PJM CTS transactions.

6.6.2 CTS Bid Clearing

The Intermediate Term Security Constrained Economic Dispatch (IT SCED) engine clears CTS bids in PJM. Look Ahead Commitment (LAC) engine clears CTS bids for MISO. Only the CTS bids commonly cleared between PJM and MISO will be scheduled to flow. The reconciliation of commonly cleared CTS bids is discussed in section 6.6.3.

MISO receives CTS bids plus the forecasted PJM interface price from PJM. Using these inputs plus MISO's forecasted LMP, CTS bids are cleared as noted below:

A CTS bid that is scheduled from MISO to PJM gets cleared if:

The CTS bid Segment Price <= $PJM_interface - $MISO_interface

A CTS bid that is scheduled from PJM to MISO gets cleared if:

The CTS bid Segment Price <= $MISO_interface - $PJM_interface

Where

$PJM_interface: LMP for the MISO interface as calculated by PJM
$MISO_interface: LMP for the PJM interface as calculated by MISO

In the case of a tie among multiple bids, cleared MWs will be prorated across tying bids based on the size of the marginal MW segment for each tying bid. The proration of cleared MW across tying bids is calculated based on the following formula:

$MW_{transaction}$ = *(MWneeded for power balance) * (MW from transaction's marginal segment/ total MW from the marginal segment)*

6.6.3 CTS Common Clearing

Common Clearing is a process that reconciles the results of CTS clearing from the MISO and PJM solutions. For each CTS bid, only those transaction MW cleared by both PJM and MISO will be scheduled to flow. Therefore:

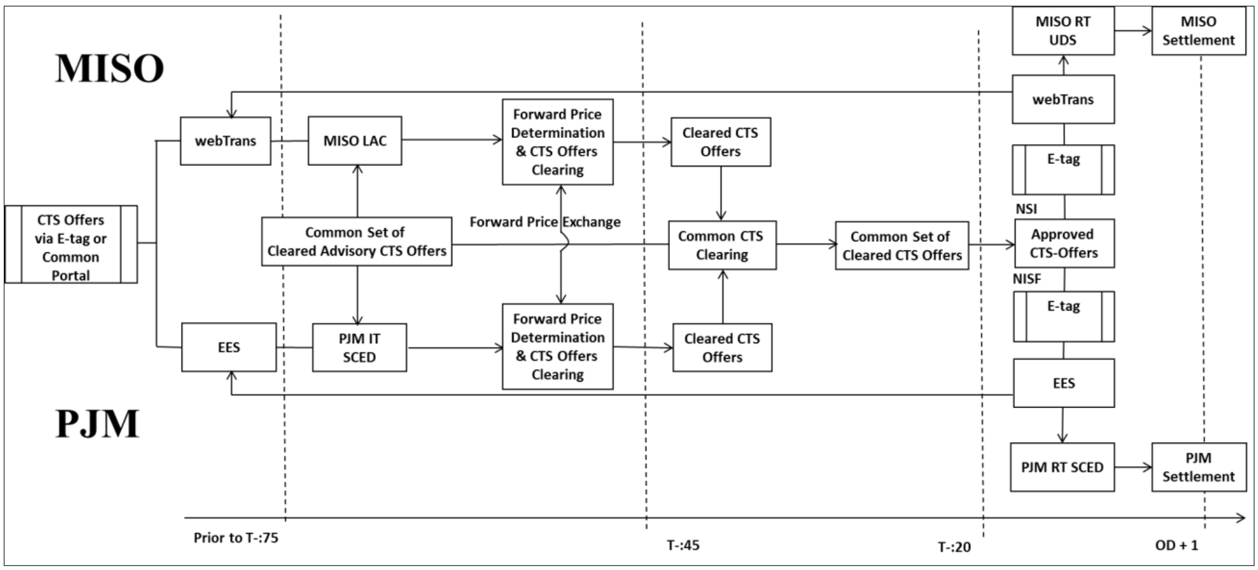
Common Cleared CTS Transaction MW = min (Cleared MISO MW, Cleared PJM MW)

The Common Clearing process executes for each 15 minute scheduling interval (HH:00, HH:15, HH:30, HH:45) at approximately 25 minutes before the start of CTS transaction. For example, the common clearing process for 12:00 runs at approximately 11:35.

The commonly cleared CTS results are posted in the ExSchedule portal and electronic tag (E-Tag) applications following the approval of the common clearing process.

6.6.4 CTS Timing and Data Exchange

The figure below shows the general timing of the various processes that will occur so that CTS transactions will flow at T-0:00. This figure shows the timeline for submittal of CTS bids, data exchanges between MISO and PJM, and common clearing process for each ISO.



Described below is the sequence of events associated with CTS processing:

1. E-Tag and E-Tag adjustments must be submitted at least 75 minutes prior to the listed start time.
2. The MISO advisory prices and schedules will come from the most recent MISO CTS clearing engine run that executes at T- 0:55.
3. At T- 0:40, the ITSCED case will execute for T-0 binding interval and include validated bid data and advisory pricing.
4. At T-25, common clearing case is executed at both ISO's.
5. Prior to T-20,scheduling system issues CTS Tag adjustments on MISO sinking Tags for T-0 intervals based on common cleared results.

6.6.5 CTS Clearing Suspension

For reliability or system maintenance reasons, either PJM or MISO may suspend the evaluation and clearing of CTS transactions temporarily. During the affected time, all CTS transactions will be cleared to 0 MW. Possible reasons for CTS suspension include but are not limited to:

- Initiation of Maximum Emergency Warning procedures.
- Scheduled system outage / maintenance.
- Inability to send or receive accurate forecast LMP data to/from partner RTO.

A message will be displayed in the ExSchedule system whenever CTS suspension is in effect.

6.6.6 CTS Settlement

MISO and PJM will settle the CTS transactions on each side of the MISO-PJM interface based on actual LMPs, not the projected prices. In other words, although the market clearing process for CTS transactions will use projected prices, the market settlement process for CTS transactions will use actual real-time prices. In MISO, CTS transactions will be settled as Real Time physical schedules, will be treated as generation dispatched up and down and, therefore, will be exempt from uplift charges such as Revenue Sufficiency Guaranty (RSG) and Revenue Neutrality Uplift (RNU) charges in the MISO market. Please refer to the Market Settlements calculation guide for additional details.

7. Day-Ahead Energy and Operating Reserve Market Activities

MPs who wish to participate in the Day-Ahead Energy and Operating Reserve Market must submit Resource Offers, Virtual Supply Offers, Demand Bids, and/or Interchange Schedules for the purchase and sale of Energy and Offers for the sale of Operating Reserve no later than 1030 EPT on the day prior to the Operating Day (OD-1) for use in clearing the Day-Ahead Energy and Operating Reserve Market. Exhibit 7-1 shows the timeline for the principal activities associated with the Day-Ahead Energy and Operating Reserve Market.

Exhibit 7-1: Day-Ahead Energy and Operating Reserve Market Activities Timeline

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Data Required for the Day-Ahead Energy and Operating Reserve Market		
As previously scheduled	OD-1 @ 1030EPT	Scheduled transmission facility outages
As previously scheduled	OD-1 @ 1030 EPT	Scheduled Generation Resource and Stored Energy Resource outages
OD-7 @ 0000 or previous submittal	OD-1 @ 1030 EPT	Resource Offer submittal into the Day-Ahead Energy and Operating Reserve Market for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve
OD-7 @ 0000	OD-1 @ 1030 EPT	Fixed Demand Bids and Price-Sensitive Demand Bids into the Day-Ahead Energy and Operating Reserve Market only
OD-7 @ 0000	OD-1 @ 1030 EPT	Virtual Supply Offers and Virtual Demand Bids into the Day-Ahead Energy and Operating Reserve Market only
OD-7 @ 0000	OD-1 @ 1030 EPT	Day-Ahead Fixed Interchange Schedules – not considered binding until OD-1 @ 0900 – roll into Real-Time Energy and Operating Reserve Market, if cleared and not “zeroed” by MP
OD-7 @ 0000	OD-1 @ 1030 EPT	Day-Ahead Dispatchable Interchange Schedules – not considered binding until OD-1@0900 – roll into Real-Time Energy and Operating Reserve Market as Fixed Interchange Schedules, if cleared
OD-7 @ 0000	OD-1 @ 1030 EPT	Up-to-TUC Interchange Schedules (Day-Ahead Energy and Operating Reserve Market only) not considered binding until OD-1@0900 - roll into Real-Time Energy and Operating Reserve Market as Fixed Interchange Schedules, if cleared
OD-7 @ 0000	OD-1 @ 1030 EPT	GFA Schedules (Option B)
As scheduled by RAC	OD-1 @ 1030 EPT	Long lead time Resource schedules – from RAC
As previously entered	OD-1 @ 1030 EPT	Bid and Offer parameters and Network Model parameters
As previously entered	OD-1 @ 1030 EPT	Updated facility ratings

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Day-Ahead Energy and Operating Reserve Market Activities		
	OD-1 @ 1030 EPT	Close the Day-Ahead Energy and Operating Reserve Market and acquire data
OD-1 @ 1030 EPT	OD-1 @ 1330 EPT	Clear the Day-Ahead Energy and Operating Reserve Market
	OD-1 @ 1330 EPT	Post the Day-Ahead Energy and Operating Reserve Market Awards Results and Ex-Ante LMPs and MCPs
OD-1 @ 1330 EPT	OD-1 @ 1630 EPT	Post the Day-Ahead Energy and Operating Reserve Market Ex-Post LMPs and MCPs
OD-7 @ 0000	OD+6 @ 1200	Enter Financial Schedules for the Day-Ahead Energy and Operating Reserve Market (Note: Financial Schedules for Deviations must be submitted by OH-4)
OD = Operating Day RAC = Reliability Assessment Commitment SSR = System Support Resource TUC = Transmission Usage Charge	Note: All times are in EST unless indicated otherwise	

MISO may extend or reopen the Day-Ahead Energy and Operating Reserve Market after market close time (1030 EPT) as listed in Exhibit 7-1, based on unanticipated events that:

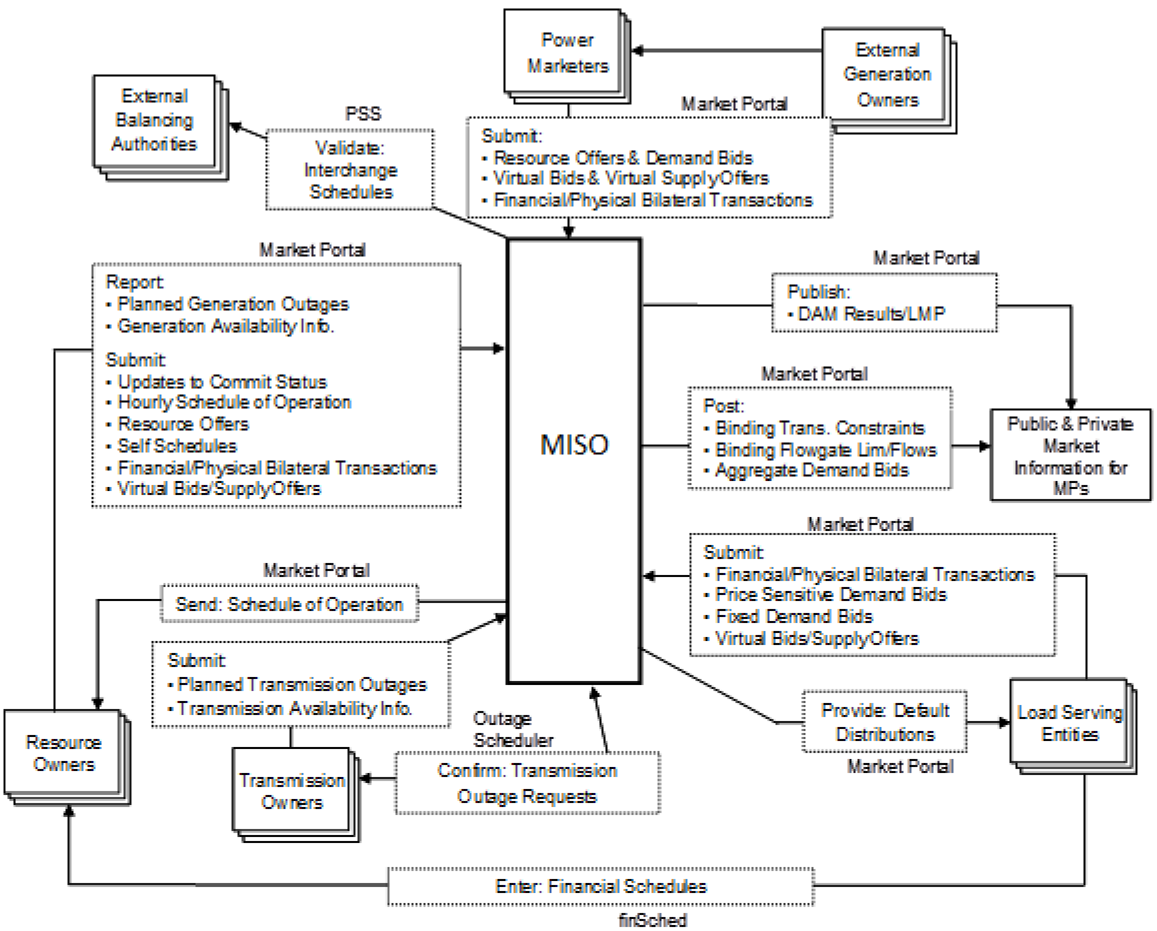
i) interfere with MISO's ability to receive or process Bid, Offer, or Interchange Schedule data;
ii) render Bid, Offer, or Interchange Schedule data plainly inaccurate in a manner that is likely to significantly impede MISO's ability to deliver a feasible market solution; or
iii) are otherwise likely to have a widespread negative impact on the results of the Day-Ahead Energy and Operating Reserve Market, in a manner that adversely threatens or affects the reliability of market operations or of the Transmission System.

MISO will post a notice of any extension or reopening of the market. The notice will state each extension or reopening's circumstances, rationale, duration, and whether such action enabled MISO to successfully address or minimize the issue that necessitated the extension or reopening.

Similarly, though MISO will strive to post the Day-Ahead Energy and Operating Reserve Market clearing results before 1330 EPT as listed in Exhibit 7-1, additional time may be needed for such posting from time to time due to unanticipated events.

The interactions and data flows between the entities that participate in the Day-Ahead Energy and Operating Reserve Market are shown in Exhibit 7-2.

Exhibit 7-2: Data Flow for Day-Ahead Energy and Operating Reserve Market



7.1 Market Participant Activities

MPs submit Offers and Interchange Schedules for use in the Day-Ahead Energy and Operating Reserve Market clearing process as follows.

7.1.1 Submitting Resource Offers

MPs may submit Resource Offers up to Day-Ahead Energy and Operating Reserve Market close time 1030 EPT on the day prior to the Operating Day for use in the Day-Ahead Energy and Operating Reserve Market clearing process. See Section 4 of this BPM for a description of the valid Offer parameters. The following rules apply to all Resources:

- ***Resources designated as Capacity Resources for Module E Purposes*** – If not on a forced or maintenance outage, such Resources must offer into the Day-Ahead Energy and Operating Reserve Market any designated capacity, including Energy and Contingency Reserve if qualified except to the extent that the Resource is unable to provide Energy or Contingency Reserve due to a forced or planned outage or other physical operating restrictions.
- ***Other Resources*** – These Resources can, but are not obligated to, offer any available capacity into the Day-Ahead Energy and Operating Reserve Market.

DRR-Type I Offers should be accompanied by a Fixed Demand Bid for the associated host load zone equal to the expected Targeted Demand Reduction Level; otherwise, a Load deviation will be created in the Real-Time host load one settlement equal to the Targeted Demand Reduction Level if the DRR-Type I is committed.

Resources selected and committed as part of the Day-Ahead Energy and Operating Reserve Market clearing must adhere to MISO's instructions, including start times. These Resources must also submit an Energy Offer (except for Stored Energy Resources) for their full range of Operable Capacity, from Hourly Emergency Minimum Limit to Hourly Emergency Maximum Limit, regardless of Module E capacity designation status for use in the RAC Processes and in the Real-Time Energy and Operating Reserve Market. Generation Resources and DRRs-Type II committed by MISO are guaranteed recovery of Start-Up Offers, No-Load Offers, Energy Offers (at actual output), Regulating Reserve Offers, Spinning Reserve Offers and On-Line Supplemental Reserve Offers (if applicable) net the value of Day-Ahead Energy and Operating Reserve Market revenues earned based upon the Day-Ahead Schedule for Energy and Operating Reserve, and subject to restrictions on Self-Scheduling. DRRs-Type I committed by MISO are guaranteed recovery of Shut-Down Offers and Hourly Curtailment net the value of Day-Ahead Energy and Operating Reserve Market revenues earned based upon the Day-Ahead Schedule for Energy. Further detailed Settlement information can be found in the BPM for *Market Settlements*.

The availability of Generation Resources, DRRs-Type I, DRRs-Type II and Stored Energy Resources is also determined in the Day-Ahead Energy and Operating Reserve Market clearing by incorporating the status of the Resource in Outage Scheduler. Under normal operating conditions, if a Generation Resource, DRR-Type I or DRR-Type II is listed in Outage Scheduler with an outage type of “Maintenance”, “Construction”, “Urgent”, “Emergency”, or “Forced”, the Resource will be considered unavailable in the Day-Ahead Energy and Operating Reserve Market Clearing. Generation Resources listed in Outage Scheduler with an outage type of “Economy” or “Deration” will be considered available. Further detailed Outage Scheduler information can be found in the BPM for *Outage Operations*.

7.1.2 Submitting Bids and Virtual Supply Offers

MPs may submit Virtual Supply Offers, Demand Bids and Virtual Demand Bids up to Day-Ahead Energy and Operating Reserve Market close time (1030 EPT) on the day prior to the Operating Day for use in the Day-Ahead Energy and Operating Reserve Market clearing process. As stated in Section 7.1.17.1.1 above, Fixed Demand Bids must be submitted in conjunction with DRR-Type I and DRR-Type II Offers. See Section 4 of this BPM for a description of the valid Offer parameters.

7.1.3 Submitting Interchange Schedules

The following rules apply to submitting Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market. See Section 4 of this BPM for detail relating to the types of Interchange Schedules that may be submitted.

- Interchange Schedules must start on the top, quarter-past, half-past, or quarter till the hour.
- MPs must submit all Interchange Schedules for the Day-Ahead Energy and Operating Reserve Market, via NERC E-Tag, prior to 1030 EPT of the day prior to the Operating Day (OD-1).
- Day Ahead Interchange Schedules must be fully approved and implemented prior to 1030 EPT in order to be considered as a DA Market submission.
- Should a Day Ahead Interchange Schedule be implemented after1030 EPT, the schedule will be rejected from the Day Ahead market, and an adjustment request will be sent to the corresponding E-Tag.
- If that Market Adjustment is denied by an external Balancing Authority or Transmission Provider; the Market Result remains unchanged. Any MWs that flow in Real Time will be settled at the Real-Time Ex Post LMP.
- On multi-day tags the pricing information must be the same.
- If an External Asynchronous Resource (“EAR”) Offer is submitted, an associated Fixed Dynamic Interchange Schedule must also be submitted. The estimate of the maximum schedule amount for Imports and/or Exports into MISO should be less than or equal to the EAR’s Hourly Emergency Maximum Limit. The estimate of the

maximum schedule amount for Exports out of MISO should be less than or equal to the EAR's Hourly Emergency Minimum Limit.

For further information on Interchange Schedules, please refer to the BPM for *Physical Scheduling (BPM-007).*

7.2 MISO Activities

MISO operates the Day-Ahead Energy and Operating Reserve Market via Security Constrained Unit Commitment ("SCUC"), Security Constrained Economic Dispatch ("SCED") and SCED-Pricing algorithms to develop commitment schedules and Day-Ahead Schedules of operation for each MP. The Day-Ahead Energy and Operating Reserve Market is a forward market in which hourly Ex Ante and Ex Post LMP values and hourly Ex Ante and Ex Post MCP values are calculated on a simultaneously co-optimized basis for each hour of the next Operating Day based on MP Offers and Bids for Energy and Offers for the sale of Operating Reserve. MPs purchase Energy and sell Energy and Operating Reserve in the Day-Ahead Energy and Operating Reserve Market at financially binding Day-Ahead Ex Post LMPs and Day-Ahead Ex Post MCPs.

The Day-Ahead unit commitment utilizes a simultaneously co-optimized Security-Constrained Unit Commitment algorithm ("SCUC") to commit sufficient Resources to meet the Fixed Demand Bids, cleared Price Sensitive Demand Bids, Fixed Interchange Schedule Exports, cleared Dispatchable Interchange Schedule Exports, cleared Virtual Demand Bids, forecasted Zonal and Market-Wide Regulating Reserve Requirements and forecasted Zonal and Market-Wide Contingency Reserve Requirements on an hourly basis. The objective of the SCUC is to minimize total costs over the entire commitment period while simultaneously enforcing physical constraints and reliability requirements.

The day-ahead economic dispatch utilizes a simultaneously co-optimized Security-Constrained Economic Dispatch algorithm ("SCED") and SCED-Pricing algorithm to dispatch Resources to meet the Fixed Demand Bids, cleared Price Sensitive Demand Bids, Fixed Interchange Schedule Exports, cleared Dispatchable Interchange Schedule Exports, cleared Virtual Demand Bids, forecasted Zonal and Market-Wide Regulating Reserve Requirements and forecasted Zonal and Market-Wide Contingency Reserve Requirements on an hourly basis. The objective of the security-constrained economic dispatch is to minimize total hourly costs while simultaneously enforcing physical constraints and reliability requirements. The SCED algorithm produces DA Ex Ante LMPs and Ex Ante MCPs. The SCED-Pricing algorithm produces DA Ex Post LMPs and Ex Post MCPs.

MISO performs the Day-Ahead Energy and Operating Reserve Market Settlement based on the hourly Day-Ahead Schedules, hourly Day-Ahead Ex Post LMPs and hourly Day-Ahead Ex Post MCPs.

7.2.1 Energy and Operating Reserve Markets Requirements

Prior to the operation of the Energy and Operating Reserve Markets, MISO identifies Reserve Zones, calculates Zonal and Market-Wide Operating Reserve Requirements and develops Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve which are required inputs into the Energy and Operating Reserve Markets clearing process. Calculation of Zonal and Market-Wide Operating Reserve Requirements is described under Section 3 of this BPM. Demand Curve development is described under Section 5 of this BPM.

7.2.2 Interchange Schedules

MISO applies the following rules and actions relating to MP-submitted Interchange Schedules for use in the Day-Ahead Energy and Operating Reserve Market. See Section 4 of this BPM for detail relating to the types of Interchange Schedules that may be submitted.

- MISO confirms the validated and compliant Interchange Schedule requests with appropriate neighboring external BAs.
- If the transaction clears the Day-Ahead Energy and Operating Reserve Market, the MP is settled at the Day-Ahead Ex Post LMP for the cleared MW amount.
- If cleared Day-Ahead Interchange Schedules are adjusted after the market clearing but before 20 minutes prior to the Operating Hour, the original schedule will be used in the Day-Ahead Energy and Operating Reserve Market and the adjusted MW schedule will be used in the Real-Time Energy and Operating Reserve Market.
- Partial hour pricing is not permitted.
- Interchange Schedule implementation is subject to ramping availability (see the BPM for *Physical Scheduling, BPM-007*).
- Interchange Schedules not adhering to the webTrans data requirements are denied. The MP is notified of the reason for denial via transaction denial and the MP may then submit another Interchange Schedule via a NERC E-Tag, if there is sufficient time prior to the submission deadlines.

- MISO submits a 'Market Adjust' to the NERC E-Tag when a Day-Ahead Energy and Operating Reserve Market Interchange Schedule is not cleared or is partially cleared. Entities with approval rights, as defined by NERC, must take approval actions.
- If a Market Adjust is denied by a non-MISO entity, the PSE will be responsible to provide the Energy in the Real-Time Energy and Operating Reserve Market or PSE adjusts the schedule to the market adjusted value.
- After the Day-Ahead Energy Market closes and prior to Day-Ahead Energy Market clearing, changes will not be permitted to Day-Ahead Schedules running the next day. MISO will deny such changes. Changes are allowed after Day-Ahead Energy Market clearing.

For further information on Interchange Schedules, please refer to the BPM for *Physical Scheduling (BPM-007).*

7.2.3 Day-Ahead Energy and Operating Reserve Market Clearing

The Day-Ahead Energy and Operating Reserve Market clears for each hour of the upcoming Operating Day. A simultaneous co-optimization methodology, utilizing the SCUC, SCED and SCED-Pricing algorithms, is employed to simultaneously perform the following tasks:

- Commit offered Resources at least-Offer price using the SCUC algorithm to meet the Energy, Operating Reserve, transmission constraint and Sub-Regional Power Balance Constraint requirements throughout the projected upcoming Operating Day while respecting Resource operating constraints, including minimum run-times and minimum down-times, considering any carryovers from the previous day; and
- Clear Offers and Import Schedules to meet Demand Bids and Operating Reserve requirements for each hour of the upcoming Operating Day using the SCED and SCED-Pricing algorithm to yield Day-Ahead Schedules, Day-Ahead Ex Ante and Ex Post LMPs and Day-Ahead Ex Ante and Ex Post MCPs, respectively.

The objective in clearing the Day-Ahead Energy and Operating Reserve Market is to minimize the costs of Energy and Operating Reserve procurement over the 24-hour dispatch horizon, subject to network constraints and Resource operating constraints. The overall procurement costs include:

- Start-Up Offers and No-Load Offers for Generation Resources and DRRs-Type II committed by SCUC;

- Shut-Down Offers and Hourly Curtailment Offers for DRRs-Type I committed by SCUC;
- Energy Offers, Regulating Reserve Offers, Spinning Reserve Offers and Supplemental Reserve Offers of all Generation Resources, DRRs-Type II and External Asynchronous Resources selected by SCED for Day-Ahead Schedules;
- Regulating Reserve Offers of all Stored Energy Resources selected by SCED for Day-Ahead Schedules;
- Dispatchable Import Daily Offers selected by SCED for Day-Ahead Schedules;
- Spinning Reserve Offers or Supplemental Reserve Offers for DRRs-Type I selected by SCED for Day-Ahead Schedules that were not committed for Energy by SCUC;
- Price adjustments for the cost of committing Fast Start Resources, the Energy cost of Fast Start Resources dispatched at limits, Up Ramp Capability and Down Ramp Capability by SCED-Pricing; and
- Virtual Supply Offers.

The rules applying to the Day-Ahead Energy and Operating Reserve Market clearing of Energy, Regulating Reserve and Contingency Reserve on specific Resources are as follows:

- If a Resource has been scheduled to potentially provide Regulating Reserve, the cleared sum of Energy, Regulating Reserve, Contingency Reserve and Ramp Capability is constrained by the Hourly Regulation Maximum Limit.
- If a Resource has been scheduled to potentially provide Regulating Reserve, cleared Energy less cleared Regulating Reserve less cleared Down Ramp Capability is constrained by the Hourly Regulation Minimum Limit.
- If a Resource has not been scheduled to potentially provide Regulating Reserve, the cleared sum of Energy, Contingency Reserve and Up Ramp Capability is constrained by the Hourly Economic Maximum Limit.
- If a Resource has not been scheduled to potentially provide Regulating Reserve, Energy less cleared Down Ramp Capability is constrained by the Hourly Economic Minimum Limit.
- The cleared Energy is constrained by the applicable ramp rates.
- The cleared Regulating Reserve is constrained by the applicable ramp rates.
- The cleared Contingency Reserve is constrained by the applicable ramp rates.
- The amount of Regulating Reserve that may clear on a Resource is limited to a configurable percentage of the Market-Wide Regulating Reserve Requirement. This limit is required to ensure reliable dispersion of Regulating Reserve and may be modified by MISO based upon observed historical Regulating Reserve dispersion.

To the extent that this limit causes Regulating Reserve or Operating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.

- The amount of Contingency Reserve that may clear on a Resource is limited to a configurable percentage of the Market-Wide Contingency Reserve Requirement. This limit is required to ensure reliable dispersion of Contingency Reserve and may be modified by MISO based upon observed historical Contingency Reserve dispersion. To the extent that this limit causes Operating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.
- The amount of Ramp Capability that may clear on a Resource is limited to a configurable percentage of the Market-Wide Ramp Capability Requirement. This limit is required to ensure reliable dispersion of Contingency Reserve and may be modified by MISO based upon observed historical Contingency Reserve dispersion. To the extent that this limit causes Operating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.

MISO clears the Day-Ahead Energy and Operating Reserve Market, calculates the Day-Ahead Ex-Ante LMPs and MCPs and posts the results on MISO's Market Portal at 1330 EPT. MISO also calculates Ex-Post LMPs and MCPs and posts the results on MISO's Market Portal between 1330 and 1630 EPT. Posting of results may be delayed due to unanticipated events. The following Day-Ahead Energy and Operating Reserve Market results are posted:

- The 24 hourly injections for each Resource of each MP whose Offers are accepted in the Day-Ahead Energy and Operating Reserve Market, including all Self-Scheduled Resources, all cleared Resource Offers, all cleared Virtual Supply Offers, and all cleared Import Schedules.
- The 24 hourly withdrawals of each MP whose Bids are accepted in the Day-Ahead Energy and Operating Reserve Market, including all Fixed Demand Bids, cleared Price-Sensitive Demand Bids, cleared Virtual Demand Bids, and all cleared Export Schedules.
- The Day-Ahead Ex Ante and Ex Post LMPs and Day-Ahead Ex Ante and Ex Post MCPs are determined as described under Section 5 of this BPM.

7.2.3.1 Clearing Under Shortage Conditions

If, while clearing the Day-Ahead Energy and Operating Reserve Market, the sum of the Day-Ahead Fixed Demand Bids, Fixed Export Schedules and Operating Reserve requirements, either on a system-wide or zonal basis, cannot be satisfied with all available non-Emergency Offers (Generation Offers, DRR-Type I Offers, DRR-Type II Offers, Stored Energy Resource

Offers, External Asynchronous Resource Offers, Import Schedules, and Virtual Supply Offers), shortage conditions occur, MISO will attempt to meet fixed demands by utilizing offered Emergency Resources, and Emergency ranges of available resources. In order to appropriately value the Emergency resources such as and released Emergency range, Proxy Offers will be utilized in the ex post Emergency pricing as the maximum of the Emergency Offer Floor and the resource's offer for the applicable capacity block. The Emergency Offer Floor is calculated as the highest available economic energy offer or dispatchable import transaction existing prior to the release of the Emergency Resources and Emergency ranges.

MISO will implement the following steps to clear the Day-Ahead Energy and Operating Reserve Market:

- ***Step One*** – Market Participant Offers submitted for each Resource up to the Hourly Emergency Maximum Limit and Generation Resources, DRRs-Type I and DRRs-Type II that are designated as available only for use in Emergency conditions are made available to the SCUC algorithms.
  - Ex Ante. If use of this Emergency Capacity is sufficient to relieve an anticipated Operating Reserve shortage condition in a capacity Emergency, the Day-Ahead Energy and Operating Reserve Market will clear by incorporating the Emergency Resource, and Resource Emergency limit Offers as part of the co-optimized Day-Ahead Energy and Operating Reserve Market clearing results and the Ex Ante LMPs and Ex Ante MCPs produced by the SCED algorithm will not reflect any Scarcity Prices but will reflect the Emergency Offers associated with the Emergency ranges of those Resources.
  - Ex Post. Similarly if use of this Emergency Capacity is sufficient to relieve an anticipated Operating Reserve shortage condition in a capacity Emergency, the Day-Ahead Energy and Operating Reserve Market will clear by incorporating the Emergency Resource, and Resource Emergency limit Proxy Offers as part of the co-optimized Day-Ahead Energy and Operating Reserve Market clearing results. The Ex Post LMPs and Ex Post MCPs produced by the SCED-Pricing algorithm will not reflect any Scarcity Prices but will reflect the emergency pricing Proxy Offer for all Emergency Resources, external resources qualified as Planning Resources and Emergency range deployment.
  - If inclusion of the Emergency Capacity is sufficient to meet bid-in demand requirements but is not sufficient to relieve an anticipated Operating Reserve shortage in a capacity Emergency, the Day-Ahead Ex Ante and Ex Post MCPs

for Operating Reserve will reflect Scarcity Prices set by the Demand Curves based upon the level of the shortage.

- ***Step Two*** –If inclusion of this Emergency Capacity is not sufficient to meet bid-in demand requirements, the bid-in demand requirements, including fixed Export Schedules, are reduced pro-rata to match the available Capacity and all Day-Ahead Ex Ante and Ex Post LMPs and Ex Ante and Ex Post MCPs are set at the VOLL and Day-Ahead Schedules for demand are based upon the reduced pro-rata amount.

7.2.3.2 Clearing Under Surplus Conditions

If, while clearing the Day-Ahead Energy and Operating Reserve Market, either on a market-wide or zonal basis, the sum of: (1) Self-Scheduled Generation levels; (2) Self-Scheduled DRR-Type I Targeted Demand Reduction levels; (3) Self-Scheduled DRR-Type II levels; (4) Hourly Economic Minimum Limits (or Hourly Regulation Minimum Limits if cleared for Regulating Reserves) for Must Run Generation Resources; (5) Hourly Regulation Minimum Limits for any other Resources committed to provide Regulating Reserve; (6) Fixed Import Schedules; and (7) the applicable Regulating Reserve Requirement (either market-wide or zonal) exceeds the sum of: (1) Fixed Demand Bids; (2) cleared Price Sensitive Demand Bids; (3) cleared Export Schedules and (4) cleared Virtual Demand Bids, MISO will perform the following steps to clear the Day-Ahead Energy and Operating Reserve Market:

- ***Step One*** – For each Resource that is not providing Regulating Reserve, MP Offers submitted down to the Hourly Emergency Minimum Limit are made available to the SCUC algorithm. If use of this Emergency Capacity is sufficient to relieve the anticipated supply surplus condition, the Day-Ahead Energy and Operating Reserve Market will clear by incorporating the Resource Hourly Emergency Minimum Limit Offers as part of the co-optimized Day-Ahead Energy and Operating Reserve Market clearing results and the Ex Ante and Ex Post LMPs and Ex Ante and Ex Post MCPs will not reflect any Scarcity Prices but will reflect the Emergency Offers associated with the Hourly Emergency Minimum Limits of those Resources.
- ***Step Two*** – If inclusion of the Hourly Emergency Minimum Limits in Step One is not sufficient to relieve the supply surplus condition, MP Offers submitted down to the Hourly Emergency Minimum Limit are made available to the SCUC,SCED and SCED-Pricing algorithms for each Resource that had been providing Regulating Reserve. Use of these Hourly Emergency Minimum Limits will create a Regulating Reserve shortage and Ex Ante and Ex Post LMPs will contain negative Regulating Reserve Scarcity Prices and Regulating Reserve Ex Ante and Ex Post MCPs will

include positive Regulating Reserve Scarcity Prices based upon the applicable (market-wide or zonal) Regulating Reserve Demand Curves.

- ***Step Three*** – If the Energy balance is not achieved after Step Two, MISO reduces supply proportionately until Energy balance is achieved and the Day-Ahead Energy and Operating Reserve Market is cleared. Ex Ante and Ex Post LMPs and Regulating Reserve Ex Ante and Ex Post MCPs will continue to be set based upon the Regulating Reserve Demand Curves.

Note: Fast Start Resources shall not be partially committed in SCED-Pricing in Steps one, two or three

7.3 Monitoring and Mitigating Day-Ahead Energy and Operating Reserve Market

Any Offer, or change in availability submitted to MISO by MPs is subject to market monitoring and mitigation measures. The complete process is described in the BPM for *Market Monitoring and Mitigation*.

8. Real-Time Energy and Operating Reserve Market Activities

MPs that participate in the Real-Time Energy and Operating Reserve Market must submit new or revised Offers and/or new or revised Interchange Schedules for the purchase and sale of Energy and new or revised Offers for the sale of Operating Reserve no later than 30 minutes prior to the Operating Hour (OH-30) for use in clearing the Real-Time Energy and Operating Reserve Market. Exhibit 8-1Exhibit 8-1: shows the timeline for the principal activities associated with the Real-Time Energy and Operating Reserve Market.

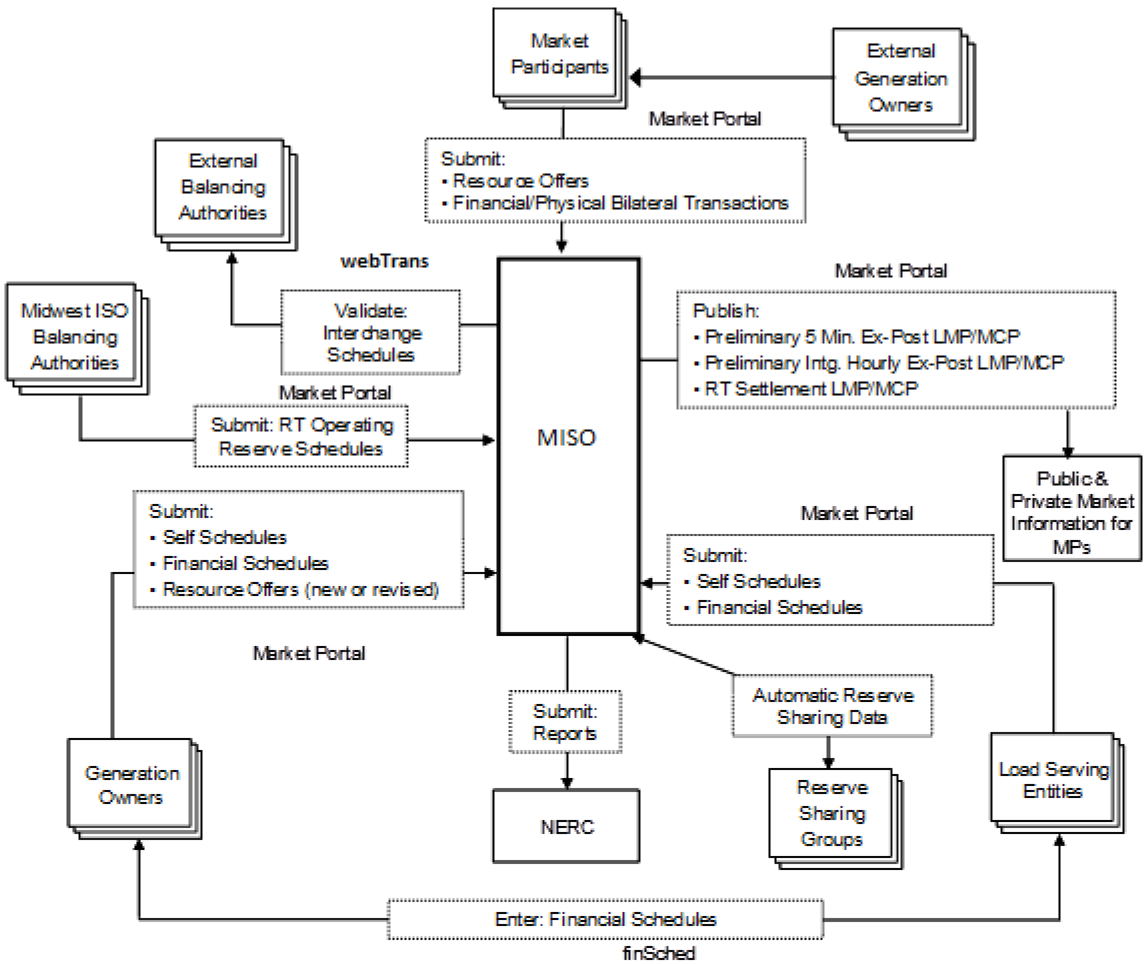
Exhibit 8-1: Real-Time Energy and Operating Reserve Market Activities Timeline

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Data Required for Real-Time Energy and Operating Reserve Market		
OD-7 @ 0000	OD @ OH-30	Fixed Interchange Schedules into the Real-Time Energy and Operating Reserve Market
OD-7 @ 0000	OD @ OH-30	Dynamic Interchange Schedules (dispatchable and import only) into the Real-Time Energy and Operating Reserve Market
OD-7 @ 0000	OD+6 @ 1200	Financial Schedules for the Real-Time Energy and Operating Reserve Markets
OD-7 @ 0000	OD @ OH-30	Generation Resource Offers into the Real-Time Energy and Operating Reserve Market
OD-7 @ 0000	OD @ OH-30	DRR-Type I, DRR-Type II, Stored Energy Resource and External Asynchronous Resource Offers into the Real-Time Energy and Operating Reserve Market
OD @ OH-60	OD@RT	DIR Forecast Maximum Limit submitted into the Real-Time Energy and Operating Reserve Market via MUI
Ongoing	OD @ RT-10 min.	Constraint limits applied and removed based on MISO's power system security analyses
	OD @ RT-10 min.	Contingency Reserve deployment
Real-Time Energy and Operating Reserve Market Activities		
OD-1 @ 1800 EPT	OD-1 @ 2300	Review Load Forecasts and Reports
	OD @ 0000	Open/Close Operator's Log
	OD @ OH-30	Close the Real-Time Energy and Operating Reserve Market 30 minutes prior to the top of each Operating Hour
OD @ RT-10 Starts every 5 minutes	OD @ RT-5 Ends within 5 min. of start	Execute UDS
	OD @ RT-5	Send Resource Dispatch Targets to Resource operators

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
OD Continuous	OD Continuous	Send Setpoint Instructions to Resource operators on a 4 second periodicity that consists of Dispatch Target for Energy adjusted for Regulating Reserve deployment and Contingency Reserve deployment
OD = Operating Day OH = Operating Hour (00 to 23) RT = Real-Time (target time for UDS base points) UDS = Unit Dispatch System Note: All times are in EST unless indicated otherwise		

The interactions and data flows between the entities that participate in the Real-Time Energy and Operating Reserve Market are shown in Exhibit 8-1, excluding RAC.

Exhibit 8-1: Data Flow for Real-Time Energy and Operating Reserve Market (Excluding RAC)



8.1 Market Participant Activities

MPs submit Offers and Interchange Schedules for use in the Real-Time Energy and Operating Reserve Market clearing process as follows.

8.1.1 Notification Deadline

The Notification Deadline is the cut-off time, four hours prior to the beginning of each operating hour, by which schedule changes must be reported to the Transmission Provider to enable it to reflect such changes in the RAC process. For certain assets, schedule changes are automatically gathered from existing offers at the Notification Deadline; for others, specific Notification Deadline offer submittals are required. The following list describes the process that MISO uses to gather Notification Deadline information for each impacted schedule, asset, etc.:

- For Load Zones, a Real-Time Load Zone Demand Forecast may be submitted prior to the Notification Deadline, via the "Real-Time Demand Forecast submittal in the MUI. For Load Zones, positive values represent load. If a value is not submitted prior to the Notification Deadline, it will be deemed to be equal to the Day-Ahead Schedule.
- For Interchange Transactions, the MW quantity of each scheduled transaction that has an "Implemented" status in webTrans is automatically gathered.
- For Financial Schedules, the MW quantity of each Fin Sched that is an RSG Deviations Contract is automatically gathered.
- For Generation Resources (including DIRs and Intermittent Resources), and DRRs Type - II, the as-offered Economic Minimum Limit is automatically gathered.
- For Generation Resources (other than DIRs and Intermittent Resources), and DRRs Type - II, the as-offered Economic Maximum Limit is automatically gathered.
- For DIRs and Intermittent Resources, a Notification Deadline DIR Forecast may be submitted prior to the Notification Deadline, via the "Real-Time Demand Forecast" submittal in the MUI. For a DIR or Intermittent Resource, positive values represent generation. If a value is not submitted prior to the Notification Deadline, it will be deemed to be equal to the Day-Ahead Schedule. The as-offered Economic Minimum Limit for DIRs is automatically gathered.
- For Stored Energy Resources, the as-offered Regulation Minimum Limit and Regulation Maximum Limit are automatically gathered.
- For External Asynchronous Resources, the as-offered Economic Maximum Limit for imports into MISO and as-offered Economic Minimum Limit for exports out of MISO is automatically gathered.

For more information regarding the implications of Notification Deadline information, please see the BPM for *Market Settlements.*

8.1.2 Submitting Real-Time Resource Offers

In the Real-Time Energy and Operating Reserve Market, Resource Offers can be submitted that differ from the Day-Ahead Resource Offers. An MP with Resources that are scheduled in the Day-Ahead Energy and Operating Reserve Market or committed in the RAC process must promptly notify MISO's Real-Time Operators of any changes to the availability or operating plan of its Resource(s) for the Operating Day but no later than 30 minutes after the changes have occurred. MPs with Generation Resources can modify Energy Offers for the capacity that has not yet been dispatched, but is available during the Operating Day.

Resources within the Market Footprint can participate in the Real-Time Energy and Operating Reserve Market by submitting Resource Offers provided they can respond to 5-minute Dispatch Setpoint Instructions. These Resources are termed “dispatchable”. A Resource that is considered dispatchable but does not consistently follow Setpoint Instructions may be reclassified as non-dispatchable. Such considerations are made on a case-by-case basis considering severity, number of occurrences, and reasons for deviations from Setpoint Instructions.

All other Resources (not able to respond to a 5-minute dispatch signal) except DRRs-Type I must Self-Schedule their Resource output.

8.1.2.1 Real-Time Resource Offer Rules

Resource Offers may be submitted in the Real-Time Energy and Operating Reserve Markets only at the registered location of that Resource. These Offers must be submitted at least 30 minutes prior to the Operating Hour[48].

- For Generation Resources and DRRs-Type II, the non-price related Offer parameters must reflect the actual known physical capabilities and characteristics of the Resource except that the Hourly Emergency Maximum Limit, Hourly Economic Maximum Limit, or Forecast Maximum Limit may, at the discretion of the MP, be reduced by an amount equal to any Capacity associated with the Resource that is i) not designated as a Capacity Resource, ii) not being used to provide Energy and/or Operating Reserve to the Day-Ahead Energy and Operating Reserve Market, iii) not being used to provide Capacity in any RAC process, iv) not being used to provide Energy and/or Operating Reserve to the Real-Time Energy and Operating Reserve Market and v) not being used to provide Energy and/or Operating Reserve to any other party or entity.
- An MP whose Resources are scheduled in the Day-Ahead Energy and Operating Reserve Market, committed in the RAC process, and/or have offered into the Real-Time Energy and Operating Reserve Market must promptly notify MISO’s Real-Time Operators of any changes to the availability of its Resource(s) as soon as possible, but no later than 30 minutes after the changes have occurred.

[48] The DIR Forecast Maximum Limit is not subject to this requirement

- If a change has occurred that affects the Resource later in the day (e.g., loss of a coal mill that results in a derating from the Hourly Economic Maximum Limit of the unit) but that does not immediately affect the unit, the MP must update their Real-Time Schedule Offer to reflect the change in unit conditions. These changes can be submitted up to 30 minutes prior to the hour for a new or existing Real-Time Schedule Offer or 30 minutes prior to the hour for an existing Real-Time Schedule Offer.
- If the change in conditions affects Resource operations within the next 30 minutes, the MP must notify MISO's Real-Time Operators of the change by voice communications or by submitting a Real-Time Offer Override request via the Market Portal. MPs are urged to use Portal submitted override requests rather than voice requests. Override requests submitted via the portal are subject to same rules as real time offers (e.g., Emergency Max > Economic Max > Regulation Max etc.). Override requests must be submitted in complete sets and should be accompanied by a valid reason. Override requests can be accompanied with a reason "Other" along with a free form text description. Override requests are organized into eight sets as listed in the table below. Real-Time Offer Override requests submitted via the Market Portal are effective for the current hour and expire at the end of the next market hour to allow the Market Participants sufficient time to update their hourly offers. Portal submitted override requests are organized in sets. In general, a complete set must be submitted with an override request for a particular parameter. Sets are listed in Exhibit 8-2below.

Exhibit 8-2: Offer Override Sets

Set	Gen/DRR2/EAR Override Parameters	SER Parameters	DRR1 Parameters
Run Times	Notification Time		Notification Time
Operating Limits	Economic Min, Eco Max, Regulation Min, Reg Max, Emergency Min, Emer Max	Reg Min, Reg Max	Target Demand Reduction MW
Offline Response	OfflineRespMax		
Ramp Rates	RR Up, RR Down, Reg RR (bi-directional)	Ramp Rate Bidirectional	
Self Schedules	SelfMWEnergy, SelfMWSpin, SelfMWOnlineSupp, SelfMWReg, SelfMWOfflineSupp	SelfMWReg	SelfMWSpin, SelfMWOnlineSupp
Dispatch Status	Energy Dispatch Status, Reg Status, Spinning Reserve Status, Online Supp Status, Offline Supp Status, Ramp Capability Status	Reg Status	Online Supp Status, Spin Status
Commit Status	Energy Commit Status	Commit Status	Energy Commit Status
Off Control, EEE Flag	OffControlFlag, EEE Flag	OffControlFlag, EEE Flag	OffControlFlag, EEE Flag

- To commit a Generation Resource or DRR-Type II in the Real-Time Energy and Operating Reserve Market that does not have a current commitment or is outside of its Day-Ahead Energy and Operating Reserve Market schedule, the MP must submit the status of "Must-Run" for the desired run period. Any Resource that operates without a commitment from the Day-Ahead or Real-Time Energy and Operating Reserve Markets will be considered to be "Must-Run" during the period of time for which no commitment is present.

- To decommit a Generation Resource or DRR-Type II in the Real-Time Energy and Operating Reserve Market that is not scheduled in the Day-Ahead Energy and Operating Reserve Market or the RAC, the MP must submit a status update of "Unavailable" or notify MISO's Real-Time Operators if the Real-Time Energy and Operating Reserve Market is closed for that hour or submit the override request for the commit status via Market Portal if the Real-Time Energy and Operating Reserve Market is closed for that hour.

If a Resource is scheduled in the Day-Ahead Energy and Operating Reserve Market or the RAC and wishes to deviate from that schedule (i.e., not run or run at a reduced output level) for economic reasons, the MP must contact MISO's Real-Time Operators to determine if this course of action is acceptable. MISO will determine one of the following:

- That the Resource is not needed for reliability purposes for the Operating Day; if so, then the Market Participant can decide not to run the Resource on an economic basis. The MP is still responsible for Settlement of the deviation between its Day-Ahead Schedule and Real-Time output.
- That the Resource is needed for reliability purposes and informs the MP that the Resource must remain committed to its schedule.

The guideline for notifying MISO of deviations for Generation Resources or DRRs-Type II is the sum of the unit's notification time plus the time to start. The minimum notification time is 90 minutes prior to the start time required for the operation of the Resource. This allows adequate time for determining if the unit is needed for reliability.

8.1.3 Submitting Real-Time Interchange Schedules

The following general rules apply to submitting any Interchange Schedules in the Real-Time Energy and Operating Reserve Market:

- All Interchange Schedules must begin on the top, quarter past, half, or quarter till the hour.
- MPs must submit all Interchange Schedules for the Real-Time Energy and Operating Reserve Market, via NERC E-Tag, at least 20 minutes prior to the start of the Interchange Schedule; however, Interchange Schedules may not be submitted

during the operating hour except for reliability purposes as determined by MISO. MISO confirms the validated and compliant Interchange Schedule requests with appropriate external BAs.

- Real-time PSE adjustments to Interchange Schedules must also be submitted no later than 20 minutes before the start of the schedule change or the start of the operating hour. Adjustments due to Transmission Loading Relief Procedures ("TLRs") or loss of generation will be permitted after this timeframe as specified by MISO.

8.2 MISO Activities

The Real-Time Energy and Operating Reserve Market provides a continuous process for least cost balancing of supply and demand while recognizing current operating conditions. MISO uses a Network Model to accurately dispatch Resources to match the short-term demand forecast and Operating Reserve requirements and manage congestion in Real-Time.

The Real-Time Energy and Operating Reserve Market clearing produces Resource Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve and Supplemental Reserve and provides Ex Ante Real-Time LMPs for injections and withdrawals within MISO's Market Footprint and Ex Ante Real-Time MCPs for cleared Operating Reserve. MISO uses a Real-Time Security-Constrained Economic Dispatch ("SCED") algorithm to balance injections and withdrawals, meet Operating Reserve requirements, manage congestion, and produce LMPs and MCPs on a simultaneously co-optimized basis. The Real-Time Energy and Operating Reserve Market clearing operates continuously on a five-minute basis. The SCED runs every five minutes to develop Resource Dispatch Targets for the end of the next dispatch interval.

The objective of the security-constrained economic dispatch will be to minimize total costs for the dispatch interval while simultaneously enforcing physical constraints and reliability requirements. Total costs to be minimized include energy costs, reserve availability costs and reserve scarcity costs.

8.2.1 Checkout of Interchange Schedules

All MISO-adjacent external Balancing Authorities that are parties to Interchange Schedules with MISO are contacted and NSI is confirmed. Individual Interchange Schedules are not verified unless necessary to resolve any discrepancy.

Verification starts prior to the Operating Hour and is only performed if the NSI has not already been verified at a previous time.

See the BPM for *Physical Scheduling* for a detailed description of Checkouts (BPM-007).

8.2.2 Operating Reserve Requirements

The Market-wide and Zonal Regulating Reserve and Contingency Reserve Requirements for the Real-Time Energy and Operating Reserve Market will generally be the same as those requirements developed for use in the Day-Ahead Energy and Operating Reserve Market. MISO may increase these requirements if necessary to address system condition changes following the clearing of the Day-Ahead Energy and Operating Reserve Market and/or Emergency conditions in Real-Time.

8.2.3 Real-Time Energy and Operating Reserve Market Clearing

MISO clears the Real-Time Energy and Operating Reserve Market by determining the security-constrained dispatch that is the least costly means of balancing generation and Load (supply/demand) while meeting Operating Reserve requirements within the Market Footprint based on actual conditions, forecasted conditions, and on submitted Offers. The inputs to the SCED are identified and described below:

- ***Load Forecast*** – MISO forecasts Real-Time demand for use in the Real-Time Energy and Operating Reserve Market. The forecast is distributed to individual Load Buses using the most recent State Estimator results.
- ***Network Model*** – The Real-Time Energy and Operating Reserve Markets Network Model is populated with the most recent State Estimator results before starting the Real-Time Energy and Operating Reserve Market clearing process. This includes the current on-line status and output of Generation Resources, DRRs-Type II, Stored Energy Resources and External Asynchronous Resources. In addition, the current set of active constraints is obtained from the Constraint Logger (CLOGGER).
- ***Interchange Schedules*** – The expected values of Interchange Schedules for the following five-minute period, including any Transmission Loading Relief (“TLR”), are obtained from the webTrans.

- ***Resource Status* –** The Resource Status consists of a Regulation Flag and an Off-Control Flag. If the Off-Control Flag is set, the Resource is treated as having a fixed dispatch equal to the output from the most recent State Estimator result (or with fixed dispatch at zero output, if a SER). If the Off-Control Flag is not set and the Regulation Flag is set, the Resource is considered to be scheduled to potentially provide Regulating Reserve. Otherwise, the Resource will be considered to be a "Load Following" Resource. The ICCP-telemetered Resource Control-Mode is not an input to the SCED algorithm.
- ***Resource Information*** – The Real-Time Energy and Operating Reserve Market clears based upon the Generation Resource, DRR-Type-I, DRR-Type-II, Stored Energy Resource and External Asynchronous Resource Offers received 30 minutes prior to the operating hour for the next five-minute period. For Regulating Reserve, only Offers associated with Resources that have been scheduled to potentially provide Regulating Reserve are considered.
- ***SER - Specific Information*** – The ICCP-telemetered Energy Storage Level for each Stored Energy Resource is used, along with Stored Energy Resource Offers, to pre-determine the Energy Dispatch Target for the Stored Energy Resource in such a way as to maximize the Regulating Reserve capability available to the SCED co-optimization. For more information on the methodology for determining the Energy Dispatch Target pre-processing for Stored Energy Resources, see Attachment D of this BPM.

MISO economically dispatches, subject to ramp rate and other Resource constraints, Generation Resources, DRRs -Type II, Stored Energy Resources and External Asynchronous Resources that effectively meet forecast Load, Operating Reserve requirements and Interchange Schedules, subject to activated network constraints. The objective of the SCED algorithm is to minimize the as-offered Energy and Operating Reserve prices of Real-Time Energy and Operating Reserve procurement over the next dispatch interval, on a simultaneously co-optimized basis, subject to network constraints and Resource operating constraints, with the exception that Stored Energy Resource energy dispatch is not a component of this objective. Dispatch Target information is communicated directly to Generation Resources, Stored Energy Resources, External Asynchronous Resources, and DRRs Type-II via Setpoint Instructions.

The rules applying to the Real-Time Energy and Operating Reserve Market clearing of Energy, Regulating Reserve and Contingency Reserve on specific Resources are as follows:

- If a Resource has been scheduled to potentially provide Regulating Reserve the cleared sum of Energy, Regulating Reserve, Contingency Reserve, and Ramp Capability is constrained by the Hourly Regulation Maximum Limit.
- If a Resource has been scheduled to potentially provide Regulating Reserve, the cleared quantity of Energy less Regulating Reserve less Down Ramp Capability is constrained by the Hourly Regulation Minimum Limit.
- If a Resource has not been scheduled to potentially provide Regulating Reserve, the cleared sum of Energy, Contingency Reserve, and Up Ramp Capability is constrained by the Hourly Economic Maximum Limit.
- If a Resource has not been scheduled to potentially provide Regulating Reserve, Energy less Down Ramp Capability is constrained by the Hourly Economic Minimum Limit.
- The cleared Energy is constrained by the applicable ramp rates.
- The cleared Regulating Reserve is constrained by the applicable ramp rates.
- The cleared Contingency Reserve is constrained by the applicable ramp rates.
- The amount of Regulating Reserve that may clear on a Resource is limited to a configurable percentage of the Market-Wide Regulating Reserve Requirement. This limit is required to ensure reliable dispersion of Regulating Reserve and may be modified by MISO based upon observed historical Regulating Reserve dispersion. To the extent that this limit causes Regulating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.
- The amount of Contingency Reserve that may clear on a Resource is limited to a configurable percentage of the Market-Wide Contingency Reserve Requirement. This limit is required to ensure reliable dispersion of Contingency Reserve and may be modified by MISO based upon observed historical Contingency Reserve dispersion. To the extent that this limit causes Operating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.
- The amount of Ramp Capability that may clear on a Resource is limited to a configurable percentage of the Market-Wide Ramp Capability Requirement. This limit is required to ensure reliable dispersion of Contingency Reserve and may be modified by MISO based upon observed historical Contingency Reserve dispersion. To the extent that this limit causes Operating Reserve Scarcity, clearing above this amount on a single Resource will be allowed.

The SCED program produces the following outputs:

- ***Dispatch Targets*** – The Real-Time Energy and Operating Reserve Market clearing process develops the Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve and On-Line Supplemental Reserve (if applicable) for each offered Generation Resource, DRR-Type II and External Asynchronous Resource, Dispatch Targets for Spinning Reserve or Supplemental Reserve for each offered DRR-Type I, and Dispatch Targets for Energy and Regulating Reserve (if applicable) for each offered Stored Energy Resource for the five-minute period. MISO communicates the desired Energy, Regulating Reserve, Spinning Reserve and/or On-Line Supplemental Reserve deployment to each Resource selected via Setpoint Instructions approximately every four seconds and communicates the Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, On-Line Supplemental Reserve (if applicable) and Supplemental Reserve (DRR-Type I) to each applicable Resource on a five-minute basis. Deviation from Setpoint Instructions may result in Excessive/Deficient Energy Deployment Charges, Contingency Reserve Deployment Failure Charges and/or Real-Time RSG Charges. MISO communicates Dispatch Targets (via XML notification and ICCP) and Setpoint Instructions (via ICCP) to the MP responsible for scheduling and dispatching the Resource. All MPs responsible for responding to Setpoint Instructions must have the ability to receive electronic Dispatch Targets and Setpoint Instructions from MISO. MISO also sends Dispatch Target Notifications and Start/Stop Notifications, via XML, to the Local Balancing Authority of each Resource. The Dispatch Targets for Energy are for the end of the five-minute period. All Generation Resources and DRRs-Type II that are on-line and External Asynchronous Resources and Stored Energy Resources that are available receive a Setpoint Instruction, regardless of whether they have submitted Self-Schedules and/or Offers.
- ***Ex-Ante LMPs*** – The Real-Time Energy and Operating Reserve Market clearing process also develops ex-ante LMPs for the five-minute period. These values are posted and are developed for informational purposes only.
- ***Ex-Ante MCPs*** – The Real-Time Energy and Operating Reserve Market clearing process also develops ex-ante MCPs for SER-based and generation based Regulating Reserve, demand-based and generation-based Spinning Reserve and demand-based and generation-based Supplemental Reserve on a Reserve Zone and Market-Wide basis for the five-minute period. These values are posted and are developed for informational purposes only.

The SCED-Pricing program produces the following outputs:

- ***Real-Time Ex Post LMPs* –** The Real-Time Energy and Operating Reserve Market clearing process also develops Real-Time Ex-Post LMPs for the five-minute period. These values are posted and developed utilizing the SCED-Pricing algorithm which includes the Extended LMP formation. The Real-Time Ex-Post formulation allows Fast Start Resources, Emergency Demand Response, Load Modifying Resources, Emergency Energy purchases as well as Emergency Resources and Emergency ranges to set prices. The Real-Time Ex-Post LMPs are used by MISO to settle the Real Time Energy and Operating Reserve Market.
- ***Real-Time Ex Post MCPs* –** The Real-Time Energy and Operating Reserve Market clearing process also develops Real-Time Ex-Post MCPs for SER-based and generation based Regulating Reserve, demand-based and generation-based Spinning Reserve and demand-based and generation-based Supplemental Reserve on a Reserve Zone and Market-Wide basis for the five-minute period. The Real-Time Ex-Post MCPs are used by MISO to settle the Real Time energy and Operating Market.

Real-time ex post and ex ante prices are expected to be identical majority of the time but could differ. There are specific circumstances that could result in Real-time ex ante and ex post price differences. Typically Real-Time Ex Post LMPs will be higher than Real-Time Ex Ante LMPs when online Fast Start Resources are available to set real-time ex post prices. Because the online Fast Start Resource's no load and start up portion of the Offer is included in the price setting, the Real-Time Ex-Post LMPs could be higher compared to the Real-Time Ex Ante LMPs. On the other hand, Real-Time Ex Post LMPs can be lower when there is transmission scarcity or Operating Reserve scarcity in the ex ante phase. In the latter case, Real-Time Ex Post LMPs can be lower due to the availability of Offline Fast Start Resources that are eligible to participate in price setting in Real-Time Ex Post LMP calculation and could result in the alleviation of the scarcity conditions,

The Real-Time Energy and Operating Reserve Market utilizes the same Network Model that is used in the Day-Ahead Energy and Operating Reserve Market, with all real-time network configurations and constraints as determined from the most recent State Estimator results.

8.2.3.1 Clearing Under Shortage Conditions

8.2.3.1.1 Real-Time Ex Ante

The Ex Ante SCED algorithm will utilize MP Offers for all Resource Capacity used in the RAC process immediately preceding the real-time operating Hour, including selected Hourly Emergency Maximum Limit segments, Emergency-only Resources and Emergency Energy purchases, in clearing the Real-Time Energy and Operating Reserve Market for each Dispatch Interval. If there is an actual Operating Reserve shortage during any Dispatch Interval, the Ex Ante MCPs for Operating Reserve will reflect Scarcity Prices set by the Demand Curves based upon the level of the shortage. As a last resort, if there is a shortage of available Capacity to meet demand requirements within the Operating Hour, MISO will issue an EEA Level 3 and begin Load Shedding procedures as described in the Tariff, and all Real-Time Ex Ante LMPs and Ex Ante MCPs will be set at the VOLL.

8.2.3.1.2 Real-Time Ex Post

The Ex-Post SCED-Pricing Algorithm will additionally utilize a Proxy Offer for all Emergency-Only Resources, External Resources qualified as Planning Resources, Emergency range of available on-line Resources, Emergency Energy Purchases, Load Modifying Resources, and Emergency Demand Response resources dispatched in the Real-Time Market. The Proxy Offer is described in section 5.2.3 (Market Clearing under Emergency Shortage Conditions) of this BPM.

8.2.3.2 Clearing Under Surplus Conditions

Within the real-time operating Hour, the SCED algorithm will utilize MP Offers for all Resource Capacity used in the RAC process immediately preceding the real-time operating Hour, including selected Hourly Emergency Minimum Limit segments, in clearing the Real-Time Energy and Operating Reserve Market for each Dispatch Interval. If use of Hourly Emergency Minimum Limits creates a Regulating Reserve shortage during any Dispatch Interval, the Ex Ante MCPs for Regulating Reserve will reflect Scarcity Prices and Ex Ante LMPs will reflect negative Scarcity Prices as set by the Regulating Reserve Demand Curve.

8.2.4 Regulating Reserve Deployment

Regulating Reserve Deployment in the up or down direction is limited to Resources that have cleared Regulating Reserve. The set of Resources available to regulate during a Dispatch Interval is limited to the set of Resources that cleared Regulating Reserve during the Dispatch Interval and that submit an ICCP-telemetered Control Mode equal to 2, and the amount of Regulating Reserve that can be deployed on these Resources during the Dispatch Interval is limited to the amount of Regulating Reserve that cleared on these Resources during the Dispatch Interval. Regulating Reserve is deployed on specific Resources via Setpoint Instructions via the AGC system on a graduated pro-rata basis, based on the ramp available to each Resource providing Regulating Reserve; that is, the ramp rate of each Resource over five minutes less the change in Dispatch Target for that Resource during the Dispatch Interval. Resources are allocated into five groups, with Group 1 containing the Resources with the greatest ramp available and Group 5 containing the set of Resources with the least Ramp Available. Resources in Group 1 will be deployed on a pro-rata basis first, and Resources in Group 5 will be deployed on a pro-rata basis last. Resource undeployments occur in reverse order.

A Resource that has Control Mode equal to 1 or 2 but does not consistently follow Setpoint Instructions may be reclassified as Control Mode equal to 3, Off Control, per Section 3.13 of RTO-OP-010-r20 Generator Operator Communication with MISO including EEE Procedure. Such considerations are made, including input from the Market Participant, on a case-by-case basis considering severity, number of occurrences, and reasons for deviations from Setpoint Instructions.

Exhibit 8-3 shows the various ICCP-telemetered Resource Control Modes that may be selected by Market Participants and the corresponding AGC system treatment.

Exhibit 8-3: AGC System Resource Control Modes

Resource Control Mode	MISO AGC System Treatment
0	Offline (indicates Resource is NOT available to the market)
1	Online, NOT capable of Regulating (indicates Resource is available for Dispatch Target for Energy and/or Contingency Reserve deployment)
2	Online, capable of Regulating (indicates Resource is available for Regulating Reserve Deployment, Dispatch Target for Energy, and/or Contingency Reserve deployment)
3	Off Control (indicates Resource is online but off control) – Setpoint Instruction is an echo of the current MW reading)

For example, assume 20 Resources each cleared 30 MW of Regulating Reserve. Assume the change in the Energy Dispatch Target for 3 Resources is 0 MW, for 5 Resources is + 10 MW, and for the remaining 12 Resources is +15 MW. There will be five groups, each containing four Resources: Group 1 will contain the three Resources with a change in Energy Dispatch Target of 0 MW and one Resource with a change in Energy Dispatch Target of 10 MW; Group 2 will contain the remaining four Resources with a change in Energy Dispatch Target of 10 MW; and Groups 3, 4 and 5 will each contain four Resources with a change in Energy Dispatch Target of 15 MW. Assume the AGC system requires a system-wide regulation deployment of 120 MW in the upward direction. The AGC system would deploy + 30 MW on each of the four Resources in Group 1. No Regulating Reserve would be deployed from the remaining Groups, but should the system-wide regulation deployment signal increase, Regulating Reserve could be deployed on the other Resources within the remaining Groups as well.

8.2.5 Ensuring Bulk Electric System Reliability

The MISO Reliability Coordinator has ultimate responsibility for the reliability of MISO's Reliability Coordination footprint. As such, the RC must have the authority to take the actions deemed necessary to ensure a reliable system. MISO develops congestion management procedures in conjunction with its stakeholder groups that give the Reliability Coordinator guidance on appropriate mitigation strategies and actions available. These procedures may indicate a preferred order of mitigating actions while recognizing the Reliability Coordinator has the authority to take the actions in the order deemed necessary to protect the Bulk Electric System. The available mitigation options may include, but are not limited to:

- Implementation of Operating Guides
- System Reconfiguration
- Security Constrained Economic Dispatch
- Use of TLR
- Curtailment of Intermittent Resources
- Commitment/Decommitment of Resources
- Manual Dispatch of Resources
- Declaration of System or Local Emergencies and implementation of Emergency Procedures

8.2.6 Congestion Management and Transmission Constraint Demand Curves

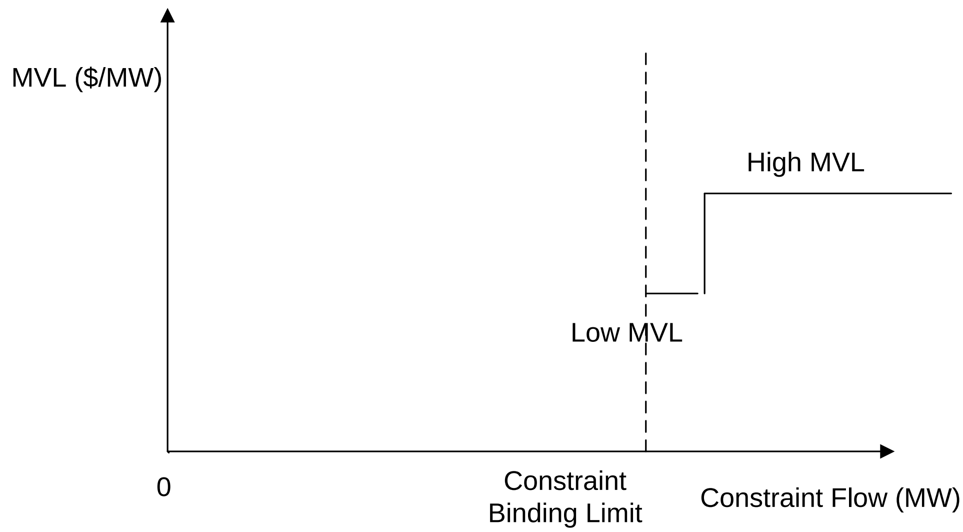
In order to solve the Security Constrained Economic Dispatch, each Transmission Constraint must have a marginal value limit (or MVL, also known as shadow price limit), expressed in $/MW, assigned to it. The MVL is the maximum marginal benefit that the SCED will consider when evaluating resource dispatches to meet the constraint. During any Dispatch Interval in which a transmission constraint cannot be managed within its limit, the marginal value (also known as the shadow price) of the constraint will be set to the MVL for the constraint. The following procedure is used to determine MVLs. For a more in-depth understanding of how MVLsare used in the co-optimization, please see Attachment A to this BPM, which provides an overview on optimization problems and constraint formulation.

MISO utilizes Transmission Constraint Demand Curves ("TCDC") in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets to determine the MVL of each transmission constraint. The TCDC assigns a $/MW MVL according to the quantity flow across the constraint. The TCDC in use for each binding constraint will be published for each Dispatch Interval in Real-Time, regardless of what type of TCDC is used for that constraint.

8.2.6.1 TCDC Development

In the MISO Real-Time and Day-Ahead market, each MISO transmission constraint is assigned a TCDC which includes two pairs of Marginal Value Limits (in $/MW) and constraint flow (in MW or percentage of binding limit). The two block MVLs may be equal as in the case of IROLs. The TCDC is utilized to determine the MVL(s) that is used for commitment and dispatch of Resources.

Exhibit 8-4: Example of Transmission Constraint Demand Curve



There are three methods that MISO utilizes to assign a transmission constraint to a TCDC and determine the associated MVL.

- Group 1
- Group 2
- Temporary Override

Detailed TCDCs for Group 1 and 2 are available in Tariff Schedule 28A.

8.2.6.2 Assign Transmission Constraints with Group 1 TCDCs

MISO assigns a TCDC to each transmission Constraint based on its voltage level or impact (e.g., IROL). Most constraints will be assigned to default TCDC based on voltage level, TLR or IROL status. For simplicity, a two-step TCDC is currently used. The lower portion of the TCDC is used for flows just at or exceeding limits up to the higher block breakpoint. The higher TCDC will be used for larger exceedances of the transmission constraint limit.

8.2.6.3 Assign Transmission constraints with Group 2 TCDCs

There are a small number of constraints that do not respond well to Group 1 TCDCs. These constraints may be impacted by broad regional flows or may need different MVLs to achieve control. An example of this type of exception is a transmission constraint that is highly impacted by wind generation such that increasing wind output adversely impacts the constraint. Assuming a very low production cost, a very low LMP is necessary to provide incentive for downward dispatch to the wind Resource(s).

When an exception is identified that is not managed well to the Group 1 TCDCs, MISO will add this constraint to Group 2.

Updates to the contents of Group 2 will be posted within two business days after a transmission constraint has been assigned to or removed from Group 2. This posting will identify the monitored element and the assigned TCDC for each constraint in Group 2.

8.2.6.4 Assign Transmission constraints with TCDC Temporary Overrides

To maintain reliable operation, MISO operators can temporarily override the MVL associated with Group 1 or 2 TCDC based on operating conditions for particular constraints in both the Day-Ahead and Real-Time markets. The MVL is returned to the Group 1 or 2 TCDC value as soon as system conditions and congestion management no longer require an overridden MVL. There are various circumstances that require the MISO operator to temporarily override the default TCDC. Any Operator Overrides to a Group 1 or Group 2 TCDC will be posted within two business days.

If MISO identifies that a TCDC does not allow for reliable constraint management, MISO Real-Time Operations personnel will assess the current costs and capabilities (shift factors) of available resources that impact the transmission constraint, and identify appropriate modifications to the TCDC to capture the benefits of further economic re-dispatch, in order to maintain both the reliability of constrained transmission elements and the economic efficiency of the market. This assessment will determine the shape and magnitudes of an override TCDC that allows MISO to achieve the required relief for the transmission constraint. The magnitude of the required TCDC change can be impacted by, but is not limited to impact by, the following:

- Economic and Physical characteristics of resources that impact the constraint.
- Local and system-wide product pricing.
- Changing system conditions (current and projected flows across the constrained element as well as nearby transmission element).

The following examples demonstrate the situations that operators need to temporarily override TCDC for particular constraints.

8.2.6.4.1 Temporary Overrides-Increasing the MVL

If a system operating limit (SOL) condition is expected to persist and the condition raises reliability concerns, the MVL values of the TCDC may be raised to reflect the heightened reliability concerns and mitigate the condition. Conditions that may lead to MVL increases include, but are not limited to: conflicting constraints, and high system-wide LMPs. Conflicting constraints refers to system conditions where congestion management of one transmission constraint adversely impacts the reliable management of one or more other transmission constraints. High system-wide marginal energy costs may require an increase to the MVLs because resources with negative impacts on a constraint tend to be dispatched upward during periods in which the MEC is high. The adjustment in the TCDC for a particular constraint required for congestion management is dependent on a number of factors, including the relief required, the ramp rates and limits of impacting resources, associated sensitivities of resources, and the MEC.

8.2.6.4.2 Temporary Overrides-Lowering the MVL

It may also be necessary to lower the MVL values of a TCDC for a particular constraint from the default values. The most common reason for doing so is to avoid conflicting constraints. In other situations, temporary operating guides or other action plans, which rely on post-contingency action to avoid SOL events, may provide the basis for lowering the MVLs of a transmission constraint.

8.2.7 Sub-Regional Power Balance Constraint Curves

In order to manage dispatched intra-regional flows, all constraints relating to applicable seams agreements, coordination agreements or operating procedures (Sub-Regional Power Balance Constraints) have a Marginal Value Limit (or MVL, also known as shadow price limit) assigned to them. The MVL is the maximum marginal benefit that the SCED will consider when evaluating resource dispatches to meet the Sub-Regional Power Balance Constraint. For any Dispatch Interval where a Sub-Regional Power Balance Constraint cannot be managed within its limit, the Marginal Value (also known as shadow price) will be set to the Marginal Value Limit.

8.2.7.1 Sub-Regional Power Balance Constraint Curve Development

In both the MISO Real-Time and Day-Ahead markets, each Sub-Regional Power Balance Constraint is assigned a curve that includes predefined levels of exceedance percentages and their corresponding prices. The curve is utilized to determine the MVL(s) used for commitment and dispatch of Resources. The curve can be found in Schedule 28B of the Tariff.

8.2.7.2 Assign Sub-Regional Power Balance Constraints with Appropriate Sub-Regional Power Balance Constraint Curve

MISO uses a tiered system to control Sub-Regional Power Balance Constraints. When the dispatch flow rises over the predefined percentage of exceedance, the price rises proportionally to allow the SCED to exert additional control.

8.2.7.3 Temporary Overrides of Sub-Regional Power Balance Constraint Curve

When the dispatch flow is expected to be greater than the limit for two or more consecutive Dispatch Intervals, MISO may temporarily override the Sub-Regional Power Balance Constraint Curve to more effectively manage flows. Constraint exceedance will be returned to the limit as soon as MISO determines system conditions and/or reliability no longer need the override. For any period where MISO overrides a limit, MISO will make a public posting on its website with:

1) The circumstances in which the temporary override was executed,
2) The Dispatch Intervals the temporary overrides were in place,
3) The values applied during the temporary override, and

8.2.8 Excessive/Deficient Energy Deployment Charges

The Excessive/Deficient Energy Deployment Charge is an hourly charge that is applied to any Resource that has Excessive Energy and/or Deficient Energy in four or more consecutive Dispatch Intervals in the same clock hour. The Excessive/Deficient Energy Deployment Charge consists of two components: (1) the Excessive/Deficient Charge Rate multiplied by the Resource's Actual Energy Injection; and (2) a recapture of net Regulating Reserve credits paid to the Resource. The first portion of the charge applies equally to all applicable Resources for causing an increased Regulating Reserve burden. The second portion of the charge applies only to Resources with Dispatch Targets for Regulating Reserve and is equivalent to non-payment of any net credits for cleared Regulating Reserve for failure to provide the Regulation Service. If a MP has elected to use the Common Bus option, the output of Resources identified at the Common Bus location will be considered in aggregate for the purposes of determining whether or not an Excessive/Deficient Energy Deployment Charge will apply, as described below. See the BPM for *Market Settlements* for additional details.

8.2.8.1 Excessive/Deficient Energy Deployment Charge Waiver

A MP is exempted from the Excessive/Deficient Energy Deployment Charge under certain conditions where the MP would otherwise be subject to the charge due to events beyond its control and without the fault or negligence of the MP. Such conditions include but are not limited to:

- Emergencies;
- A Resource in test mode;
- A Resource in start-up or shut-down mode;
- The Hour in which a Resource trips and goes offline;
- During a Contingency Reserve Deployment event, if the Resource has cleared Contingency Reserves; and/or
- Extremely high wind or other weather-related conditions materially impacting a Dispatchable Intermittent Resource's ability to provide Energy and resulting in a substantial reduction or cessation of wind generation activities.

A MP may request the Generation Balancing Authority Operator to waive the Excessive/Deficient Energy Deployment Charge for conditions other than those listed above, and the Generation Balancing Authority Operator shall grant such request subject to the Regional Generation Dispatcher's determination that the reason for the request is due to events beyond the MPs control that were not caused by the fault or negligence of the MP. A MP can also request to waive the Excessive/Deficient Energy Deployment Charge by submitting a real time override request via the Market Portal, stating valid reasons. Please see section 8.1.2 for details.

8.2.9 Contingency Reserve Deployment

Contingency Reserve procured in Real-Time will be deployed through a Contingency Reserve Deployment Instruction, via both ICCP and XML instruction, following a system event, normally following the sudden loss of a supply Resource. The amount of Contingency Reserve deployed will depend upon the MW size of the Resource loss or other extreme condition, and the anticipated response capability of the MISO Contingency Reserve Resources. Contingency Reserves will be deployed only on Resources with cleared Contingency Reserve. On-line Contingency Reserve (i.e., Spinning Reserve and Supplemental Reserve cleared on on-line Generation Resources, on-line DRRs – Type II, DRRs – Type I with Contingency Reserve Status set to "online", and/or on-line External Asynchronous Resources) will be prioritized ahead of off-line Contingency Reserve (i.e., Supplemental Reserve cleared on off-line Quick-Start Resources and DRRs - Type I with Contingency Reserve Status set to "offline"). If the amount of undeployed Contingency Reserve carried on on-line Resources is greater than or equal to the Contingency Reserve Deployment Instruction, no off-line Contingency Reserve will be deployed. Contingency Reserve will be deployed on on-line Resources in proportion to the amount of Contingency Reserve cleared on each Resource. Should it be necessary to deploy Contingency Reserve on off-line Resources as well, off-line Quick-Start Resources and DRRs – Type I with Contingency Reserve Status set to "offline" will be deployed in merit order, subject to Reserve Zone import limits, based on economics. Offline merit order prices will be calculated as follows:

For an off-line Quick-Start Resource:

$$CRD\_CallonCost =$$

$$SU_i + \sum_{i=start\_hour}^{End\_hour} [(NL_i + \int_0^{Off-Line\_Deployed\_MW} IncEnergy_i) * Minutes\_run_i / 60]$$

$$MeritOrder = CRD\_CallonCost /(eventduration * Off - Line\_Deployed\_MW)$$

For a DRR Type-1:

$$CRD\_CallonCost = Shut\_Down\_Offer + \sum_{i=start\_hour}^{Endhour} HourlyCurtailmentOffer_i * Minutes\_run_i / 60$$

$$MeritOrder = CRD\_CallonCost /(eventduration * FixedReductionMW)$$

Where

- *CRD_CallonCost* is the Total Production cost for the Resource commitment for the commitment period
- SU_i is the Resource's Start-Up Offer. This Offer is a function of the unit condition, 'Hot', 'Intermediate', or 'Cold'
- NL_i is the Resource's No-Load Offer in hour i
- $IncEnergy_i$ is the Resource's Incremental Energy Offer in hour i
- *Shut_Down_Offer* is the DRR Type 1's Shut-Down Offer
- $HourlyCurtailmentOffer_i$ is the DRR Type 1's Hourly Curtailment Offer in hour i
- $Minutes\_run_i$ is the number of minutes of the commitment period in hour i
- *Off-Line_Deployed_MW*= Max (EconomicMin, Dispatched Supplemental)
- *Dispatched Supplemental* is MW of the Cleared Supplemental for the UDS interval on the off-line Resource
- *Start_hour* is Mkthour for current time

- *End_hour* is
  - Mkthour for current time + Max(min_run_time, event_duration) for Quick-Start Resources and
  - Mkthour for current time + Max(Minimum Interruption Time, event_duration) for DRRs - Type I
- *Fixed Reduction MW* – is the offered Targeted Demand Reduction Level of the DRR Type – I.

In order to provide maximum continuity in Setpoint Instructions during the loss recovery period, MISO may switch early to and send Setpoint Instructions based on the next Dispatch Interval, if available. Contingency Reserve deployment will be based on the Contingency Reserve cleared in the next Dispatch Interval, and setpoints will be adjusted to reflect the Contingency Reserve deployment, Regulating Reserve cleared and Energy cleared for the next Dispatch Interval. When a Contingency Reserve deployment is required early in a Dispatch Interval, MISO will re-execute the Real-Time Energy and Operating Reserve Market SCED algorithm for the next Dispatch Interval. The re-executed SCED algorithm will recognize the lost resource and the Contingency Reserve deployment.

When Contingency Reserve is deployed on Resources by the AGC system, that deployment is held for a period of 15 minutes.

8.2.10 Contingency Reserve Deployment Failure and Consequence

Compliance monitoring methods to ensure that Resources follow their Contingency Reserve Deployment Instructions are described in the following two sections. For Resources registered at a Common Bus, the sum of the output of all on-line Resources at the Common Bus plus the output of all Common Bus-registered Resources that were off-line prior to the Contingency Reserve Deployment Instruction will be added together to determine the actual output of the Resource or Resources deployed for Contingency Reserve at the Common Bus for the purposes of the four tests described under Section 8.2.10.1. However, if any of the Resources registered at the Common Bus have their Control Mode set equal to 3 at any time during the Contingency Reserve deployment event, those Resources may be excluded from the total Resource output calculation. Additionally, for a single Resource that is not associated with a Common Bus that is deployed for Contingency Reserve, if the Resource Control Mode is changed to 3 following receipt of the Contingency Reserve Deployment Instruction, the Resource will continue to receive a Setpoint Instruction that includes the full amount of

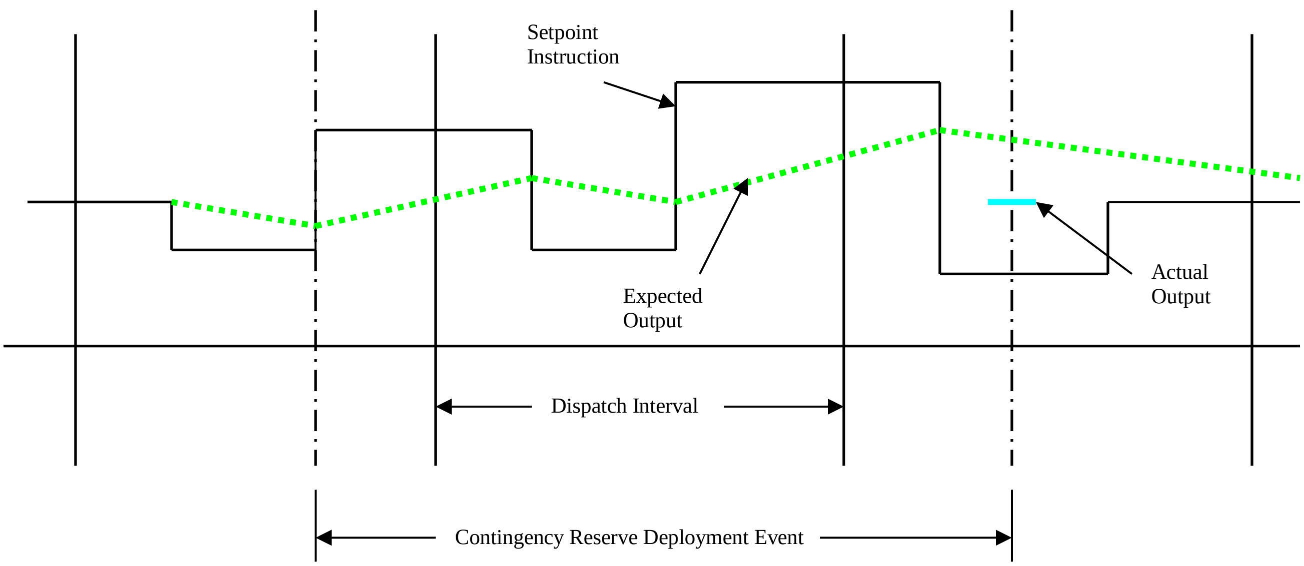
Contingency Reserve deployment as opposed to an echo of the current MW reading. See Section 8.2.4 for a description of Control Modes.

8.2.10.1 Generation Resources, EARs and DRRs-Type II

If a Generation Resource, an EAR or a DRR-Type II passes one or more of the following four tests, then that Resource has deployed Contingency Reserve in an amount greater than or equal to the amount specified in the Contingency Reserve Deployment Instruction within the Contingency Reserve Deployment Period and no Contingency Reserve Deployment Failure Charges will be assessed. For the purposes of this testing, the Setpoint Instruction for a Resource deploying Offline Supplemental Reserves is the lesser of the Cleared Offline Supplemental MW and the Maximum Off-Line Response Limit offer parameter.

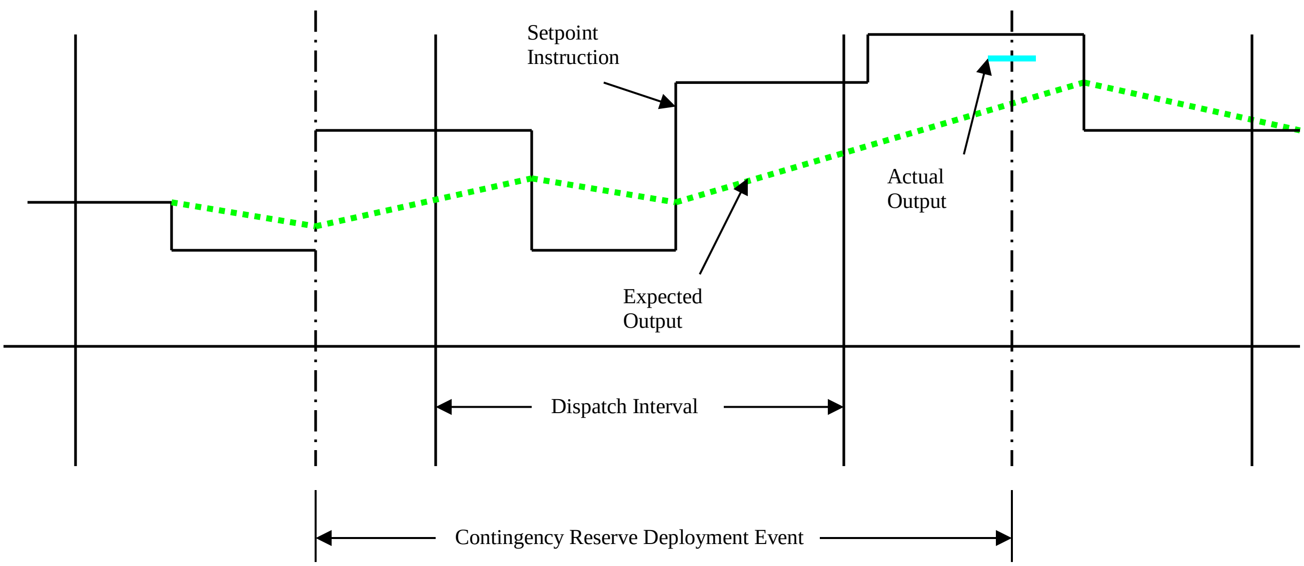
- Test 1: At the end of the Contingency Reserve Deployment Period, if the Resource output is greater than or equal to the Resource Setpoint Instruction, the Resource has passed Test 1. Exhibit 8-5 shows an illustration of how a Resource would pass Test 1.

Exhibit 8-5: CR Deployment Test 1 Illustration



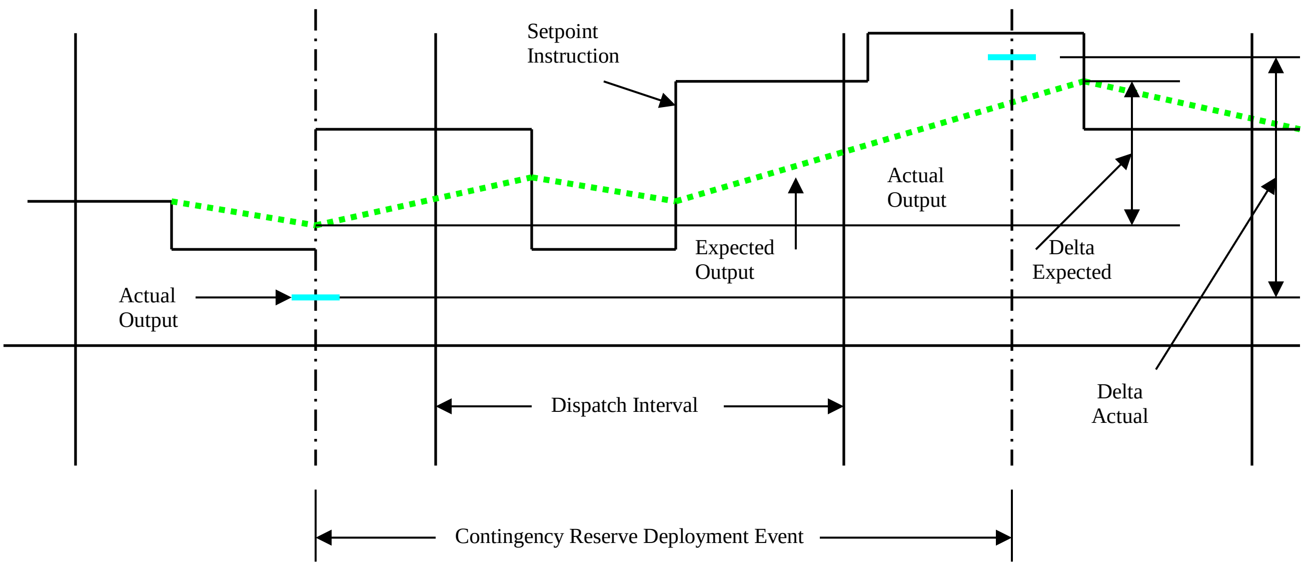
- Test 2: At the end of the Contingency Reserve Deployment Period, if the Resource output is greater than or equal to the expected Resource output, the Resource has passed Test 2. The expected Resource output is calculated assuming the Resource follows its Setpoint Instructions via a linear ramp based on the applicable ramp rate. Exhibit 8-6shows an illustration of how a Resource would pass Test 2.

Exhibit 8-6: CR Deployment Test 2 Illustration



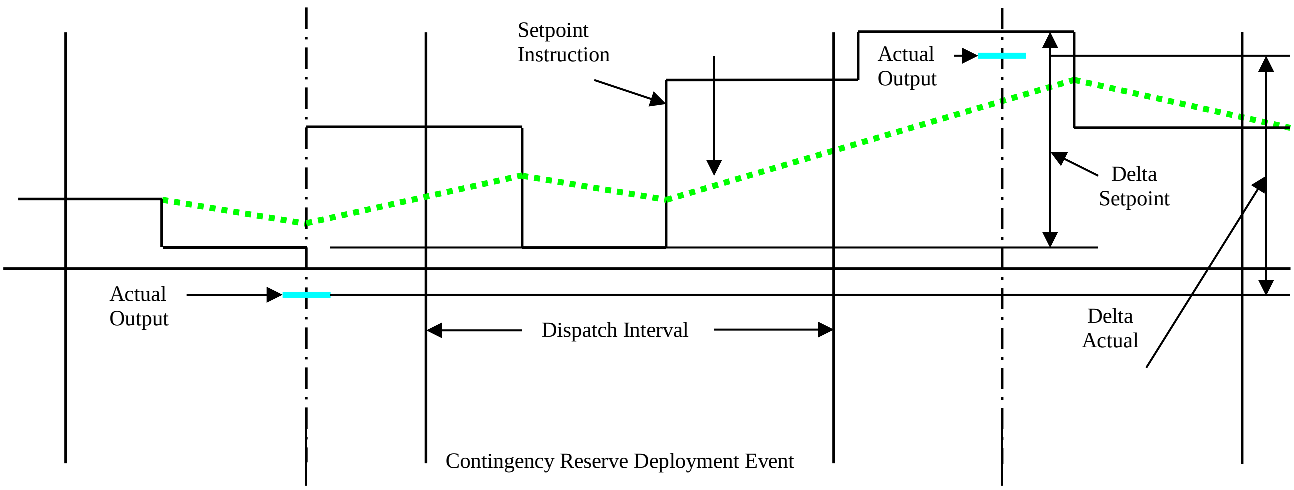
- Test 3: If the change in Resource output is greater than the change in expected Resource output across the Contingency Reserve Deployment Period, the Resource has passed Test 3. The expected Resource output is the Resource output assuming the Resource follows the Setpoint Instructions via a linear ramp based on the applicable ramp rates. Exhibit 8-7 shows an illustration of how a Resource would

Exhibit 8-7: CR Deployment Test 3 Illustration



- Test 4: If the change in Resource output is greater than the change in Setpoint Instruction across the Contingency Reserve Deployment Period, the Resource has passed Test 4. Exhibit 8-8 shows an illustration of how a Resource would pass Test 4.

Exhibit 8-8: CR Deployment Test 4 Illustration



If a Resource fails all of these four tests, then the Resource is subject to a Contingency Reserve Deployment Failure Charge for the Shortfall Amount. If the Resource is a Generation Resource, a DRR – Type II or an External Asynchronous Resource, the Shortfall Amount is calculated as the difference between the change in the expected output of the Resource less the change in the actual output of the Resource over the Contingency Reserve Deployment Period. For example, if a Resource fails to successfully deploy Contingency Reserve, the actual Resource output increased by 25 MW and the expected Resource output was expected to increases by 30 MW, then the Shortfall Amount is equal to 5 MW.

MPs with Resources that have failed to deploy the full amount of Contingency Reserve specified in the Contingency Reserve Deployment Instruction are subject to a Contingency Reserve Deployment Failure Charge that is equal to the shortfall amount multiplied by the Resource's Ex Post LMP for each Hour in which a failure occurs.

In addition to the Contingency Reserve Deployment Failure Charge, payment will not be made for any Contingency Reserve cleared but not deployed for the hour and the Dispatch Target for

Contingency Reserve on that Resource will be limited to the actual amount of Contingency Reserve provided for each remaining Hour of the Operating Day. See the BPM for *Market Settlements* for additional details.

For any Offline Supplemental Contingency Reserve Deployment failure, the Asset Owner is required to limit their Maximum Off-Line Response Limit offer parameter in both Day-Ahead and Real-Time Markets to the actual output achieved at the end of the Contingency Reserve Deployment Period until a higher level is achieved in a subsequent deployment or test.

8.2.10.2 Demand Response Resources – Type I

For Contingency Reserve deployment compliance related to a DRR-Type I, the difference between the Calculated DRR-Type I Output at the end of the Contingency Reserve Deployment Period and the Calculated DRR-Type I Output at the beginning of the event must be greater than or equal to the lesser of the DRR-Type I Dispatch Target for Contingency Reserve at the time of the request or the Targeted Demand Reduction Level. To the extent that this condition is not met, the Shortfall Amount is calculated as the difference between: (1) the lesser of the DRR-Type I Dispatch Target for Contingency Reserve at the time of the request or the Targeted Demand Reduction Level; and (2) the change in Calculated DRR-Type I Output over the Contingency Reserve Deployment Period. For example, if a DRR-Type I has cleared 20 MW of Supplemental Reserve and has a Targeted Demand Reduction Level of 30 MW and is deployed, if the Calculated DRR-Type I Output at the end of the Contingency Reserve Deployment Period is 15 MW, the Shortfall Amount would be equal to 5 MW (assuming a Calculated DRR-Type I Output of 0 MW at beginning of deployment period).

MPs with DRRs – Type I that have failed to deploy the lesser of the amount of cleared Contingency Reserve or the full amount of Contingency Reserve specified in the Contingency Reserve Deployment Instruction are subject to a Contingency Reserve Deployment Failure Charge that is equal to the Shortfall Amount multiplied by the Resource's Ex Post LMP for each Hour in which a failure occurs.

In addition to the Contingency Reserve Deployment Failure Charge, payment will not be made for any Contingency Reserve cleared but not deployed for the hour and the Dispatch Target for Contingency Reserve on that Resource will be limited to the actual amount of Contingency Reserve provided for each remaining Hour of the Operating Day. See the BPM for *Market Settlements* for additional details.

For any Offline Supplemental Contingency Reserve Deployment failure, the Market Participant is required to limit their Maximum Off-Line Response Limit offer parameter in both Day-Ahead and Real-Time markets to the actual output achieved at the end of the Contingency Reserve Deployment Period until a higher level is achieved in a subsequent deployment or test.

8.2.10.3 Resource Offline Supplemental Testing

Any Resource that becomes eligible to qualify to provide Offline Supplemental Reserves to the MISO (i.e., new Resources, or Resources that add capabilities to supply Offline Supplemental Reserves) must contact MISO, through their Regional Generation Dispatcher, and request an Offline Supplemental test be performed. These resources shall be paid Ex Post LMP for the MW produced.

Any resource that has failed to provide their offered level of Offline Supplemental Reserves when deployed may request a test of the resource when the issues causing the failure have been identified and corrected. These resources shall be paid Ex Post LMP for the MW produced. If the resource is subsequently committed by MISO for capacity in the Day-Ahead or Real-Time processes, the resource shall be paid under normal market settlement practices for the capacity commitment period.

Upon receipt of the testing request, the MISO will test the resource within the next 5 business days, based on the need to commit resources for capacity needs.

MISO may test resources that are clearing Offline Supplemental Reserves if they have not been deployed or tested within the previous 6 months. These resources shall be paid as though committed by MISO in a RAC process.

The Offline Supplemental test consists of a notification from the MISO Generation Balancing Authority Operator to the Asset Owner that a test of the Resource's Offline Supplemental Reserve is being conducted. The notification will be either through normal Contingency Reserve Deployment electronic notification and verification by phone or by direct notification and verification by phone if necessary. The Resource should respond as though the test is an actual deployment of Supplemental Reserves. The level of output at the end of 10 minutes from time of test notification will be captured by MISO and verified with the Asset Owner at the end of the test. The output level achieved during the test must be used as the highest level for the Resource's Maximum Off-Line Response Limit offer parameter in both Day-Ahead and Real-Time markets.

8.2.11 Inadvertent Interchange

The Inadvertent Interchange Energy is the difference between NSI and Net Actual Interchange ("NAI") for MISO and is calculated separately for On-Peak and Off-Peak hours. Inadvertent Interchange is tracked on a monthly basis.

MISO manages and pays back its net Inadvertent Interchange balance following NERC policy. Inadvertent Interchange payback is performed based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal "breathing" of balances) and is performed during periods and in amounts such that payback does not burden others. MISO does not use financial gain as a factor when determining whether to payback or recover Inadvertent Interchange.

MISO will pay back inadvertent "in-kind" as outlined by applicable Reliability Standards and MISO policies and procedures.

8.2.12 Calculating Ex-Post LMPs and MCPs

MISO calculates initial Real-Time Ex-Post LMPs and MCPs on a simultaneously co-optimized basis using the same input data that is used to clear the Real-Time Energy and Operating Reserve Market in the SCED-Pricing algorithm. Initial Real-Time Ex-Post LMPs and MCPs may be recalculated if input data errors are detected and/or adjustments are needed to comply with the Tariff (i.e., remove the impact of penalty pricing).

See Section 5 and Section 9 of this BPM for further descriptions of the Ex-Post LMP and MCP Calculations.

8.3 Local Balancing Authority Activities

LBAs perform the following activities to support the Real-time Energy and Operating Reserve Market:

- Provide Load Forecast
- Implement MISO Setpoint Instructions, if applicable.

8.3.1 Providing Load Forecast

MISO determines the Load forecast for the Real-Time Energy and Operating Reserve Market. MISO requires each LBA within the Market Footprint to send an hourly, rolling seven-day Load Forecast to MISO. This forecast must be at an hourly granularity and reflects the amount of Load in the LBAA that is served by the generation that is modeled by MISO.

LBAs submit the actual LBAA Load via ICCP and may submit a short-term forecast of non-conforming Load, exclusive of any non-conforming Load associated with DRRs-Type II, via ICCP if desired. If non-conforming Load Forecast data is not submitted, MISO assumes all Load is conforming in its short-term Load Forecast for the Real-Time Energy and Operating Reserve Market.

When it is necessary to indicate the expected performance of a non-conforming Load or to make a correction to MISO's Real-Time Load Forecast, the LBA may indicate a Load Forecast adjustment through the ICCP.

Section 3 of this BPM describes the Load Forecast process in greater detail.

8.3.2 Implementing MISO Setpoint Instructions

Dispatch is the process of signaling controllable Resources to follow their Setpoint Instructions. The LBA (and the selected Resource) receive Dispatch Targets every five minutes via XML and four-second Setpoint Instructions via ICCP from MISO.

Dynamic Interchange Schedules require Real-Time telemetry between MISO and the adjacent external BA. Both apply adjustments to their four-second NSI target received from MISO, which is the Real-Time DS amount from the telemetry observed by the two BAs.

8.4 Monitoring and Mitigating Real-Time Energy and Operating Reserve Market

Any Offers, adjustments, or changes in availability submitted to MISO by MPs to the Real-Time Energy and Operating Reserve Market are subject to Market Monitoring and Mitigation. Market power mitigation measures are described in the BPM for *Market Monitoring and Mitigation*.

9. Energy and Operating Reserve Markets Closure Activities

This section describes the activities that take place during and after the closure of the Real-Time Energy and Operating Reserve Market Operating Day but prior to the "Day 7" settlements. These activities are separated into three parts:

- Real Time Ex-Post LMP and MCP calculations that occur on a five-minute interval basis
- Five-minute interval and Hourly data verification in preparation for settlement and billing
- Post Operations Processor hourly billing determinant calculation for use in settlement and billing.

Exhibit 9-1 presents the sequence of processes following Operating Hour, Operating Day and culminating in Settlement.

Exhibit 9-1: Real-Time Market Closure Activity Timeline.

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Preliminary Hourly Real-Time Ex-Post LMP Calculator – Repeat Following Each OH		
	OD @ OH+1:00	Acquire the interval Ex-Post LMPs and MCPs that were calculated for the OH.
OD @ OH+1:00	OD @ OH+1:mm	Calculate the Preliminary Hourly Ex-Post LMP and Ex-Post MCP.
	OD @ OH+1:mm	Store the Preliminary Hourly Ex-Post LMP and Ex-Post MCP for information only.
Real-Time Ex-Post LMP Verification Window – Repeat Following Each OD		
	OD+1@ 1200	Post the preliminary Hourly Ex-Post LMPs and Hourly MCPs for the OD
OD+1 @ hh:mm	OD+5B @ 1700	Acquire Ex-Post LMP and MCP data for the OD and make any necessary corrections
	OD+5B @ 1700	Posting Deadline for the Final Hourly Ex-Post LMPs and MCPs[49] for the OD
Bilateral Transactions – Repeat for Each OD		
OD-7 @ 0000	OD+6 @ 1200	Financial Schedules can be entered for the Day-Ahead and Real-Time Energy and Operating Reserve Markets
OD+1 @ 0000	OD+1 @ 1200	After-the Fact Checkout of Interchange Schedules for the OD is performed by MISO
OD @ OH+1:00	OD+2B @ 1200	After-the Fact Entry of Reserve Sharing and other Emergency Schedules for the OD is performed by MISO

[49] Note that the time and quantity-weighted hourly MCPs for use in Settlement will not be publicly posted as they are Resource specific. **But MCPs will be *privately* posted for the respective MPs.**

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Energy and Operating Reserve Markets Settlements – Repeat Following Each OD		
	OD+6 @ 1200	Acquire all validated settlement data
OD+6 @ 1200	OD+7@ 07:00	Prepare Energy and Operating Reserve Markets Settlements
	OD+7+1B @ 0800	Publish the Energy and Operating Reserve Markets Settlements (privately to MPs)
OD = Operating Day B = Business Day	OH = Operating Hour (00 to 23)	BA = Balancing Authority

9.1 Real Time Ex-Post LMP/MCP Calculation

MISO calculates the Real-Time Locational Marginal Prices ("LMPs") for Energy at Load Zone, Hub, Interface, and Resource CPNodes and Market Clearing Prices ("MCPs") for Regulating Reserve, Spinning Reserve and Supplemental Reserve at Generating Resources CPNodes, Demand Response Resource CPNodes and External Asynchronous Resource CPNodes. The LMPs include separate components for the marginal costs of energy, congestion, and losses as described under Section 5 of this BPM. Real Time Ex-Post LMPs and MCPs are calculated every five minutes using the SCED-Pricing algorithm. The five-minute Ex-Post LMPs are integrated on a time-weighted basis, and the five-minute Ex-Post MCPs are integrated on a time and quantity-weighted basis to form the hourly Real-Time Energy and Operating Reserve Market LMPs and MCPs used for Settlement. This section describes the process by which these Real-Time Ex-Post LMPs and MCPs are calculated.

9.1.1 Real Time Ex-Post LMP/MCP Calculation Sequence

The calculation of Ex-Post LMPs and MCPs is performed every five minutes, depending on and following UDS case approval. The sequence of operations that is repeated every five minutes is shown in Exhibit 9-2.

Exhibit 9-2: Ex-Post LMP Calculation - Timeline

Beginning Time in minutes	Ending Time in minutes	Description of Processes and Events
UDS – Repeat Every 5 Minutes		
	RT-10	Acquire initial conditions data and RT Load Forecast for RT SCED
RT-10	RT-5	Execute UDS for RT, producing desired Resource Dispatch Targets, Ex-Ante LMPs and Ex-Ante MCPs
	RT-5	Send Dispatch Targets to Resources
Setpoint Instructions – Send and Execute Continuously		
	RT-5	Resources receive Dispatch Targets from MISO
RT-5	RT	Send Setpoint Instructions to Resources, which include Dispatch Target for Energy adjusted to include Regulating Reserve and Contingency Reserve deployment
Ex-Post Calculator		
RT-5 (UDS case approval time)	RT	Calculate interval Ex-Post LMPs and MCPs for RT in RT SCED-Pricing
	RT	Store Ex-Post LMPs and MCPs for hourly calculations
RT = Real-Time (target time for Dispatch Target Instructions) UDS = Unit Dispatch System		

The following sequence of processes produces the Ex-Post LMPs and MCPs:

- ***Real-Time Security Constrained Economic Dispatch ("SCED")*** – Executes during the five-minute period, beginning at (RT-10 minutes), where the time "RT" serves as a reference point for discussion purposes. At time (RT-5 minutes), the results of the RT-SCED for power system conditions projected at (RT minutes) are sent to Resources.
- ***Setpoint Instructions*** – Setpoint Instructions, which reflect the Dispatch Target for Energy adjusted for Regulating Reserve and Contingency Reserve deployment, are sent directly to Resources on a 4 second periodicity for generation adjustment and real-time system control.
- ***Ex-Post Calculator* ("SCED-Pricing")** – A set of Ex-Post LMPs and MCPs is produced using the same input data as the Real-Time Market in the SCED-Pricing

algorithm. Ex Post LMPs and MCPs may differ from the Ex Ante LMPs and MCPs related to Fast Start Resources as outlined in Section 5 of this BPM.

9.1.2 Real Time Ex-Post LMP/MCP Calculation Process

The Real-Time Ex-Post LMP/MCP calculation algorithm executes automatically upon the approval of each UDS case. The initial five-minute Ex-Post LMPs and MCPs are calculated using the same input data as and utilize the SCED-Pricing algorithm applied by the Real-Time Energy and Operating Reserve Market. The calculated interval Ex-Post LMPs and MCPs are integrated into hourly LMPs and MCPs values and considered preliminary and not used for Settlement purposes until the daily verification of Ex-Post LMPs and MCPs is complete.

9.1.3 Real Time Ex-Post LMP/MCP Verification

The Real-Time Ex-Post LMP/MCP verification process is an off-line analysis that occurs during and after the Operating Day. The purpose of the verification process is to identify and correct any intervals with input data errors, program failures, or any prices that do not comply with the Tariff (i.e., prices that contain penalty pricing components not specified in the Tariff) The verification process ensures the Ex-Post LMPs and Ex-Post MCPs used for the Real-Time Energy and Operating Reserve Market Settlement comply with the tariff and reflect accurate input data. Following the verification process, the Ex-Post LMPs and MCPs are sent to the Settlement system.

9.1.3.1 Verification Process

The verification process is an audit of Ex-Post LMPs and MCPs for the Operating Day. MISO actively monitors both inputs and outputs of the Ex-Post Calculator process. Predetermined limits have been established for these inputs and outputs, and whenever these limits are violated, the specific interval is flagged for an in-depth analysis. In addition, the verification staff may randomly flag Ex-Post intervals for audit to ensure that a sufficient cross-section of cases has been analyzed. For these flagged intervals, the verification staff then performs a detailed review. The inputs/outputs to the Ex-Post Calculator process, operator actions affecting each 5-minute case audited, and all records available describing MISO’s system state at the time are reviewed and validated. The verification process is intended to ensure appropriate and accurate inputs were fed into the Ex-Post Calculator process leading to appropriate and accurate Ex-Post LMPs and MCPs, as well as to ensure Ex-Post LMPs and MCPs comply with the Tariff. If the in-depth analysis of flagged cases reveals a data input failure or program failure, MISO corrects the error and recalculates the Ex-Post LMPs and MCPs prior to releasing the calculation as final.

9.1.3.1.1 MISO Verification Actions

MISO staff drives the verification process with the Ex-Post Calculator Market Operator Interface ("MOI"). Five-minute interval inputs and outputs describing CPNodes, Binding Transmission Constraints, the Sub-Regional Power Balance constraint and Market wide/Zonal market clearing prices are available for review. The MOI helps identify and correct intervals and is used to examine the data within those intervals. If a problem is uncovered during the verification process, staff may change specific inputs for the interval from the Ex-Post Calculator MOI. The Ex-Post Calculator MOI allows for the exclusion or re-execution of intervals with questionable data. Intervals may be re-executed due to a data input failure or program failure, when it is determined that more accurate data is available. The same interval may be re-executed multiple times if additional data changes are required.

Results from the re-run are reviewed from the Ex-Post Calculator MOI summary screens with the re-run case replacing the original output data. The process of reviewing results, changing inputs and re-executing is repeated for all impacted intervals from the verification day. Once MISO is satisfied with the Operating Day's five minute results, the impacted hourly LMPs and MCPs are recalculated. Staff verifies that after the recalculation, LMPs and their related components should be available for each CPNode for every hour for the current Network and Commercial Model. In addition, staff verifies that Market Clearing Prices ("MCPs") for every Operating Reserve Zone are available for all valid intervals.. Once approved, the Real-Time Energy and Operating Reserve Market results are used for the settlement of the MISO Real Time Energy and Operating Reserve Market.

9.1.4 Real Time LMP/MCP Replacements

In the event of a data input failure or program failure that makes Ex-Post LMPs and MCPs unavailable or inaccurate without any way to perform a correction, leading to exclusion, 'replacement' values are calculated in the following way:

- Where the stale data or program failure exists for eleven or fewer intervals within the same Hour, the affected intervals are replaced with data from the last successful interval or the next successful interval, as appropriate, as described in Section 9.1.5.1.
- Where the stale data or program failure exists for all intervals within the same Hour, the following occurs:
    1. Where the Hour is unconstrained and Scarcity Prices have not been applied, the Ex-Post LMP is replaced with the Ex-Ante LMP and the Ex-Post MCP is replaced with the Ex-Ante MCP;

2. Where the system is constrained, the Ex-Post LMP values and Ex-Post MCP values are recalculated using data from the best available sources. The Ex-Post LMP and MCP values are recalculated for each five-minute Dispatch Interval and then integrated and weighted in accordance with the calculations under Sections 9.1.5 and 0 of this BPM.

9.1.5 Real Time Hourly Ex-Post LMPs

9.1.5.1 Hourly Bus LMPs

Hourly average LMPs are computed to be the time-weighted average of 5-minute interval Real-Time Ex-Post LMPs. Each interval is assigned a 5-minute weight. For instances where an interval is not available, the weight for the missing interval will be assigned to the last successful interval or the next successful Dispatch interval, as appropriate, within the same Hour. Where multiple intervals within the same hour, but not the entire hour, are missing, the weight for all missing intervals will be assigned to the last successful interval or next successful Dispatch Interval, as appropriate, within the same Hour. For instance, if interval 1225 is missing, intervals 1220 and 1230 will split the weight for the missing interval and each will be assigned 7.5 minutes for the hourly calculation. If intervals 1225 and 1230 are missing, then intervals 1220 and 1235 will be assigned 10 minutes for the hourly calculation. If interval 1205 is missing, interval 1210 will be weighted for ten minutes. If interval 1300 is missing, interval 1255 will be weighted for ten minutes during the hourly time weighted calculation.

Hourly marginal price for Energy at Node ei:

$$\overline{\lambda}_{ei,h} = \frac{\sum_{t \in Hour(h)} \lambda_{ei,h} * AMinutes_t}{\sum_{t \in Hour(h)} AMinutes_t}$$

Where:

- *Aminutes$_t$* is the number of minutes that the Ex-Post Calculator case is active. Typically, each interval will be active for five minutes. There will be a total of sixty active minutes for each hour.
- λ_t is the marginal price for Energy at Node ei for interval *t*.

Hourly marginal transmission loss price at Node *ei*:

$$\bar{\gamma}_{ei,h} = \frac{\sum_{t \in Hour(h)} \gamma_{ei,h} * AMinutes_t}{\sum_{t \in Hour(h)} AMinutes_t}$$

Where:

- $AMinutes_t$ is the number of minutes that the Ex-Post Calculator case is active. Typically, each interval will be active for five minutes. There will be a total of sixty active minutes for each hour..
- $\gamma_{ei,t}$ is the Transmission Loss Price at Node *ei* for interval *t*.

Hourly marginal congestion price at Node *ei*:

$$\bar{\rho}_{ei,h} = \frac{\sum_{t \in Hour(h)} \rho_{ei,h} * AMinutes_t}{\sum_{t \in Hour(h)} AMinutes_t}$$

Where:

- $AMinutes_t$ is the number of minutes that the Ex-Post Calculator case is active. Typically, each interval will be active for five minutes. There will be a total of sixty active minutes for each hour.
- $\rho_{ei,t}$ is the Transmission and Sub-Regional Power Balance Congestion Price at Node *ei* for interval *t*.

Composite hourly LMP at Node *ei*:

$$\overline{LMP}_{ei,h} = \bar{\lambda}_{ei.h} + \bar{\gamma}_{ei,h} + \bar{\rho}_{ei,h}$$

9.1.5.2 Hourly Aggregate Node LMPs

The following are hourly average calculations for aggregate Commercial Pricing Nodes. A distinction is made between the calculation for aggregates that represent a combined cycle (and cross compound) and all other aggregate CPNodes (which include Hub and Load Zone aggregates).

Hourly system marginal price for energy at aggregate pnode api:

The hourly Energy prices at aggregate CPNodes are weighted averages of Energy prices at participating electrical Nodes. This is expressed as follows:

$$\bar{\lambda}_{api,h} = \frac{\sum_{ei \in pNode(api)} \bar{w}_{ei,h} * \bar{\lambda}_{ei,h}}{\sum_{ei \in pNode(api)} \bar{w}_{ei,h}}$$

Where:

For combined cycle (and cross compound) aggregates the hourly average weighting factor for electrical Node *ei* participating in aggregate combined cycle (and cross compound) pnode *api* is:

$$\bar{w}_{ei,h} = \frac{\sum_{t \in Hour(h)} P_{ei,t} * AMinutes_t}{\sum_{ei \in pNode(api)} \left(\sum_{t \in Hour(h)} P_{ei,t} * AMinutes_t \right)}$$

Where:

- $AMinutes_t$ is the number of minutes that the Ex-Post Calculator case is active. Typically, each interval will be active for five minutes. There will be a total of sixty active minutes for each hour.
- $P_{ei,t}$ is the Total Real-Time MW injection at Node *ei* and the interval *t*.

For all other aggregates (including Hub and Load Zone aggregates):

- $\bar{w}_{ei,h}$ is the weighting factor from the database for electrical Node ei participating in aggregate pnode *api*.
- For Load Zone Aggregates and ARR Zone-Related Hubs the same weighting factors are used for all 24 hours of the Operating Day, and are based on the average of the 24 hourly State Estimators, seven days prior to the Operating Day.

Hourly marginal transmission loss price at aggregate pnode *api*:

The hourly Marginal Losses prices at aggregate CPNodes are weighted averages of Marginal Losses prices at participating electrical Nodes. This is expressed as follows:

$$\bar{\gamma}_{api,h} = \frac{\sum_{ei \in pNode(api)} \overline{w}_{ei,h} * \bar{\gamma}_{ei,h}}{\sum_{ei \in pNode(api)} \overline{w}_{ei,h}}$$

Where:

- $\bar{\gamma}_{ei,h}$ is the hourly marginal transmission loss price at Node *ei.*
- $\overline{w}_{ei,h}$ is the weighting factor from the database for electrical Node ei participating in aggregate pnode *api*.
- For Load Zone Aggregates and ARR Zone-Related the same weighting factors are used for all 24 hours of the Operating Day and are based on the average of the 24 hourly State Estimators, seven days prior to the Operating Day.

Hourly marginal congestion price at aggregate pnode *api*:

The hourly marginal congestion prices at aggregate CP Nodes are weighted averages of transmission and Sub-Regional Power Balance congestion prices at participating electrical Nodes. This is expressed as follows:

$$\bar{\rho}_{api,h} = \frac{\sum_{ei \in pNode(api)} \overline{w}_{ei,h} * \bar{\rho}_{ei,h}}{\sum_{ei \in pNode(api)} \overline{w}_{ei,h}}$$

Where:

- $\bar{\rho}_{ei,h}$ is the hourly marginal transmission and Sub-Regional Power Balance congestion price at Node *ei.*
- $\overline{w}_{ei,h}$ is the weighting factor from the database for electrical Node ei participating in aggregate pnode *api.*
- For Load Zone Aggregates the same weighting factors are used for all 24 hours of the Operating Day and are based on the average of the 24 hourly State Estimators, seven days prior to the Operating Day.

Composite LMPs at aggregate Node api:

$$\overline{LMP}_{api,h} = \overline{\lambda}_{api,h} + \overline{\gamma}_{api,h} + \overline{\rho}_{api,h}$$

9.1.6 Real Time Hourly Time-Weighted MCPs

Hourly time-weighted MCPs for Regulating Reserve, Spinning Reserve and Supplemental Reserve are calculated and posted for informational purposes only and are not used in Settlement.[50] Hourly time-weighted MCPs are calculated as follows for each Reserve Zone:

$$MCP_{RZ,h} = \left\{ \frac{\sum_{t \in Hour(h)} MCP_t * AMinutes_t}{\sum_{t \in Hour(h)} AMinutes_t}, \right.$$

Where:

- $Aminutes_t$ is the number of minutes that the Ex-Post Calculator case is active. Typically, each interval will be active for five minutes. There will be a total of sixty active minutes for each hour.
- MCP_t is the MCP for Regulating Reserve, Spinning Reserve or Supplemental Reserve, as applicable, for interval *t*.

9.1.7 Real Time LMP/MCP Results Posting

Preliminary Hourly Ex-Post LMPs and their components are normally posted for all CPNodes and Hourly Ex-Post MCPs are normally posted for all Reserve Zones[51] by 1200 EST the day after the Operating Day (OD+1). Final approval of Ex-Post LMPs and MCPs will be done as soon as the verification process is complete, but the OD should be approved by 1700 EST on the fifth Business Day (OD+5) following the Operating Day. Any posting of final Hourly Ex-Post LMPs exceeding five Business Days from the applicable Operating Day requires approval by MISO's Board of Directors.

[50] Hourly Ex-Post MCPs for use in Settlement are computed to be the time and quantity-weighted average of 5-minute Real-Time Ex-post MCPs for each Resource. The quantity-weighted Hourly Ex-Post MCP calculations are described under Section 9.2.

[51] The hourly time-weighted MCPs are for information purposes only and are posted for each Generation Resource and Demand Response Resource in each of the MISO Reserve Zones.

9.2 Hourly Post Operations Processor Calculations

The Post Operations Processor ("POP") performs calculations using validated 5-minute data to create hourly billing determinants for use in Settlements. Please see MS-OP-031 Post Operating Processor Calculation Guide in the Market Settlements BPM for calculation details.

9.3 After-the-Fact Schedules

After-the-fact ("ATF") schedules that had not previously been entered into webTrans because a tag had not been required are added to the list of schedules. These are:

- Reserve Sharing Schedules
- Schedules created as part of an Operating Guide

9.4 After-the Fact Check Out

Beginning at 0000 EST during Daylight Savings Time ("DST") and at 0100 EST when DST ends of the day following the Operating Day, all adjacent external BAs and RTOs that have Interchange Schedules with MISO are contacted by MISO scheduling staff and the ATF checkout process begins. Import Schedule and Export Schedule values are checked for the previous day.

9.4.1 Regional Reporting Procedures

MISO will check out for the previous month with all adjacent external BAs and RTOs by the 15th Business Day of each current month. On the 15th Business Day, MISO will report the on and off-peak totals for each BA and RTO to the necessary regions using the appropriate tools. If re-reporting is needed, MISO will contact the necessary region to re-report.

10. Current Tuning Parameter Settings

This section describes current parameter settings for Day-Ahead Market Engines, Reliability Assessment Commitment Engines, and Real-Time Settings. Appendices B, C and D to this document contain more information on the use of these parameters.

10.1 Day-Ahead Market Tuning Parameter Settings

Following are the current parameter settings for the Day-Ahead Market Engines.

10.1.1 Day-Ahead SCUC Tuning Parameter Settings

Listed below are the current tuning parameter settings for the Day-Ahead SCUC algorithm:

- ContResRampMult = 1.0
- ContResDeployTime = 10 Minutes
- MaxContResFactor = 0.2
- MaxRegResFactor = 0.2
- RegRampMult = 1.0
- RegResponseTime = 5 Minutes

10.1.2 Day-Ahead SCED and SCED-Pricing Tuning Parameter Settings

Listed below are the current tuning parameter settings for the Day-Ahead SCED and SCED-Pricing algorithm:

- ContResRampMult = 1.0
- ContResDeployTime = 10 Minutes
- MaxContResFactor = 0.2
- MaxRegResFactor = 0.2
- RegRampMult = 1.0
- RegResponseTime = 5 Minutes

10.2 Reliability Assessment Commitment Tuning Parameter Settings

Following are the current parameter settings for the RAC engines.

10.2.1 RAC SCUC Tuning Parameter Settings

Listed below are the current tuning parameter settings for the RAC SCUC algorithm:

- ContResRampMult = 1.0
- ContResDeployTime = 10 Minutes
- MaxContResFactor = 0.2
- MaxRegResFactor = 0.2
- RegRampMult = 1.0
- RegResponseTime = 5 Minutes

10.3 Real-Time Market Tuning Parameter Settings

Following are the current parameter settings for the Real-Time Market Engines.

10.3.1 Real-Time SCED and SCED-Pricing Tuning Parameter Settings

Listed below are the current tuning parameter settings for the Real-Time SCED and SCED-Pricing algorithm:

- ContResRampFact = 1.0
- ContResDeployTime = 10 Minutes
- MaxContResFactor = 0.2
- MaxRegResFactor = 0.2
- RegRampFact = 1.0
- RegResponseTime = 5 Minutes