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

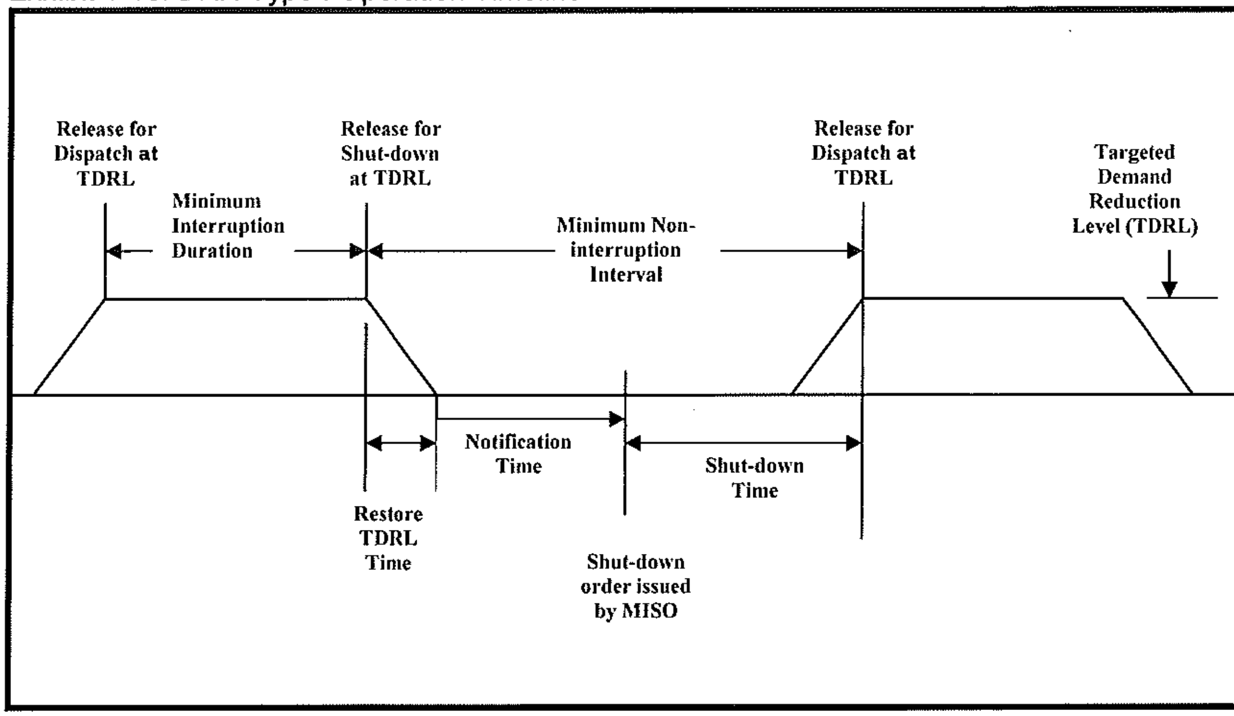
Exhibit 1-18:

- ***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

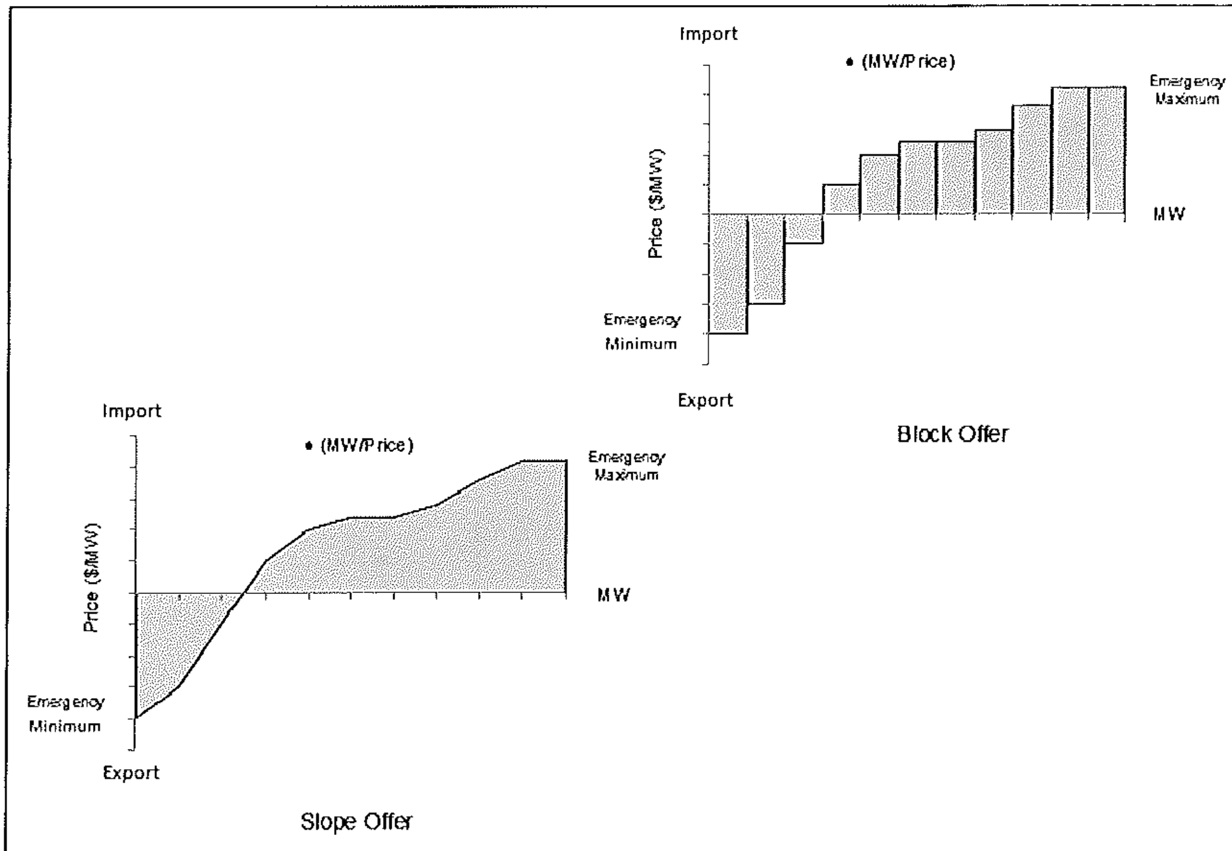
The economic Offer data parameters for EARs as identified in

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

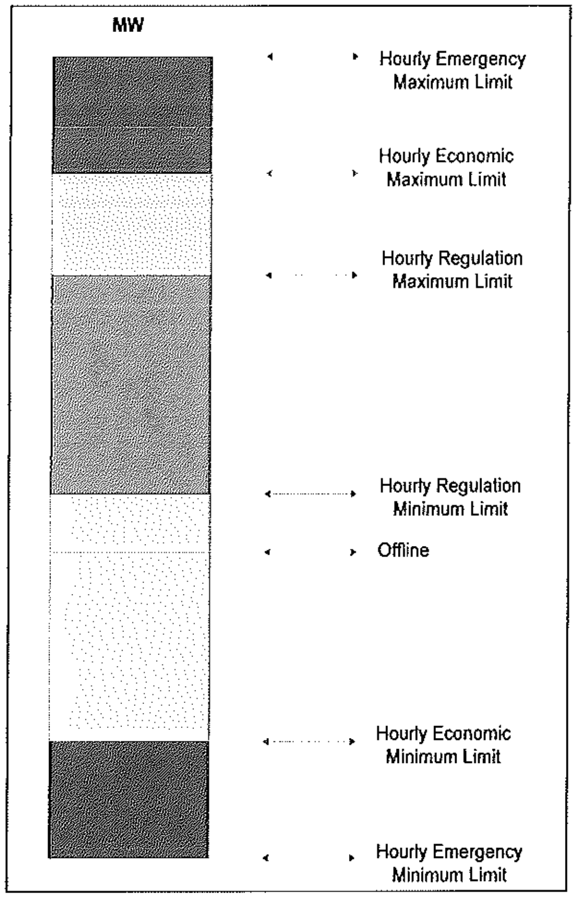


Exhibit 1-23 describes the use and validation of each of the limits and ramp rates.

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.

[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 nót 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

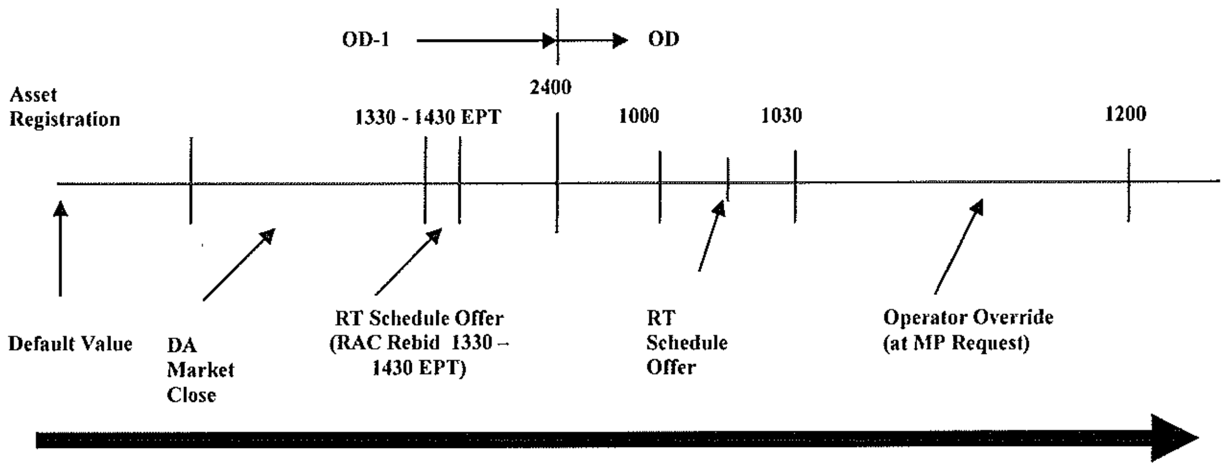
Demand Response Resource), then the Minimum Run-Time (or Minimum Interruption Duration) will be set to zero for the study interval. As an example, if the Minimum Run Time of a resource is three hours, and a segment of hourly commit status offers consist of: Economic, Must-Run, Must-Run, Economic; then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

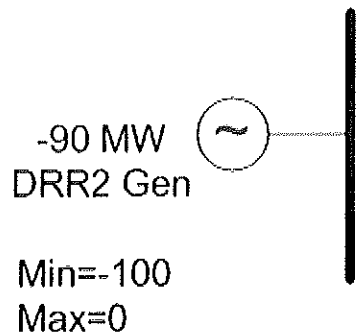
If the DRR-Type I is committed for Energy, a Dispatch Target for Energy is created for the DRR-Type I that is equal to the Targeted Demand Reduction Level. If the DRR-Type I is cleared for Contingency Reserve, amounts cleared can range from 1 MW up to the Targeted Demand Reduction Level, however, any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

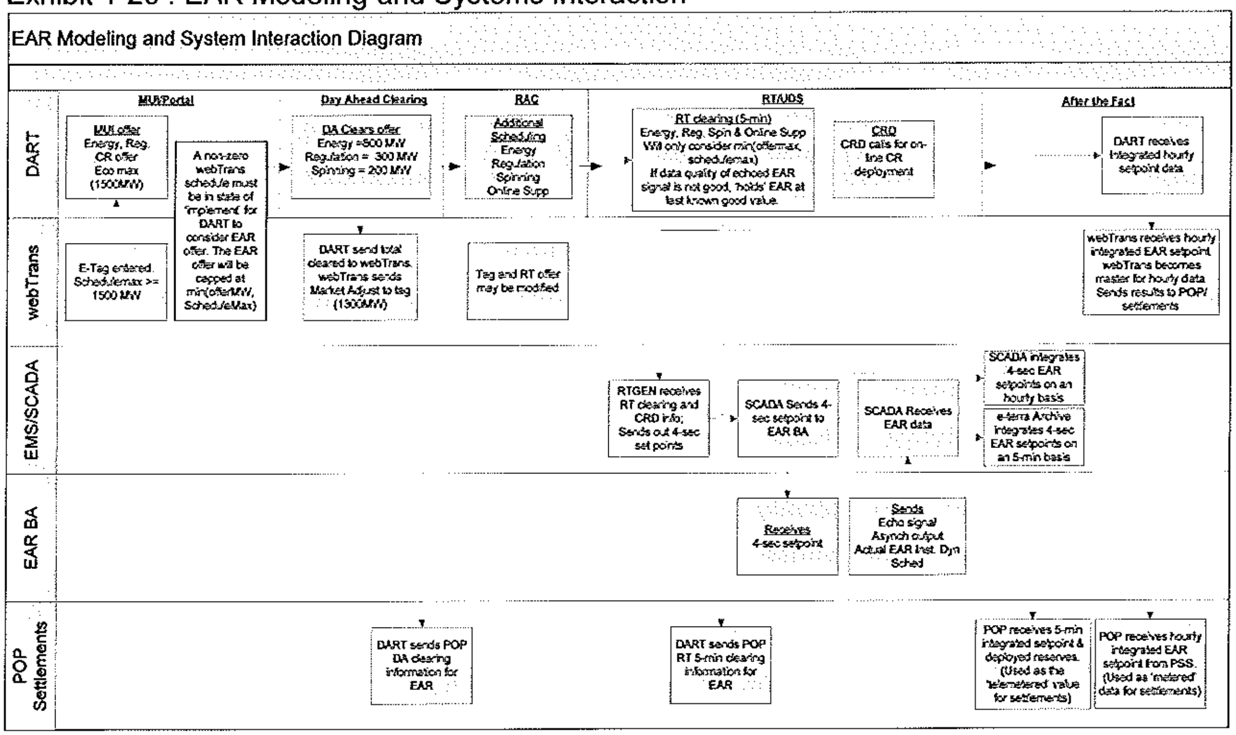
4.2.10.3 External Asynchronous Resources

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.

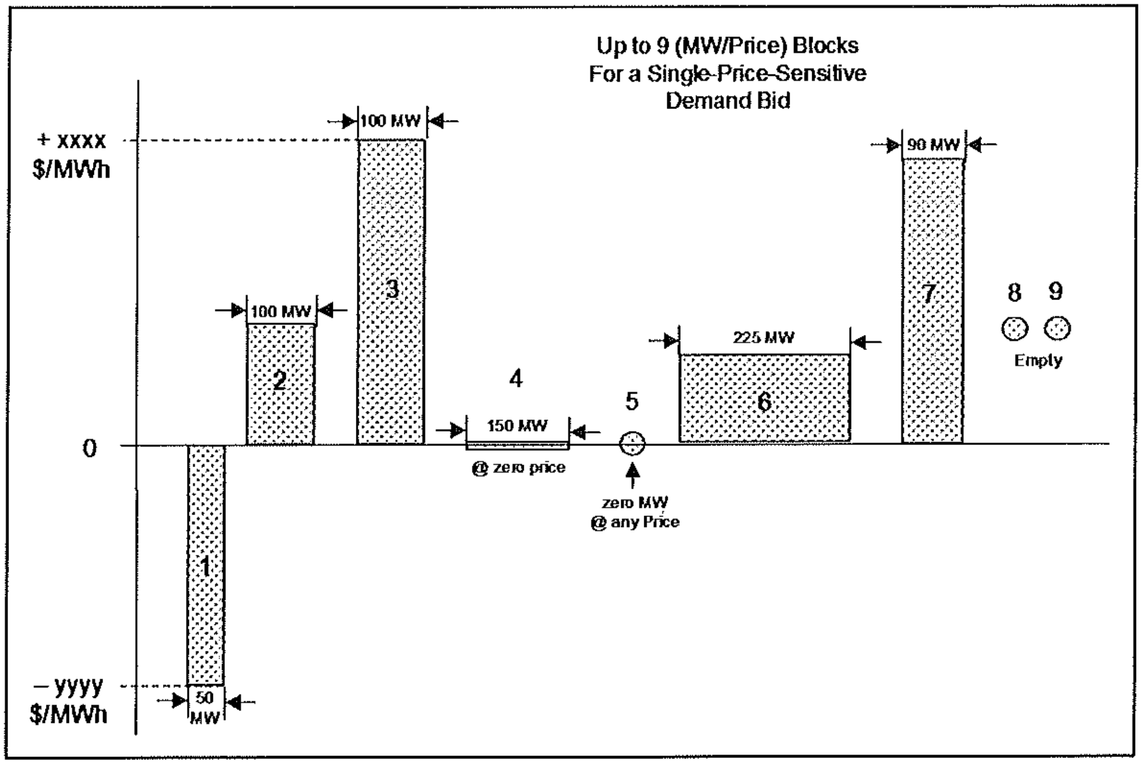


Exhibit 1-30: Price-Sensitive Demand Bid Submittal Example

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.

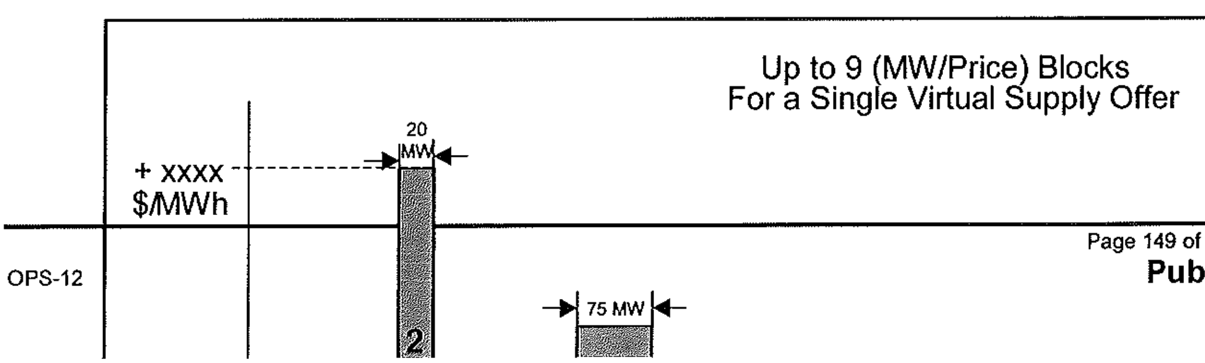
MPs submit the following information for Virtual Supply Offers:

- 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.

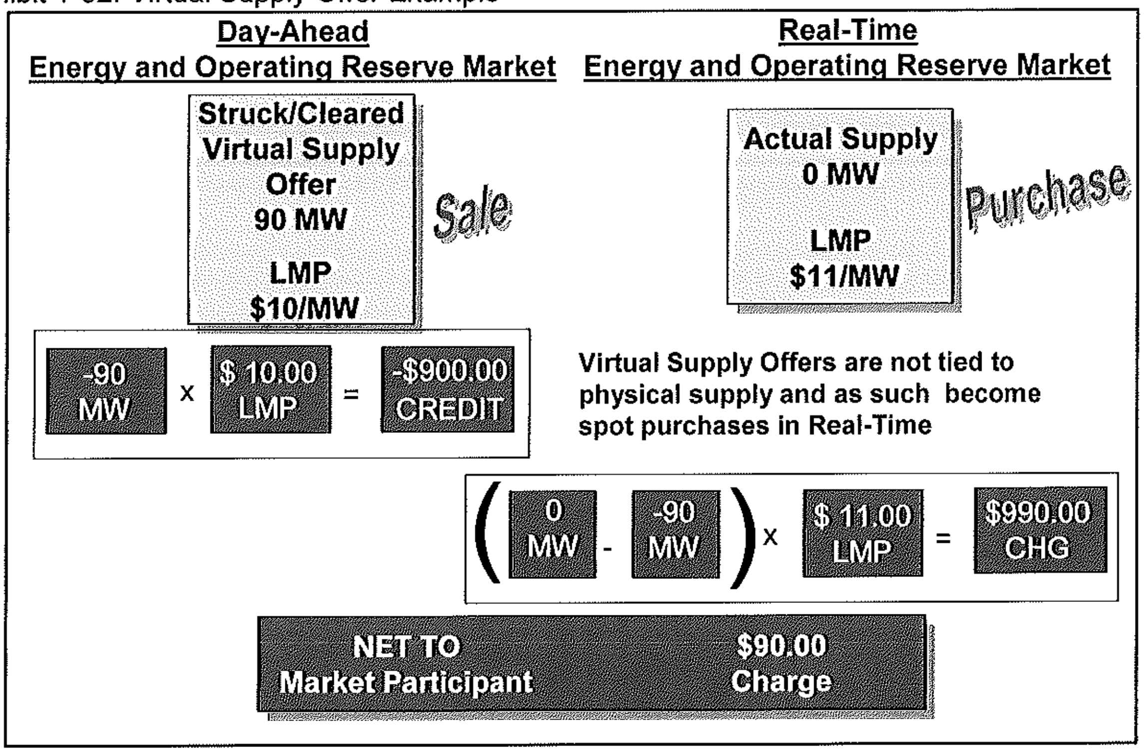
Exhibit 1-31: Virtual Supply Offer Submittal Example



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.

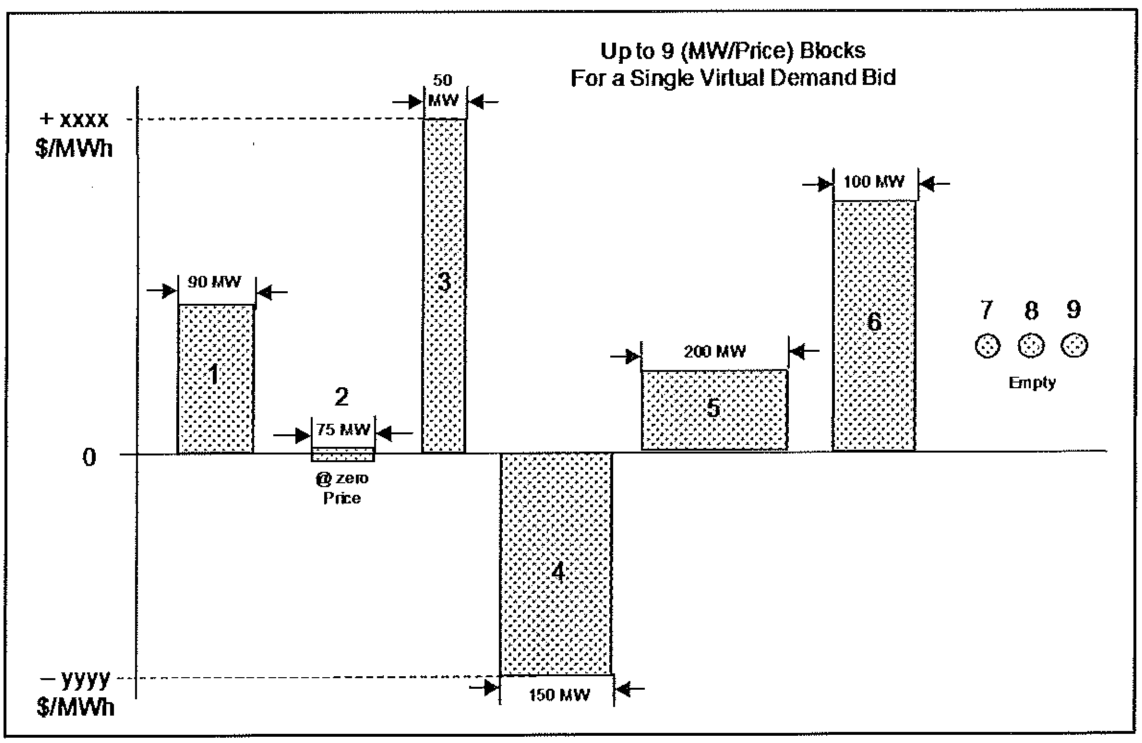
MPs submit the following information for Virtual Demand Bids:

- 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.

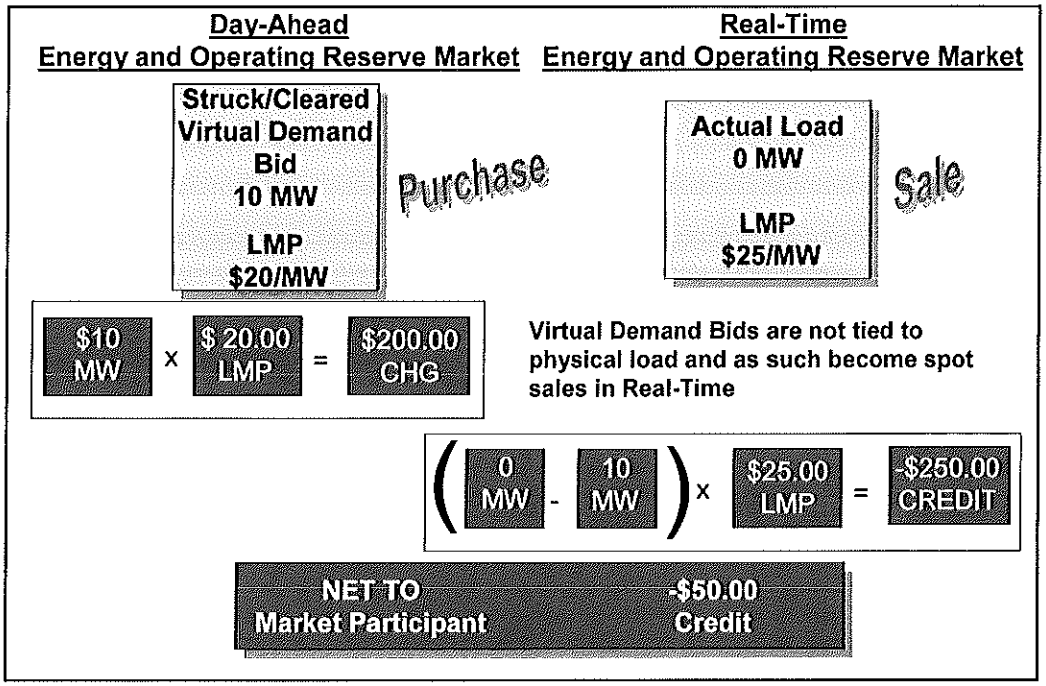
Exhibit 1-33: Virtual Demand Bid Submittal Example



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:

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

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.
- $InjC_{is}$ 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:

$$(5\text{-}10)\quad MCC_i = LMP_i - MEC_r - MLC_i$$

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:

$$(5\text{-}11)\quad LMP_i = MEC_r + MLC_i + MCC_i$$

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:

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

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:

$$\text{(5-13)} \quad \text{Load Zone Price}_j = \sum_{i=1}^{I} (\text{W}_i * \text{LMP}_i)$$

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:

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

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

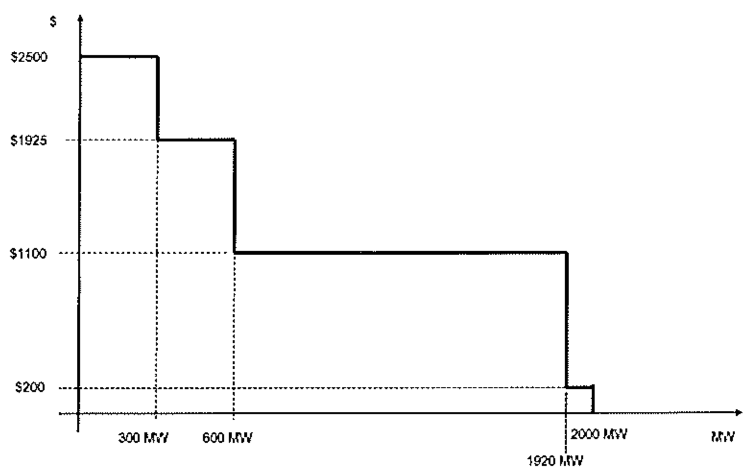


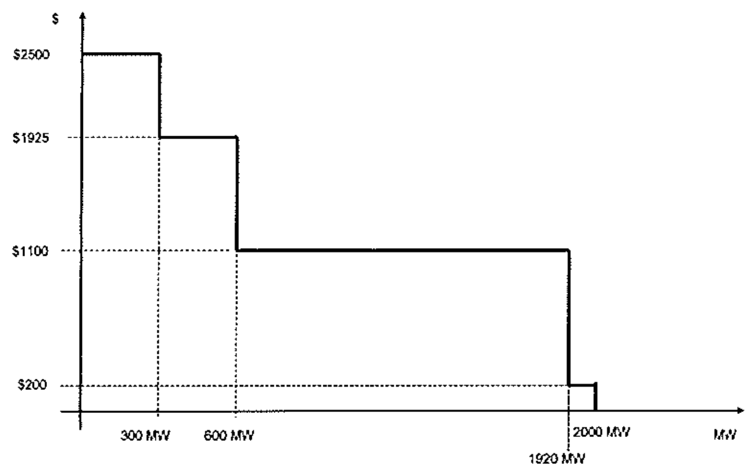
Exhibit 5-2 shows a graphical representation of the Market-Wide Operating Reserve Demand Curve calculated in Exhibit 5-1.

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

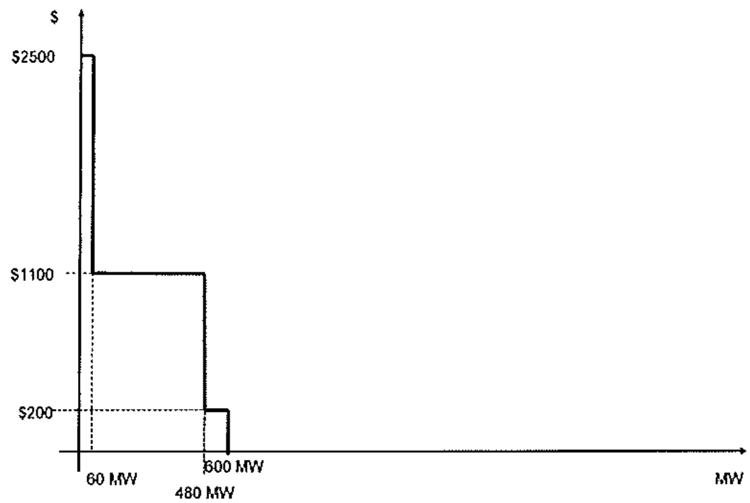


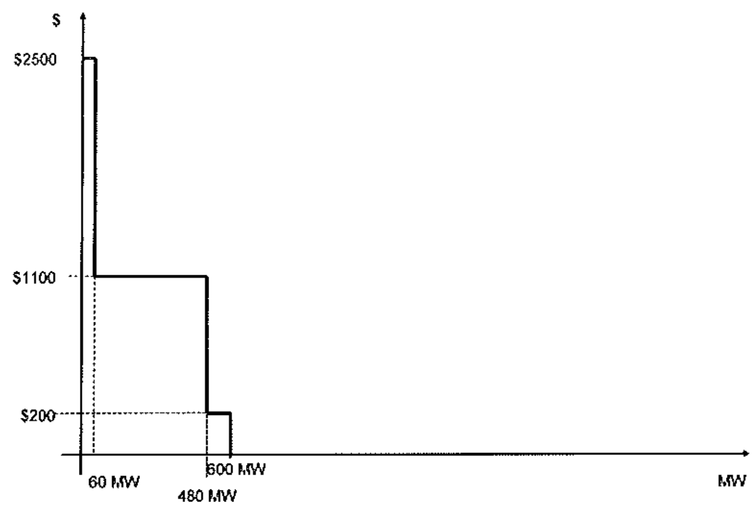
Exhibit 5-3 is illustrative of how the Zonal Operating Reserve Demand Curve is constructed.

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

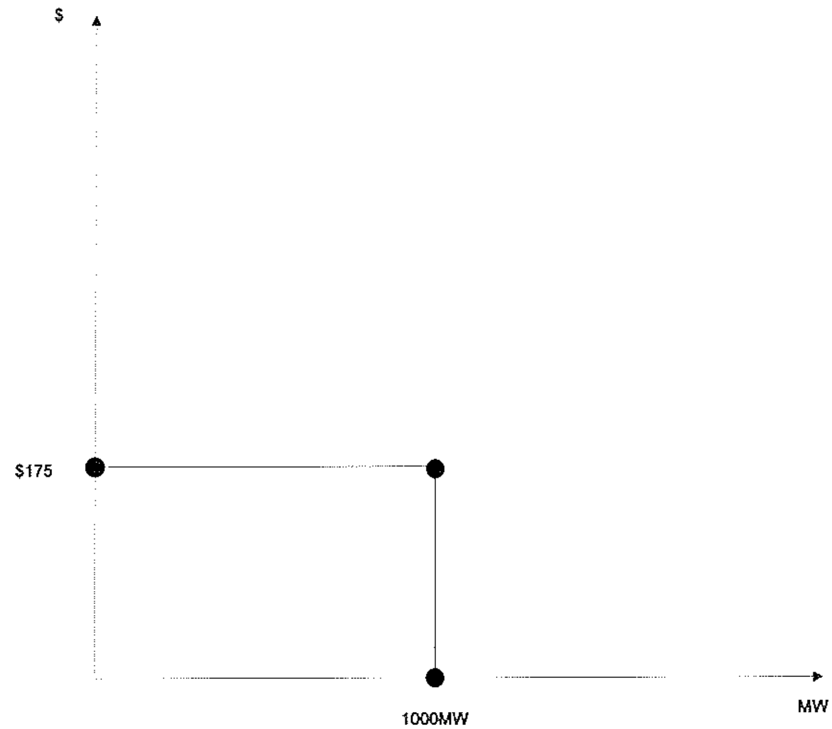
= Maximum {Contingency Reserve Offer Cap, Monthly Average Peaker Proxy Price}

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.

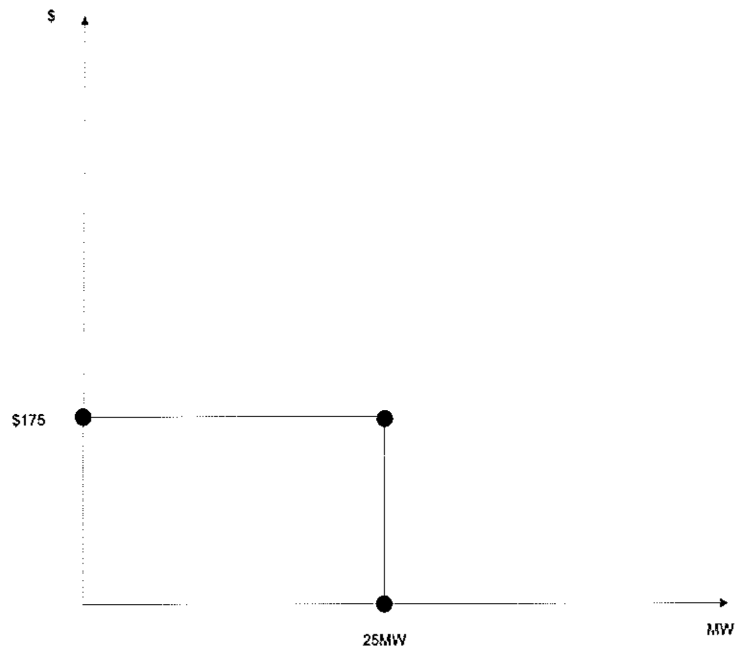
The demand curve points are determined as follows based on the formula above:

$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:
  - o 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.
  - o 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.

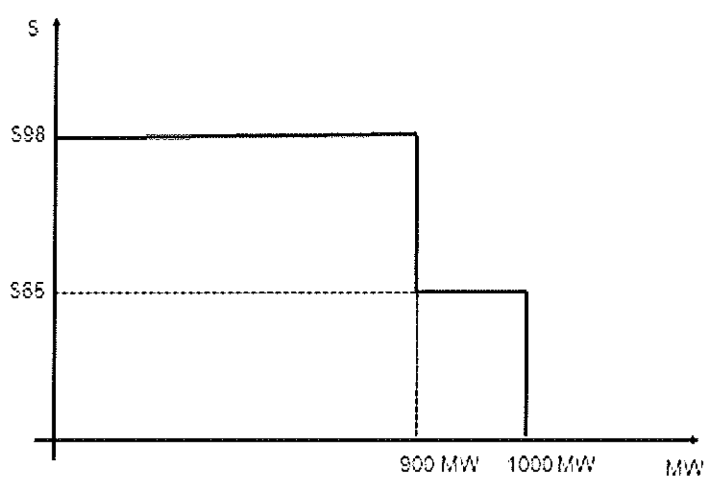
Exhibit 5-6 is illustrative of how the Market-Wide Regulating and Spinning Reserve Demand Curve is constructed. In

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:

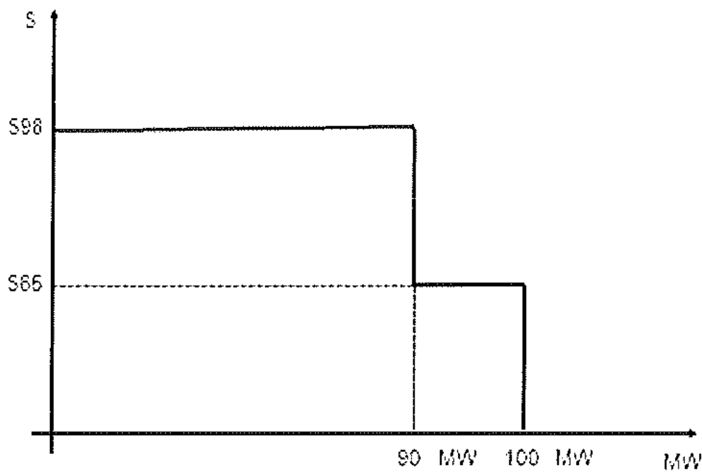
- For cleared Zonal Regulating and Spinning Reserve levels greater than or equal to the Zonal Regulating and Spinning Reserve Requirement, the Zonal Regulating and Spinning Reserve Demand Curve price is set equal to zero;
- For cleared Zonal Regulating and Spinning Reserve levels less than the Zonal 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.

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

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

$MCP_{RegMile}$ - see description below

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

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

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

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

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

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

Where:

- **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

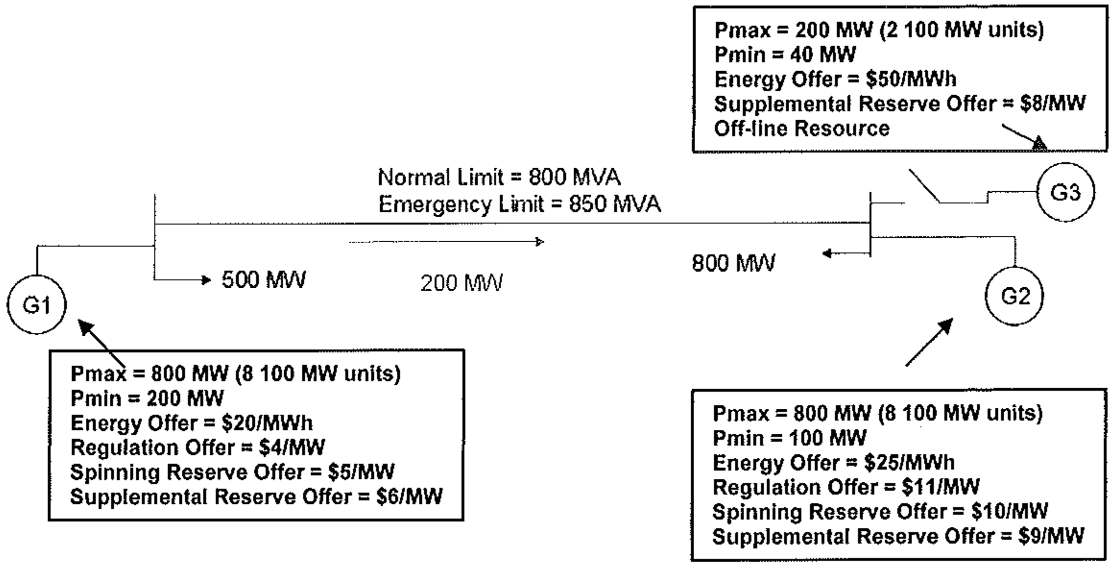
The following examples illustrate how MCPs for Regulation and Contingency Reserve are calculated based upon the methodology described above under varying input assumptions. For simplicity, all examples assume a two generating unit system.

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

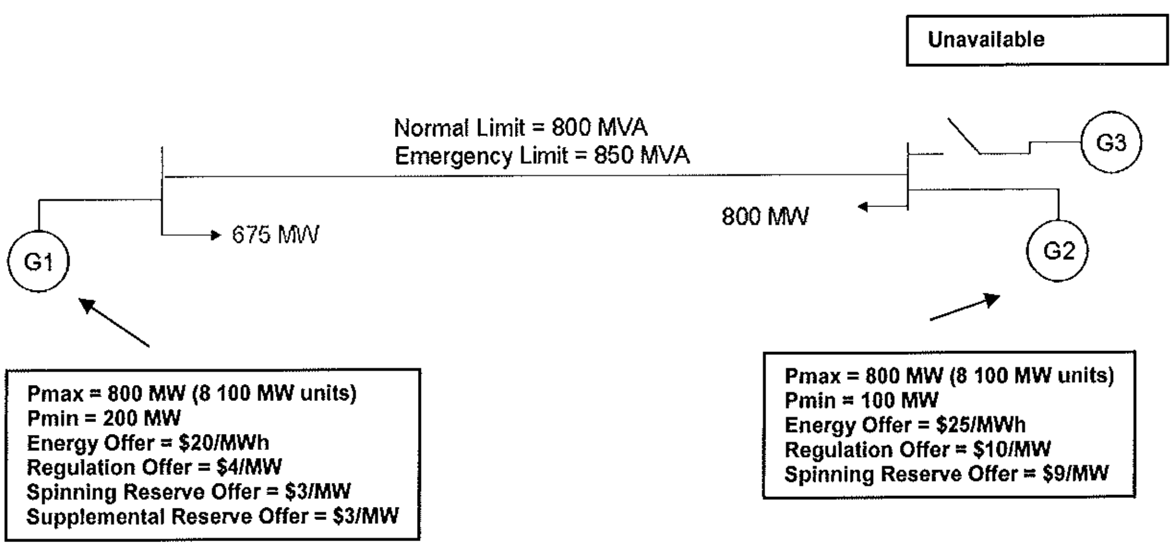


Exhibit 5-11summarizes the results of the co-optimized solution to meet the Energy, Regulation and Contingency Reserve requirements. In this example, the Supplemental Reserve requirement of 50 MW cannot be met, causing an Operating Reserve shortage, thus invoking scarcity pricing. Additionally, as shown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