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 and other 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:

$$\mathrm{MCC}_i = -\left(\sum_{k=1}^{K} \mathrm{Sens}_{ik} * \mu_k\right) + \left(\sum_{k=1}^{k'} \mathrm{Sens}_{ik} * \gamma_{\mathrm{RPRU}}(\mathbf{k})\right) \quad (5\text{-}7)$$

$$+ \left(\sum_{k=1}^{k'} Sens_{ik} * \gamma_{RPRD}(\mathbf{k}) \right)$$

$$+ \left(\sum_{k=1}^{k'} \sum_{z}^{Z} Sens_{ik} * \gamma_{RPRCR}(\mathbf{k,z}) \right)$$

$$+ \left(\sum_{k=1}^{k'} \sum_{z}^{Z} Sens_{ik} * \gamma_{RPRSTR}(\mathbf{k,z}) \right)$$

$$-\left(\sum_{s=1}^{NS} InyC_{is} * \bar{\mu}_s\right)$$

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, Short-Term 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, Short-Term 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).
- γ_{RPRU}(k) is the shadow price of the reserve procurement regulation-up deployment constraint for constraint k.
- γ_{RPRD}(k) is the shadow price of the reserve procurement regulation-down deployment constraint for constraint k.
- γ_{RPRCR}(k,z) is the shadow price of the reserve procurement contingency reserve deployment constraint for constraint k in zone z.

- γ_{RPRSTR}(k,z) is the shadow price of the reserve procurement Short-Term Reserve deployment constraint for constraint k in zone z.
- $InyC_{is}$ is the Injection coeficient for Elemental Pricing Node *i* over Sub-Regional Power Balance Constraint *s*.
- $Sens_{ik}$ is the linearized estimate of the change in the constraint k flow resulting from an incremental energy injection at Elemental Pricing Node *i* coupled with an incremental energy withdrawal at the Reference Bus, expressed mathematically as:

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

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

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

5.1.1.3 Marginal Energy Component ("MEC_r") Calculation

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

(5-9) $$\mathrm{MEC}_r = [\sum_{i=1}^{I}\{\mathrm{Demand}_i * \mathrm{LMP}_i\}]/[\sum_{i=1}^{I}\{\mathrm{Demand}_i\}]$$

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, Short-Term Reserve and Reserve Scarcity cost savings that would occur if the global power balance constraint were relaxed by 1 MWh, which means the last MWh of Energy at the Bus would not need to be served. This value corresponds to the marginal energy cost at the Elemental Pricing Nodes. As stated earlier, actual calculations are based on incremental relaxations.

5.1.1.5 Actual Calculation of LMPs and Associated LMP Components

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

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

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

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

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

5.1.2 Hub LMP Calculation

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

The price for Hub *j* is:

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

Where:

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

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

5.1.3 Load Zone Price Calculation

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

The price for Load Zone *j* is:

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

Where:

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

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

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

5.1.4 Multi-Element Flowgate Shadow Price Calculation

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

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

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, Short-Term 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:

- *I* 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, Supplemental Reserve, Ramp Capability and Short-Term Reserve at a Resource CPNode for Resources with cleared Regulating Reserve, Spinning Reserve, Supplemental Reserve, Ramp Capability and/or Short-Term 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 and/or other 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 up to a maximum of the Energy Offer Hard Price Cap ($2,000). 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 and Emergency Operations Resources, subject to a minimum of $500 and a maximum of the Energy Offer Hard Price Cap ($2,000). 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, subject to a minimum of $1000 and a maximum of the Energy Offer Hard Price Cap ($2,000). If applicable, the Emergency Tier II Offer Floor shall be greater than or equal to the preceding Emergency Tier I Offer Floor.

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[50]. 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

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

Resource or Supplemental Qualified Resource to a configurable percentage of the 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.[51]

Finally, the MCPs for the various Operating Reserve and other 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 or other 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 and other reserves 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.).

The Market-Wide Operating Reserve Demand Curve is designed to communicate the value of capacity to the MISO markets on a market-wide 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.

[51] 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 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 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. Similarly, Regulating Reserve Market Clearing Prices will reflect the deficiency observed in the Regulating and Spinning Reserve capacity.

The Market-Wide Regulating Reserve Demand Curve is 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.
- Ex Post MCPs since capacity is not a factor.

Demand Curves are also used for the Market-Wide Short-Term Reserve, Market-Wide Up Ramp Capability and Market-Wide Down Ramp Capability and are designed to communicate the value of capacity to the MISO markets on a market-wide basis. A shortage of Up or Down Ramp Capability Product or Short-Term Reserve will invoke Scarcity Pricing for Up or Down Ramp Capability Product or Short-Term Reserve Market Clearing Prices, indicating that there is a deficiency in Up or Down Ramp Capability Product or Short-Term Reserve capacity in the entire market.

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.
- 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 the percentage amount (currently set at 89% of the Market-Wide Operating Reserve Requirement) required to satisfy the Most Severe Single Contingency as determined by the Reserve Sharing Group, is set equal to $1,100.00 per MW, which is equal to the sum of the Energy Offer Soft Price Cap

($1,000.00 per MWh)[52] and the Contingency Reserve Offer Price Cap ($100.00 per MW).

- For cleared Market-Wide Operating Reserve levels less than 89% 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 maximum price, is set equal to the VOLL less the Market-Wide Regulating Reserve Demand Curve Price.
  - The minimum price is set equal to $2,100.00 per MW, which is equal to the sum of the Energy Offer Hard Price Cap ($2,000.00 per MWh) and the Contingency Reserve Offer Price Cap ($100.00 per MW).
- 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.

[52] Energy Offer Soft Price Cap is the maximum price permitted for a Verified Energy Offer, a Fast Start Resource All-in Energy Offer, or an Emergency Operations Resource All-In Energy Offer to set price in the Energy and Operating Reserve Markets without prior cost verification by the Independent Market Monitor. The Energy Offer Soft Price Cap is $1,000/MWh.

- 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 {89% Market-Wide Operating Reserve Requirement ≤ Market-Wide Operating Reserve Level < 96% Market-Wide Operating Reserve Requirement},
  Market-Wide Operating Reserve Demand Curve Price = $1100 per MW

else if {4% Market-Wide Operating Reserve Requirement ≤ Market-Wide Operating Reserve Level ≤ 89% 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 ($2,100)

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 $500 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)

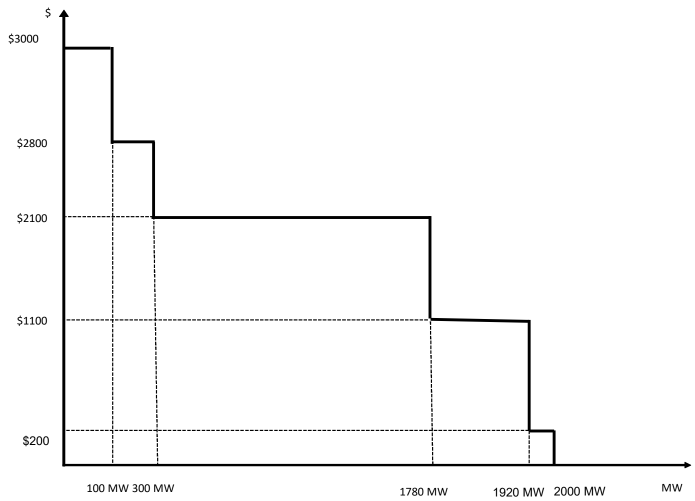
The Demand Curve points are determined as shown in Exhibit 5-1 based on the formula above assuming a stepped curve construction. The highlighted values in Exhibit 5-1 represent Operating Reserve levels that have two price points that are connected by a vertical segment.

Exhibit 5-2 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	2100	3000	3000	3000
100	20	1.00	16	0.80	3500	2800	2100	3000	3000	2800
200	16	0.80	16	0.80	2800	2800	2100	3000	2800	2800
300	16	0.80	11	0.55	2800	1925	2100	3000	2800	2100
400	11	0.55	11	0.55	1925	1925	2100	3000	2100	2100
500	11	0.55	11	0.55	1925	1925	2100	3000	2100	2100
600	11	0.55	5	0.25	1925	875	2100	3000	2100	2100
700	5	0.25	5	0.25	875	875	2100	3000	2100	2100
800	5	0.25	1	0.05	875	175	2100	3000	2100	2100
900	1	0.05	1	0.05	175	175	2100	3000	2100	2100
1000	1	0.05	1	0.05	175	175	2100	3000	2100	2100
1100	1	0.05	1	0.05	175	175	2100	3000	2100	2100
1200	1	0.05	0	0	175	0	2100	3000	2100	2100
1300	0	0	0	0	0	0	2100	3000	2100	2100
1400	0	0	0	0	0	0	2100	3000	2100	2100
1500	0	0	0	0	0	0	2100	3000	2100	2100
1600	0	0	0	0	0	0	2100	3000	2100	2100
1780	0	0	0	0	0	0	2100	3000	2100	1100
1800	0	0	0	0	0	0	1100	3000	1100	1100
1920	0	0	0	0	0	0	1100	3000	1100	200
2000	0	0	0	0	0	0	1100	3000	200	0

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



5.2.1.2 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

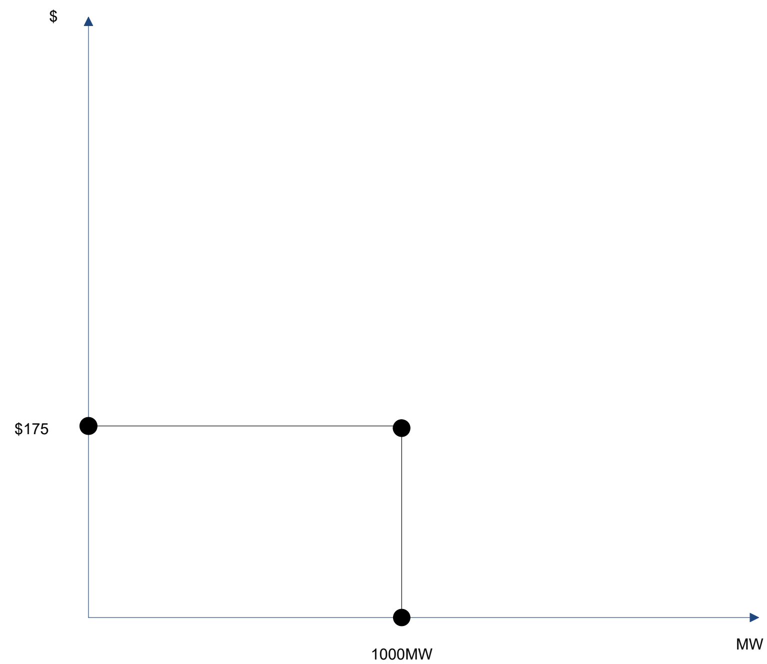
= Maximum {Contingency Reserve Offer Cap, Monthly Average Peaker Proxy Price}

Exhibit 5-3 is illustrative of how the Regulating Reserve Demand Curve is constructed. In Exhibit 5-33, 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 5-3 : Market-Wide Regulating Reserve Demand Curve Development



5.2.1.3 Market -Wide Regulating and Spinning Reserve Demand Curve Development

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

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

- For cleared Market-Wide Regulating and Spinning Reserve levels less than ninety percent (90%), of the Market-Wide regulating and Spinning Reserve, the Market Wide Regulating and Spinning Reserve Demand Curve price is $98 per MWh.

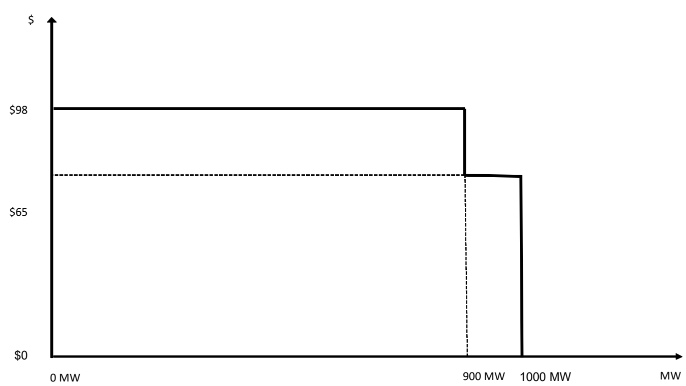
Exhibit 5-4 is illustrative of how the Market-Wide Regulating and Spinning Reserve Demand Curve is constructed. In

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



5.2.1.4 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

5.2.1.5 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.

5.2.1.6 STR Demand Curves

Demand curves for Short-Term Reserve are defined to represent the value of the product. When the cleared Short-Term Reserve level is less than the market-wide requirement, the Market-Wide Short-Term Reserve Demand Curve sets the Market-Wide Short-Term Reserve constraint shadow price as defined in MISO Tariff Schedule 28. Sub-regional and local Short-Term Reserve requirements are established using Post Reserve Deployment Constraints and are valued at the Post Reserve Deployment Constraints Demand Curves as defined in MISO Tariff Schedule 28C.

MISO sets the Market-Wide Short-Term Reserve Requirement based on offline analysis. Sub-regional and local Short-Term Reserve requirements are established using Post Reserve Deployment Constraints. These constraints dynamically determine requirements based on the loss of generation elements and associated change in flow, and the flow limits.

5.2.2 Market Clearing Price Calculation Details

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

$$MCP_{REG} = \gamma_{OR} + \gamma_{RS} + \gamma_{RR} + \gamma_{GOR} + \gamma_{GRS}$$

$$MCP_{REG}(z) = \gamma_{RPOR}(z) + \gamma_{RPRS}(z) + \gamma_{RPRR}(z)$$

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

$MCP_{RegMile}$ - see description below

$MCP_{SPING} = \gamma_{OR} + \gamma_{RS} + \gamma_{GOR} + \gamma_{GRS}$

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

$MCP_{SPIND} = \gamma_{OR} + \gamma_{RS}$

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

$MCP_{SUPPG} = \gamma_{OR} + \gamma_{GOR}$

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

$MCP_{SUPPD} = \gamma_{OR}$

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

$MCP_{URCP} = \gamma_{URCP}$

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

$MCP_{DRCP} = \gamma_{DRCP}$

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

$MCP_{STR} = \gamma_{STR}$

$MCP_{STR}(z) = \gamma_{RPSTR}(z)$

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, Stored Energy Resources –Type II and External Asynchronous Resources;
- **MCP_{REG} (z)** = Reserve Zone clearing price for non-SER Regulating Reserve. Non-SER Regulating Reserve includes Regulating Reserve cleared on Generation Resources, DRRs – Type II, Stored Energy Resources –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.[53]

- **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_{SPING} (z)** = Reserve Zone 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, Stored Energy Resources – Type II are considered generation-based, not demand-based and DRRs-Type I do not qualify to provide Spinning Reserve;
- **MCP_{SPIND} (z)** = Reserve Zone clearing price for demand-based Spinning Reserve. Based on current reliability standards, DRRs-Type II, Stored Energy Resources – 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, Stored Energy Resources – Type II and External Asynchronous Resources;
- **MCP_{SUPPG}(z)** = Reserve Zone clearing price for generation-based Supplemental Reserve. Generation-based Supplemental Reserve includes Supplemental Reserve cleared on Generation Resources, DRRs – Type II, Stored Energy Resources – 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;

[53] 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".

- **MCP_{SUPPD}(z)** = Reserve Zone 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;
- **MCP_{URCP}** = Market Clearing Price for Up Ramp Capability Product.
- **MCP_{URCP}(z)** = Reserve Zone clearing price for Up Ramp Capability Product **MCP_{DRCP}** = Market Clearing Price for Down Ramp Capability Product.
- **MCP_{DRCP}(z)** = Reserve Zone clearing price for Down Ramp Capability Product
- **MCP_{STR}** = Market Clearing Price for Short-Term Reserve.
- **MCP_{STR}(z)** = Reserve Zone clearing price for Short-Term 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 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.
- γ_{URCP} = The Shadow Price of the MISO market-wide Up Ramp Capability requirement constraint. Under abundant capacity conditions, this Shadow Price represents the marginal cost of supplying Up Ramp Capability Product. Under scarce capacity conditions, this Shadow Price represents the Up Ramp Capability Demand Curve price at the cleared market-wide Up Ramp Capability level. This Shadow Price will be equal to zero if the cleared MISO market-wide Up Ramp Capability exceeds the MISO market-wide Up Ramp Capability requirement.
- γ_{DRCP} = The Shadow Price of the MISO market-wide Down Ramp Capability requirement constraint. Under abundant capacity conditions, this Shadow Price represents the marginal cost of supplying Down Ramp Capability Product. Under scarce capacity conditions, this Shadow Price represents the Down Ramp Capability Demand Curve price at the cleared market-wide Down Ramp Capability level. This Shadow Price will be equal to zero if the cleared MISO market-wide Down Ramp Capability exceeds the MISO market-wide Down Ramp Capability requirement.
- γ_{STR} = The Shadow Price of the MISO market-wide Short-Term Reserve requirement constraint. Under abundant capacity conditions, this Shadow Price represents the

marginal cost of supplying Short-Term Reserve. Under scarce capacity conditions, this Shadow Price represents the Short-Term Reserve Demand Curve price at the cleared market-wide Short-Term Reserve level. This Shadow Price will be equal to zero if the cleared MISO market-wide Short-Term Reserve exceeds the MISO market-wide Short-Term Reserve requirement.

- $\gamma_{RPOR}(z)$ = 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.
- $\gamma_{RPSTR}(z)$ = The Shadow Price of the Reserve Procurement Minimum Reserve Zone Short-Term Reserve Requirement Constraint that ensures the cleared Short-Term Reserve in a zone can be converted to Energy when needed while respecting transmission constraints. This Shadow Price represents the marginal cost of Short-Term Reserve in satisfying the minimum Reserve Zone Short-Term Reserve 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, subject to a minimum of \$500 and a maximum of the Energy Offer Hard Price Cap (\$2,000). This Offer Floor will be determined based on the ELMP logic including start-up and no-load costs of Fast Start Resources and Emergency Operations 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, subject to a minimum of \$1000 and a maximum of the Energy Offer Hard Price Cap (\$2,000). If applicable, the Emergency Tier II Offer Floor shall be greater than or equal to the preceding Emergency Tier I Offer Floor.

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.

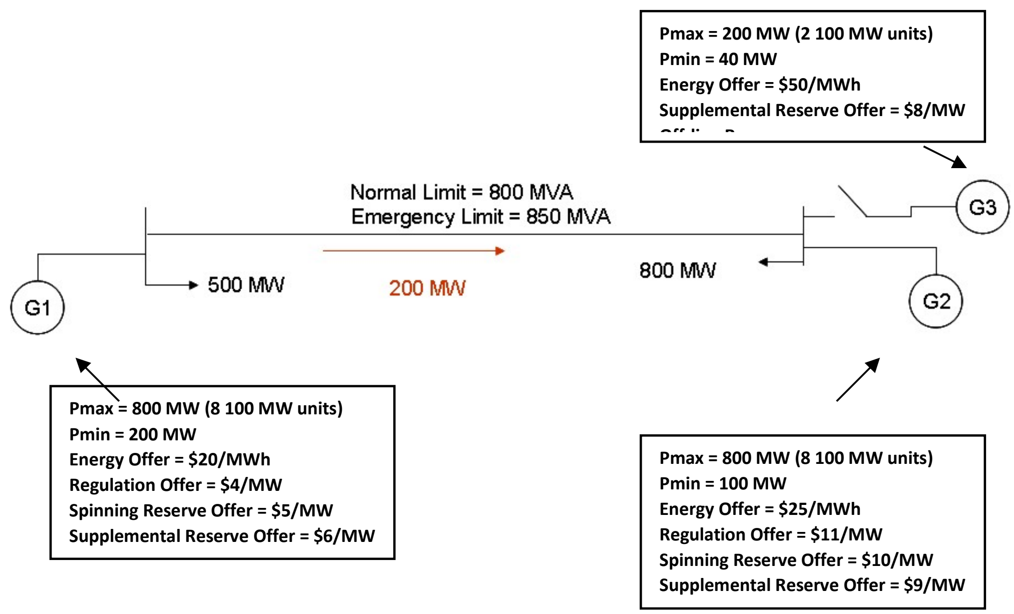
5.2.4.1 Co-optimized Clearing Example – No Scarcity Pricing

Consider the two Bus system as depicted in Exhibit 5-5 For this example, two 800 MW[54] 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

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

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.

Exhibit 5-5: 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 5-6 summarizes the results of the co-optimized solution to meet the Energy, Regulating Reserve and Contingency Reserve requirements:

Exhibit 5-6: 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 5-6 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[55], 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.

[55] 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 $MCP_{SUPPG} = \gamma_{OR} + \gamma_{RPOR(z)} + \gamma_{GOR}$ and the demand-based Supplemental Reserve $MCP_{SUPPD} = \gamma_{OR} + \gamma_{RPOR(z)}$. In this example, there is no binding zonal Operating Reserve requirement or minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{RPOR(z)} = \gamma_{GOR} = 0$ 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 $MCP_{SPING} = \gamma_{OR} + \gamma_{RS} + \gamma_{GOR} + \gamma_{GRS} + \gamma_{RPOR(z)} + \gamma_{RPRS(z)}$ and the demand-based Spinning Reserve $MCP_{SPIND} = \gamma_{OR} + \gamma_{RS} + \gamma_{RPOR(z)} + \gamma_{RPRS(z)}$. In this example, there is no binding zonal Operating Reserve requirement, no binding zonal Regulating plus Spinning Reserve requirement, no binding minimum Non-DRR1 Operating Reserve requirement and no binding minimum Non-DRR1 Regulating plus Spinning Reserve Requirement and therefore, $\gamma_{RPOR(z)} = \gamma_{RPRS(z)} = \gamma_{GOR} = \gamma_{GRS} = 0$ 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 $MCP_{REG} = \gamma_{OR} + \gamma_{RS} + \gamma_{RR} + \gamma_{RPOR(z)} + \gamma_{RPRS(z)} + \gamma_{RPRR(z)} + \gamma_{GOR} + \gamma_{GRS}$ and the SER-based Regulating Reserve $MCP_{REGSER} = \gamma_{OR} + \gamma_{RS} + \gamma_{RR} + \gamma_{MSERR} + \gamma_{GOR} + \gamma_{GRS}$. In this example, there is no binding zonal requirements, binding minimum Non-DRR1 Operating Reserve requirements and no binding minimum Non-DRR1 Regulating plus Spinning Reserve Requirement and therefore, $\gamma_{RPOR(z)} = \gamma_{RPRS(z)} = \gamma_{RPRR(z)} = \gamma_{GOR} = \gamma_{GRS} = 0$ and $MCP_{REG} = MCP_{REGSER}$.. The Regulating Reserve MCP_{REG} and MCP_{REGSER} are 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 5-7. For this example, two on-line 800 MW[56] 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 5-7: Co-optimized Clearing, Contingency Reserve Scarcity – Assumptions

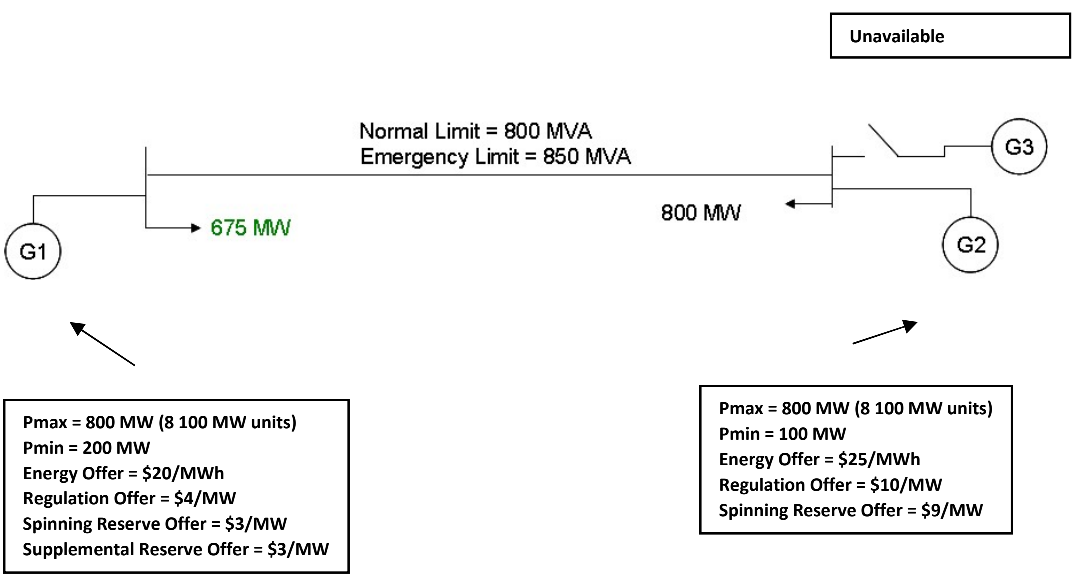


Exhibit 5-8summarizes the results of the co-optimized solution to meet the Energy, Regulation and Contingency Reserve requirements. In this example, the Supplemental Reserve requirement of 50 MW cannot be met, causing an Operating Reserve shortage, thus invoking scarcity pricing. Additionally, as shown in

[56] 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 5-8, in this example the LMP is impacted by the Operating Reserve Scarcity Price[57] 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.

[57] 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 5-8: 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 5-8 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[58], 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

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

procured remains the same[59]. 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[60]. 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 $MCP_{SUPPG} = \gamma_{OR} + \gamma_{RPOR(z)} + \gamma_{GOR}$ and the demand-based Supplemental Reserve $MCP_{SUPPD} = \gamma_{OR} + + \gamma_{RPOR(z)}$. In this example, there is no binding zonal Operating Reserve requirement or minimum Non-DRR1 Operating Reserve requirement and therefore, $\gamma_{RPOR(z)} = \gamma_{GOR} = 0$ 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.

[59] 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.

[60] 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 $MCP_{SPING} = \gamma_{OR} + \gamma_{RS} + \gamma_{GOR} + \gamma_{GRS} + \gamma_{RPOR(z)} + \gamma_{RPRS(z)}$ and the demand-based Spinning Reserve $MCP_{SPIND} = \gamma_{OR} + \gamma_{RS} + \gamma_{RPOR(z)} + \gamma_{RPRS(z)}$. In this example, there is no binding zonal Operating Reserve requirement, no binding zonal Regulating plus Spinning Reserve requirement, no binding minimum Non-DRR1 Operating Reserve requirement and no binding minimum Non-DDR1 Regulating plus Spinning Reserve requirement and therefore, $\gamma_{RPOR(z)} + \gamma_{RPRS(z)} = \gamma_{GOR} = \gamma_{GRS} = 0$ 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 Regulating Reserve $MCP_{REG} = MCP_{REG} = \gamma_{OR} + \gamma_{RS} + \gamma_{RR} + \gamma_{GOR} + \gamma_{GRS}$ and the SER-based Regulating Reserve $MCP_{REGSER} = \gamma_{OR} + \gamma_{RS} + \gamma_{RR} + \gamma_{MSERR} + \gamma_{GOR} + \gamma_{GRS}$. In this example, there is no binding zonal requirements, binding minimum Non-DRR1 Operating Reserve requirement and no binding minimum Non-DRR1 Regulating plus Spinning Reserve Requirement and therefore, $\gamma_{GOR} = \gamma_{GRS} = 0$ and $MCP_{REG} = MCP_{REGSER}$. The Regulating Reserve MCP_{REG} and MCP_{REGSER} are then equal to the Shadow Price of the Operating Reserve constraint plus the Shadow Price of the Regulating plus Spinning Reserve constraint plus the Shadow Price of the Regulating Reserve constraint, or \$1100/MW + \$0/MW + \$1/MW = \$1101/MW.

6. Reliability Assessment Commitment and Look-Ahead Commitment Activities

The RAC and LAC processes provide input into the operation of the Real-Time Energy and Operating Reserve Market to ensure that sufficient Resources are available and on-line to meet the demand, Operating Reserve, and other reserve requirements within the Market Footprint, as projected by MISO for each hour, or sub-hour, or sub-hour, period of the Operating Day. These processes enable MISO to reliably operate the Transmission System throughout the Operating Day by committing additional Resources[61]:

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

The RAC process employs a SCUC algorithm to minimize the cost of committing the required capacity to meet forecasted demand, confirmed Interchange Schedule Exports and Operating Reserve requirements, including Start-Up Offer, No-Load Offer, cost to operate at the Hourly Economic Minimum Limit, Regulating Reserve Offers, Spinning Reserve Offers, Supplemental Reserve Offers, on-line Short-Term Reserve capability, and Off-Line Short-Term Reserve Offers for Generation Resources and DRRs-Type II and including Energy Offers, Shut-Down Offers, Hourly Curtailment Offers, Spinning Reserve Offers, Supplemental Reserve Offers and Off-Line Short-Term Reserve Offers for each DRR-Type I. The RAC analysis minimizes the cost of committing sufficient Resources[62] to meet the forecasted capacity requirements, not the cost to serve the forecasted Energy. The RAC SCUC analysis focuses on hourly time intervals.

The LAC process employs a similar SCUC algorithm, with the exception that the SCUC algorithm used by LAC minimizes the total cost of production of the required capacity to meet forecast

[61] Electric Storage Resources are not optimally committed in RAC and LAC processes, because Electric Storage Resources are required to submit a Commitment Status for each market interval. Commitments on ESR in RAC and LAC processes are determined entirely based on the submitted Commitment Status.

[62] MISO's LAC process uses an advanced security constrained commitment algorithm based on MISO's SCUC algorithm. Electric Storage Resources are not committed by MISO's SCUC commitment engine and subsequently are not recommended for commitment by LAC.

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

Resources are guaranteed to receive their Offers if committed. Offer rules that apply to the RAC/LAC are described in Section 4. **Error! Reference source not found.**of this BPM. The RAC/LAC timeline is presented in
Exhibit 6-1, covering the four RAC/LAC processes:

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

Exhibit 6-1: RAC/LAC Timeline

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
Data Required for RAC Pre Day-Ahead Process		
OD-7 @ 0000	As available during RAC run	Transmission Owners/Operators submit requests for transmission facility outages
OD-7 @ 0000	As available during RAC run	Generation Owners/Operators submit planned generation facility outage Schedules
OD-7 @ 0000	As available during RAC run	LBAs submit Load Forecasts that are utilized as input to the MISO Load Forecast
RAC Pre Day-Ahead Process		
OD-7 @ 0000	OD-1 @ 1430 EPT	Perform Multi-day RAC as necessary to evaluate need for Long Lead Start Units
RAC Post Day-Ahead Process		
OD-1 @ 1330 EPT	OD-1 @ 1430 EPT	Resource Offer re-bidding

Beginning Day @ Time	Ending Day @ Time	Description of Processes and Events
OD-1 @ 1430EPT	OD-1 @ 1800EPT	Perform RAC Next-Day Analysis
OD-1 @ 1800EPT	OD @ 0000	Notify Resources of scheduled commitment: ▪ Start time and Dispatch Minimum ▪ Stop time
RAC Intraday Process		
OD-1 @ 1800 EPT	OD @ 2400	Perform RAC Intraday Analysis as needed
LAC Process		
OH-4	DI-15	Perform LAC Analysis as needed
OD = Operating Day OH = Operating Hour (00 to 23) DI = Dispatch Interval RAC = Reliability Assessment Commitment LBA = Balancing Authority		Note: All times are in EST unless noted otherwise.

6.1 RAC/LAC Process Input Assumptions

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

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

6.1.1 Forecasting Load

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

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

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

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

The coincident peak of the MISO STLF (as described in Section 3.6.3.2) is used as the forecast for the LAC process.

6.1.2 Reserve Requirements

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

6.1.3 Pre-Scheduling Interchange Schedules Greater than One Day Out

Pre-scheduled Interchange Schedules are transactions that are scheduled one or more days prior to their Operating Day for the Day-Ahead or Real-Time Energy and Operating Reserve Markets. Each MP making an Import Schedule or Export Schedule covering a period greater than the

Operating Day must furnish all required information to MISO via a NERC E-Tag that transfers into webTrans.

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

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

6.1.4 Submitting Resource Offers for Reliability Assessment Commitment

The following rules apply to all Resources:

- ***Resources designated as Capacity Resources for Module E Purposes*** – Not on a forced or maintenance outage must offer into the RAC any designated capacity, including Energy, Contingency Reserve if qualified, and Short-Term Reserve if qualified, not scheduled in the Day-Ahead Energy and Operating Reserve Market or during any RAC process conducted prior to the Operating Day except to the extent that the Resource is unable to provide Energy, Contingency Reserve or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions. These Resources can, but are not obligated to, offer any available capacity that has not been scheduled in the Day-Ahead Energy and Operating Reserve Market or any RAC processes performed prior to the Operating Day for use during the Operating Day.
- ***Other Resources*** – Can, but are not obligated to offer any available capacity that has not been scheduled in the Day-Ahead Energy and Operating Reserve Market.

Resources selected and committed by MISO in any RAC or LAC process(es) must adhere to MISO instructions, including start times. These Resources (except for Stored Energy Resources) must also submit an Energy Offer for their full range of Operable Capacity (or for Targeted Demand Reduction Level for DRRs-Type I), from Hourly Emergency Minimum Limit to Hourly

Emergency Maximum Limit (or, to expected maximum limit, for DIRs), regardless of Module E capacity designation status, for use in the Real-Time Energy and Operating Reserve Market.

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

6.1.5 Committing Long Start-Up Resources

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

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

- ***Seven to Four Days prior to Operating Day:***
    - Generation Resources and DRRs-Type II with Start-Up Time plus Start-Up Notification Times greater than 24 hours must submit binding Hourly Economic Minimum and Maximum Limits and binding Start-Up Offers, No-Load Offers, and Energy Offers at Hourly Economic Minimum Limit along with the submittal of Start-Up Time and Start-Up Notification Time.
    - DRRs-Type I with Shut-Down Time plus Shut-Down Notification Times greater than 24 hours must submit binding Targeted Demand Reduction Levels and

binding Energy Offers, Shut-Down Offers and Hourly Curtailment Offers along with the submittal of Shut-Down Time and Shut-Down Notification Time.
    - If adequacy violations are detected, they are logged and evaluated but no specific commitment action is taken until three days prior to the market day, unless three days prior would not allow sufficient time to resolve the potential violations.
- ***Three to Two Days prior to Operating Day:***
    - Generation Resources and DRRs-Type II that have not been committed by MISO may submit revised Start-Up Times and Start-Up Notification Times and binding Hourly Economic Minimum and Maximum Limits and binding Start-Up Offers, No-Load Offers, and Energy Offers at Hourly Economic Minimum Limit.
    - DRRs-Type I with Shut-Down Time plus Shut-Down Notification Times greater than 24 hours must submit binding Targeted Demand Reduction Levels and binding Energy Offers, Shut-Down Offers and Hourly Curtailment Offers along with the submittal of Shut-Down Time and Shut-Down Notification Time.
    - If violations of reliability criteria are detected, MISO coordinates with the local Operators to verify the violation. After the violation has been verified, MISO will direct certain Resource operations if the only alternative to resolve the Resource-adequacy or constraint violation is to commit a Generation Resource or DRR-Type II with a Start-Up Time plus Start-Up Notification Time requirement or commit a DRR-Type I with a Shut-Down Time plus Shut-Down Notification Time requirement that is longer than can be accommodated in (OD-2) or (OD-1) RAC processes.

6.1.6 Scheduling Outages

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

6.1.7 Maintaining Facility Ratings

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

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

6.1.8 Managing Hourly Regulation Schedules

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

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

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

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

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

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

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

6.2 RAC Processes Under Shortage Conditions

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

- ***Step One:*** MISO issues an alert, warning or event , in accordance with Emergency Operating Procedure – 002 (EOP-002) and posts on its website: (1) the hours in the Operating Day during which an EEA Level 1 is anticipated; (2) the hours during the Operating Day in which Export Schedules are expected to be curtailed; (3) the hours during the Operating Day in which Resource Hourly Emergency Maximum Limits[63] are expected to be utilized; and (4) the hours during the Operating Day in which Emergency only Resources[64] are expected to be committed.
- ***Step Two:*** If MISO projects that it cannot meet its Regulating Reserve requirement and all Contingency Reserve has been depleted, MISO issues an alert or warning in accordance with Emergency Operating Procedure – 002 (EOP-002) and posts on its website the anticipated hour in which an EEA Level 2 Emergency is expected to occur. If MISO declares an EEA-2 event, the following actions may be initiated in accordance with EOP-002: (1) instruct the Local Balancing Authorities to issue public appeals, (2) begin Emergency Energy purchase procedures described under Section 6.2.1 of this BPM; (3) issue EDR Dispatch Instructions to EDR Participants based on EDR Offers submitted; (4) direct LBAs to initiate voltage reduction procedures; and/or (5) direct LSEs to curtail appropriate amounts of Load Modifying Resources. At this point, MISO has exhausted all measures at its disposal to alleviate the shortage condition prior to entering into the real-time Operating Hour.

6.2.1 Emergency Energy Purchases

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

[63] Individual Resources are notified directly by MISO.

[64] Individual Resources are notified directly by MISO.

6.3 RAC Processes Under Surplus Conditions

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

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

6.4 LAC Processes Under Shortage/Surplus Conditions

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

6.5 RAC/LAC Processes Results

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

- For each affected Resource, a commitment schedule is produced for the Operating Day indicating which hours the Resource is scheduled to operate, which hours uncommitted Quick-Start Resources have been scheduled to provide off-line Supplemental Reserve, and which hours uncommitted Off-Line Short-Term Reserve Qualified Resources have been scheduled to provide off-line Short-Term Reserve. This schedule does not become physically binding until it is communicated to the MP by MISO.
- For each affected Resource under the shortage conditions described under Section 6.2 above, a commitment schedule is produced for Resources with a Commitment Status of "Emergency" and an off-line Supplemental Reserve schedule is produced for uncommitted Resources with an Off-Line Supplemental Reserve Dispatch Status of Emergency. In addition, MISO will notify Market Participants electronically that the